EVALUATING THE EFFECTS OF ADVANCED ENERGY SYSTEM PATHWAYS ON ENERGY FLOWS AND EMISSIONS IN CALIFORNIA

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Preface

The Public Interest Energy Research (PIER) Program supports public interest energy research and development that will help improve the quality of life in California by bringing environmentally safe, affordable, and reliable energy services and products to the marketplace.

The PIER Program, managed by the California Energy Commission (Energy Commission), conducts public interest research, development, and demonstration (RD&D) projects to benefit California.

The PIER Program strives to conduct the most promising public interest energy research by partnering with RD&D entities, including individuals, businesses, utilities, and public or private research institutions.

PIER funding efforts are focused on the following RD&D program areas:

- Buildings End-Use Energy Efficiency
- Energy Innovations Small Grants
- Energy-Related Environmental Research
- Energy Systems Integration
- Environmentally Preferred Advanced Generation
- Industrial/Agricultural/Water End-Use Energy Efficiency
- Renewable Energy Technologies
- Transportation

Evaluating the Effects of Advanced Energy System Pathways on Energy Flows and Emissions in California is the final report for the Advanced Energy Pathways project (contract number #500-02-004, work authorization number UC MR-038) conducted by the Institute of Transportation Studies, UC Davis. The information from this project contributes to PIER’s Transportation Program.

For more information about the PIER Program, please visit the Energy Commission’s website at www.energy.ca.gov/pier or contact the Energy Commission at 916-654-5164.
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Abstract

This report is the primary output of a three-year project funded by the California Energy Commission’s PIER (Public Interest Energy Research) program. The goals of this project were to assess the use of advanced vehicle and fuel technologies that might be used in California to meet its environmental goals (including reducing pollution, resource usage and greenhouse gas emissions), develop energy demand scenarios for the state and develop a model that would analyze the interactions between the evolving transportation sector and the rest of the energy system. The California Advanced Energy Pathways Model (CAEPM), developed and used for the analysis, analyzed several scenarios including the widespread adoption of plug-in hybrid electric vehicles (PHEVs) and fuel cell vehicles (FCVs) and found that both of these vehicles helped to reduce overall CO₂ emissions as well as costs associated fueling vehicles (relative to conventional gasoline vehicles).

Keywords: scenarios, modeling, transportation, alternative fuels, electricity, infrastructure, hydrogen
Executive Summary

Introduction

Growing concern in California about gasoline prices, oil imports, tailpipe emissions, and vehicle greenhouse gas emissions has sparked interest in a variety of potentially cleaner vehicle technologies and alternative fuels for transportation. The Advanced Energy Pathways project focuses on understanding how the introduction of advanced vehicle technology and alternative fuels in California will impact its energy system. This is a joint project between UC Davis, Lawrence Livermore National Lab, and the Global Environment and Technology Foundation (GETF).

Project Purpose

The purpose of this project is to analyze the effects on the electricity sector of potential energy paths for the transportation sector during the period from 2005 to 2050. The study quantifies how the structure of the state’s energy sectors could evolve under different policies as advanced transportation technologies are introduced. The analysis also takes into account the overall effects of potential energy paths on greenhouse gas emissions and feedstock usage, as well as technical issues, economic impacts, and policy implications.

Project Objectives

To provide a detailed look at the future energy system in California, the project had several major objectives:

- Assess the cost, performance, and emissions characteristics of advanced transportation technologies
- Develop California energy demand scenarios out to 2050
- Develop a technology-rich model of the California energy system and assess the impact of advanced transportation technologies on the energy system

Project Outcomes

The project developed technical assessments for many different types of advanced vehicle technologies and alternative fuels, which provide detailed information on the technologies, their costs, benefits and commercialization prospects. The project also developed demand scenarios from 2005 to 2050 for electricity, natural gas, and transportation fuels for a number of different potential futures. These provide a context for analyses of integrated energy supply strategies and the impact of advanced transportation technologies and fuels. This project developed an energy model for the state of California to analyze the impacts of the introduction of advanced transportation technologies on the energy system (especially the electricity grid). Detailed analysis results describe the effects of fuel cell and plug-in hybrid vehicles on system costs, the structure and operation of the electricity grid and CO₂ emissions.

Summary and Conclusions
A number of advanced vehicle and fuel technology options are available for use in the light-duty vehicle sector in order to enable the State to reduce oil use, greenhouse gas emissions and improve the environmental impact of transportation. These options include hydrogen fuel cell vehicles, plug-in hybrid electric vehicles and vehicles running on biofuels like cellulosic ethanol. The first two options will lead to significant interactions between the infrastructure for providing vehicle fuel (hydrogen or electricity) and the current energy system. This analysis includes energy system modeling that investigates these interactions, including the change in structure, cost, resource usage, and emissions of the electric sector. Because the energy system is moving towards more integration between the electric and transportation sectors, the addition of advanced vehicles and supporting infrastructure will influence the optimal structure of the overall energy system. One of the key results is the change in the optimal composition of the electric sector (reducing the amount of peaking capacity required and increasing the amount of baseload or intermediate generation). Overall, the addition of fuel cell vehicles or plug-in hybrid electric vehicles into the transportation mix will reduce greenhouse gas emissions and costs of providing energy from the energy system in California.
1.0 Introduction

1.1. Background and Overview
Growing concern in California about gasoline prices, oil imports, tailpipe emissions, and vehicle greenhouse gas emissions has sparked interest in a variety of potentially cleaner and more efficient vehicle technologies and alternative fuels for transportation. The Advanced Energy Pathways project focuses on understanding how the introduction of specific advanced vehicle technology and alternative fuels in California will impact the structure and operation of its energy system and resulting greenhouse gas (GHG) emissions.

California’s energy system serves residential, commercial, and industrial/agricultural end users with electricity and natural gas as well as transportation fuels. Historically, the transportation fuels sector has largely been distinct from other sectors of the energy system, which rely on different primary energy feedstocks and different energy infrastructures. However, with emerging advanced transportation technologies—including vehicles that use electricity, biofuels, synthetic fuels, and hydrogen—California’s current energy system will need to evolve as these sectors converge in their use of common energy feedstocks and even, potentially, energy carriers and infrastructures.

All alternative fuel pathways will impact the electricity and natural gas systems, either directly (for example, by consuming electricity) or indirectly (by competing for energy resources such as natural gas or biomass that might otherwise be used to make electricity). For California in particular, the two key technologies that can plausibly help the state meet goals for significant GHG emissions reduction—hydrogen fuel cells and plug-in hybrid gasoline-electric vehicles—would likely have an enormous impact on demands for natural gas, electricity, and petroleum fuels, and on the structure of the natural gas, electricity, and petroleum supply systems.

This project studies the possible effects of widespread use of advanced transportation fuels—such as hydrogen and electricity—by light-duty vehicles on the structures, costs, and emissions of the energy-supply and end-use systems. The project examines possible structures for the energy system in 2025 and 2050, while assessing the potential trajectories of system change between the present and 2050.

1.2. Project Objectives
The purpose of this project is to analyze the effects on the natural gas and electricity systems of potential energy paths for transportation during the period from 2005 to 2050. The study quantifies how the structure of the state’s energy sectors will evolve as advanced transportation technologies are introduced. The analysis also takes into account the overall effects of potential energy paths on greenhouse gas emissions and feedstock usage, as well as technical issues, economic impacts, and policy implications.

To provide a detailed look at the future energy system in California, the project had several major objectives:

- Assess the cost, performance, and emissions characteristics of advanced transportation technologies
- Develop California energy demand scenarios out to 2050
• Develop a technology-rich model of the California energy system and assess the impact of advanced transportation technologies on the energy system

1.3. Report Organization
Chapter 2 contains technical assessments of a number of advanced vehicle and fuel technologies, characterizing them in terms of vehicle energy efficiency, fuel consumption, and emissions. These assessments describe both the benefits of and the potential challenges and barriers to these technologies with respect to their implementation in California and their ability to reduce GHG emissions.

Chapter 3 presents California energy demand scenarios encompassing both baseline and alternative scenarios of demand for energy in various sectors. The purpose of having multiple scenarios is to test the conditions under which advanced energy technologies could have a significant impact on the future energy system. Various energy demand scenarios are used to assess the ability to achieve the state’s GHG emissions goals through implementation of advanced technologies. Scenarios for the introduction of advanced vehicles and fuels are also included.

Chapter 4 discusses a technology-rich energy model based on the META-Net model at Lawrence Livermore National Labs. This model uses the energy demand scenarios, costs, and technical parameters derived from the technology assessments to describe the current and future energy system in California. It identifies the most efficient means to structure and operate the energy system under various scenarios to 2050 based on optimizing costs across the economy in several key areas:
• Electricity generation
• Natural gas supply
• Petroleum supply
• Alternative fuel (such as hydrogen, ethanol) supply

The model is used to assess the impact of the different vehicle and energy demand scenarios by simulating the optimal structure and operation of the energy sectors and tracking resulting emissions.

Appendix A and Appendix B provide detailed assessments of advanced vehicle technologies, and fuels and production, respectively. Appendix C describes the UC Davis Grid Dispatch Model. Energy demand scenarios are described in Appendix D and transportation sector scenarios are presented in Appendix E. The California Advanced Energy Pathways Model (CAEPM) is described in Appendix F. Finally, a description of various future scenarios is presented in Appendix G.
2.0 Advanced Vehicle Technologies and Alternative Fuels

California faces many important energy challenges as it continues to grow and develop. As part of the Global Warming Solutions Act of 2006 (AB 32), greenhouse gas (GHG) emissions limits will be adopted in California by 2011, with reductions to 1990 levels required by 2020 (California Office of the Governor 2006). Much evidence suggests that while fuel economy improvements for petroleum-fueled vehicles can contribute to reductions in petroleum imports and GHG emissions, alternative fuels used in significantly more efficient vehicles are vital to obtaining the necessarily large reductions in petroleum use and GHG emissions that are required for sustainable transportation.

While alternative transportation fuels and advanced vehicles are not the least expensive means of near-term emissions reductions (Creyts et al. 2007), achieving longer-term targets, such as the Governor’s mandated 80% reduction by 2050, will require a significant portion of these reductions to come from the decarbonization and diversification of transportation fuels in California (Yang et al. 2008). Multiple attempts have been made in the past to begin a shift in transportation energy use away from petroleum, but alternatively fueled vehicles have yet to penetrate the market in significant numbers. Given the magnitude of the challenges associated with shifting the population of vehicles and fuel infrastructure, it is important that choices about vehicle and fuel technologies be made with a far-reaching view of their ability to achieve long-term goals.

Most light- and heavy-duty vehicles have been and still are powered by internal combustion engines (ICE). There are, however, a number of options for the next generation of ICE vehicles with alternative powertrains that are being developed to address issues related to petroleum dependence, criteria air pollutants, and GHG emissions. Any attempt to reduce GHG emissions from light-duty vehicles will rest on three primary legs: total travel demand, vehicle efficiency, and fuel GHG intensity. The use of advanced vehicles and fuels is an attempt to address the last two legs in order to reduce the GHG emissions per vehicle mile driven.

The major options for implementing advanced vehicle platforms and alternative fuels in California to the year 2050—including electric vehicles based on batteries and fuel cells, and hybrid vehicles with internal combustion engines and electric power systems—are reviewed in this chapter. These options are summarized in Table 1. All fuels listed there (besides gasoline/diesel) are reviewed in this report.

<table>
<thead>
<tr>
<th>Vehicle technology</th>
<th>Fuel options</th>
</tr>
</thead>
<tbody>
<tr>
<td>Advanced internal combustion engine (ICE) vehicles,</td>
<td></td>
</tr>
<tr>
<td>including hybrid electric vehicles (HEVs)</td>
<td>Gasoline/diesel</td>
</tr>
<tr>
<td></td>
<td>Cellulosic ethanol</td>
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<tr>
<td></td>
<td>Synfuels</td>
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<td></td>
<td>Hydrogen</td>
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<tr>
<td>Battery electric vehicles (BEVs)</td>
<td>Electricity</td>
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<tr>
<td>Plug-in hybrid electric vehicles (PHEVs)</td>
<td>Electricity plus</td>
</tr>
<tr>
<td></td>
<td>gasoline/diesel</td>
</tr>
<tr>
<td>Fuel cell vehicles (FCVs)</td>
<td>Hydrogen</td>
</tr>
</tbody>
</table>

Table 1. Summary of advanced vehicle technologies and alternative fuels reviewed
In the sections that follow, advanced engines / power plants and fuels are discussed in terms of their potential to reduce emissions and increase energy efficiency for light-duty transportation. Detailed technology assessments for vehicles and fuels are found in Appendices A and B. These technology assessments are used as quantitative inputs to the detailed energy system modeling in Chapter 4 to determine fuel consumption, GHG emissions, and other important energy system impacts associated with meeting future demands for light-duty transportation.

2.1. Important Vehicle Parameters

A vehicle's fuel consumption depends on a number of parameters including vehicle road load, engine or power plant energy conversion efficiency, and drivetrain efficiency.

2.1.1. Road Load

The energy that must be supplied to the wheels in order to move a vehicle is called the road load energy and defined by the road load equation:

\[ E_{\text{road}} = d\left[C_R M_v g + \frac{1}{2} \rho_a C_D A_v V^2 \right] \]

where \( d \) is the distance, \( C_R \) is the coefficient of rolling resistance, \( M_v \) is the mass of the vehicle, \( g \) is the acceleration due to gravity, \( \rho_a \) is the air density, \( C_D \) is the drag coefficient, \( A_v \) is the frontal area of the vehicle, and \( V \) is the vehicle speed. As seen in the equation, the rolling resistance component of energy loss (the first term) depends on the tire and road surfaces and the mass of the vehicle. The air resistance component of energy loss (the second term) depends on the aerodynamic shape and area of the vehicle, air density, and vehicle speed.

The energy that must be supplied as fuel to the vehicle depends on the road load energy requirements and the overall efficiency of the vehicle powertrain (\( \eta_{\text{drivetrain}} \)) as shown in the following fuel requirements equation:

\[ E_{\text{fuel}} = \frac{E_{\text{road}}}{\eta_{\text{drivetrain}}} = \frac{d\left[C_R M_v g + \frac{1}{2} \rho_a C_D A_v V^2 \right]}{\eta_{\text{drivetrain}}} \]

Vehicles are designed with a number of important factors in mind, such as occupant safety and comfort, road handling, power and performance, and aesthetic styling, as well as energy efficiency. Vehicle characteristics such as weight, aerodynamic drag, and rolling resistance have often not been given the highest priority in conventional vehicle design. However, for many advanced vehicles, energy storage is often limited and costly compared to conventional vehicles, and as a result, careful consideration is given to weight, aerodynamics, and powertrain efficiency in order to maximize the vehicle range and minimize energy storage costs.

Vehicle Weight

The vehicle body and chassis contribute considerably to the total vehicle weight. Weight reduction can provide an improvement in vehicle energy use and fuel economy. What complicates weight reduction is the need for strong, stiff members to provide the structural integrity necessary to withstand collision.

Typical cars and trucks are made of steel. Aluminum is the most common alternative material used for weight reduction, but manufacturing aluminum is energy intensive and may offset energy reductions achieved during vehicle use. Lightweight composite materials—which are
well suited to vehicle applications due to their high specific strength, energy absorption, design
flexibility, noise dampening, and corrosion resistance—could reduce body and chassis weight
by as much as 50–67% (Gjostein 1995). Despite the large potential for energy savings through
the use of advanced composite materials, automotive manufacturers have been reluctant to
integrate them into production vehicles because of unfamiliarity and concerns about higher
costs.

**Tire Rolling Resistance**

The friction (rolling resistance) of the tires on the road surface contributes to energy dissipation
as the vehicle moves. However, friction is also needed to prevent unsafe wheel slippage and to
enable proper vehicle handling. Optimizing the tire tread, inflation pressure, suspension
stiffness, and tire dimensions can significantly reduce the rolling resistance.

Where efficiency is a priority, as in electric vehicles or hybrids, vehicles often use low rolling
resistance tires. In recent years, tire pressure monitoring systems, lower rolling resistance tires,
and nitrogen inflation systems have been introduced to help reduce the impact of rolling
resistance on energy use for even conventional ICE vehicles. According to a recent study, tire
underinflation can significantly reduce tire life span (12–15%) and increase fuel use (1.5–2%)
(Lutsey et al. 2006).

**Aerodynamic Drag**

Aerodynamic drag leads to dissipative energy losses as the vehicle moves through air. Most of
this resistance, sometimes called shape drag, results from the shape of the body. The drag
coefficient for conventional vehicles is between 0.3 and 0.5, while more aerodynamic vehicles
have lower drag coefficients, including the Honda Insight (0.25), GM EV1 (0.19), and Toyota
Prius (0.26). Shape drag can be reduced through modifications such as smoothing the vehicle’s
underside, minimizing protrusions like rearview mirrors, and, most of all, reducing the high-
and low-pressure zones at the front and rear of the vehicle.

### 2.1.2. Powertrain Components

The input energy (in the form of fuel or electricity) required to supply a given amount of road
load energy to a vehicle’s wheels is determined by the efficiency of the engine or power plant
on the vehicle and the efficiency of the mechanical and electrical components that convert
engine power to wheel power (the powertrain). Besides modifying the vehicle road load factors,
the other main strategies for influencing vehicle efficiency and GHG emissions involve
modifying the vehicle powertrain through the use of alternative fuels and alternative energy
conversion technologies.

For conventional vehicles, the powertrain includes the engine, transmission, and driveshaft. For
advanced technology vehicles, the powertrain can also include the power plant and/or
batteries, power electronics, and the electric motor(s). Gas-electric hybrid vehicles such as the
Toyota Prius are a combination of these two distinct powertrains.

### 2.2. Advanced Vehicle Technologies

This section describes each of the important advanced vehicle technologies in terms of their
components, their benefits, and their prospects. Advanced internal combustion engine vehicles
use a conventional powertrain. Battery electric, plug-in hybrid, and fuel cell vehicles are all based on incorporating electric-drive technologies into the powertrain.

Appendix A contains more detailed assessments of advanced vehicle technologies.

2.2.1. Advanced Internal Combustion Engine Vehicles

The vast majority of light- and heavy-duty vehicles manufactured throughout automotive history have been internal combustion engine (ICE) vehicles. Advanced technologies applied to ICE vehicles can help address several critical issues associated with their use, including resource use efficiency and diversification and emissions of local air pollutants and GHGs.

The standard ICE vehicle is powered by either a gasoline-fueled spark-ignition (SI) engine or a diesel-fueled compression-ignition (CI) engine. SI engines rely on a spark to ignite the air-fuel mixture in the cylinder, while combustion in CI engines is induced by the high temperature generated when gases in the cylinder are compressed. In 2006, approximately 97.8% of new light-duty vehicles sold in the United States used gasoline SI engines, while the remaining 2.2% used diesel CI engines (Energy Information Administration 2007). This contrasts with Europe, where nearly 50% of new cars sold in 2005 had diesel engines (U.S. Department of Energy 2005a).

ICE vehicles have provided drivers with a durable, powerful, and affordable means of transportation and are expected to remain an important vehicle technology for the next several decades. These vehicles have the following advantages relative to many of the alternative technologies:

- High energy density of gasoline and diesel fuel, translating into longer range
- Low cost of energy storage tanks
- Low cost and durability of engine technologies
- Significant progress toward reducing criteria air pollutants to low levels
- Ubiquitous refueling network

Some of the key challenges associated with the use of conventional ICE vehicles include improving engine efficiency, reducing GHG emissions, and decreasing reliance on petroleum. The next sections highlight technologies that are being researched and developed to further improve efficiency (especially for SI engines), reduce criteria pollutant emissions (especially for CI engines), and incorporate alternative fuels. The advanced technologies discussed here (shown in Table 2) are mainly improvements to the powertrain—that is, improvements to engine combustion, operation, and control.
Table 2. Advanced ICE vehicle propulsion, emissions control, and other technologies, plus fuels that can be used

<table>
<thead>
<tr>
<th>Propulsion</th>
<th>Emissions control</th>
<th>Other technologies</th>
<th>Fuels</th>
</tr>
</thead>
<tbody>
<tr>
<td>Spark ignition</td>
<td>Port injection (SIPI)</td>
<td>Particulate filters (for SIDI engines only)</td>
<td>Gasoline</td>
</tr>
<tr>
<td>(SI)</td>
<td>Direct injection (SIDI)</td>
<td>Lean NOx traps (LNTs) (for SIDI engines only)</td>
<td>Ethanol</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Hybridization</td>
<td>Hydrogen</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Variable valve timing (VVT)</td>
<td>Liquefied petroleum gas (LPG)</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Cylinder deactivation</td>
<td>Natural gas</td>
</tr>
<tr>
<td></td>
<td></td>
<td>Lightweight materials</td>
<td></td>
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<tr>
<td></td>
<td></td>
<td>Idle stop/start systems</td>
<td></td>
</tr>
<tr>
<td></td>
<td></td>
<td>Advanced transmissions (CVT, EMAT)</td>
<td></td>
</tr>
<tr>
<td>Compression</td>
<td>Direct injection (CIDI)</td>
<td>Diesel particulate filters (DPFs)</td>
<td>Diesel</td>
</tr>
<tr>
<td>ignition</td>
<td>Homogeneous charge (HCCI)</td>
<td>Lean NOx traps (LNTs)</td>
<td>Biodiesel</td>
</tr>
<tr>
<td>(CI)</td>
<td></td>
<td>Selective catalytic reduction (SCR)</td>
<td>Liquefied petroleum gas (LPG)</td>
</tr>
<tr>
<td></td>
<td></td>
<td></td>
<td>Natural gas</td>
</tr>
</tbody>
</table>

**Advanced Propulsion Technologies**

Nearly all light-duty vehicles in North America are powered by spark-ignition port-injection (SIPI) engines burning gasoline. Advanced designs based on direct injection (SIDI) can lead to leaner operation, higher compression ratios, and, as a result, higher fuel economy. Zhao et al. (1999) reported a potential fuel consumption reduction of 5–35% under varying conditions. However, SIDI engines present a tradeoff, where lean operation can lead to incomplete combustion and higher nitrogen oxides (NOx) and particulate matter (PM) emissions.

Compression-ignition direct-injection (CIDI, or diesel) engines are also more efficient than gasoline SIPI engines, mainly as a result of their lean operation. Weiss et al. (2000) state that “diesel propulsion technology . . . offers about another 13% reduction in life-cycle energy consumption over the advanced body gasoline car, but at about a 6% added vehicle cost.” However, because current CI engines operate by injecting fuel near the end of the compression stroke, rather than mixing the air and fuel before they enter the cylinder, these engines have higher pollutant emissions. Diesel combustion is inherently heterogeneous; PM is formed in regions with excess fuel and NOx is formed in regions with high combustion temperature.

An alternative CI engine technology called homogeneous charge compression ignition (HCCI) is under development and appears capable of addressing the pollutant issue. HCCI combines attributes of gasoline and diesel engines in that fuel and air are mixed before injection, which achieves more uniform distribution of fuel and cleaner, more complete combustion, yielding
significantly lower NOx and PM emissions. Thus, HCCI may provide diesel-like efficiency and low emissions.

**Advanced Emissions Control Technologies**

Current and near-term SI engine and emissions control technologies have reduced pollutant emissions to low levels. Even lower levels are achievable but there is a tradeoff between reducing criteria emissions and system efficiency.

While CI engines are more efficient than SI engines, the primary challenge for current and advanced CIDI engines is reducing emissions, especially PM and NOx. Strategies for taking advantage of the higher fuel efficiency of CI engines while still meeting criteria pollutant emissions targets include improving combustion within the engine, adding NOx exhaust after-treatment, and using particulate filters and alternative fuels. These strategies, however, can add costs and complexity and reduce fuel economy.

NOx emissions are an important issue for CIDI engines, and after-treatment is necessary to reduce emissions to an acceptable level. NOx can be reduced up to 90% via selective catalytic reduction (SCR) and lean NOx traps (LNTs), though these after-treatment systems can reduce fuel economy in diesel vehicles 2–8%. Strategies for reducing PM formation in the engine cylinder generally cause an increase in NOx formation. As a result, cleaning the exhaust gases after combustion with diesel particulate filters (DPFs) appears to be the best solution for CIDI engines, and some are already on vehicles sold in Europe and the United States. Such filters can reduce PM by more than 75% and result in a fuel economy penalty of only 1% or so.

**Other Advanced Technologies**

A number of other technology improvements can help advanced ICE vehicles achieve higher fuel economy and lower emissions.

Hybridization can improve ICE vehicle fuel economy by permitting engine operation closer to optimal conditions of rpm and power, allowing reduced engine size and weight, reducing engine idling fuel consumption, and recovering and reusing braking energy. A growing number of vehicle manufacturers are marketing hybrid vehicles across a range of vehicle classes, generally with significant improvements in fuel economy compared to similar conventional vehicles. Hybrid systems offer the greatest improvement in fuel economy under urban as opposed to highway driving conditions. Hybrid powertrains can be coupled with the other advanced technologies discussed here, including advanced engines and exhaust after-treatment.

Advanced electro-mechanical automatic transmissions (EMATs) and continuously variable transmissions (CVTs) are other means of improving efficiency of the powertrain, allowing for optimal operation of the engine. Other options for powertrain improvements include shutting down the vehicle during idling, higher voltage (42V) vehicle electrical systems, and system diagnostics. Advances in engine control that can improve engine efficiency include variable valve timing (VVT) and cylinder deactivation (National Research Council 2002).

**Use of Alternative Fuels**

SI engines can run on several alternative fuels besides gasoline, which can help to alleviate petroleum dependence and resource scarcity as well as emissions of criteria air pollutants and
GHGs. GHG emissions are determined by the quantity and type of fuel used, so improved fuel economy and lower-carbon fuels can help with their reduction.

One of the most commonly discussed alternative fuels is ethanol; currently around 900 million gallons of ethanol are sold annually in California (California Energy Commission 2005b) as a 5.7 percent (or more) blend by volume with gasoline. The current use of ethanol (in a low blend) is a means to meet federal oxygenate requirements and boost fuel octane. Higher blends, such as E85, can be used only in flex-fuel vehicles or dedicated ethanol vehicles. Flex-fuel vehicles running on ethanol are expected to lower criteria pollutants, with fuel economy similar to that of a conventional gasoline vehicle.

Other fuels that can be used in an SI engine include liquefied petroleum gas (LPG), natural gas, and hydrogen. These gaseous fuels do not increase fuel economy but can lower certain types of pollutants and GHG emissions. Natural gas is expected to reduce tailpipe GHG emissions relative to a conventional gasoline vehicle by around 25%, and a hydrogen ICE will generally reduce GHG emissions, though the amount of reduction will depend on the source of the hydrogen. However, energy storage is an issue for these gaseous fuels due to their lower energy density and the need for a compressed gas storage tank.

Biodiesel is an alternative fuel option in diesel engines for reducing criteria pollutants, well-to-wheels GHG emissions, and the use of petroleum relative to conventional diesel and gasoline fuels. It is produced from virgin or recycled waste vegetable oil and animal fats and is currently available in blends of 20% (B20) and 100% (B100). The use of biodiesel does not improve the fuel economy of conventional diesel vehicles, though it is possible to improve engine efficiency by optimizing the engine to take advantage of biodiesel’s higher cetane number. In current diesel engines, biodiesel reduces PM, hydrocarbon (HC), and carbon monoxide (CO) emissions but may cause an increase in NOx emissions.

**Summary of Advanced ICE Vehicle Technologies**

Table 3 provides a summary of the technologies that can be applied to advanced ICE vehicles and their expected cost and effect on fuel economy and emissions. See Appendix A for sources of each of the table values.

ICE engines have seen incremental improvements in efficiency of approximately 1–2% a year in the last two decades, but fuel economy during that time has stagnated as these efficiency gains have been offset by the increasing size and power of vehicles. Future evolution of conventional ICE technology may continue to improve fuel economy by 1–2% per year, if efficiency gains are applied to fuel economy rather than increased vehicle power, mass, or performance (An and Santini 2004). The advanced vehicle technologies described here can offer significant improvements in vehicle fuel economy beyond these incremental efficiency gains. A combination of these technologies could reduce fuel consumption over the next decade or so by more than 50% compared with conventional gasoline vehicles.

These technologies offer near-term potential for fuel economy and emissions improvements because they require relatively modest changes in the design and operation of vehicles relative to more advanced vehicle designs. As these technologies are widely incorporated into ICE vehicles, they essentially become part of the conventional vehicle that other alternatives technologies have to compete with.
Table 3. Advanced ICE vehicle technology impacts on fuel economy, vehicle cost, and emissions

<table>
<thead>
<tr>
<th>Advanced ICE technology</th>
<th>Conventional comparison vehicle</th>
<th>Fuel economy change</th>
<th>Vehicle cost increase</th>
<th>Change in tailpipe emissions</th>
</tr>
</thead>
<tbody>
<tr>
<td>CIDI</td>
<td>SIPI</td>
<td>+15%</td>
<td>+40%</td>
<td>6%</td>
</tr>
<tr>
<td>SIDI</td>
<td>SIPI</td>
<td>0</td>
<td>+18%</td>
<td>$600</td>
</tr>
<tr>
<td>HCCI</td>
<td>CIDI</td>
<td>-1%</td>
<td>-2%</td>
<td>$400</td>
</tr>
<tr>
<td>DPF</td>
<td>CIDI</td>
<td>-1%</td>
<td>-5%</td>
<td>$600</td>
</tr>
<tr>
<td>SCR</td>
<td>CIDI</td>
<td>-1%</td>
<td>-5%</td>
<td>$600</td>
</tr>
<tr>
<td>LNT</td>
<td>CIDI</td>
<td>-1%</td>
<td>-5%</td>
<td>$400</td>
</tr>
<tr>
<td>Hybridization</td>
<td>SIPI / CIDI</td>
<td>+54%</td>
<td>+82%</td>
<td>3–5%</td>
</tr>
<tr>
<td>VVT</td>
<td>SIPI / CIDI</td>
<td>+5%</td>
<td>+18%</td>
<td>$150</td>
</tr>
<tr>
<td>Cylinder deact.</td>
<td>SIPI / CIDI</td>
<td>+5%</td>
<td>+25%</td>
<td>$300</td>
</tr>
<tr>
<td>Lightweighting (5% weight reduction)</td>
<td>SIPI / CIDI</td>
<td>+4%</td>
<td>+4%</td>
<td>5%</td>
</tr>
<tr>
<td>Idle stop/start</td>
<td>SIPI / CIDI</td>
<td>+4%</td>
<td>+8%</td>
<td>$350</td>
</tr>
<tr>
<td>CVT</td>
<td>SIPI / CIDI</td>
<td>+4%</td>
<td>+8%</td>
<td>$250</td>
</tr>
<tr>
<td>EMAT</td>
<td>SIPI / CIDI</td>
<td>+4%</td>
<td>+8%</td>
<td>$250</td>
</tr>
</tbody>
</table>

Note: “+” or “-” sign indicates an increase or decrease when more exact data is not available or highly variable.

2.2.2. Battery Electric Vehicles

Battery electric vehicles (BEVs) store electricity in batteries charged by the power grid and use electric motors to convert that electrical energy into mechanical work to power the wheels. Electric motors have higher efficiency (70–95%, depending on operating parameters), higher power density (power per unit weight and volume), and better low-speed torque characteristics than ICEs. But BEVs have a limited range as a result of the relatively low energy density of batteries. Auto manufacturers have indicated that this limited range along with battery cost and lack of a widespread charging infrastructure are the primary deterrents to the mass marketing of BEVs. Still, despite their limitations, BEVs have attributes that may be more attractive to consumers, such as home refueling/recharging (which eliminates trips to the gas station), quiet driving, excellent acceleration, zero emissions, and independence from oil use (Heffner, Kurani, and Turrentine 2007).

Interest in BEVs was highest between 1990, when General Motors announced the development of its BEV (the GM Impact), and 2002, when the California Air Resources Board made significant changes to its zero emission vehicle (ZEV) mandate. Since that time, issues surrounding vehicle range, recharging time, and battery life and cost have caused automakers to shift their emphasis to the development of other clean vehicle technologies. Today, none of the major automobile manufacturers in the United States are selling BEVs and they have shown little interest in doing so in the foreseeable future. The only BEVs available for sale or lease are smaller, lower-speed neighborhood and city electric vehicles that are considered niche vehicles. However, with the announcement of BEVs from smaller companies like Tesla Motors and others, a new generation of all-electric vehicles may be on the horizon.
**BEV Components**

The powertrain in a BEV consists primarily of an electric motor, power electronics (including charge controller and DC/AC inverter), and a battery pack. The battery pack for a BEV is large (weighing at least 200 kg), since it is the primary energy storage unit and must provide all the energy needed by the vehicle for propulsion and auxiliaries. The electric motor provides all of the wheel torque to accelerate the vehicle and to recover energy during regenerative braking. The motor and electronics must be sized to meet the maximum torque/power required to accelerate/brake the vehicle and to maintain the maximum speed of the vehicle on a grade.

The key technical aspects of the battery pack are usable energy stored, peak power, and cycle and calendar life. In addition, the unit’s weight, volume, and cost must meet the criteria for packaging in a vehicle. Cycle and calendar life—which are affected by the operating characteristics of the battery, such as depth of discharge—are among the key determinants of economic viability for a particular battery technology. The U.S. Advanced Battery Consortium has set a calendar life goal of 10 years and a cycle life goal of at least 1000 cycles to 80% depth of discharge for batteries that will enable commercialization of BEVs.

While many different types of batteries have been developed for electric and hybrid vehicles, only two battery technologies are being considered for electric vehicles at present—namely, nickel metal hydride (NiMH) and lithium ion. Lithium-ion batteries have undergone less real-world experience and testing than NiMH batteries, which are used in current hybrid vehicles. NiMH batteries have lower energy density than lithium-ion batteries but have been used more in vehicle applications and are better understood with respect to cycle and calendar life, lasting at least five years and 2000 cycles for deep discharges of 60–70%.

The technical limitations of batteries also translate into high costs. Large batteries for BEVs are currently very expensive, costing about $700–800/kWh for NiMH and even more for lithium-ion batteries. Achieving an acceptable range (more than 200 miles) in a BEV would require more than $10,000 worth of batteries, even making an optimistic future assumption of $200/kWh for battery costs.

**BEV Benefits**

The energy storage limitations of BEVs have forced manufacturers to give priority to weight, aerodynamics, and powertrain efficiency in order to achieve the driving range and vehicle performance expected by car buyers. As a result, these vehicles have lower road load energy requirements in addition to their high efficiency powertrain and can significantly reduce GHG emissions compared with conventional vehicles. BEVs can drive more than 100 miles on an amount of electrical energy equivalent to a gallon of gasoline (in other words, they can get more than 100 mpgge\(^1\)), so the well-to-wheels GHG emissions are generally lower than for a conventional gasoline or diesel vehicle. The extent of the emissions reduction depends on how the electricity used to charge the vehicle is generated. Based on an average U.S. grid mix, the GHG emissions of a BEV are less than half that of a conventional vehicle (see Table 4); they can

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1 The abbreviation mpgge stands for “miles per gallon gasoline equivalent” and refers to the fuel economy of a vehicle on the energy equivalent of a gallon of gasoline. For example, for a vehicle that uses ethanol (which has less energy in a gallon than gasoline) or diesel (which has more energy in a gallon than gasoline), this corrects for the difference in energy content and is directly comparable to the fuel economy of a vehicle that runs on gasoline.
be even lower on the California grid mix and nearly zero on a renewable and low-carbon portfolio.

<table>
<thead>
<tr>
<th>Vehicle type</th>
<th>Battery weight (kg)</th>
<th>Battery capacity (kWh)</th>
<th>Electricity consumption (Wh/mi)</th>
<th>Range (mi)</th>
<th>GHG emissions on U.S. grid mix (gCO₂/mi)</th>
<th>ICE vehicle GHG emissions (gCO₂/mi)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Cars</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Compact</td>
<td>285</td>
<td>20.2</td>
<td>202</td>
<td>80</td>
<td>153</td>
<td>405</td>
</tr>
<tr>
<td>Mid-size</td>
<td>380</td>
<td>24.9</td>
<td>249</td>
<td>80</td>
<td>189</td>
<td>472</td>
</tr>
<tr>
<td>Full</td>
<td>475</td>
<td>28.5</td>
<td>285</td>
<td>80</td>
<td>216</td>
<td>540</td>
</tr>
<tr>
<td>Trucks and sport utility vehicles</td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
<td></td>
</tr>
<tr>
<td>Small</td>
<td>380</td>
<td>31.9</td>
<td>319</td>
<td>80</td>
<td>242</td>
<td>515</td>
</tr>
<tr>
<td>Mid-size</td>
<td>475</td>
<td>33.3</td>
<td>333</td>
<td>80</td>
<td>253</td>
<td>667</td>
</tr>
<tr>
<td>Full</td>
<td>570</td>
<td>38.0</td>
<td>380</td>
<td>80</td>
<td>380</td>
<td>756</td>
</tr>
</tbody>
</table>

**BEV Prospects**

Significant penetration of BEVs into light-duty automotive markets does not appear likely, as a result of the higher initial vehicle price and the range limitations relative to conventional vehicles. While battery technology is improving in terms of cycle life, energy and power density, and cost, it is not clear that these improvements will enable an affordable battery-powered vehicle with sufficient range and performance in the near term.

However, BEVs are part of a larger class of electric-drive vehicles, those that use electricity as some or all of their propulsive energy. These vehicles all share common components including batteries, electric motors, and power electronics and controller systems. Examples of other electric-drive vehicles include ICE hybrid electric vehicles such as the Toyota Prius, PHEVs, and FCVs. Because of their shared components, development of any of the other vehicle types benefits the entire class of electric-drive vehicles, helping to expose consumers to new technologies and bringing experience and cost reductions into the research and development, vehicle design, and manufacturing processes.

Thus, although BEVs are not likely to be mass-market consumer vehicles in the near term, development of batteries for hybrid electric vehicles and PHEVs will help to bring down component costs and perhaps improve the prospects for BEVs in the long term.

**2.2.3. Plug-In Hybrid Electric Vehicles**

PHEVs combine attributes of current hybrid electric vehicles and BEVs. Existing hybrid vehicles employ a small battery in combination with an internal combustion engine, but the battery can be charged only by the engine or regenerative braking. Plug-in hybrids have a larger battery that can be recharged by plugging it into the power grid. The grid connection can be as simple as a 120-volt household outlet. A higher voltage will allow for more rapid charging, but even a standard outlet will allow a vehicle to be fully charged in just a few hours.
Because they have a gasoline engine, PHEVs avoid two of the biggest problems of pure electric vehicles. First, they are not limited in range by the battery capacity. Second, limited charging time between trips or lack of local charging capability does not render the vehicle inoperable. In some respects, PHEVs combine the best of both hybrids and pure electric vehicles.

**PHEV Components**

Many of the components of a PHEV are similar to the components of a BEV. The control technology is fairly straightforward. The vehicle uses the battery power when it is available (state of charge above 20% or so) and appropriate (speeds low enough for the vehicle to efficiently run in all-electric mode). At higher speeds, the gasoline engine is normally used, since it can run in its more-efficient full-load state. The electric motor assists the gasoline engine as long as possible, but when the state of charge drops too low, the car operates on gasoline and whatever charging occurs through regenerative braking.

A PHEV with an all-electric range of 20 miles (PHEV20) would have sufficient all-electric range for the majority of commuting travel for most American drivers (Research and Innovative Technology Administration 2003). This PHEV would have a usable battery capacity of approximately 6 kWh (assuming a highly efficient vehicle similar to a Toyota Prius). Considering that battery life is best maintained by limiting depth of discharge to 80% or so, the nominal battery capacity would be about 7.5 kWh. At the current values of specific energy (50–60 Wh/kg) and cost ($1000/kWh), this battery would weigh 100–125 kg (about 10% of the weight of a typical car) and cost about $7500 (Graham 2001). And while the addition of weight does carry a fuel economy penalty (approximately 5–7%) compared to a hybrid electric vehicle, the ability to use a high-efficiency drivetrain and lower-carbon fuel (electricity) will reduce GHG emissions and more than offset the weight penalty.

Larger battery packs, allowing longer all-electric driving distances, are certainly possible, but this analysis will focus on a 20-mile range as the most likely near-term average all-electric driving distance in commercially available vehicles. While running on gasoline after the battery has been depleted, a PHEV will have fuel economy comparable to that of a conventional hybrid, slightly reduced by the additional battery weight but considerably above the fuel economy of a conventional car. In all-electric mode, a passenger vehicle PHEV will require 250–400 Wh/mile (80–130 mpgge).

Charging efficiency affects the total energy demand of the vehicle. Most studies represent energy demand in terms of the electricity drawn from the battery. If battery charging and discharging are 80% efficient, then an on-vehicle energy demand of 300 Wh/mile really represents a demand of 375 Wh/mile to the electricity system.

The higher efficiency of PHEVs results from several factors. First, energy storage and discharge in batteries is quite efficient, often 75–80%. Approximately 50% of the kinetic energy that would otherwise be dissipated as heat from braking can be stored as electricity and used to recharge the batteries via regenerative braking. Second, the electric motor allows for a smaller gasoline engine, which will often run at higher loads and higher efficiency. Reducing the engine size also provides some weight savings, partially offsetting the weight increase from batteries and the electric motor.
The critical technology component in these vehicles, as in BEVs, is the battery. Unlike batteries for conventional hybrid vehicles, PHEV batteries must have high specific energy and must be able to withstand thousands of deep-cycle discharges with minimal degradation of performance. The battery pack for a PHEV is much smaller than for a BEV because driving can be done in charge-sustaining mode. However, the small battery packs in PHEVs require higher specific power than larger battery packs in BEVs to sustain useful all-electric-mode speeds and power—and for a given battery technology, higher specific power tends to increase cost per kWh of storage capacity.

Both NiMH and lithium-ion batteries are considered viable options for PHEVs. In the near term, NiMH is expected to be the technology of choice, with lithium-ion emerging as a competitor. As battery technology improves and costs decline over time, PHEVs with larger all-electric range can be introduced (Kromer and Heywood 2007).

**PHEV Benefits**

PHEVs can offer significant advantages over conventional ICE vehicles in reducing GHGs, criteria air pollutants in urban areas, and gasoline consumption. They also have the potential to improve the efficiency and operation of the electrical grid. First, by charging at night, they take advantage of idle base-load capacity or increase the load factor on plants running at part load. Second, if in the future they could provide a form of energy storage for the grid, PHEVs could allow grid operators to run more plants at full load on a predictable schedule and could allow for greater penetration of renewable resources. They could also make unnecessary the operation of peaker plants—plants such as low-cost and low-efficiency gas turbines that run only a few hundred hours per year during times of highest demand.

The actual GHG emission benefits of PHEVs will depend on the source of the electricity and the relative fraction of energy that comes from gasoline and the electric grid. Energy efficiency is much higher and CO\textsubscript{2} emissions are much lower when the vehicles operate in all-electric mode. In hybrid mode, they are still better than conventional vehicles and almost as good as a typical hybrid, but carbon benefits are maximized when all-electric travel is maximized. Several studies show the reduction in CO\textsubscript{2} emissions for a PHEV20 to be more than 60% relative to a conventional vehicle and between 14% and 21% relative to a hybrid vehicle on a California grid mix (Kintner-Meyer, Schneider, and Pratt 2007; Markel et al. 2006).

**PHEV Prospects**

No commercial PHEVs are currently available in the United States, but aftermarket conversions are available to retrofit the Toyota Prius and Ford Escape hybrids as plug-ins. In Europe, the Daimler Chrysler Hybrid Sprinter van is available and sold in small quantities. Other auto manufacturers, including GM and Toyota, have announced plans to produce PHEVs though they have not issued firm timelines.

Presently, conventional gasoline-electric hybrids have a retail price of approximately $4000 more than cars that run only on gasoline. Batteries account for half of that premium. If PHEVs were mass produced, their comparatively higher battery cost might add another $3500–$4000 in component cost over a conventional hybrid. Even with very little markup on these increased component costs, the resulting premium could be $8000 over a conventional vehicle and $4000 over a typical hybrid. These cost figures are for a PHEV20 and would increase for additional range.
It is difficult to determine whether this level of cost premium would be a significant barrier to the adoption of PHEVs, especially when considering the benefits associated with all-electric driving—emissions reduction, increases in performance, and lower fuel costs. The primary infrastructure needed for PHEV vehicles is a network of charging locations. Most household garages have electrical outlets that are sufficient for charging a PHEV. More options for daytime charging would increase the daily all-electric travel of PHEVs but negate some of the benefits associated with nighttime charging.

2.2.4. Fuel Cell Vehicles

Like PHEVs in all-electric mode and BEVs, fuel cell vehicles (FCVs) offer the benefits of zero point-of-use emissions, low-noise operation, and the capability to operate on renewably derived and/or low-carbon energy. FCVs use hydrogen as a fuel, and the inherent properties of hydrogen make FCV development both highly attractive and complex.

Hydrogen used in fuel cells offers an alternative route to a viable electric vehicle. Hydrogen can be stored in large quantities and can be transported using well-established commercially available methods, such as truck, or by pipeline. Like electricity, hydrogen is a carbon-free energy carrier, and thus its use does not directly contribute to GHG or criteria pollutant emissions. However, indirect emissions may be produced through the conversion of a primary feedstock (such as natural gas) to hydrogen, and through energy inputs such as compression electricity or truck transport.

FCV Components

Fuel cells are electrochemical devices that can directly convert chemical energy to electrical energy and can achieve very high efficiencies. They are based on an electrochemical reaction involving the oxidation of hydrogen and the reduction of oxygen to form water and electricity. The fuel cell technology being developed for automotive applications is the proton exchange membrane (PEM) fuel cell. Typical fuel cell operating efficiencies are in the range of 40–60%, which is significantly higher than typical spark-ignition ICEs, which currently have maximum operating efficiencies of 25–35% (Srinivasan et al. 1999). Beyond the fuel cell itself, key components of the fuel cell system are the air supply, water management, thermal management, and power management systems.

Hydrogen is the ideal fuel for fuel cells and provides flexibility in production and zero emissions at the point of use. Hydrogen storage is one of the most important components of automotive fuel cell systems. While existing H₂ storage systems can store more energy than advanced batteries, challenges are still associated with storing sufficient quantities onboard the vehicle to ensure adequate range for consumers (typically assumed to be greater than 300 miles before refueling). Automakers are currently developing storage systems based on compressed gas and cryogenic liquid technologies.

As a compressed gas, hydrogen is stored at high pressures in a composite tank. Storage in 5000-psi tanks is the most common method of H₂ storage for fuel cell vehicle prototypes built to date, but even at this high pressure, the energy density of hydrogen is well below that of gasoline. Other challenges associated with compressed gas storage include a required minimum tank pressure and overpressuring requirements to deal with heating during H₂ filling (U.S. Department of Energy 2005b).
Liquid hydrogen is the other common form of hydrogen stored in FCV prototypes. BMW has focused exclusively on this form. It has the advantage of significantly higher energy density and lower tank costs, but the main disadvantages are the large energy costs associated with liquefaction to below 20ºK and the potential for boiloff. Other methods of hydrogen storage (for example, metal hydrides and alanates) are more experimental but offer the potential to meet the U.S. DOE’s storage goals.

FCVs have many of the same powertrain components as other EVs, including electric motors and controllers, power electronics, and batteries. A hybrid system allows the fuel cell to be operated at lower power levels, as the batteries supplement motor electrical current during acceleration. This helps to extend the fuel cell’s life and improve fuel cell efficiency. Additionally, batteries can help provide the vehicle with power when the fuel cell system is starting up, especially in cold climate conditions. Batteries also allow the FCV to capture regenerative braking energy, which provides a very significant efficiency improvement, particularly in stop-and-go driving conditions.

**FCV Benefits**

FCVs are more efficient than ICE vehicles running on gasoline and diesel. Many studies and analyses estimate that FCVs get double or triple the fuel economy of ICE vehicles (Kromer and Heywood 2007). Many of the current generation of demonstration FCVs achieve better than 50 mpg, and each generation of prototype FCV has improved both performance and fuel economy over the earlier versions (Knight 2006).

While fuel cell vehicles offer the potential for low criteria pollutant and GHG emissions, current and near-term-future hydrogen production is likely to come at least partly from natural gas, which lowers but does not eliminate total life-cycle pollutant and carbon emissions (Jacobson, Colella, and Golden 2005; Wang, Ogden, and Nicholas 2007). For an FCV, tank-to-wheels energy use is quite low and emissions are nonexistent, but fuel (hydrogen) production and transport do have an environmental impact. Thus, it is the well-to-tank portion of emissions that, as in the case of vehicles running on grid electricity, depends greatly on the sources of hydrogen production. For example, when compared to emissions from a conventional gasoline ICE vehicle (430 gCO₂/mi), a 60 mile/kg H₂ FCV will show a significant reduction in GHG emissions that varies by the method of production, whether from biomass (20 gCO₂/mi, 95% reduction), natural gas (190 gCO₂/mi, 56% reduction), or coal (340 gCO₂/mi, 20% reduction) (Delucchi 2007).

**FCV Prospects**

Nearly all of the components in an FCV powertrain—including the PEM fuel cell, hydrogen storage tank, electric motor, power-assist battery pack, and power electronics—are currently very expensive because they are not mass produced. At high-volume production, the fuel cell stack and hydrogen tank would still likely present significant cost issues. Kromer and Heywood (2007) estimate that the cost premium for a mass-produced hybrid FCV will be between $3600 and $5100 relative to a 2030 baseline spark-ignition vehicle.

The promise of FCVs in the eyes of some vehicle manufacturers is full integration of the powertrain, body, and chassis, significantly reducing the number of vehicle platforms. These designs, which can encompass weight reduction and efficient component packaging, promise to
simplify the manufacturing process and reduce the cost of vehicle design (Burns, McCormick, and Borroni-Bird 2002).

Hydrogen storage methods suffer from the same limitation as batteries; it is challenging to store enough energy to provide adequate driving range given constraints on system cost, weight, and volume. At least several manufacturers appear to believe that by developing a highly integrated powertrain, they may be able to meet longer driving range targets by improved engineering design of storage tank packaging rather than fundamental breakthroughs in hydrogen storage density. For example, Honda claims its latest FCV can achieve a range of 270 miles with 5000-psi tanks (Honda 2008), while Toyota has estimated its 2007 vehicle can drive more than 350 miles with 10,000-psi tanks.

The other piece of the hydrogen fuel cell vehicle puzzle is the supply of hydrogen. Lack of a hydrogen infrastructure, including refueling stations, has been widely discussed as a potential barrier to the adoption of FCVs. The “chicken-or-egg” problem highlights the challenge of developing a widespread hydrogen refueling network at the same time as the market for FCVs grows.

California is one of the more promising environments for the introduction of commercial FCVs. The state has shown strong political support for FCV and refueling station development, as evidenced by its Hydrogen Highway blueprint. The California Air Resources Board’s revision of the ZEV mandate to encourage FCV production, coupled with multiple vehicle demonstrations taking place throughout the state, shows a commitment to nurturing the FCV market in California.

Though companies such as GM and Honda have announced commercial FCV release between 2011 and 2015, an affordable FCV (one comparable in price to a conventional ICE vehicle) may not be available until 2020 or even later (U.S. News and World Report 2008). The numerous challenges associated with producing an affordable FCV that will meet consumer needs are currently being addressed by most major auto companies. The optimistic view is that cost and performance targets can be met and FCVs can make up a large portion of the market by 2050. However, this future requires significant long-term commitment from government as well as the auto and energy industries (Greene et al. 2007).

### 2.2.5. Summary and Comparison of Advanced Vehicle Technologies

The impetus for the use of advanced vehicles comes from the need to address several of the negative externalities associated with conventional gasoline ICE vehicles, including petroleum consumption, air pollutants, and GHG emissions. Although each of the advanced vehicle technologies faces distinct challenges that might limit adoption in the marketplace, each offers some benefit relative to current conventional vehicles. Table 5 shows several of these benefits, including increases in fuel economy and reductions in GHG emissions, along with the cost premium compared to conventional vehicles.
Table 5. Summary of alternative vehicle benefit and cost estimates in 2030

<table>
<thead>
<tr>
<th>Vehicle technology</th>
<th>Vehicle fuel economy (mpgge)</th>
<th>GHG emissions (gCO₂/mi)</th>
<th>Vehicle incremental cost ($)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Conventional gasoline vehicle (2000)</td>
<td>25</td>
<td>450</td>
<td></td>
</tr>
<tr>
<td>Advanced ICE vehicle</td>
<td>30–50</td>
<td>220–360</td>
<td>$1,000–$3,000</td>
</tr>
<tr>
<td>BEV</td>
<td>133</td>
<td>88¹</td>
<td>$6,900–$10,200</td>
</tr>
<tr>
<td>PHEV</td>
<td>EV:100, HEV:40</td>
<td>171¹</td>
<td>$2,700–$4,300</td>
</tr>
<tr>
<td>FCV</td>
<td>60–100</td>
<td>110–180²</td>
<td>$3,600–$5,100</td>
</tr>
</tbody>
</table>

Source: Kromer and Heywood 2007

1. Electricity emissions are based on California grid.
2. Hydrogen production is assumed to be from natural gas.

Compared to conventional gasoline vehicles, advanced ICE vehicles offer the potential for significant fuel economy and GHG emissions improvements for the lowest additional cost. These advanced ICE vehicles could take several forms, including hybrid vehicles with advanced SI or CI engines and technologies for reducing emissions. Having flexible fuel capability to run on either gasoline or diesel or alternative liquid fuels, these vehicles offer the lowest barrier to adoption as well, given their similarities to current vehicles and slight additional cost. Operating on gaseous fuels would raise additional barriers to adoption, as refueling infrastructure investment and availability become an issue.

Electricity is an ideal fuel for vehicles with respect to GHG emissions per mile, especially when considering the low carbon intensity of electricity generation in California. It has very low energy cost per mile driven. However, the BEV is not really a viable option to replace the conventional ICE vehicle, given the limited range and high incremental vehicle cost and especially when compared with the PHEV. The PHEV is a more flexible vehicle that offers the ability to travel 20 miles on grid electricity while also providing the travel range and short refueling times associated with conventional vehicles. The exact fuel economy and GHG benefits will depend on the proportion of time spent in each driving mode (EV versus HEV). While having two distinct and complementary drivetrains offers additional flexibility, it also leads to additional costs. The main technical barrier to PHEV market adoption is the cost and durability of batteries. The cost of vehicle charging may also impose some up-front costs on a vehicle purchaser, though they are not expected to be large. These vehicles have the potential to operate on zero-carbon electricity (such as renewables).

Finally, the FCV also offers significant improvements in fuel economy and potential for GHG reductions. The reductions in GHG emissions will depend on the source of hydrogen, but quite a number of hydrogen pathway options lead to low or zero carbon production. The numerous estimates of the incremental cost of a future mass-produced hydrogen FCV, like battery costs, imply a certain level of technological development and manufacturing experience to lower system costs. However, batteries are being produced in large quantities for use in hybrid vehicles, and battery costs will come down as volumes rise. Also, vehicle makers can incorporate larger battery packs as battery costs come down. The challenge for FCVs is that the components, especially the fuel cell stack and the hydrogen storage tank, have high initial costs and cannot be incrementally added to vehicles like hybrid electric components can. As a result,
at low volumes, early fuel cell vehicles will likely have a higher incremental cost than most other advanced technology vehicles.

The other challenge associated with FCVs lies in the refueling infrastructure. Because of the need for a dedicated infrastructure, especially at low levels of vehicle penetration, the cost of hydrogen will initially be significantly higher than gasoline as hydrogen production is low and refueling equipment is used only sparingly. Over time and with sufficiently high demand, the cost of hydrogen will come down below that of gasoline and hydrogen will be significantly cheaper on a life-cycle basis. However, it is this initial period of high-priced fuel and vehicles that the FCV must overcome to become a viable alternative to current vehicles.

Also relevant to comparisons between advanced technology vehicles is the issue of energy storage. Table 6 compares the energy storage technologies for different alternative fuels. Gasoline and diesel have the highest energy density of any light-duty transportation fuel. Many of the alternatives have significantly lower energy densities than gasoline (an order of magnitude for hydrogen and almost two orders of magnitude for batteries—but note that batteries are both the energy storage and energy conversion device, while hydrogen requires a fuel cell and gasoline requires an engine to be converted to work). Lower fuel storage translates into a reduction in vehicle range, even when considering the higher efficiency associated with these advanced vehicles.

<table>
<thead>
<tr>
<th>Energy storage technology</th>
<th>Fuel storage density (kWh/liter)</th>
<th>Fuel storage cost ($/kWh)</th>
</tr>
</thead>
<tbody>
<tr>
<td>Batteries</td>
<td></td>
<td></td>
</tr>
<tr>
<td>NiMH lithium-ion</td>
<td>0.1–0.2</td>
<td>$300–500</td>
</tr>
<tr>
<td></td>
<td>0.2–0.3</td>
<td>$300–500</td>
</tr>
<tr>
<td>Hydrogen storage system</td>
<td></td>
<td></td>
</tr>
<tr>
<td>compressed gas @ 5,000psi</td>
<td>0.61</td>
<td>$9–15</td>
</tr>
<tr>
<td>liquid</td>
<td>1.2</td>
<td>$6</td>
</tr>
<tr>
<td>Gasoline</td>
<td>8.6</td>
<td>$0.2</td>
</tr>
<tr>
<td>Ethanol (E85)</td>
<td>5.9</td>
<td>$0.3</td>
</tr>
</tbody>
</table>

Sources: Anderman 2003, Kromer and Heywood 2007

Given the higher incremental costs associated with advanced technology vehicles, the prospects for their widespread adoption are likely to be dependent on policies to offer incentives for their purchase. Tax incentives (deductions and credits) have been available in the United States to purchasers of hybrid and alternatively fueled vehicles. These incentives may be necessary, especially for vehicles with higher incremental cost, when the benefits of these vehicles are mainly public (reducing GHG emissions, pollution, and petroleum consumption) and when the vehicles may carry additional private costs (lower range and higher vehicle cost). Additional features (mobile electricity, quiet drive, faster acceleration) or symbolism (environmentally friendly, high-tech) may help encourage consumers to adopt these vehicles even in the face of higher costs.
2.3. Alternative Fuels

This section describes each of the alternative fuels most likely to power advanced technology vehicles. All fuels require more energy to produce than they contain, so the main concern about energy balance relates to the quantity of fossil energy inputs. Gasoline, cellulosic ethanol, and synthetic fuels from coal (synfuels) can be used in conventional ICE vehicles as well as hybrids and PHEVs. Hydrogen can also be used in vehicles with an ICE, though it is typically assumed to be used in FCVs. Electricity can be used in both BEVs and PHEVs.

Appendix B contains more detailed assessments of fuels and production pathways.

2.3.1. Cellulosic Ethanol

Ethanol (grain alcohol) has been used as a fuel for motor vehicles since the beginning of the automotive age. In the United States, it is currently used as an oxygenate, blended with gasoline in a low ratio for use in spark-ignition engines. It may also be blended in higher ratios, such as E10 (10% ethanol) or E85 (85% ethanol). At the higher blend level (E85), it can be used only by flex-fuel or dedicated ethanol vehicles. U.S. ethanol production in 2005 was approximately 4 billion gallons (Renewable Fuels Association 2006), and California’s estimated demand in that year was 900 million gallons (California Energy Commission 2005b).

Ethanol can be made from a variety of feedstocks. Brazilian manufacturers use sugarcane, while U.S. companies overwhelmingly rely on corn. Because of concerns about food prices, attention has turned to cellulosic ethanol, which is made from cellulosic materials found in a wide range of biomass, including wood, paper, and agricultural wastes (corn stover, wheat straw, rice hulls, tree trimmings, and grass clippings). Cellulosic ethanol thus provides the opportunity to utilize a wide variety of crop residues, inedible material, and even dedicated “energy crops,” resulting in lower resource inputs (energy, water, land, fertilizers) and costs as compared to using food crops.

Cellulosic Ethanol Production

Cellulosic biomass typically contains three primary components: cellulose, hemicellulose, and lignin. Cellulose and hemicellulose are polymer chains consisting of sugar molecules, which can be fermented, while lignin is a non-sugar based organic polymer and cannot be fermented. At the beginning of the process, crops are grown and harvested and the feedstock (either dedicated energy crops or waste products) is transported to the processing plant. The next step is physical preparation of the feedstock, such as milling it to a smaller size. This is typically an energy-intensive step, requiring about one-third of the plant’s energy consumption. Then the cellulosic materials must be broken down into component sugars, typically with acid. Genetically engineered bacteria ferment all of the sugars into ethanol, which is then distilled.

Some of the most important factors determining the actual life-cycle energy and emissions impact associated with the production of cellulosic ethanol are these:

- Nature of the feedstock (waste product versus energy crop)
- Energy and resource usage during harvesting and cultivation (including land use change and net soil carbon release)
- Mode of transport of the feedstock to the plant
- Source of the plant electricity supply (external grid versus generation using lignin)
• Energy usage during plant milling and processing

The efficiency of ethanol production will be improved by advances in biochemical technology aimed at achieving greater yields of ethanol from the biomass feedstock. The fossil energy input to cellulosic ethanol production (for harvesting, feedstock transport, and plant processes) may decline if bioenergy plays a larger role in the energy supply.

The most important technologies needed for future cellulosic ethanol development will be organisms, enzymes, chemicals, and processes to decompose cellulose and hemicellulose into their component sugars. Genetic engineering of fermenting organisms may increase the rate and yield of ethanol production. And consolidated bioprocessing, a strategy involving advanced plant designs and organisms that can combine multiple steps, such as hydrolysis and fermentation, may lower costs.

Ethanol has a lower energy density than gasoline, with a lower heating value of 21 megajoules (MJ)/liter compared to gasoline’s 32 MJ/liter. However, the higher octane number of ethanol means that higher compression ratios can be used in an engine designed to take advantage of this property, thereby increasing energy output to a degree. Flex-fuel vehicles are so named because they can use either ethanol or gasoline, but since they are not specifically optimized for ethanol, they do not achieve the higher fuel economy of a dedicated and optimized ethanol engine.

**Cellulosic Ethanol Benefits**

Cellulosic ethanol has a much higher energy return than corn ethanol does, in the range of 85–90% for cellulosic ethanol (meaning that the fossil energy input is only about 10–15% of the ethanol output) versus approximately 20–50% for corn ethanol.

Closely related to energy balance is the fact that cellulosic ethanol offers the potential for significant reductions in GHG emissions compared to gasoline. Recent studies have projected cellulosic ethanol to contribute emissions of approximately 11 grams of CO₂ per MJ of energy; this is roughly 12% of the GHG emissions of gasoline (Farrell et al. 2006). Corn-based ethanol is estimated to contribute between 81 and 96 grams of CO₂ per MJ (86–102% of the GHG emissions of gasoline). The higher values are associated with a coal-fired ethanol plant that requires long-distance shipping of feedstock. These estimates do not include the emissions from land clearing that result from direct and induced conversion of natural systems to managed agriculture. The extent to which this is relevant depends on the relative level of waste/residues versus energy crops in the cellulosic biomass supply.

Cellulosic ethanol is much less petroleum-intensive than corn ethanol, but petroleum is still used to transport feedstock to large, centralized plants, which are generally preferred for economies of scale. Based on the current mix of fuels for transporting the feedstock, cellulosic ethanol would require about 0.08 MJ of petroleum for every 1 MJ of ethanol produced (Farrell et al. 2006).

**Cellulosic Ethanol Prospects**

Cellulosic ethanol would be made partly from plentiful crop residues, with no additional land requirements. However, residue supply is limited, and not all crop residues are waste, as some residues must be left in fields to provide protection against erosion and to maintain soil fertility. Energy crops would require some cultivation of land, though most studies expect the initial
cultivation to occur on lands that are intentionally idled through the Conservation Reserve Program.

Fully replacing California’s gasoline consumption (15 billion gallons in 2005) with ethanol would require about 300 million tons of biomass with current technology. Supporting documents for California’s Biomass Action Plan estimate the state’s total technically recoverable solid biomass resources could replace only 10% of state gasoline consumption (Germain and Katofsky 2006). Thus for ethanol to make a significant dent in the gasoline consumption of the state, large quantities of imports would be required.

The cost of a commercial-scale cellulosic ethanol facility is still speculative at this point. Initial facilities will face higher costs and, barring government support, steeper investment and financing hurdles. However, projections for large-scale production costs are in the $1–$1.50/gallon range (Aden et al. 2002; U.S. Department of Agriculture and Department of Energy 2000; Wyman 1999). Cellulosic ethanol production is currently in the precommercial stage. A small-scale facility is producing and selling cellulosic ethanol, using the same technologies that are expected to be employed in commercial-scale plants. Because no commercial-scale facilities are currently under construction, commercialization of this technology is not expected before 2010; though at projected prices, cellulosic ethanol should be competitive with petroleum fuels.

Perhaps the main technical and economic barrier to the widespread use of cellulosic ethanol is the availability of low-cost cellulosic feedstocks. Another key issue is the use of water, since it appears likely that cellulosic ethanol plants will require more water than conventional corn ethanol plants (four to five gallons water per gallon of ethanol).

### 2.3.2. Synthetic Fuels from Coal

Coal is the most abundant fossil fuel on the planet. The U.S. Department of Energy estimates that recoverable coal reserves worldwide amount to approximately 1 trillion tons, with domestic reserves of 270 billion tons (Energy Information Administration 2006). Industrial processes developed in the early 20th century, and expanded considerably during the Second World War, enable the conversion of coal into liquid fuels. These synfuels are a suitable replacement for petroleum liquids such as gasoline or diesel fuel.

**Synfuel Production**

The Fischer-Tropsch process and indirect coal liquefaction are the most well-established technologies for coal liquefaction and allow a great degree of customization of the outputs, providing an opportunity to reduce aromatic content and thereby reduce the emissions of hazardous air pollutants. The conversion of coal to liquid fuels is not especially efficient. Existing plants can convert one ton of sub-bituminous coal into about 1.2 barrels of liquid fuel (primarily diesel, with naphtha available to make gasoline), plus some electricity for export. Even considering possible co-production of electricity, the net plant efficiency is less than 50%.

**Synfuel Environmental Impacts**

Two main GHG contributions are associated with the use of coal-based synfuels. The first is the carbon in the fuel itself, which is approximately equal to that in conventional diesel. The second contribution is from the production process, as turning coal into liquid fuel produces CO$_2$ emissions that can equal or exceed the carbon in the fuel itself (essentially doubling the carbon content of the fuel). Emissions from production and combustion of coal-based synfuels can
range from 40 to 50 g\textsubscript{CO\textsubscript{2}e}/MJ\textsuperscript{1} (Brandt and Farrell 2007). The CO\textsubscript{2} associated with synfuel production could be captured and sequestered, which would significantly reduce carbon emissions, but this would still leave the carbon content of the fuel itself.

Beyond CO\textsubscript{2} emissions, another GHG known as black carbon is released in the combustion of diesel fuel synthesized from coal. However, synthetic diesel produced from coal generally emits fewer criteria pollutants than petroleum diesel, because the processing of coal removes nearly all sulfur so that catalytic converters can be used in vehicles burning synthetic diesel. Williams and Larson (2003) note, “Sulfur and aromatic-free [Fischer-Tropsch] middle distillates are already being used as blend stock with conventional crude oil–derived diesel in California to provide fuel that meets that state’s stringent specifications for diesel.”

The production of liquid fuels from coal also requires up to five gallons of water per gallon of diesel fuel. And coal mining can cause significant environmental impacts, including mountaintop removal, stream filling, and leaching of acid, chemicals, and heavy metals.

**Synfuel Prospects**

Synfuels produced by coal gasification are more costly than those produced from natural gas, because of difficulty in handling and processing coal for gasification (Brandt and Farrell 2007). However, given recent petroleum prices, the use of coal to produce liquid fuel appears to be quite economically viable. A Bechtel Corporation research effort for the U.S. Department of Energy analyzed a facility that used coal gasification to produce electricity, hydrogen, liquid fuels, and steam and found that liquid fuels production became profitable when oil prices exceeded $32 a barrel (Bechtel Corporation, Global Energy Inc., and Nexant Inc. 2003).

Coal-to-liquid technology assures countries with significant coal resources access to liquid fuels in the event of a supply disruption or a diminishing supply following peak oil, embargo, or other factors. For this political reason, some countries, including China and the United States, are investing in coal-to-liquid technology despite the cost and environmental impact.

The Fischer-Tropsch process has been around since the 1920s and was used to provide a significant amount of fuel in the Second World War. Technologies used in the process, such as coal gasification, also have an extensive history. As in any field, new technologies continue to emerge, offering the promise of incremental improvement. However, the technology of carbon sequestration is much less advanced, and for coal-derived liquids to play a significant role in a world facing constraints on GHG emissions, sequestration must be proven effective, verifiable, and economical.

Until this occurs, coal-derived liquids are unlikely to form a significant part of the U.S. energy supply in a carbon-constrained future. Even with carbon sequestration at the refinery, the resulting fuel has approximately the same carbon content as conventional liquid fuels and would not lead to reductions in GHG emissions (Brandt and Farrell 2007).

\textsuperscript{1} CO\textsubscript{2}e is the mass of greenhouse gases expressed in an equivalent mass of CO\textsubscript{2} based upon the global warming potential (GWP)
2.3.3. Hydrogen

Hydrogen for transportation fuel can be made from a variety of sources, including coal, natural gas, biomass, and water, using a range of energy sources, including fossil fuels, renewables (solar, wind, and hydro), and nuclear electricity (National Research Council and National Academy of Engineering 2004). Life-cycle impacts of hydrogen as a vehicle fuel will depend greatly on the feedstocks and methods used for hydrogen production and delivery.

Current U.S. hydrogen production is about 9 million metric tons per year (enough to fuel about 35 million cars), mostly from natural gas. Current uses include ammonia synthesis, methanol production, a number of refinery applications, food processing, and fuel for the NASA space shuttle’s main rocket.

This section describes producing hydrogen from natural gas, coal, and biomass. Electrolysis (using electricity to split water) is another commonly discussed method of hydrogen production, which is discussed along with another important interaction between hydrogen and electricity, the co-production of hydrogen and electricity. Finally, the section covers the system design of hydrogen refueling infrastructure and challenge of developing that infrastructure in parallel with introduction of FCVs.

Hydrogen from Natural Gas

Steam reforming of natural gas is currently the most economical form of hydrogen production and will likely be one of the common near-to-medium-term methods of hydrogen production for vehicle use as well (National Research Council and National Academy of Engineering 2004). Natural gas reformers are often characterized as either small-scale distributed facilities where the hydrogen is produced at the point of use (for example, at the hydrogen refueling station) or large-scale centralized facilities from which the hydrogen must be distributed to the point of use. Large-scale hydrogen production from natural gas is a mature technology. Currently, large-scale production facilities are typically located at refineries and ammonia synthesis plants.

Small-scale natural gas production plants can range in output from 24 kg/day to 3000 kg/day. One of the main benefits of distributed hydrogen production is that the cost and complexity associated with delivery of hydrogen is eliminated. These small-scale systems, based on natural gas reformers integrated into a refueling station, also include hydrogen compression, storage tanks, and fuel dispensing equipment. Since the late 1990s, a significant level of R&D activity has been aimed at developing low-cost small-scale hydrogen production systems, and a number of companies have developed such systems.

Some of the key technical challenges to small-scale reformers identified by a U.S. Department of Energy (DOE) research program include improving reforming and separation efficiency, identifying more durable catalysts, decreasing system size, and reducing capital, manufacturing, and operations and maintenance costs. Other goals of the DOE research program for small reformers include fuel flexibility, reduction of GHG emissions, and control for optimal performance and safety (U.S. Department of Energy 2005b).

While hydrogen production from natural gas is the most technically mature hydrogen pathway, a critical issue is the supply and cost of natural gas. Natural gas prices in California have increased very significantly over the past few years; California currently imports 85% of its natural gas, and in-state natural gas production is declining (California Energy Commission...
Current natural gas prices (in the $8–10 per million Btu’s range) make hydrogen production from natural gas less attractive because the feedstock alone would account for $1.20 to $1.50 of the cost of a kilogram of hydrogen. Total levelized production costs would be around $2/kg (H2A Analysis Group 2005) and delivery and refueling would add even more to the cost of H₂.

**Hydrogen from Coal**

Coal is a low-cost primary energy source for hydrogen production with abundant domestic availability in the United States (and elsewhere). While GHG emissions from the use of coal are a major concern, coal gasification will offer one of the lowest-cost mechanisms for producing large quantities of hydrogen (National Research Council and National Academy of Engineering 2004). Carbon capture and sequestration (CCS) is one of the critical enabling technologies that could lead to production of hydrogen from coal for use as a transportation fuel.

Gasification is a process that converts coal and other carbonaceous materials, such as petroleum and biomass, to a synthetic gas (syngas) consisting primarily of carbon monoxide and hydrogen. Gasification systems can be used to produce both hydrogen and electricity from coal, though at present commercial gasifiers are not widely used in power generation or hydrogen fuel production. One technology, the integrated gasification combined-cycle (IGCC) power plant, has many of the same components as a coal-based hydrogen plant and could be implemented widely for electricity generation much sooner than hydrogen plants. As a result, it could be a key enabler for the production of hydrogen from coal by helping to bring down the cost of key components such as the gasifier. Coal gasification technologies benefit from economies of scale, and plants would likely not be built below a size of 250 metric tons of output per day. Large plants on the order of several hundred metric tons of hydrogen per day (capable of serving hundreds of thousands of fuel cell vehicles) can yield production costs below $1/kg (H2A Analysis Group 2005).

The prospects for coal-based hydrogen in California remain unclear. A traditionally coal-averse policy environment may prevent widespread introduction of coal gasification technologies into the state. In particular, recent climate change policies that strive to reduce GHG emissions would seem to preclude coal. However, coal gasification coupled with CCS for electricity production could be an option to fill some of the state’s growing electricity demand over the next decades. Such a system could be utilized for producing hydrogen as well and could substantially reduce GHG emissions from the transportation sector.

**Hydrogen from Biomass**

Biomass has a relatively low energy density when compared to coal, crude oil, or refined liquid fuels. Like coal-based hydrogen production, the most promising pathway for hydrogen production from biomass involves gasification to produce a syngas, which is then processed using the same methods as in natural gas and coal-based hydrogen production. Biomass gasification for the production of hydrogen is not practiced commercially at present, but gasification technology of a type suitable for hydrogen synthesis has been demonstrated for electricity production using biomass feedstocks.

Biomass includes a great variety of possible feedstocks, from agricultural residues to forestry and forest products, municipal solid waste, and energy crops. Different biomass feedstocks will require different preparation and handling and perform differently in the gasification facility.
Facility designs must account for the feedstocks available for use. Biomass is generally dispersed, and the costs of gathering and transporting it need to be balanced against conversion plant economies of scale. Another important factor to consider is the moisture and ash content of the biomass.

Deriving hydrogen from biomass is likely the lowest-cost method to produce renewable hydrogen. Estimates of the cost of producing hydrogen from biomass range from less than $1/kg to about $5/kg, depending on the size of the facility, the processing technology used, and the cost of the feedstock. Large plants (with outputs greater than 300–400 metric tons a day) are estimated to produce hydrogen for less than $1.50/kg (Hamelinck and Faaij 2002; Katofsky 1993; Larson, Gin, and Celik 2005).

Only a few biomass gasifiers are currently operating in energy applications worldwide (none in California). Further research on and development of several components of the biomass gasification system—including biomass preparation, handling, and injection into gasifiers, as well as reactor design—are needed.

At present, the three principal biomass resources in California, distributed throughout the state, are agricultural residues, forestry residues, and biomass from urban and industrial wastes. (Energy crops are not yet being produced in the state.) These three resources combined currently represent an annual gross of more than 80 million dry tons, of which between 30 and 40 million dry tons are considered technically available. This is enough to produce 2.5 million tons of hydrogen (enough to power approximately 4 million fuel cell vehicles).

Comparison of Hydrogen Production Pathways

Hydrogen production from large-scale natural gas reformers is typically around 70–75% efficient on a lower heating value basis, while coal and biomass gasification produce hydrogen at efficiencies in the range of 57–59% and 50–65% respectively. As part of the California Hydrogen Highway action plan, the state has indicated that it intends to initially implement a 20% renewable portfolio standard (RPS) for hydrogen production, which will increase over time (including a goal of 33% renewable by 2010) (Lowenthal 2006).

GHG emissions from the production of hydrogen vary widely depending on feedstock (Delucchi 2007). Large-scale natural gas reformers produce 9569 gCO₂e/kg H₂ (gCO₂e/gge). This compares favorably with gasoline, considering the increased efficiency of FCVs relative to ICE vehicles. Hydrogen production from coal generates significantly more GHGs (17,805 gCO₂e/kg) because of the higher carbon content of the feedstock and the lower efficiency of the production method, unless CCS is employed. With CCS, emissions could be reduced by more than 90%. Production of biomass-derived hydrogen creates only 1246 gCO₂e/kg H₂.

Biomass gasification provides a pathway for producing renewable hydrogen with low life-cycle GHG emissions. Net GHG emissions come mostly from fossil energy used in growing, harvesting (or collecting and separating in the case of residues), and transporting the feedstock, processing at the refinery, and distribution and storage. If biomass feedstocks are used in

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1 Lower heating value refers to the energy released in a reaction when water vapor (rather than liquid water) is created.
combination with CCS technology, hydrogen (or other fuels) can be produced with net negative GHG emissions.

**Co-production of Hydrogen and Electricity**

A number of different energy resources and systems for co-producing or cogenerating hydrogen and electricity are possible. Potential benefits of co-producing hydrogen and electricity include the following:

- Flexibility in meeting demands
- Increased utilization
- Increased efficiency
- Lower emissions
- Carbon capture
- Lower costs

One important caveat is that not all of these benefits will be realized for all co-production projects and facilities. In many systems, tradeoffs between some of the benefits are likely.

The first possible co-production method involves production of syngas from coal, biomass, natural gas, or another hydrocarbon resource, separation of some of the hydrogen for delivery to fuel cell vehicles or other uses, and conversion of the remaining syngas, in a gas turbine or fuel cell, to electricity. Hydrogen for vehicle use must be very pure, so CO$_2$ separation is required, and the CO$_2$ can be injected into oil fields to enhance oil recovery or can be sequestered in geologic formations. A number of pilot plants and system design analyses for co-production facilities of this kind already exist (Chiesa et al. 2005; Consoni and Vigano 2005; Gray and Tomlinson 2002; Yamashita and Barreto 2005).

Another method of hydrogen and electricity co-production employs one of a number of possible thermochemical cycles to split water into hydrogen and oxygen. This method has not been studied to the same extent as fossil-based co-production but is being proposed and investigated as a means of employing decarbonized energy resources such as nuclear or concentrated solar heat to produce hydrogen. Given the high temperatures and large temperature differences required in the chemical cycle, it seems likely that some heat could be utilized for electricity production as well (Schultz et al. 2003).

A third method of hydrogen and electricity co-production involves using electrolysis (passing an electric current through chemically bonded elements or compounds) to split water into hydrogen and oxygen. While technically not co-production, some system designs and applications use a primary resource—such as wind, solar, or nuclear power—to produce electricity and hydrogen at the same location. In these cases, electricity is generated first, but hydrogen can be a useful means of electricity storage or a potentially higher-value product than electricity. In the case of high-temperature electrolysis, some of the energy for water splitting can come from heat (the remainder comes from electricity), and this process may be suitable in conjunction with a high-temperature waste heat source.
**Hydrogen Refueling Infrastructure**

One of the major challenges associated with a transition to a hydrogen economy is developing a hydrogen refueling infrastructure in parallel with the rollout of hydrogen-powered vehicles. Sufficient refueling infrastructure must exist before consumers will invest in FCVs, but at the same time enough vehicles must be purchased to justify infrastructure investment. This is the epitome of a “chicken or egg” problem.

It is generally assumed that some threshold percentage of station coverage must be crossed in an early market to satisfy consumer concerns about fuel availability. Approximately 10% of stations in urban areas has been suggested as the figure for this threshold (Nicholas, Handy, and Sperling 2004; Sperling and Kitamura 1986). With any alternative fuel infrastructure, the minimum number of stations is critical because in the early years when demand is low, having more than this minimum number of stations to satisfy consumer concerns reduces utilization of individual stations and raises hydrogen costs.

A significant portion of the cost of hydrogen is associated with the infrastructure required to transport the fuel from a central plant to the refueling station, store it there, and dispense it to the consumer. The high costs stem, in part, from the expenses associated with raising the hydrogen’s energy density, either through compression or liquefaction. Compressed hydrogen has a lower energy density and thus higher transportation and storage costs than liquid hydrogen, but energy and capital costs for liquefaction are significant.

Hydrogen refueling stations can also produce hydrogen on-site from either natural gas or water. In the early years of a hydrogen economy, it is likely that hydrogen will be produced at the refueling station because of the large costs associated with delivery systems at low levels of utilization. Only after demand has grown to a sufficient level will dedicated central production with delivery make economic sense. At that point the cost of hydrogen delivery and the choice of the lowest-cost delivery mode will depend on specific geographic and market characteristics, such as city size and population, population density, and the size and number of refueling stations.

Demonstrations of many types of hydrogen refueling stations are now under way, though typically for controlled fleets rather than consumer vehicles. These stations can be supplied by on-site production or one of several delivery modes described in more detail in Appendix B, including compressed hydrogen via tube trailer truck, liquid hydrogen tanker trucks, and pipelines. The choice of delivery method depends on the total demand, local spatial and geographic conditions, and other considerations (Yang and Ogden 2007).

**2.3.4. An Enabling Technology: Carbon Capture and Sequestration**

Carbon capture and sequestration (CCS) is one of the critical enabling technologies that must advance before coal-derived liquids and coal-based hydrogen can play significant roles as transportation fuels in a world facing constraints on GHG emissions. It could also reduce the GHG emissions associated with increased production of electricity to fuel vehicles. The general idea of CCS is to separate CO$_2$ from the other emissions and flue gases from an industrial complex and then transport it and store it in a location separated from the atmosphere for a period of many years. CCS must be proven effective, verifiable, and economical before fuel production pathways that release great quantities of CO$_2$ can be seen as viable.
Although a number of fundamental questions still need answering before any large-scale use of CCS is undertaken, much of the technology for CCS already exists and is used in industrial settings today. As a result, CCS is often thought of as a relatively low-cost option for making significant CO₂ emissions reductions now, as R&D works to improve the technological feasibility and cost effectiveness of more sustainable next-generation energy technologies. If it lives up to its promise, CCS could be a transition technology that provides a bridge to a sustainable energy future while helping to prevent dangerous atmospheric levels of GHGs.

**CO₂ Capture**

Virtually all CO₂ produced today by power plants and other industrial complexes is released into the atmosphere. Three main types of combustion systems have been proposed for capturing CO₂: postcombustion, precombustion, and oxyfuel combustion.

Postcombustion capture refers to the process by which CO₂ is separated from flue gases using an organic liquid solvent after a fossil fuel (coal, oil, natural gas) has been combusted in air. Heat is then applied in order to regenerate the solvent, imposing an energy penalty on such systems: about 14.5% for a retrofitted plant versus 9.2% for a newly built plant (MIT faculty 2007). This is currently the most technologically feasible and well understood method for capturing CO₂.

In precombustion capture, a fossil fuel is reacted with steam and/or air (or pure oxygen) to generate a syngas, and the hydrogen and CO₂ are separated using liquid solvents or solid adsorbents. Precombustion separation is generally easier than the postcombustion process because the concentration and pressure of CO₂ in the gas is higher (IPCC 2005a). This reduces the efficiency penalty to about 7.2% for precombustion capture of CO₂ in an integrated gasification combined-cycle plant.

A third approach for capturing CO₂ is oxyfuel combustion, where a fossil fuel is combusted in pure oxygen and the CO₂ concentration in the flue gas (mainly water vapor and CO₂) is greater than 80% by volume. This high concentration of CO₂ and the ease of condensing water vapor make the separation step easier; but the other processes, particularly the initial step of separating oxygen from air, are more complicated than for traditional fossil fuel combustion.

**CO₂ Transport and Sequestration**

Carbon dioxide can be transported by pipeline, ship, rail, or truck. Of these options, the greatest amount of experience has been obtained with pipelines; in fact, more than 2500 km of CO₂ pipelines in the United States currently transport more than 40 megatons (Mt) of CO₂ a year, primarily for use in enhanced oil recovery (IPCC 2005b). In the pipelines, CO₂ is typically transported as a pressurized fluid above a critical temperature, as the increased density makes the CO₂ cheaper and easier to transport.

Several options exist for securely storing CO₂: geological storage, ocean storage, and storage in mineral carbonates. Geological storage refers to storage in underground reservoirs, such as saline aquifers and oil and gas fields. Saline aquifers offer the greatest predicted storage capacity, but there is little experience with storing CO₂ in them (IPCC 2005a). Storage in oil fields, on the other hand, has a relatively long history and has mainly been used for CO₂ for enhanced oil recovery. Underground in a geological reservoir, two principal CO₂-trapping mechanisms can be used: physical trapping, which involves placing a caprock at the top of the
storage reservoir to prevent CO₂ escape, and geochemical trapping, where CO₂ reacts and is eventually converted into a solid carbonate mineral (IPCC 2005b).

Ocean sequestration involves injecting CO₂ at depth into the ocean, where it would dissolve (IPCC 2005a). It has been estimated that 65–100% of CO₂ stored in the ocean would be retained for at least 100 years, and 30–85% would be retained for at least 500 years (IPCC 2005a). However, there are concerns about ocean sequestration, including ocean acidification.

Carbon dioxide could also be reacted with a metal oxide silicate rock to form a stable solid mineral carbonate material. The process would involve mining, crushing, and milling and transporting ores to a processing plant where the silicate rock and CO₂ from a power plant would be reacted to form the mineral carbonate. This method is currently more energy intensive than either the geological or ocean storage option: a power plant that captured CO₂ and stored it in mineral carbonates would consume 60–180% more energy than a plant without CCS.

Geological storage probably has a much lower capacity than ocean storage but is the most likely method of storage. One advantage of geological storage is that many large CO₂ point sources are fairly close to geological reservoirs (IPCC 2005b). In North America, an estimated 61% of large CO₂ point sources are located directly above a potential geological reservoir, and an estimated 73% are located within 100 miles of at least one reservoir (IEA Greenhouse Gas R&D Programme 2005).

The U.S. Department of Energy’s Regional Carbon Sequestration Partnership has found that by far the greatest potential for CO₂ storage is in saline aquifers. Estimates vary, but there is likely enough storage capacity in U.S. saline aquifers to hold somewhere between 1000 and 3800 gigatons (Gt) of CO₂ (National Energy Technology Laboratory 2007). Within WESTCARB, the sequestration partnership region that includes California, the greatest potential for CO₂ storage—between 76 and 304 GtCO₂—is in saline aquifers located mainly in California’s Central Valley. A second, though much less significant, storage option is in oil and gas fields—about 5.3 GtCO₂.

To summarize, there is varied experience with each of the different aspects of CO₂ capture, transport, and storage. There is no experience, however, with applying a fully integrated CCS system to a large-scale power plant. At the moment, a great deal of uncertainty still exists as to how each of the CCS system components could come together to form an efficient, low-emission, economical, and reliable power plant. The U.S. Department of Energy has started several projects to answer some of the remaining questions.

**Costs and Market Potential**

Estimates are that CCS would increase the cost of electricity by 2–5 cents/kWh for pulverized coal plants, 1–3 cents/kWh for natural gas combined-cycle plants, and 1–3 cents/kWh for integrated gasification combined-cycle plants, assuming the CO₂ was stored in a geological reservoir (IPCC 2005b). If a new hydrogen production plant were outfitted with CCS, the estimated cost of hydrogen would increase by 7–21% for coal-to-hydrogen plants and 18–33% for natural gas-to-hydrogen plants.

CCS shows promise as a tool for mitigating significant quantities of carbon dioxide emissions. It could provide a means of using abundant resources (such as coal and natural gas) and proven
technologies to continue to power the world’s energy needs while helping to reduce climate-changing GHG emissions to the atmosphere. However, despite the promise, a number of questions still need answering before CCS can be counted on as a viable climate change mitigation strategy. While many CCS system components are fairly mature technologies, overall costs must be reduced. The greatest potential for cost reduction is in the area of CO₂ capture since it is the least understood component of CCS.

2.3.5. Electricity

Today’s electricity and transportation energy systems are distinct sectors with little interaction, but a shift to many of the advanced vehicles and fuels described in this chapter would generate additional electricity demands from the transportation sector. This connection is obvious for battery electric vehicles (BEVs) and plug-in hybrid vehicles (PHEVs). Although less obvious, it exists for hydrogen as well—electricity demands are high for some hydrogen pathway components, including production by electrolysis as well as liquefaction and compression for hydrogen distribution. The impacts of these new demands on the electricity grid, the sector’s subsequent evolution, and the resulting economic and emissions impacts for both electricity and fuels production will be shaped by two important factors: total energy demand and timing of demand.

Researchers at UC Davis have developed a simplified dispatch model of the California grid and estimated the GHG emissions impacts associated with potential new transportation electricity demands in California (McCarthy, Yang, and Ogden 2008). An electricity dispatch model enables comparison of the generation resources used to meet marginal electricity demands for several alternative fuels and vehicle platforms, considering the current grid composition in California. It allows exploration of the effect of replacing conventional vehicles with BEVs, PHEV20s, or FCVs supplied by various hydrogen pathways. The model provides a useful tool for investigating the aggregate systemwide response of the electricity system to changing demand load profiles, based on the composition of generation assets on the grid. This section details how advanced vehicles would affect the current California grid composition.

Specific findings from this initial application include:

- Additional electricity for supplying transportation fuels will vary in quantity and timing, depending on the vehicle type.
- Electricity-related CO₂ emissions and natural gas usage can vary widely for different electric-drive vehicle pathways and can vary significantly within a single pathway, depending on timing.
- The system of emissions allocation will affect the distribution of emissions among sectors, but not total emissions, unless sector-specific emissions limits are imposed.

A more detailed description and discussion of the dispatch model and results is found in Appendix C.

Electricity Generation and Dispatch

The dynamic nature of electricity demand, coupled with the inability to efficiently store electricity on a large scale, requires generation to vary continuously in order to respond to
demand in real time. Because electricity demand is not constant, some plants will be used more than others.

Certain types of plants (such as coal or nuclear power plants) are run almost continuously and are often called baseload plants. These plants typically have high capital but low fuel costs and cannot be started and stopped frequently. Other plants, called intermediate plants and exemplified by combined-cycle power plants, are operated less frequently. These plants have lower capital cost but higher fuel and variable costs. One other class of plants, called peaking plants, have very low capital costs but high fuel costs and are operated only a few hundred hours per year. The various types of plants are operated in such a way as to minimize the total cost (both capital and operating) of generating electricity to meet demand in real time, through a process called electricity dispatch.

Electricity dispatch is the process by which ever-changing generation requirements are assigned to available power plants. It is used by utilities, regional transmission organizations, independent system operators, and others to assign lowest-cost generation in day-ahead and real-time markets. At the most basic level, dispatch involves creating a schedule of costs versus production levels for each available generator, and dispatching plants in order of increasing cost until generation requirements (that is, demands) are met. Thus, the last plant dispatched in a given hour is typically the most expensive one of the plants that are generating that hour.

Figure 1 shows a sample week’s electricity demand. The figure depicts a seven-day span and shows the breakdown of generation into the three main categories. The plants are dispatched to generate electricity to meet demand in any given hour. Baseload plants are typically always running. Intermediate plants are dispatched first to meet additional demand and peaking plants are dispatched last.
**Vehicles and Demand Timing**

Different types of advanced vehicles will impose different charging and electricity demands on the electric grid and affect which generators are dispatched. FCVs can be supplied by a number of potential hydrogen pathways with different electricity demands and profiles: on-site electrolysis, on-site natural gas steam methane reformation (SMR), centralized production with liquefied hydrogen transport, and centralized production with hydrogen transport via pipeline. Other than electrolysis, there are only minor differences between different hydrogen production methods in terms of electricity usage. The hydrogen delivery method can have an important influence on electricity demand associated with a hydrogen pathway.

FCVs fueled by hydrogen from on-site electrolysis can consume more than twice as much electricity per mile as the next most electricity-intensive pathway (BEVs), mainly because of the inefficiency of electrolysis and the higher efficiency of BEVs. PHEVs and FCVs using hydrogen transported as a liquid also require significant electricity input. Electricity demands for other hydrogen pathways using pipeline delivery of hydrogen are relatively small, limited mostly to compression and auxiliary requirements at refueling stations.

BEVs and PHEVs can be charged at different times of the day, and the timing of charging will determine the impact on the grid. The addition of FCVs will also impact electricity demand, mostly through electricity demands related to hydrogen fuel production, delivery, and refueling. Some hydrogen-related demands will lead to additional daytime demand, such as for compression at refueling stations, while some demands may be deferred until low-demand periods at night, such as electrolysis using-off peak electricity.

A demand profile for additional vehicle-related electricity that peaks during the day will coincide with the daytime peak for conventional electricity demands and create an even higher peak, which will require more peaking generation. Adding demand to the nighttime low periods will lead to more usage of intermediate generation, and raising the minimum demands overall may permit replacing some intermediate generation with more inexpensive baseload generation.

Some advanced vehicle electricity demands will follow the daily profile of gasoline refueling, while others will peak at night when overall electricity demand is low. Load leveling represents the optimal distribution for adding these extra demands to the system. As electricity demand falls after the evening peak, the additional demands can be added slowly to maintain overall electricity demand at a constant level, until the morning, when the increase in conventional demand leads to a reduction in the vehicle electricity demands. Overall, load leveling adds demand to the nighttime troughs until demand is equalized across the off-peak period.

Load-leveling demand could transform the electricity sector by reducing the need for peaking power plants, which tend to be more expensive, inefficient, and polluting than baseload and intermediate power plants, especially in California. Such a shift would encourage the development of more baseload plants, changing the average generation mix, increasing the system load factor, and reducing emissions and electricity prices. It would also have an important impact on the viability of wind energy, which tends to generate during nonpeak hours.
Resources and Emissions

In California, the marginal generators (i.e. the last, most expensive plant that is dispatched on an hourly basis to meet demand) are typically some type of natural gas plant, either combined-cycle systems, steam turbines, or gas turbines. The addition of vehicle demands at night will typically involve the dispatch of combined-cycle plants, while additional demands during the daytime peak will involve the dispatch of steam and gas turbines. The latter tends to raise the cost and emissions associated with daytime electricity usage because of the lower efficiency of gas and steam turbines relative to combined-cycle plants. Also, adding to the peak demand will require additional capacity or additional imports to be available to serve infrequent demands, while nighttime demands will improve the utilization of existing plants and lower costs.

Average electricity CO$_2$ emissions in California from coal, nuclear, hydroelectric, natural gas, and other, renewable electricity sources are approximately 400 gCO$_2$/kWh. Natural gas is used to meet additional demands, and because its emissions rate is between 500 and 600 gCO$_2$/kWh, average emissions will increase when marginal demand increases. As a result, unlike in many parts of the country where coal is the dominant baseload technology (emitting more than 1000 gCO$_2$/kWh), California’s marginal emissions rate is higher than its average emissions rate. Still, despite the fact that average electricity emissions will go up with additional vehicle-related demands, transportation emissions will most likely decrease quite significantly when conventional gasoline vehicles are replaced by higher efficiency electric-drive vehicles (including BEVs, PHEVs, and FCVs).

2.3.6. Summary and Comparison of Alternative Fuels

Table 7 shows a comparison of costs, GHG emissions, and other important issues for each of the alternative fuels described in this section. The table expresses costs and emissions in terms of gallon of gasoline equivalent (gge). For hydrogen and electricity it also expresses these figures in terms of equivalent vehicle miles driven (gallon of gasoline equivalent efficiency, ggee); FCVs running on hydrogen are assumed to get double the fuel economy of an ICE vehicle running on gasoline, and electric vehicles are assumed to get triple the fuel economy of an ICE vehicle running on gasoline.

Reducing fuel-related GHG emissions is a critical piece of reducing overall transportation and light-duty vehicle GHG emissions. Certain fuels may have higher carbon intensity than gasoline (such as hydrogen from coal or from water by electrolysis), but because they can be used much more efficiently by a vehicle than gasoline can, GHG emissions per mile (or as shown in the table, per gallon of gasoline efficiency equivalent) can be significantly lower. With the rising price of conventional fuels, the cost of each of the alternative fuels is expected to be competitive with or lower than that of gasoline, given large-scale production and distribution.
<table>
<thead>
<tr>
<th>Fuel</th>
<th>Cost ($/gge) [$/ggee]</th>
<th>GHG emissions (gCO$_2$/gge) [gCO$_2$/ggee]</th>
<th>Important issues</th>
</tr>
</thead>
<tbody>
<tr>
<td>Gasoline</td>
<td>$2.50 untaxed</td>
<td>11,280</td>
<td>Finite resource, may peak in next decades</td>
</tr>
<tr>
<td>Cellulosic ethanol</td>
<td>$1.79–$2.20</td>
<td>1,320</td>
<td>Finite in-state resource (only 10% of 2005 gasoline consumption)</td>
</tr>
<tr>
<td>Synfuels</td>
<td>$1.20–$1.60$^1$ untaxed</td>
<td>21,000</td>
<td>High CO$_2$ emissions even with CCS</td>
</tr>
<tr>
<td>Hydrogen from biomass$^2$</td>
<td>$1.50 [0.75]</td>
<td>1,246 [623]</td>
<td>Finite in-state resource, chicken-or-egg problem</td>
</tr>
<tr>
<td>Hydrogen from natural gas$^2$</td>
<td>$2.00 [1.00]</td>
<td>9,569 [4,785]</td>
<td>Chicken-or-egg problem, resource price</td>
</tr>
<tr>
<td>Hydrogen from coal$^2$</td>
<td>$1.00 [0.50]</td>
<td>17,805 [8,902.5]</td>
<td>Chicken-or-egg problem, high CO$_2$ emissions</td>
</tr>
<tr>
<td>Marginal electricity in CA</td>
<td>$4.20 [1.42]</td>
<td>20,000 [6,667]</td>
<td>Charging infrastructure</td>
</tr>
<tr>
<td>Average electricity in CA</td>
<td>$4.20 [1.42]</td>
<td>14,000 [4,667]</td>
<td>Charging infrastructure</td>
</tr>
</tbody>
</table>

1. Based on synthetic crude prices of $32–50/bbl.
2. Production cost only (distribution and refueling would cost approximately $2/gge or $1/ggee additional).
3.0 California Energy Demand Scenarios

Growth in energy demand will have important implications for future energy supplies in California. It will affect availability of resources, cost and reliability of energy services, and the environmental impact of meeting energy demand. The project developed demand scenarios from 2005 to 2050 for electricity, natural gas, and transportation fuels. These provide a context for analyses of integrated energy supply strategies and the impact of advanced vehicle technologies and alternative fuels.

The main drivers of energy demand are population, per-capita activity (for example, vehicle miles traveled), and efficiency (for example, vehicle fuel economy). The potential scenarios presented in this chapter are the calculated result of a series of plausible assumptions about population, activity, and efficiency changes in different California energy sectors. These assumptions and the methods used to develop these energy demand scenarios are detailed in Appendix D.

3.1. Background Energy Demand Scenarios

The project created five different energy demand scenarios that span a wide range of demographic, economic, and technology development assumptions. It calculated annual and monthly demands for each energy carrier and further apportioned electricity demand into hourly demands.

The scenarios presented here generally represent final energy demands (that is, demands for specific energy carriers and fuels) rather than service demands (demands for specific services such as heating or cooling, which can potentially be met by more than one kind of technology or energy carrier), though these can be determined. For natural gas and electricity, the demand was projected by end-use sector (residential, commercial, industrial, agricultural, and other) and then aggregated to provide total statewide demands. Transportation fuel demand was calculated separately for light-duty vehicles, heavy-duty vehicles, and aircraft and then aggregated to arrive at total transportation fuel demand.

The five energy demand scenarios are as follows:

- The baseline demand scenario, which provides a set of possible energy demand growth curves based on extensions of current trends, assuming no significant policy or demographic shifts. This scenario provides a reference point to understand the impact of large-scale shifts in technology, demographics, and/or policy.
- The maximum demand and minimum demand cases, which represent a convergence of presumed maxima and minima in all the relevant underlying assumptions.
- Two moderate scenarios, which bracket baseline demand—using similar demographic and economic assumptions but varying energy efficiency and other parameters—and result in energy demands that are less extreme than the minimum and maximum cases.

These five energy demand scenarios provide a wide range of possible energy demands, useful as a basis for energy systems modeling.

This analysis does not address how the scenarios might materialize. The Global Business Network has developed a set of narratives that describe three alternate baseline scenarios for
California, presented in Appendix G. This work outlines various climatic, economic, political, and social events and trends and hypothesizes how they might shape California over the next half century.

### 3.1.1. Parameters That Drive Demand

Figure 2 summarizes the population and California gross state product (GSP) parameters that drive demand, relative to their value in 2005. The baseline demand scenario forecasts a 50% increase in population by 2050, to about 55 million residents, and sees an annual growth rate of 2.75% in GSP, more than tripling to almost $5 trillion in 2050. In the maximum demand and minimum demand cases, year 2050 population is 70 million and about 45 million, and GSP increases at annual rates of 1.05% and 3.73%, respectively.

![Figure 2. Growth in population and gross state product (GSP) relative to 2005 under three scenarios](image)

### 3.1.2. Electricity Demand

The total annual electricity demand for each of the scenarios is presented in Figure 3. Also shown in the figure is the California Energy Commission’s electricity projection through the year 2016 from the 2005 Integrated Energy Policy Report (California Energy Commission 2005a).

The range of annual electricity demand varies widely among the five different scenarios, from 217,000 gigawatt hours (GWh) to 688,000 GWh in 2050. This factor-of-three difference illustrates the multiplicative impacts of population growth, per-capita activity growth, and technology and efficiency assumptions on total energy demand. Minimum demand shows a 20% reduction in electricity demand despite growth (albeit slow) in population and the state economy. Maximum demand shows a very large increase in electricity demand because of population growth, growth in economic and activity drivers, and minor increases in energy efficiency. Though not shown, the hourly profile for electricity demand in each of the scenario years is used as an input for the energy system model described in Chapter 4.
Per-capita electricity consumption (see Figure 4) is projected to increase an average of 0.63% annually in the maximum demand scenario, to 9836 kilowatt hours (kWh)/year in 2050, and 0.24% per year in the baseline—low efficiency case, to 8280 kWh/year. The baseline—high efficiency and minimum demand scenarios see average annual reductions in per-capita electricity consumption of 0.29% and 0.94%, respectively, to 6514 kWh/year and 4853 kWh/year in 2050.
3.1.3. **Natural Gas Demand**

Figure 5 shows total annual natural gas demand in California for each of the alternative scenarios to 2050.

![California annual natural gas consumption by demand scenario](image)

**Figure 5. Total annual natural gas demand under five scenarios**

In the scenarios, natural gas demand varies from 8800 to 37,400 million (MM) therms in 2050. Much of the fourfold difference between the minimum demand and maximum demand scenarios, and the difference between maximum demand and baseline—low efficiency, can be attributed to the significant differences in the assumptions about industrial activity that is linked to GSP growth. As shown by the relatively small spread between the baseline—low efficiency and baseline—high efficiency scenarios for both electricity (Figure 3) and natural gas (Figure 5), the impact of the most aggressive efficiency changes is relatively small if not also coupled with changes in population and economic growth.

Annual per-capita natural gas consumption is illustrated in Figure 6 for the alternate scenarios. In the baseline demand scenario, year 2050 per-capita consumption is 8% below current levels. Minimum demand sees a 50% reduction in per-capita consumption by 2050, while for maximum demand, consumption increases 35% per capita by 2050. The baseline—low efficiency and baseline—high efficiency cases see an increase in per-capita consumption of 6% and a reduction of 26%, respectively, by 2050. These scenarios illustrate the range of efficiency assumptions included in the natural gas projections.
3.1.4. Transportation Fuel Demand

Figures 7 and 8 show the total transportation fuel (gasoline, diesel, and jet fuel) consumption (gallons of gasoline equivalent on an energy basis) and per-capita fuel consumption in California for each of the demand scenarios out to 2050. Also shown in Figure 7 is the IEPR 2005 fuel consumption projection to 2025, which is matched and then extended to 2050 in the baseline demand scenario. These transportation fuel demand scenarios do not include advanced vehicles and alternative fuels, which are investigated separately.
The key drivers of light-duty transportation fuel demand are population, VMT per capita, fuel economy, and sales distribution by vehicle type. Transportation fuel shows the greatest variation between the highest and lowest demands of any of the three energy categories, in part because of the significant reductions assumed possible in the minimum demand scenario as a result of very large efficiency improvements for light-duty vehicles and a significant decline in travel demand. Of the sevenfold difference in demand between the extreme scenarios for light-duty vehicles (sixfold for total fuel demand when including heavy-duty and aircraft demand), the fuel economy and travel demand (VMT per capita) assumptions account for approximately a factor of four.

3.2. Advanced Vehicle Scenarios

In addition to the baseline fuel demands for conventional vehicles described in the last section, the project team also developed fuel demand scenarios for each of three additional vehicle platforms—flex-fuel vehicles (FFVs), plug-in hybrid vehicles (PHEVs), and fuel cell vehicles (FCVs). Each of these scenarios focuses on a single advanced vehicle type and does not mix vehicle types. These advanced vehicles operate on ethanol (blends), electricity, and hydrogen. Natural gas, biodiesel, and other alternatives were not considered.

The advanced vehicle and alternative fuel scenarios aim to provide reasonable (although optimistic) medium and high fuel demand projections through 2050 for these alternative fuels. The intention is to create interesting contexts for modeling and comparing pathways in order to understand the implications for the structure and function of the energy system. Using high market-penetration rates for vehicles and fuels of interest promotes this intention.
Each advanced vehicle penetration scenario is applied within the context of parameters established in the baseline scenario. These parameters remain constant across alternative fuel scenarios and include vehicle population, vehicle miles traveled (VMT), distribution of cars and trucks in the fleet, and fuel economy of “nonadvanced” vehicles.

3.2.1. Market Penetration Scenarios

Medium- and high-penetration scenarios are presented for each advanced vehicle type in Figure 9.

Note the following:

- FFV_high reflects a scenario where all new vehicles are FFVs by 2012 (adapted from Jackson 2007).
- FFV_mid extrapolates penetration from the CA Low Carbon Fuel Standard (LCFS) scenarios H10 and H15 through to 2050 (Farrell and Sperling 2007). In this case, FFVs comprise 90% of new vehicle sales by 2050.
- PHEV_high follows the high penetration curve from EPRI (2007).
- PHEV_mid follows the trajectory from the “GETF” curve taken from the PHEV technology assessment detailed in Appendix A.
- FCV_high represents Future #4 in the HyTrans model developed by Oak Ridge National Laboratory (Greene et al. 2007).
- FCV_mid is adapted from the “pessimistic” scenario developed for the CEC by ITS-Davis (Miller 2005), shifted six years into the future.
The PHEV_high and FCV_high penetration scenarios are used for the energy system modeling in section 4.0. These two scenarios achieve 70% and 82% penetration of PHEVs and FCVs respectively by the year 2050.

### 3.2.2. Fuel Economy Assumptions

Table 8 summarizes the sales-weighted average fuel economy assumptions for conventional, hybrid, and diesel vehicles from the baseline scenario. (Note that this analysis does not represent the adoption of AB 1493 or increased CAFE standards.) Six car classes and 9 light-duty truck classes comprise 15 vehicle classes for each drivetrain configuration. Advanced vehicles penetrate the market as one of two generic vehicle classes, cars or trucks. The conventional vehicle efficiency assumptions in the scenarios influence the fuel economy of advanced vehicles (for example, the FCV efficiency will be higher when applied to the minimum demand scenario than for the baseline scenario). The table expresses fuel economy in terms of an equivalent amount of energy (miles per gallon of gasoline equivalent, mpgge).

<table>
<thead>
<tr>
<th>Year</th>
<th>Conventional Cars</th>
<th>Conventional Trucks</th>
<th>Hybrids Cars</th>
<th>Hybrids Trucks</th>
<th>Diesels Cars</th>
<th>Diesels Trucks</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>24.3</td>
<td>17.7</td>
<td>32.5</td>
<td>24.9</td>
<td>32.8</td>
<td>21.6</td>
</tr>
<tr>
<td>2025</td>
<td>25.5</td>
<td>19.3</td>
<td>34.2</td>
<td>26.8</td>
<td>33.9</td>
<td>23.4</td>
</tr>
<tr>
<td>2050</td>
<td>27.5</td>
<td>21.8</td>
<td>36.9</td>
<td>29.9</td>
<td>36.3</td>
<td>26.2</td>
</tr>
</tbody>
</table>

Table 9 presents parameters for the FFV/ethanol scenarios. FFV fuel economy is equal to fuel economy in conventional vehicles when the FFV is not using E85. Using E85 reduces fuel economy by 25% because of ethanol’s lower energy density relative to gasoline. These assumptions pertain to both ethanol scenarios, but equivalent fuel economy is higher in FFV_mid than in FFV_high as a result of increased utilization of E85 in the latter scenario. Utilization of E85 is assumed to increase linearly to 5% in 2050 in the FFV_mid scenario beginning in 2011, while it increases linearly to 20% in 2050 in the FFV_high scenario. All FFVs have the same average E85 utilization in a given year, regardless of purchase year.

<table>
<thead>
<tr>
<th>Year</th>
<th>Fuel economy (mpg gasoline) Cars</th>
<th>Fuel economy (mpg E85) Cars</th>
<th>% of E85 utilization Mid</th>
<th>Fuel economy (mpgge) Mid High</th>
<th>Ethanol demand (millions of gallons) Mid High</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>24.3</td>
<td>18.3</td>
<td>0</td>
<td>20.9</td>
<td>1,618</td>
</tr>
<tr>
<td>2025</td>
<td>25.5</td>
<td>19.2</td>
<td>2%</td>
<td>22.1</td>
<td>2,093</td>
</tr>
<tr>
<td>2050</td>
<td>27.5</td>
<td>20.7</td>
<td>5%</td>
<td>24.2</td>
<td>3,331</td>
</tr>
</tbody>
</table>

In addition to increasing penetration of FFVs and utilization of E85, both FFV scenarios assume that 10% ethanol is blended into gasoline beginning in 2010. (In other words, from 2010 to 2050, 10% of all gasoline is ethanol in the FFV_mid and FFV_high scenarios, compared to 5.7% in the other scenarios.)
Table 10 lists fuel economy assumptions for the PHEV scenarios. The scenarios make similar assumptions regarding vehicle fuel economy, both in conventional hybrid mode and in all-electric mode. In hybrid mode, PHEV fuel economy is 5% less than the sales-weighted average fuel economy of conventional hybrids. All-electric fuel economy is assumed to improve by 1% annually from the values in 2010. Combined fuel economy differs between the scenarios due to assumptions about the utilization of all-electric mode.

**Table 10. PHEV fuel economy and all-electric mode assumptions**

<table>
<thead>
<tr>
<th>Year</th>
<th>% of miles traveled in all-electric mode</th>
<th>Hybrid mode (mpg)</th>
<th>All-electric mode (Wh/mi)</th>
<th>Combined (mpgge)</th>
</tr>
</thead>
<tbody>
<tr>
<td></td>
<td>PHEV_mid</td>
<td>PHEV_high</td>
<td>Cars</td>
<td>Trucks</td>
</tr>
<tr>
<td>2010</td>
<td>12%</td>
<td>12%</td>
<td>30.8</td>
<td>23.7</td>
</tr>
<tr>
<td>2025</td>
<td>38%</td>
<td>47%</td>
<td>32.5</td>
<td>25.5</td>
</tr>
<tr>
<td>2050</td>
<td>31%</td>
<td>50%</td>
<td>35.0</td>
<td>28.4</td>
</tr>
</tbody>
</table>

Utilization of all-electric mode is determined based on the distribution of PHEV sales by battery size and the associated fraction of all-electric VMT. Both scenarios begin with penetration of vehicles with 10 miles of all-electric range (PHEV10s) and see PHEV20s and PHEV40s enter the market in 2015 and 2020, respectively. In PHEV_high, PHEV40s dominate the market after 2025, whereas PHEV20s dominate long-term in PHEV_mid. These penetration curves are coupled with utility factors adapted from EPRI (2007) to determine the all-electric utilizations (percentage of miles traveled in all-electric mode) listed in Table 10. (Utilization decreases between 2025 and 2050 in PHEV_mid as a result of assumed increases in annual new vehicle miles traveled over time.)

Fuel cell car and truck fuel economy is assumed to be twice the sales-weighted average of conventional car and truck fuel economy over the time frame of the study.

### 3.2.3. Fuel Demand Scenarios

The resulting fuel demands in millions of gallons of gasoline equivalent (MMgge) are illustrated in Figure 10 and described in Table 11. The baseline demand shown in Table 11 is from the fuel demand scenario described in section 3.1.4. These fuel demands are used as inputs to the energy system modeling in Chapter 4. The total quantity of fuel demanded is the same for each of the scenarios in 2010 but the use of advanced vehicles changes the fuels needed for light-duty transportation in each of the subsequent years. Also, overall fuel demand declines in the PHEV and FCV scenarios because of the higher efficiencies of these vehicles.
To summarize the results presented in Table 1:

- California’s ethanol consumption increases from approximately 900 million gallons (MMgal) in 2007 to 3331 million gallons in 2050 in FFV_mid and to 7598 million gallons in 2050 in FFV_high. FFV_high is optimistic for ethanol consumption in the state—the trajectory set by the scenario requires 2.6 billion gallons by 2020.

- Electricity consumption reaches 28,784 GWh by 2050 in PHEV_mid and 65,148 GWh in PHEV_high. This is a large amount of additional electricity required for electric vehicle usage, representing about 10% and 23% of year 2007 baseline electricity demand, respectively.

- Hydrogen demand reaches 3915 million kg (MMkg) and 10,454 million kg in the medium and high FCV penetration scenarios, respectively.
Table 11. Summary of preliminary results: Total annual fuel consumption by fuel type for each advanced vehicle scenario

<table>
<thead>
<tr>
<th>Year</th>
<th>Fuel Type</th>
<th>MMgal</th>
<th>FFV_mid</th>
<th>FFV_high</th>
<th>PHEV_mid</th>
<th>PHEV_high</th>
<th>FCV_mid</th>
<th>FCV_high</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>Gasoline</td>
<td>15,245</td>
<td>14,558</td>
<td>14,575</td>
<td>15,244</td>
<td>15,241</td>
<td>15,245</td>
<td>15,245</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>15,245</td>
<td>14,558</td>
<td>14,575</td>
<td>15,244</td>
<td>15,241</td>
<td>15,245</td>
<td>15,245</td>
</tr>
<tr>
<td></td>
<td>Diesel</td>
<td>93</td>
<td>86</td>
<td>73</td>
<td>93</td>
<td>92</td>
<td>93</td>
<td>93</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>104</td>
<td>96</td>
<td>82</td>
<td>104</td>
<td>103</td>
<td>104</td>
<td>104</td>
</tr>
<tr>
<td></td>
<td>Ethanol</td>
<td>921</td>
<td>1,617</td>
<td>1,619</td>
<td>921</td>
<td>921</td>
<td>921</td>
<td>921</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>609</td>
<td>1,069</td>
<td>1,070</td>
<td>609</td>
<td>609</td>
<td>609</td>
<td>609</td>
</tr>
<tr>
<td></td>
<td>Electricity</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>4</td>
<td>16</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Hydrogen</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td>2025</td>
<td>Gasoline</td>
<td>18,108</td>
<td>17,791</td>
<td>18,098</td>
<td>17,611</td>
<td>16,074</td>
<td>17,911</td>
<td>17,201</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>18,108</td>
<td>17,791</td>
<td>18,098</td>
<td>17,611</td>
<td>16,074</td>
<td>17,911</td>
<td>17,201</td>
</tr>
<tr>
<td></td>
<td>Diesel</td>
<td>1,467</td>
<td>996</td>
<td>29</td>
<td>1,334</td>
<td>968</td>
<td>1,444</td>
<td>1,366</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>1,638</td>
<td>1,112</td>
<td>32</td>
<td>1,491</td>
<td>1,082</td>
<td>1,613</td>
<td>1,526</td>
</tr>
<tr>
<td></td>
<td>Ethanol</td>
<td>1,094</td>
<td>2,092</td>
<td>3,529</td>
<td>1,064</td>
<td>971</td>
<td>1,082</td>
<td>1,039</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>723</td>
<td>1,383</td>
<td>2,333</td>
<td>703</td>
<td>642</td>
<td>715</td>
<td>687</td>
</tr>
<tr>
<td></td>
<td>Electricity</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>3,875</td>
<td>16,281</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>115</td>
<td>483</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Hydrogen</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>120</td>
<td>549</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>118</td>
<td>543</td>
<td></td>
</tr>
<tr>
<td>2050</td>
<td>Gasoline</td>
<td>18,490</td>
<td>20,582</td>
<td>18,830</td>
<td>15,439</td>
<td>11,669</td>
<td>12,704</td>
<td>2,963</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>18,490</td>
<td>20,582</td>
<td>18,830</td>
<td>15,439</td>
<td>11,669</td>
<td>12,704</td>
<td>2,963</td>
</tr>
<tr>
<td></td>
<td>Diesel</td>
<td>4,040</td>
<td>913</td>
<td>19</td>
<td>2,069</td>
<td>1,131</td>
<td>2,711</td>
<td>561</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>4,513</td>
<td>1,020</td>
<td>0</td>
<td>2,312</td>
<td>1,264</td>
<td>3,028</td>
<td>627</td>
</tr>
<tr>
<td></td>
<td>Ethanol</td>
<td>1,117</td>
<td>3,331</td>
<td>7,598</td>
<td>933</td>
<td>705</td>
<td>767</td>
<td>179</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>739</td>
<td>2,202</td>
<td>5,023</td>
<td>617</td>
<td>466</td>
<td>507</td>
<td>118</td>
</tr>
<tr>
<td></td>
<td>Electricity</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>28,784</td>
<td>65,148</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>854</td>
<td>1,933</td>
<td>0</td>
<td>0</td>
</tr>
<tr>
<td></td>
<td>Hydrogen</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>3,915</td>
<td>10,453</td>
<td></td>
</tr>
<tr>
<td></td>
<td>MMgge</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>0</td>
<td>3,873</td>
<td>10,341</td>
<td></td>
</tr>
</tbody>
</table>
4.0 Economic model of advanced vehicles and the energy system

The introduction of either hydrogen fuel cell vehicles or PHEVs will place new demands on the California energy system. PHEVs will require electricity directly, while hydrogen vehicles will require electricity indirectly, which is used for the production, transport, and refueling of hydrogen. At the same time, both types of vehicles will decrease the demand for petroleum based vehicle fuels and will decrease or eliminate their tailpipe CO$_2$ emissions. To meet these new fuel demands, the future energy system, particularly the electricity sector, will be restructured in order to produce additional electricity and serve the new patterns of demand. The actual emissions, resource use, and costs from this future energy system will be determined partly by the way that the system is restructured. This model has been developed to investigate the restructuring of the energy system (specifically the electric sector and alternative fuel infrastructure) and the changes in costs and emissions that will result from the introduction of these advanced vehicles.

The analysis is designed to find the effects of different levels of advanced vehicle penetration. It is driven by scenarios of vehicle penetration and the corresponding fuel demands out to 2050. The system is modeled in five snapshots at the years 2010, 2020, 2030, 2040, and 2050. In each year the total demands for each type of fuel are model inputs (as defined by scenarios described in section 3.2 of this report). The model finds the cost minimizing system configuration and operation to meet those demands in that year. The analysis does not model the competition between different types of vehicles and fuels. Rather it examines the energy system impacts associated with the penetration of advanced vehicles and fuels.

The California energy system relies on national and international markets for supplies of natural gas, crude oil, nuclear fuel, imported electricity, and (indirectly) coal. The costs of these primary fuels also figure into the overall costs of the system and into the capacity mix used in the electric sector. The effect that changes in the California demand might have on national and international markets is beyond the scope of this analysis. Their prices are taken as given here (rather than being endogenously determined in the model). It should be noted that since the model does not simulate the competition between different types of vehicle and fuels, large variations in the prices of commodities such as crude oil do not affect the penetration of the vehicles. Price variations do affect the total costs and the fuel savings associated with the adoption of these technologies.

The electric sector is structured to economically serve loads that vary hourly over the course of the year. The patterns of hourly variations have a substantial effect on both the optimal capacities and the operation of the electric system. Introducing advanced vehicles, particularly PHEVs, will add a significant load to the electric system. Because these loads can be substantial, it is important to include their hourly patterns in the model. In addition to the variations in hourly demands from the vehicles, there is a significant amount of flexibility in when PHEVs can be recharged (since they are likely to be plugged in for long periods of time) and significant storage capacity of hydrogen fuel in the hydrogen infrastructure. These provide a degree of flexibility to the system so that the demands for energy production can be better coordinated with the conditions in the system. This flexibility can affect the capacity mix and the operation of electric generators. The model has also been structured to incorporate intermittent renewable
technologies such as wind and solar. The hourly patterns of generation by these technologies are significant in evaluating their overall penetration and their impact on the capacities and operation of the system.

In this analysis investigating the structure of a new energy system with the use of advanced vehicles and fuels, there are two, sometimes competing, objectives: reduction of system CO\textsubscript{2} emission and minimization of costs. The introduction of advanced vehicles is expected to reduce the emissions that come directly from the vehicles. However, if the balance of the system is restructured to minimize cost, the CO\textsubscript{2} emissions from the rest of the system may increase or decrease. Several policies have been implemented or proposed to ensure that CO\textsubscript{2} emissions are also reduced in the balance of the system. In California, a Renewable Portfolio Standard (RPS) has been implemented, which requires a certain fraction of electricity production to come from renewable sources, which helps to reduce emissions from the electric sector. Carbon caps and CO\textsubscript{2} taxes are also mechanisms to directly manage CO\textsubscript{2}. The total system impact of introducing advanced vehicles is expected to depend on the type of CO\textsubscript{2} control regime that is implemented. This study assesses the CO\textsubscript{2} impact of advanced vehicles under two CO\textsubscript{2} policy paths (1) with no CO\textsubscript{2} controls and (2) under an RPS. The model has been structured to implement CO\textsubscript{2} taxes and the effect of such taxes will be evaluated in future studies.

4.1. Description of model

This section describes the structure, the underlying analytic approach and major assumptions of the model. Appendix F contains more detailed discussions of these issues.

4.1.1. Overview of model structure and major components

The California AEP model (CAEPM) models the energy system as three main energy market sectors: electricity, hydrogen, and petroleum/hydrocarbons. In CAEPM, each sector is required to meet an exogenously-specified level of demand for its energy service (as described in section 3.0 of this report).

Figure 11 shows an overview of the system sectors (electricity, hydrogen, and petroleum fuels), the end use demands (non-vehicle electric demand, vehicle fuels), and the resources. The detailed structure of the processes and their inter-connections are shown in Appendix F. The following sections provide an overview of the major approaches and assumptions in each sector of the model.
Figure 11. Block diagram of the major sectors in the model

Note that the model does not include demands for natural gas from space heating or fuel demands for transportation other than light duty vehicles (i.e., it does not include aircraft and heavy duty transportation demands). These fuel demands are not expected to be impacted by the penetration of advanced light-duty vehicles into California.

4.1.2. Analytic approach used by the model

The CAEP model has been developed to model electricity and hydrogen markets for vehicle fuels. It has been developed using the MetaNet economic modeling system (Lamont 1994, Lamont 2008). MetaNet is an economic optimization software package that finds the least cost system structure and operation to serve a given set of demands. Scenarios are run as a sequence of years with MetaNet finding the optimal system capacities and operation for each year.

MetaNet can be run in two different modes. In one mode all of the years are included in a single run, so that stock build-up and resource depletion are accounted for. However, that mode does not account for hourly variations in demands or resource availability and it does not represent intermittent renewables and storage well. The other mode models a single year at a time with hourly time steps. This single-year mode was used in this study since it can handle
the hourly pattern of intermittent renewables, variations in fueling patterns, and fuel storage. The single-year mode does not explicitly account for build up and retirements of capital stocks. However, this is only a serious concern in cases where there are shifts in policies, resources or technologies during the modeled time horizon leading to obsolescence and abandonment of some capital investments. This is not a significant concern in this analysis since the capacities in all significant areas are growing over time. One exception may be the infrastructure for delivering hydrogen (liquid trucks versus pipelines). This is discussed with the model results.

Details of the underlying optimization for the model are described by Lamont (2008). The following paragraphs give a brief statement of the optimization problem solved by the model.

The structure and operation of the system are characterized by several variables:

- Capacities of each energy system process, including production/generation, transmission and distribution and refueling (determined on an annual basis)
- Dispatch of each energy system process each hour
- Charging and discharging of storage each hour

The optimization model finds the optimal values of these variables to minimize the total annual system costs which is the sum of:

- Annualized capacity investment costs
- Operating costs
- Resource costs

The optimized solution must meet several constraints:

- Enough capacity must be installed so that all energy demands are met in each hour
- The production process must be dispatched in each hour so that the capacities of production processes are not exceeded
- The total hydro electricity used is equal to the total energy available over the year
- Storage cannot be overfilled or over-drawn

These conditions lead to three types of sub-optimization problems to be solved by MetaNet.

- Hour-by-hour dispatch optimization to manage the rate of production from the technologies,
- Optimization across hours for managing hydro electricity and storage processes
- Capacity optimization to manage the total capacity for each type of technology

These optimization problems are described in more detail in following sections.
**Hourly operation optimization**

The operation of the system to meet the demands for electricity and vehicle fuels are optimized every hour over the year. This is most complicated within the electric sector. Since the electricity demands vary substantially over each hour of the day and over the seasons, a set of electric generators is used with each type of generator having different capital and operating costs. Within the electric generation sector, the demands of each hour are met by dispatching generators to meet the demand in the most economical fashion (i.e. the generators with the lowest operating costs are dispatched first).

CAEPM includes solar and wind generation technologies whose output is intermittent and often varies substantially from hour to hour. The model accounts for this intermittency by including hourly data on generation from intermittent generators at various locations. It computes the economic dispatch each hour, taking into account the hourly power available from each type of intermittent generator.

**Optimization across hours, storage processes and hydro electricity**

CAEPM requires optimization across hours in the case of storage processes for hydrogen, electricity for PHEVs, and for the dispatch of hydro-electricity. In the case of storage, the optimal storage process must charge during those hours when the input commodity is least expensive, while taking in enough to ensure that it can supply all of the demands made upon it.

The storage processes in the model can have a significant interaction with production processes. Without storage, production processes would have to operate in a way that precisely matches the hourly demands. There will have to be enough production capacity to meet the peak hourly demands. If peak demands are larger than average demands, this will lead to more production capacity than is strictly needed to meet the total, annual demand. Storage processes can buffer the production from the demand and allows the production to operate at a more steady rate, with a production capacity that is closer to the meeting the average demand, rather than the peak demand.

The use of the storage processes in the system is responsive to hourly prices in the system—more charging is done in hours when the energy prices are low and less when prices are high. However, in the final solution this behavior tends to produce prices that are fairly constant over time. If a storage process uses more energy in hours when prices are low, the prices in those hours tend to increase as the demand increases. Conversely, if it uses less energy in those hours when prices are high, the prices in those hours tend to decrease. If the storage process is large enough (relative to the other demands in the system), it will cause energy prices to even out over time. We find this sort of result in the later years of the PHEV scenarios when the vehicle demands for electricity become significant.

**Capacity optimization**

Finally, CAEPM finds the optimal capacities for each of the production processes (generation, transmission and distribution, and refueling stations). Adding a marginal increment of capacity to a conversion process provides some benefit to the system. Usually it is because the system can reduce the dispatch of some other, more expensive, process. The benefit is different in each hour over the year depending on the demands and the availability of other generators (such as wind or solar) and the total benefit over the year is the sum of the incremental benefits over all the hours of the year. At the same time, adding the increment of capacity has a cost. The
system is optimized when the cost and the benefits from a marginal unit of capacity are just equalized. The model adjusts capacities until this condition is satisfied. This approach minimizes the cost of all energy system components while still meeting the energy demands.

**Marginal costs in MetaNet**

The optimization reaches a solution based on the marginal prices of production from each process. The marginal prices are the basis for determining whether or not capacity should be added to or subtracted from a process. The results in later sections show some of these prices each hour for the solutions and show price duration curves for some of the processes\(^1\). The price in any hour represents the marginal costs of production in that hour. Whenever the level of production is below capacity, the price represents operating costs of the process. When the level of demand approaches the installed capacity, the price also includes operating and capital costs. Consequently, the prices in the model are higher in those hours when the system is operating at full capacity. The capital costs of each process are recovered through these high price hours. In the real world, prices are not charged in this way. Rather, the capital cost component is generally spread out over all of the hours, often through a tiered pricing or average pricing which smooth out the price spikes while still recovering capital cost. The price behavior in this model is like a real-time pricing market for each of the energy products.

### 4.2. Demand processes for electricity and vehicle fuels

The *Baseline* energy demand scenario (described in section 3.0 and Appendices A and B) provides the demands for vehicle fuels, electricity for PHEVs and the non-transportation related electricity demands for each scenario year. These demands include residential, commercial, and industrial demands. The annual demands were converted to hourly demands based on the hourly electricity demand patterns from the California Energy Commission (CEC) for the year 2003 (CAISO 2008). Total demands for vehicle fuels of each type (gasoline, diesel, ethanol, and hydrogen) for each year are also given by the *Baseline* scenario, along with hours fueling patterns for vehicles. It is assumed that the hourly fueling patterns for these fuels will be similar to today’s patterns of demand for gasoline. These are used to convert the total demand to an hourly demand for vehicle refueling.

The advanced transportation technologies described in these scenarios require electricity, either directly for the PHEVs or indirectly for the production and distribution of hydrogen for use in FCVs. These additional transportation-related electricity demands are added to the non-transportation electricity demands provided by the *Baseline* scenarios.

The scenarios provide the total annual demands for PHEV electricity. The PHEVs store the electricity in on-board batteries. Thus there is flexibility over the course of the day as to when they recharge. The model assumes that they purchase electricity in an hourly pattern that is governed by marginal electricity costs on the system to minimize the total cost of charging, taking into account constraints on the total on-board storage capacity. The model essentially assumes that there is a “smart grid” which provides full information about prices to consumers at all times, and that they are able to take advantage of it. A model of this sort finds the best

\(^1\) A “price duration curve” shows the fraction of the year that a price is at, or above, a given price level, similar to a load duration curve in electric system modeling.
that can be done with full information. Future studies can examine the cost impact of alternative charging behavior by consumers.

Carbon sequestration also requires electricity for compression and pumping of CO₂. These electricity demands are also determined within the model.

### 4.3. Production pathways for final commodities

**Table 12: Description of types of nodes used to model energy system processes and the symbols used in diagrams**

<table>
<thead>
<tr>
<th>Symbol</th>
<th>Description</th>
</tr>
</thead>
<tbody>
<tr>
<td><img src="image" alt="End-use processes symbol" /></td>
<td><strong>End-use processes</strong> model the hour-by-hour demands for a commodity (gasoline, electricity, etc). In this analysis these demands are fixed for each hour and are not price sensitive.</td>
</tr>
<tr>
<td><img src="image" alt="Conversion processes symbol" /></td>
<td><strong>Conversion processes</strong> convert one commodity into another (e.g. natural gas into electricity). They also represent the transportation of commodities from one place to another. A process can require several inputs in order to produce one unit of output. The model also includes the capital and operating costs for the process. It determines the total input of each type that it requires in order to meet a demand, and it determines the prices that must be charged to cover the capital costs, operating costs, and input costs.</td>
</tr>
<tr>
<td><img src="image" alt="Market or sum processes symbol" /></td>
<td><strong>Market or sum processes</strong> add up a set of demands for a particular commodity and then allocate that demand among various suppliers. If there is only a single supplier, the total demand is simply passed on. If there are multiple suppliers, the required quantity is allocated among the suppliers based on their marginal prices using a logit function.</td>
</tr>
<tr>
<td><img src="image" alt="Storage processes symbol" /></td>
<td><strong>Storage processes</strong> take in a commodity during low price periods for release in later periods. However, these processes can also model a reservoir in which a given amount of a commodity is available over the year.</td>
</tr>
<tr>
<td><img src="image" alt="Resource processes symbol" /></td>
<td><strong>Resource processes</strong> make a commodity available at a given price.</td>
</tr>
<tr>
<td><img src="image" alt="CO₂ flow vented to atmosphere" /></td>
<td>CO₂ flow vented to atmosphere</td>
</tr>
<tr>
<td><img src="image" alt="CO₂ sequestered flow (compressed)" /></td>
<td><strong>CO₂ sequestered flow (compressed)</strong> represent flows of CO₂ that have been compressed at a production site and are ready to be transported by pipeline to a sequestration site.</td>
</tr>
<tr>
<td><img src="image" alt="CO₂ sequestered flow (uncompressed)" /></td>
<td><strong>CO₂ sequestered flow (uncompressed)</strong> represent flows of CO₂ that have been produced by a process, but which still must be compressed for pipeline transport.</td>
</tr>
<tr>
<td><img src="image" alt="Natural gas link" /></td>
<td>Natural gas link</td>
</tr>
<tr>
<td><img src="image" alt="Electricity link" /></td>
<td>Electricity link</td>
</tr>
<tr>
<td><img src="image" alt="Hydrogen link" /></td>
<td>Hydrogen link</td>
</tr>
<tr>
<td><img src="image" alt="Hydrocarbon fuels link" /></td>
<td>Hydrocarbon fuels link (gasoline, Diesel, ethanol).</td>
</tr>
<tr>
<td><img src="image" alt="Coal link" /></td>
<td>Coal link</td>
</tr>
</tbody>
</table>
Each of the final energy commodities (electricity, hydrogen, gasoline, etc) are produced and distributed through a pathway of conversion processes. The conversion technologies in the CAEPM account for the capital and operating costs of converting a commodity from one form to another (e.g. natural gas into electricity), or moving it from one place to another (e.g. transmission and distribution). There are approximately 63 conversion processes in the CAEPM. Appendix F includes a list of all the conversion processes, their descriptions, parameters, and data sources. In some cases, side calculations were needed to estimate the parameters. The appendix also describes these calculations. The sections below give an overview of the types of processes included in each sector along with a discussion of the structure and operation of the sectors.

The sections below present several diagrams of portions of the CAEPM. These show the processes included and their interconnections. The diagrams use a set of symbols to identify different types of processes. Table 12 shows the symbols used for nodes and links in the diagrams, along with brief descriptions.

**4.3.1. Electric generation sector**

The electric sector model includes descriptions of the range of technologies that are expected to be used within California in the coming decades. These include renewables – wind, biomass, geothermal, and solar. Figure 12 shows a diagram of the various components of the electric sector that are included in the model.

The electric sector modeling distinguishes between electric generation within California and sources of imported electricity. Within the state, it is expected that coal generation will not be allowed, or would not become economic (i.e., compared to importation of electricity generated by coal elsewhere). Consequently, within California, it is assumed that the primary generation will be from natural gas (both from combined cycle plants and from peaker plants such as combustion turbines), hydro, nuclear, and renewables such as wind, solar, and biomass.

The model structure includes coal generation in the Southwest that can be imported to California. Technologies based on pulverized coal and Integrated Gasification and Combined Cycle (IGCC) are available with and without CO₂ separation (transport and sequestration of CO₂ is handled separately). Under a CO₂ tax regime, the model can switch to sequestered coal capacity, or eliminate coal generation if it becomes too expensive. In these model runs, the total transmission capacity allowed is restricted to approximately the existing transmission capacity (6,000 MW).

Imports from the Northwest are also allowed in the model. However, the amount of energy available in each hour over the year is set by contracts. Currently the model does not include such contracts and the price of power is set to a high level so that it seldom is used. Contracts for power from the Northwest can be added in future versions.

The natural gas combined cycle and coal generation technologies have carbon-capture alternatives available in the CAEPM. Combined cycle generation is available as either a conventional generator or as a generator with CO₂ separation.

Nuclear generation capacity is fixed at the current capacity in the state (4,320 MW). State law does not allow nuclear capacity to expand until nuclear waste storage facilities become available.
While it is possible that there will be imports of electricity generated from natural gas, the model does not explicitly model these as imports. These would be represented as in-state natural gas generation. To a first approximation, these are equivalent in terms of investment and emissions.

Hydroelectricity is modeled as a total amount of hydroelectric energy that is available over the year. This generation is dispatched during the hours of the year when electricity is more expensive so as to maximize revenue to hydro operators while using the total hydroelectric energy available over the year. The generation capacity is fixed at the current hydroelectric capacity in California on the assumption that it will be difficult to significantly expand the capacity. This assumption could be relaxed in future analyses.

Wind is an intermittent generator. The model takes as input the hour-by-hour production per unit of wind generator capacity installed. The data in the current version of the model is based on four wind regions in California – Solano County, Altamont, the Tehachapis, and San Gorgonio – developed for the Intermittency Analysis Project (California Energy Commission 2007a).

Solar energy generation is also intermittent. The pattern of electric output, per unit of installed capacity, is taken from solar output of Central Valley (NREL 2008). The model currently uses cost data for photovoltaic (PV) generators. Solar thermal generation is not included in this analysis, though it may potentially have lower costs than PV. In future versions of the model, solar thermal generators (with the potential for heat storage, which allows for altering the pattern of electricity generation) could be modeled. However, the pattern of production is most critical in the summer and it will still be most economic to produce solar thermal electric power during the peak demand hours when the insolation is also highest, just as PV plants do. Consequently, it is expected that the operation of a solar thermal plant will be very similar to the operation of a PV plant and have a similar impact on the electric system.
4.3.2. Hydrogen production and regional considerations in hydrogen distribution

The hydrogen sector includes technologies for hydrogen production and distribution. The structure is shown in Figure 13. The hydrogen production model represents the fact that the urban parts of the state will have a high geographic density of demand (e.g. kg H₂/m²) while more rural areas have a low geographic density. These areas can be expected to have different technologies for production and distribution of hydrogen. The right hand side of Figure 13 represents the types of systems that can be used in low-density areas. It includes production by local electrolyzers and local natural gas reformers (both without possibilities for CO₂ sequestration). The left hand side of the diagram represents high-density regions. Here hydrogen can be produced through central station natural gas reforming (with and without sequestration), coal gasification with sequestration, and electrolysis.
Hydrogen fueling station capacity is a significant capital cost in the system. Each station has a peak vending rate (in tonnes per hour), so the total peak fueling rate in a geographic area is used to determine the minimum number of stations required. The relationship between peak fueling rate and the number of stations is used to determine the total capital investment required for fueling stations. In the current model, it is assumed that the number of stations is equal to the minimum number needed to meet the peak fueling rate. However, during the early years of deployment this would imply a very small number of stations in many regions. To build a practical system there will need to be a minimum geographic density of stations in a region (Nicholas 2004). Consequently, the capital investment in stations in the early years would be larger than is assumed in this model. This can be addressed in future work.
It is expected that hydrogen will eventually be produced at both small, local facilities (on the scale of a fueling station) and by large, centralized facilities located somewhat outside of the urban area. Local production is expected to be accomplished by either small electrolyzers or small natural gas reformers. The portion of hydrogen provided by local and centralized facilities is an input to the model.

When hydrogen is produced at a centralized facility for a particular region (e.g., an urban area), it can be transported to fueling stations by tanker trucks with compressed gas, tanker trucks with liquefied gas, and by pipelines. The capacity and capital investment required for any of these options depends on assumptions about the city size, the density of stations, and, in the case of trucks, their average driving speed. These are calculated and provided to the model as parameters based on the model presented in Yang and Ogden (2007). This is also discussed in greater detail in Appendix D-8 [H₂ delivery and refueling infrastructure].

Modeling the capital costs and penetration of pipelines poses a special problem in optimization models of this sort. These models assume that capacity for any production process can be added in small increments so that the total capacity, and investment cost, closely matches demand. This is approximately true for most types of facilities. However, pipeline capacity is not built in increments. When a pipeline is built, the entire line must be installed, and the entire capital cost is incurred. When hydrogen shipments are small, the total volume of hydrogen does not justify the large capital investment in the pipeline. Eventually the total volume of hydrogen to be shipped is large enough to justify an investment in a pipeline. At that point, in the real world, investors would begin to consider making the investment and the pipeline would be built.

The analysis assumes that pipelines can eventually serve Sacramento, San Francisco Bay Area, Los Angeles, and San Diego. The costs of pipelines for these areas are handled by a side calculation, not directly within the model itself. Appendix F provides more details of the calculation. The paragraphs below discuss the approach used for the analysis.

Delivering hydrogen by pipeline from a centralized facility to fueling stations requires a transmission line from the central facility to the city gate, and a set of distribution pipelines within the urban area. Since the transmission pipeline would generally pass through relatively unpopulated areas, its right-of-way costs would be substantially lower than the cost for the distribution pipeline. The length of the transmission pipeline is nominally assumed to be 10 km for each of the urban areas considered. Since the distance will be relatively short in most cases (tens of km) and the cost per km is smaller outside of the urban areas, the cost of the transmission pipelines has very little impact on the analysis.

Within the model, hydrogen can be transported by either trucks or by pipelines in each year. However, in the early years of a hydrogen infrastructure, the hydrogen volume is small and the cost of using the pipeline is very large compared to trucks, so the model will use trucks. The cost of transporting hydrogen by pipeline is based on the length of pipeline that must be installed. The length of distribution pipeline needed to cover an urban area depends on the geographic size of the area and the number of stations. A simple model of distribution pipeline length has been developed in Yang and Ogden (2007) and described in Appendix D-8. Based on this model and the pipeline cost estimates in Appendix D-8, the cost of a distribution pipeline was estimated for each area for each year modeled. The capital cost and operation and
maintenance cost was converted into a total annualized cost. For each year of the scenario, the
total volume of hydrogen to be transported and distributed is given. From this we compute the
price per unit of hydrogen needed to amortize the pipeline investment. This price is included in
the model as an operating cost, or markup, for the pipeline in each year modeled. In the early
years, when hydrogen volumes are small, this price is quite large (since the volumes are small)
and the pipeline is not competitive with other distribution pathways such as liquid hydrogen
trucks. In those years all of the hydrogen is transported by truck. By about 2030 in the scenario,
hydrogen volume increases to the point that the price of pipeline transportation becomes
competitive with other alternative transportation methods. At that point all of the hydrogen is
transported by pipeline.

4.3.3. Petroleum fuels sector
In these analyses, the fuel demands for vehicles are given by the scenarios, so there is no
economic competition between fuels. The analyses are concerned with the development of the
hydrogen and electric distribution systems that will result from the penetration of advanced
vehicles. Consequently, it is not necessary to model the petroleum refining and distribution
processes in great detail. The refining and distribution costs are modeled as a simple markup on
the cost of purchasing petroleum to meet the demand for petroleum fuels.

Biomass for vehicle fuels is not treated in this model but can be addressed in the future.

4.3.4. Carbon emissions and sequestration pathways
Several technologies in the electric and hydrogen production sectors sequester their CO₂
emissions. CAEPM accounts for the lowered efficiency of the processes due to the need to
capture the CO₂ and for the electricity required liquefying and transporting the CO₂. It is
assumed that the CO₂ will be sequestered by injection in geologic strata.

CO₂ is captured at the production/generation facility and is compressed to a liquid (or very
dense gas, depending on its temperature). It is then pumped through pipelines to a
sequestration site, where it is pumped down to a deep stratum. This pathway is represented by
the right hand side of Figure 14. All the CO₂ emitted by processes that captured CO₂ is summed
up at either the node “CaptCO₂ sum”, or “ComprCO₂ sum”. Two different summations are
made simply because the data available for some processes already include the capital cost and
electricity consumption required for liquefaction of CO₂ and others do not. In those cases that
the cost of liquefaction is not accounted for, the CO₂ produced from the plant in the model is not
in liquid form. These flows are directed to the node “CO₂ComprsSequest” which accounts for
the costs and the electricity needed to liquefy the CO₂. The CO₂ produced from the other
processes, whose data already includes the costs of compression, is already compressed. The
stream of CO₂ from these processes is sent directly to the sequestration node,
“CO₂SequestPump” which accounts for pumping costs and electricity to transport liquid CO₂ to
a sequestration site.

The cost and electricity requirements for transporting the liquid CO₂ by pipeline and injecting it
are modeled in the nodes “CO₂TransSequest” and “CO₂InjectSequest”. Just as in the case of H₂
pipelines, CO₂ pipelines will require non-incremental investments. In the current model a
nominal pipeline distance of 300 km is assumed. The costs of the pipeline are modeled as a
simple cost per tonne of CO₂ transported based on the pipeline distance, costs, and flow rate.
The pathway also includes a resource “CO2SequestRsrs” which is the capacity of the geologic storage. From the point of view of the model, sequestration capacity is a resource. In this analysis, we have placed no limits or costs on this resource. However, if there were an expense to acquire the rights to use a sequestration site, there could be a cost for the resources.

Many processes in the model do not include carbon sequestration. This is the case for vehicles, combustion turbines, and older, less efficient generators used to serve high electric loads. For these technologies the CO\(_2\) is simply vented to the atmosphere. All of these emissions are summed at the “VentCO2sum” node. The resource “CO2AtmosRsrs” represents the atmospheric sink for CO\(_2\). In some of the analyses a price can be placed on this resource to model a tax for CO\(_2\).

![Figure 14. Block diagram of the carbon capture and sequestration technologies](image-url)
4.3.5. **Distribution processes for natural gas, electricity, and petroleum**

Electricity, natural gas, and petroleum must be distributed to final end users. In this model these processes are modeled as simple price markups with a nominal efficiency.

4.4. **Resources**

The principal exogenous resources used by the CAEPM are natural gas, petroleum, and coal. The model assumes a scenario for the prices for these resources. Although it is true that their prices are, in principle, affected by the demands from the California energy system, these commodities are traded in much larger markets, and their prices would be primarily affected by events outside of the model, which are beyond the scope of this analysis.

In the natural gas sector, a price track based on the Energy Information Administration projections has been assumed (EIA 2008). These are shown in Table 13. The EIA provides price projections out to 2030. The values from 2030 to 2050 have been extrapolated. The well-head prices are the baseline natural gas prices for the model. The costs of transmission and distribution are estimated based on the EIA data (EIA 2008) and are added to the well-head prices to arrive at prices for natural gas in the electric generation and other sectors.

<table>
<thead>
<tr>
<th>Year</th>
<th>Wellhead prices</th>
<th>$/MMBTU</th>
<th>$/kWh</th>
</tr>
</thead>
<tbody>
<tr>
<td>2005</td>
<td>7.85</td>
<td>0.0268</td>
<td></td>
</tr>
<tr>
<td>2010</td>
<td>6.09</td>
<td>0.0208</td>
<td></td>
</tr>
<tr>
<td>2015</td>
<td>5.43</td>
<td>0.0185</td>
<td></td>
</tr>
<tr>
<td>2020</td>
<td>5.42</td>
<td>0.0185</td>
<td></td>
</tr>
<tr>
<td>2025</td>
<td>6.04</td>
<td>0.0206</td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td>6.60</td>
<td>0.0225</td>
<td></td>
</tr>
<tr>
<td>2035</td>
<td>7.29</td>
<td>0.0249</td>
<td></td>
</tr>
<tr>
<td>2040</td>
<td>7.98</td>
<td>0.0272</td>
<td></td>
</tr>
<tr>
<td>2045</td>
<td>8.67</td>
<td>0.0296</td>
<td></td>
</tr>
<tr>
<td>2050</td>
<td>9.37</td>
<td>0.0320</td>
<td></td>
</tr>
</tbody>
</table>

In these runs it is assumed that crude oil is priced at $50 per barrel. This seems to be somewhat optimistic at the time of writing. However, since the model is driven by scenarios over vehicle penetration and fuel demand, petroleum-based fuels do not directly compete with other fuels in the model. The price assumed for crude oil will affect the price of finished petroleum fuels, but it will not affect the competition between vehicle types. However, the total costs of the PHEV and the FCV strategies depend significantly on the assumed prices for natural gas and crude oil. The FCVs tend to reduce crude oil demand much more than the PHEVs do, at the expense of higher demands for natural gas. The impact of changing the relative prices for petroleum and natural gas are discussed in the section on results.

The coal-based generation used in the model comes from the Southwest. The price of coal assumed here is based on the price in the Four Corners area from EIA data (EIA 2006).
Biomass is also a resource in the model. In the scenarios that include a Renewable Portfolio Standard, biomass is used for electric generation. The total amount demanded in these runs is less than the amount projected to be available in California (California Energy Commission 2005d). Though not included in this analysis, biomass could also be used for $H_2$ production as well, and could be incorporated in future versions of the model.

The model allocates hydroelectric energy over the year. The total hydroelectric energy available in the model is 40 million MWh per year for all scenarios. This level is a typical, rounded value, from the total California hydro power during the 1990s (California Energy Commission 2007b). The model dispatches the energy such that it is used in the hours when it is most valuable and the total amount of hydroelectric energy used is equal to the total available. This is not, strictly speaking, the way that many hydro facilities are actually dispatched in California. Water is released from storage dams to meet a range of economic and environmental demands such as water supply and minimum flow levels in rivers. However this approach gives a good understanding of the role that hydroelectricity can play in balancing the energy production system, particularly when large intermittent generating capacities are included.

4.5. Storage processes
As noted earlier, storage processes provide buffers between the end-use demands and the production processes. This allows for a more efficient trade-off between capital and operating costs. In the vehicle fuels area, the storage processes include:

- PHEV on-board storage (batteries).
- Compressed hydrogen storage at vending stations.
- Liquid hydrogen storage at vending stations.
- Hydroelectric storage.

Within the model the storage processes hold a supply of product (e.g. electric energy, or hydrogen). The storage processes release this product as demanded by the user of the energy.

PHEVs are likely to be plugged in for long periods of time, especially at night. The on-board batteries of the PHEVs allow the vehicles to be charged in hours when other demands on the electric grid are lowest (primarily at night). The total capacity of the storage in the model is set to be one day’s average use (i.e. total annual demand/365). This is the aggregate storage capacity of all the vehicles.

In the case of hydrogen fueling stations, the demand for vehicle fueling has a strong diurnal pattern, with high demand during the daytime hours and very little at night. The storage at the station fills at night and empties during the day. The storage provides the buffer so that the hydrogen production processes can operate at a more constant rate and do not have to match the pattern of refueling. The model computes the operation of these storage processes endogenously to optimize both the operation and the capacities of the system.

In the analyses presented here, the fueling stations are allowed to have as much storage capacity as they need. Given this assumption, the fueling stations store for daily fluctuations and they store an additional amount for seasonal variations—they increase the amount in
storage during the winter and spring in order to have enough hydrogen on hand to meet the higher demands in the summer. This assumption allows for storage capacities that are higher than would be practical or economic at the fueling stations. The implications of restricting storage capacity are addressed in the discussion of the results.

The hydroelectric reservoir is a type of storage process. The reservoir node starts out filled at the beginning of the year. It then finds a price to charge such that it is only used at the most valuable hours and just uses up the total supply over the course of the year.

4.6. Description of scenarios

This analysis investigates ways that the energy system can be structured to accommodate the introduction of new types of vehicles. Several scenarios of vehicles penetration rates have been developed for the analysis. These have been combined with assumptions about policies to control CO$_2$ emissions.

4.6.1. Vehicle penetration scenarios

The analysis is based upon a set of scenarios on vehicle penetration for each type of vehicle out to 2050. One scenario assumes that conventional vehicles will be used exclusively. The others assume that one of advanced vehicles will penetrate the system. The scenarios include an estimate of the demands for gasoline, Diesel, electricity, and ethanol for the mix of vehicles over the scenario. For each of the advanced vehicles there are two scenarios, one assuming a medium penetration rate and the other assuming a high penetration rate. These analyses model the high penetration rate scenarios. The scenarios are described in section 3.2 and Appendix B. Figure 15 shows the total numbers of light duty vehicles assumed over time for all scenarios, and the numbers of advanced vehicles assumed for the PHEV and FCV hi-penetration rate scenarios. In all scenarios it is assumed that the light duty vehicle fleet will reach 51 million vehicles by 2050. In the FCV Hi Penetration case, it is assumed that by 2050 82% of vehicles will be FCV. In the PHEV hi penetration case it is assumed that 70% of the vehicles will be PHEV by 2050. In these two scenarios the PHEVs penetrate at a higher rate in the early years, but do not reach as high a total penetration.
4.6.2. Policy variations

The analyses developed here use two different policy regimes. The base case assumes no penetration by advanced vehicles and no policies to encourage the penetration of renewable energy or sequestered fossil electric generation. The second regime assumes a Renewable Portfolio Standard of 20% renewable penetration by year 2020. In this case, a mix of renewable capacities is specified for each year which together provide 20% of the electric energy demanded.

The Base Case is used as a benchmark so that we can better separate the contribution of the RPS from the penetration of advanced vehicles and determine if there are synergies, or antagonisms, between the advanced vehicles and the goals of the RPS.

Renewable portfolio scenarios

California’s Renewable Portfolio Standard requires the electric generation system to supply 20% of its generation from renewable sources by the year 2020. The RPS specifies the types of resources that can be used, but does not specify the mix. To forecast the impact of the RPS, this study has used a future mix of resources based on the mix assumed by the Intermittency Analysis Project (IAP) (California Energy Commission 2007a). The IAP assumes a mix of wind, biomass, geothermal, and solar capacities for the year 2020. This study uses a similar mix of capacities, but scaled each year to reach a level of 20% of generation by 2020. Table 14 shows the assumed mix of renewable generators capacities used in the RPS scenario.

We have assumed that wind will be supplied from four of the major California wind sites: Solano, Altamont, Tehachapi, and San Gorgonio. The IAP analysis maintains a realistic...
correlation between the power generated at each of the various wind resource areas in each hour. This should produce a realistic pattern of total wind power from the four sites.

Table 14: Renewable resource mix for 20% RPS (MW)

<table>
<thead>
<tr>
<th>Year</th>
<th>Renewable energy fraction</th>
<th>Wind Solano capacity</th>
<th>Wind Altamont capacity</th>
<th>Wind Tehachapi capacity</th>
<th>Wind San Gorgonio Capacity</th>
<th>Geothermal capacity</th>
<th>Biomass capacity</th>
<th>Solar</th>
</tr>
</thead>
<tbody>
<tr>
<td>2010</td>
<td>0.1</td>
<td>6.567E+02</td>
<td>6.567E+02</td>
<td>1.313E+03</td>
<td>6.567E+02</td>
<td>1.313E+03</td>
<td>4.925E+02</td>
<td>1.313E+03</td>
</tr>
<tr>
<td>2020</td>
<td>0.2</td>
<td>1.473E+03</td>
<td>1.473E+03</td>
<td>2.945E+03</td>
<td>2.945E+03</td>
<td>1.104E+03</td>
<td>2.945E+03</td>
<td></td>
</tr>
<tr>
<td>2030</td>
<td>0.2</td>
<td>1.589E+03</td>
<td>1.589E+03</td>
<td>3.179E+03</td>
<td>3.179E+03</td>
<td>1.192E+03</td>
<td>3.179E+03</td>
<td></td>
</tr>
<tr>
<td>2040</td>
<td>0.2</td>
<td>1.693E+03</td>
<td>1.693E+03</td>
<td>3.386E+03</td>
<td>3.386E+03</td>
<td>1.270E+03</td>
<td>3.386E+03</td>
<td></td>
</tr>
<tr>
<td>2050</td>
<td>0.2</td>
<td>1.784E+03</td>
<td>1.784E+03</td>
<td>3.567E+03</td>
<td>3.567E+03</td>
<td>1.338E+03</td>
<td>3.567E+03</td>
<td></td>
</tr>
</tbody>
</table>

Carbon taxes

The model is structured to impose taxes on CO₂ that is vented to the atmosphere. Raising this tax will eventually induce a shift from CO₂ venting technologies to sequestration technologies and renewables. At this time a few test runs have been made using CO₂ taxes. A systematic analysis will be made in future work.

4.6.3. Additional assumptions about the structure and operation of the energy system

The model makes a set of assumptions about the way that the energy system is structured and operated. The major assumptions include:

a) Amount of coal fired energy allowed from southwest remains constant (although the coal generation can shift from non-sequestered to sequestered generation)

b) Nuclear capacity is constant

c) Storage capacities for hydrogen storage at fueling stations are allowed to be large enough to operate without constraints.

d) PHEVs charge at the most economical hours, rather than on a fixed schedule

e) The interest rate for computing annualized costs is 10%

f) Transmission capacities for importing power from the northwest and southwest are held constant over the years. NW power is included in the model, with a relatively high price such that it is only used occasionally at peaks

These assumptions can be modified in future analyses.

Each of the scenarios covers the period from 2010 to 2050 with model runs made for the years 2010, 2020, 2030, 2040, and 2050. Each year is modeled individually to find the lowest cost structure and operating parameters given the demands and costs for that year.
4.7. Model results

Introduction of FCVs and PHEVs will reduce the total use of petroleum fuels, reducing both the total emissions and the total costs of purchasing and refining petroleum fuels. At the same time, both FCVs and PHEVs require considerable electricity either directly for charging the batteries on the PHEVs or indirectly for the production, transport and refueling of H₂ for the FCVs. Advanced vehicles can affect the mix of capacities of electric generators and their dispatch, affecting, in turn, fuel demands and emissions from the electric system. In particular, the model results show which types of generators are actually built and operate to produce the additional electricity needed to operate the advanced vehicles.

The high penetration scenarios for either FCV or PHEV increase the total amount of electrical energy that must be generated relative to the conventional vehicle case. The PHEVs increase total generation about 69 million MWh (16%). FCVs cause an increase of 37 million MWh (9%) for compression and production (even without electrolysis). They can also present significant loads to the system in some hours—particularly the PHEVs. The time-patterns of loads on the electric system determine both the structure and the operation of the system. In analyzing the advanced vehicles, it is essential to take into account the fact that the FCV hydrogen supply system has significant storage and PHEVs have the flexibility to charge when electricity is the lowest cost. Consequently, the capacity of the electric system does not necessarily increase proportionally with the increased generation. Instead, the structure of the system can change to economically accommodate the increased electricity generation requirements. Because the structure of the system changes, the carbon emissions from electric generation will not necessarily change in proportion to the increase in total energy.

The adoption of the Renewable Portfolio Standard (RPS) also will affect the structure and operation of the electricity system. The RPS introduces some technologies with reasonably constant generation (e.g. geothermal) and others that are intermittent and highly variable (solar and wind). The impact of the RPS can be quite different for a system that does not include the buffering of storage provided by the advanced vehicles. These analyses examine the impact of the RPS on the system with and without advanced vehicles.

4.7.1. Overview of discussion

The model results show the effects of advanced vehicles on the overall energy system, the electric system and the petroleum-based fuel system. This discussion describes the changes in capacities and operation, costs, emissions, and the tradeoffs between costs and emissions for the energy system that has been optimized to best meet all of the energy demands of the system. It also identifies the effects of the RPS on all of these issues, along with the interaction between the RPS and the advanced vehicles. The discussion addresses the following issues:

- Changes in system structure (capacities of technologies) and operation caused by penetration of advanced vehicles. The discussion shows the details of hourly operation in the electric sector and the operation of the vehicle fuels sector to illustrate the fundamentals of the interaction and the economic reasons for the shifts in overall capacity and operation.

- Impact of adopting the RPS on the conventional system and on the systems with advanced vehicles
• Impact of advanced vehicles and the RPS on system costs
• Impact of advanced vehicles and RPS on system \( \text{CO}_2 \) emissions
• Operation of the hydrogen production system
• Tradeoffs between costs and \( \text{CO}_2 \), with and without the RPS

4.7.2. Changes in system structure and operations, without the RPS

The initial question is what changes take place in both the structure and operation of the system when advanced vehicles are introduced. For each of the aspects of the system characteristics, the results are shown for each ten years over the scenario horizon (2010, 2020, 2030, 2040, and 2050). The model produces results for electric generation capacity, electric generation, system costs, and system \( \text{CO}_2 \) emissions. These are shown graphically in this section. Appendix F provides tables of the numeric values for these outputs.

The analysis uses a base case, which has only conventional vehicles and no RPS. The impacts of the advanced vehicles and the RPS are measured against changes in the system, costs and emissions relative to this base case.

To illustrate the changes, three types of charts are used. Figure 16 is an example of the first type, which shows the trajectory of basic system properties over time. Figure 16 shows the trajectory of electric generation capacities over time, while other charts show the trajectory of generation by different types of generators over time.

The second type of chart shows the changes between the base case and the other cases. Figure 17 is an example that illustrates the changes in the system that are caused by the penetration of advanced vehicles and the RPS. The upper left panel in the figure shows the total capacities of each types of generator for the base case of conventional vehicles with no RPS. The other panels show the difference between results for the base line case and each of the other vehicles, with and without the RPS.

The third type of chart shows the hourly operation of the system. These help illustrate the behaviors that lead to the system-wide changes in capacity and generation shown in the other figures. Figure 21 is an example. The upper panel of the figure shows dispatch of the electric system hour by hour for a representative time period. The lower panel shows the marginal electric prices each hour. In some other examples, there is a third panel that shows either the charging by PHEVs or hydrogen production. The hourly plots each show the operation of the system over a ten-day period (240 hours). They are presented in pairs. The first one shows the operation for a ten-day period in spring—when electric loads tend to be modest—while the other shows the operation in summer. The summer figures show the operation on the day with the highest electric load. In all cases, the same periods in spring and summer are shown so these can be compared between cases.

Turning first to changes in electric generation capacity, as noted, Figure 16 shows the evolution of electric generating capacity over time, while the changes in the system structure are highlighted in Figure 17. The introduction of the FCV increases the total generating capacity required by 2050 from about 90,000 MW in the base case to about 100,000 MW in the FCV case.
PHEVs, however, do not appreciably affect the total capacity required. This is due to the assumptions about fueling FCV and charging for the PHEV. The FCV fueling patterns follow a diurnal pattern similar to the fueling demand for gasoline, with most of the fueling during the day. Dispensing compressed hydrogen requires a significant amount of electricity to compress the hydrogen from the pipeline pressure to the vending pressure, so this load is added to the other loads on the system, even during the peak demand hours. PHEV are considerably more flexible. As can be seen in Figure 26, the PHEVs do not charge at all during the peak hours of the year so do not add to the total system load in those hours. This is discussed in more detail below.

The types of electric generating capacity also change substantially under these scenarios—even if the total capacity does not. The paragraphs below first discuss the types and magnitudes of system changes observed. Following that, the hourly dispatch of the system is shown in several graphs. These illustrate the causes of the changes.

In Figure 16, the RPS increases the system capacity in the conventional vehicle case because intermittent renewables have low capacity factors (around 30%) and additional dispatchable capacity is needed to manage this variability. Figure 17 shows that for both the FCV and the PHEVs there is a shift in capacity from peakers (represented in the model as combustion turbines) to combined cycle (a baseload generator).
Figure 16. Impact of vehicle penetration scenarios and Renewable Portfolio Standard on electric generation capacities
Figure 17. Changes in electric generation capacity for different vehicle types, with and without the RPS

The changes in capacity are reflected in the changes in generation from each type of generator. Figure 18 shows that the penetration of both the FCVs and the PHEVs increase the generation from the combined cycle generators – although the PHEVs increase the combined cycle generation considerably more.
Electric generation (MWh/yr)

<table>
<thead>
<tr>
<th>No RPS</th>
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<tbody>
<tr>
<td>Conventional vehicles</td>
<td>Conventional vehicles</td>
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</table>

<table>
<thead>
<tr>
<th>Year</th>
<th>2010</th>
<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation (MWh)</td>
<td>Geothermal</td>
<td>Biomass</td>
<td>Total Wind</td>
<td>Solar PV</td>
<td>N.G. Combustion Turbine</td>
</tr>
<tr>
<td>Generation (MWh)</td>
<td>Hydro</td>
<td>Nuclear</td>
<td>Import, SW</td>
<td>Hydro</td>
<td>Nuclear</td>
</tr>
</tbody>
</table>

| FCV |

<table>
<thead>
<tr>
<th>Year</th>
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<th>2020</th>
<th>2030</th>
<th>2040</th>
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<tbody>
<tr>
<td>Generation (MWh)</td>
<td>Geothermal</td>
<td>Biomass</td>
<td>Total Wind</td>
<td>Solar PV</td>
<td>N.G. Combustion Turbine</td>
</tr>
<tr>
<td>Generation (MWh)</td>
<td>Hydro</td>
<td>Nuclear</td>
<td>Import, SW</td>
<td>Hydro</td>
<td>Nuclear</td>
</tr>
</tbody>
</table>

| PHEV |

<table>
<thead>
<tr>
<th>Year</th>
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<th>2020</th>
<th>2030</th>
<th>2040</th>
<th>2050</th>
</tr>
</thead>
<tbody>
<tr>
<td>Generation (MWh)</td>
<td>Geothermal</td>
<td>Biomass</td>
<td>Total Wind</td>
<td>Solar PV</td>
<td>N.G. Combustion Turbine</td>
</tr>
<tr>
<td>Generation (MWh)</td>
<td>Hydro</td>
<td>Nuclear</td>
<td>Import, SW</td>
<td>Hydro</td>
<td>Nuclear</td>
</tr>
</tbody>
</table>

Figure 18. Impact of vehicle penetration scenarios and Renewable Portfolio Standard on annual electric generation

This shift towards combined cycle plants can be seen more clearly in Figure 19, which shows the differences between the cases. The peaker generation changes very little. In both the FCV case and the PHEV case the generation by combined cycle generators increases by 2050. In the FCV case, combined cycle generation increases by about 40,000,00 MWh (about 9% of total generation), while in the PHEV case combined cycle generation increases by about 60,000,000 MWh (about 14% of total generation)
Introducing either FCV or PHEV increases the total electric energy to be generated. They can also place significant loads on the system in some hours—particularly the PHEVs. Consequently, since the systems have a great deal of flexibility as to their operation due to storage processes, it is practical to shift at least some of the loads to off-peak hours. This can be seen in the hourly detail of electric generation dispatch vehicle fuels production.

**Figure 19. Changes in electric generation for advanced vehicle types, with and without the RPS**
The following figures illustrate the hourly system behavior over a ten-day periods (240 hours) in the spring and in the summer. All of the spring figures cover the same set of hours, starting at hour 2161 of the year (end of March). The summer figures start in hour 4801 (mid-July). The summer figures include the peak demand hour for the year. Figure 20 shows the key to the different types of generators in the dispatch figures.

Figure 21 and Figure 22 present the base case of conventional vehicles with no RPS. Figure 21 shows the behavior in the spring and Figure 22 shows behavior in the summer, including the day with the maximum demand over the year. The upper panels in the figures show the dispatch of the various generators. The lower panels show the marginal price of electricity. During the spring, the system can meet all demands by dispatching a set of baseload technologies (nuclear and imported coal power from the Southwest). There is also some hydro dispatched to meet the daily peaks. The electricity prices are fairly steady over this season. In the summer (Figure 22) the peak demands are substantially higher. The peaker generators (combustion turbines) must be dispatched to meet the load and hydro is used to a greater degree. The electricity prices show a strong diurnal pattern. The peak prices have been truncated in the graph since the maximum price can reach nearly 1 $/kWh. These high prices are realized when the demand approaches the total capacity of the system.

![Image: Key to types of generators in electric system dispatch figures]

**Figure 20. Key to types of generators in electric system dispatch figures**
Figure 21. Electric system dispatch and marginal electric prices in spring, conventional vehicles, no RPS, 2050

Figure 22. Electric system dispatch and marginal electric prices in summer, conventional vehicles, no RPS, 2050

Figure 22 illustrates small errors in the solution of the model. Dispatch in each hour is based on a comparison of the operating costs for each generator. The generators with the lowest operating costs should be dispatched up to their installed capacities. During a number of hours with peak demands the combined cycle and hydro generators are not quite dispatched up to their full capacity and the peaker is dispatched to serve the remaining load. This can lead to slightly more peaker generation than is optimal. Over the full year the difference in total generation is quite small.
When FCVs are deployed electricity is needed to produce, ship, and vend hydrogen. Figure 23 shows the springtime pattern of electricity production and prices, and the hydrogen production rates. In the analyses presented here, the steam methane reformer is the predominant method for producing hydrogen. The middle panel of Figure 23 shows that the pattern of hydrogen production is relatively uniform over the hours. In contrast, Figure 24 shows the pattern of production during the summer. Here the patterns of production respond to the patterns on the electricity price with production curtailed during those hours when the price is high.

**Figure 23. Electric system dispatch and H2 production patterns for FCVs in spring, no RPS, 2050**
It was pointed out in the discussion of overall system changes that the combined cycle capacity increased in the case of the PHEVs. Figure 25 and Figure 26 illustrate this on the hour-by-hour level. In both figures the overnight demands are much higher than they are in either the conventional vehicle or the FCV case. This is due to the charging of vehicles primarily overnight. In the spring there is a nighttime peak in charging, although there is still significant charging during the day. In the summer, during peak periods, the charging is done entirely at night.

The PHEV charging patterns also interact with electricity price patterns. During the spring, the charging pattern of the PHEVs helps to maintain the electric price fairly constant day and night. During the peak summer months, however, the peak electric demands from all other uses of electricity approach the total capacity of the system so prices have a strong diurnal pattern with high peaks. Although there are high daytime peaks, the charging patterns during the night maintain the nighttime prices at a constant level compared to the conventional vehicle case in Figure 22. Figure 26 provides another good example of the effect of the PHEVs charging on electric prices. The period between hours 145 to 193 covers two days with slightly lower peak demands compared to the other days in the figure. The PHEVs charging patterns are able to maintain a nearly constant electric price, during this period.
Increasing the off-peak loads encourage investment in baseload technologies (e.g., combined cycle). At the same time, the fact that the peak loads are not increased means that the total capacity required does not increase, so the peaker capacity is replaced by the additional baseload capacity.

![Electric system dispatch](image1)

![PHEV charging](image2)

![Electric marginal price](image3)

**Figure 25.** Electric system dispatch and PHEV charging patterns in spring, no RPS, 2050
Figure 26. Electric system dispatch and PHEV charging patterns in summer, no RPS, 2050

Note that maximum price is about 0.80/kWh

The load duration curve of electric demands provides another way to illustrate the interaction between the advanced vehicles and the electric system. Figure 27 shows the load duration curves for each of the vehicle cases. The FCVs tend to raise the average loads, but do not change the shape of the LDC appreciably. However, the PHEVs do not increase the peak demand and flatten out the loads during the rest of the year.
### 4.7.3. Impacts of adopting the RPS

The RPS introduces several renewable resources to the electric generation system. Some of these renewable energy sources can generate at a constant rate (i.e. geothermal) and tend to displace other base load technologies. Others, such as wind and solar, are intermittent. Their effect on the system depends on the hours that they generate over the year.

Figure 28 through Figure 33 also show the impacts of the RPS on the electric system for each of the vehicle scenarios. In general, the RPS leads to an increase in the total installed capacity since some of the renewables only generate intermittently (i.e. have lower availability) and a larger capacity is needed to produce the same amount of energy.

In each vehicle case, the RPS causes a decrease in the combined cycle capacity compared to the case without the RPS. This is due partly to the introduction of geothermal, which replaces the combined cycle capacity. It is also due to the fact that the wind component of the RPS frequently generates at night. This reduces the demand to the combined cycle in those hours, reducing the capacity factor of the combined cycle generators. To optimize, the capacity of the combined cycle generators decreases so as to improve their capacity factor.

Introducing the RPS tends to moderate the behavior of the system to a small degree in those hours that the wind or solar is available. These technologies tend to provide a bit more power when they generate which moderates prices and allows more hydrogen production or PHEV charging in some hours than would have occurred the conventional system. In Figure 31, the presence of the wind allows for a more constant hydrogen production rate compared to the case without the RPS shown in Figure 24. In the PHEV case, Figure 32 illustrates that vehicle charging can be higher during many of the daytime hours than in the case without the RPS shown in Figure 25.
Figure 28. Electric system dispatch and marginal costs in spring, conventional vehicles, with RPS, 2050

Figure 29. Electric system dispatch and marginal costs in summer, conventional vehicles, with RPS, 2050
Figure 30. Electric system dispatch and H2 production patterns in spring, with RPS, 2050

Figure 31. Electric system dispatch and H2 production patterns in summer, with RPS, 2050
Figure 32. Electric system dispatch and PHEV charging patterns in spring, with RPS, 2050

Figure 33. Electric system dispatch and PHEV charging patterns in summer, with RPS, 2050
4.7.4. **Impacts on system costs**

Figure 34 and Figure 35 show the trajectory of cost components and the differences in costs similar to the previous figures. The introduction of advanced vehicles leads to a clear cost savings in this analysis due to the savings in crude oil purchases. It is assumed here that crude oil cost $50/bbl. If prices were to climb higher over time, the savings would increase. However, the price of natural gas is also an important cost component. The natural gas prices here are based on EIA projections. Later sections discuss the differential effects of petroleum and natural gas prices.

These analyses do not explicitly include the capital and non-fuel costs of the respective vehicles required for the scenarios. There could be significant differences between the vehicle costs, which should be taken into account in any final comparison. The implications for vehicle costs are discussed below.
### Annual system cost components (k$/yr)

<table>
<thead>
<tr>
<th></th>
<th>No RPS</th>
<th>With RPS</th>
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</thead>
<tbody>
<tr>
<td><strong>Conventional vehicles</strong></td>
<td></td>
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<tr>
<td>Crv V no RPS</td>
<td><img src="image1.png" alt="Graph" /></td>
<td><img src="image2.png" alt="Graph" /></td>
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<tr>
<td>Crv V with RPS</td>
<td><img src="image3.png" alt="Graph" /></td>
<td><img src="image4.png" alt="Graph" /></td>
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<tr>
<td>FCV</td>
<td><img src="image5.png" alt="Graph" /></td>
<td><img src="image6.png" alt="Graph" /></td>
</tr>
<tr>
<td>PHEV</td>
<td><img src="image7.png" alt="Graph" /></td>
<td><img src="image8.png" alt="Graph" /></td>
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#### Figure 34. Components of system cost over time
Figure 35. Changes in the components of system costs

Cost savings per vehicle
The introduction of advanced vehicles results in an overall net savings to the fuel supply system. The analysis here does not include the cost of the advanced vehicles themselves, which could be significant. This section evaluates the fuel-related cost savings per vehicle, which could be used to offset increases in the costs of the advanced vehicles. Figure 36 shows the total annual cost reductions as a function of the total number of advanced vehicles and the crude oil prices. Table 15: Annual cost reduction as function of the penetration of advanced vehicles for different crude oil prices shows the cost savings per vehicle for the FCVs and the PHEVs as a
function of crude oil prices (the cost reductions per vehicle are the slopes of the linear fit lines in Figure 36).

The savings per vehicle are sensitive to the assumed price of crude oil. At a price of $25/bbl, the fuel for FCVs is actually more costly than using conventional fuels, with an additional annual cost of $91/vehicle (that is, a negative cost reduction), while the PHEV give an annual cost reduction of $128/vehicle. At a price of $150/bbl the cost reduction for FCVs is $1,618/vehicle and $1,171/vehicle for PHEVs. These cost savings are a result of the high efficiency of these vehicles relative to conventional gasoline vehicles. We note that at low petroleum prices the PHEV yield a greater saving, while at high prices the FCV yield a greater savings. At $66/bbl the savings are equal.
Figure 36A, B, C, D, and E. Total annual cost reduction in fuel supply sector as a function of the number of advanced PHEVs and FCVs.
Table 15: Annual cost reduction as function of the penetration of advanced vehicles for different crude oil prices

<table>
<thead>
<tr>
<th>Crude oil price ($/bbl)</th>
<th>FCV</th>
<th>PHEV</th>
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<tbody>
<tr>
<td></td>
<td>Annual cost reduction per vehicle ($/yr)</td>
<td>Annual cost reduction per vehicle ($/yr)</td>
</tr>
<tr>
<td>25</td>
<td>-91</td>
<td>128</td>
</tr>
<tr>
<td>50</td>
<td>251</td>
<td>336</td>
</tr>
<tr>
<td>66</td>
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<td>470</td>
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<tr>
<td>100</td>
<td>935</td>
<td>754</td>
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<tr>
<td>150</td>
<td>1618</td>
<td>1171</td>
</tr>
</tbody>
</table>

For both vehicle types the reduction in petroleum use results in an increase in natural gas use. Figure 37 shows the trade-off between petroleum and natural gas for both types of vehicles. The FCVs increase the amount of natural gas used nearly twice as much per unit petroleum reduction. This result comes from the assumptions about fuel requirements for the advanced vehicles and the feedstock requirements for producing hydrogen by steam reforming and producing electricity. Producing a unit of hydrogen energy for the fuel cell vehicles requires less natural gas than producing a unit of electric energy for the PHEV. But, the PHEVs are considerably more efficient at converting electricity into miles than the FCVs is at converting hydrogen into miles, so considerably less electricity must be produced per unit of petroleum saved. If natural gas were to become less expensive compared to petroleum, the costs of the FCV system would become more favorable. Conversely, lower petroleum prices favor the PHEV system.
4.7.5. Impacts on System CO₂ emissions

Figure 38 and Figure 39 illustrate the major sources and quantities of CO₂ emissions over the model horizon. The two upper panels show the emissions given that conventional vehicles are used with and without an RPS. Under either of these policies, emissions climb steadily in proposition to growth of the system.

Both the fuel cell vehicles and the PHEV substantially reduce the total emission from vehicles. In both cases, emission rates peak around 2020 – 2030 and then begin to decline as the advanced vehicle penetrate.

In the FCV case, the emissions from the vehicles themselves are almost eliminated by 2050, though there are significant CO₂ emissions that are released in producing H₂ from the natural gas reforming process. By 2050, we do see greater CO₂ emissions reductions from the FCV compared to the PHEVs. With the FCVs, the annual emissions in 2050 are around 250 million tonnes per year while with the PHEVs the emissions are a bit less than 300 million tonnes per year.
### Annual system CO2 management (Tonnes/yr)

<table>
<thead>
<tr>
<th>No RPS</th>
<th>With RPS</th>
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<tbody>
<tr>
<td><strong>Conventional vehicles</strong></td>
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<td><img src="image3" alt="Graph" /></td>
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<tr>
<td><strong>FCV</strong></td>
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<tr>
<td><img src="image7" alt="Graph" /></td>
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<tr>
<td><strong>PHEV</strong></td>
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*Figure 38. Trajectories of CO2 emissions from fuel supply under various scenarios*
### Changes in components of CO2 management (Tonnes/yr)

<table>
<thead>
<tr>
<th></th>
<th>No RPS</th>
<th>With RPS</th>
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<tbody>
<tr>
<td><strong>Conventional vehicles</strong></td>
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<tr>
<td><strong>FCV</strong></td>
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<tr>
<td><strong>PHEV</strong></td>
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</table>

#### Figure 39. Changes in electricity and fuel supply system carbon emissions under various scenarios

Both the FCVs and the PHEVs reduce CO$_2$ emissions by displacing petroleum with natural gas. Figure 39 shows the total reduction in CO$_2$ emissions as a function of the number of advanced vehicles. The slopes of the linear fits are quite similar and indicate that the FCVs reduce annual emissions by about 2.3 tonnes/vehicle/yr and the PHEVs reduce emissions by about 2.2 tonnes/vehicle/yr.
4.7.6. Hydrogen production and distribution

Hydrogen production and distribution in high density areas

Within the high density areas of the state, hydrogen was produced using centralized natural gas reformers. Other techniques such as coal gasification or electrolysis are not competitive.

In the early years of the scenario, when total demand is small, the hydrogen is distributed using liquefied hydrogen tanker trucks. However, by 2030 the volume of hydrogen increases to the point where pipelines became competitive and are used for distribution. (Appendix F discusses the costs of pipelines over time). Since this model is based on a yearly snapshot, it does not model the foresight and investment decisions involved in making the transition from trucks to pipeline. Several possible scenarios might govern such a transition. Under one view, pipeline investors will anticipate that the pipelines will become competitive and will build them out early, possibly before the volumes are large enough to fully justify the investment. This strategy would lead to higher H\(_2\) delivery prices as the pipeline is underutilized and the capital cost per unit of H\(_2\) delivered is high. Over time, as the volume of H\(_2\) increases, the capital cost per unit of H\(_2\) delivered would decrease. Another scenario suggests that the liquid H\(_2\) system (including liquefier and liquid tanker trucks) will become established for a decade or more, and will take some time to dislodge. Once the capital costs of the tanker infrastructure are paid off, they could remain competitive for some years by lowering prices closer to their operating costs. Under this scenario, pipeline investors may delay construction of pipelines a few years until the hydrogen volumes are high enough that the pipeline costing can compete effectively with tanker trucks. A third possibility is that the investors that develop the tanker infrastructure are the same investors that develop the pipeline infrastructure, so that the transition from tankers to pipelines is carefully managed to maximize profit. In any case, the transition would be
financially viable somewhere in the 2030 time frame (when around 2 million tonnes of H₂ are
produced annually).

**Hydrogen production and distribution in low density areas**
In low density areas, production is by a central reformer with delivery by compressed gas
tanker trucks. The local production methods, which operate at the scale of a station (electrolysis
and small natural gas reformer), were not used in this model.

**Hydrogen storage at pipeline stations**
The level of storage in the pipeline stations is one of the issues bearing on the design of a
hydrogen fueling infrastructure. In these runs, the storage capacity was not constrained. Under
these assumptions, the pattern of storage at the pipeline stations shows a clear seasonal pattern
with hydrogen stored during the winter and spring to be used during the summer. Figure 41
shows the case without the RPS for 2050. The maximum quantity in storage over the year is
200,000 tonnes of hydrogen. This corresponds to about seven days of hydrogen demand.
Although seven days is much more storage than would be practical at fueling stations, that fact
that only seven days is used when the model is unconstrained suggests that the system can
operate with smaller, more practical, storage capacities. More reasonable constraints for H₂
storage in the hydrogen infrastructure system (up to one day of storage) could be addressed in
future research.

![Figure 41. Quantity of H2 in storage at pipeline stations over the year for FCV, 2050, no RPS](image)

The seasonal storage required can be reduced by increasing the steam reformer capacity to
produce hydrogen at a higher rate during the summer. A rough estimate of the additional
capacity and cost can be made based on the figure. The system stores about 200,000 tonnes of
hydrogen, which is drawn down over approximately 90 days (2,160 hours) in the summer. The
additional reformer capacity would have to produce approximately an extra 92.6 tonnes per
hour to replace the seasonally stored hydrogen. The model solution currently has a production
capacity of 1,400 tonnes per hour, so the capacity would need to increase about 7%, assuming
that the additional capacity operated at 100% capacity factor. Reformer capacity cost is about $7.4 million per (tonne/hr capacity). The additional capacity would cost about $685 million, or about $80.5 million per year at a 10% discount rate. Since the total hydrogen supplied in 2050 is 10.4 million tonnes, this would increase costs of hydrogen by about $7.7/tonne. Though storage costs are not included in this analysis, this increase in costs from the additional reformer capacity would be more than made up from the reduction in system storage costs (estimates are between $400-$1000/kg).

Hourly prices for hydrogen at the pipeline stations are calculated within the model. Figure 42 shows the price duration curve for these prices in 2050. For nearly all the hours of the year, the price is determined by the operating costs of the hydrogen supply system. In those few hours when the demand for hydrogen is close to the system capacity, the prices spike to a level to cover the capital costs—particularly the capital costs of the stations. This behavior represents a real-time pricing regime. In actual practice, average pricing would probably be established to smooth out the extreme price spikes as is the case with most storable commodities.

![Price duration curve for hydrogen vended at pipeline stations in 2050](image)

**Figure 42. Price duration curve for hydrogen vended at pipeline stations in 2050**

### 4.8. CAEP Model Conclusions

The introduction of advanced vehicles reduces CO₂ emissions from the system as a whole. Both FCVs and PHEVs do increase the emissions from the electric generation and hydrogen infrastructure systems, but this increase is much smaller than the reduction in emissions from
vehicles themselves. The FCVs and the PHEVs tend to reduce emissions to a similar degree from conventional vehicles. By 2050, the FCVs reduce CO₂ emissions by 27% compared to conventional vehicles, and the PHEVs reduce emissions by 20%.

Under the assumptions in these analyses, both types of vehicles reduce the total cost of the energy supply to some degree. The FCVs reduce costs by about 9% and the PHEVs reduce costs by about 12%. Much of the cost reduction comes from the reduction in petroleum purchases, so this conclusion is highly dependent on the assumed cost of petroleum. In these analyses the petroleum price was assumed to be $50/bbl. At higher prices for petroleum the cost reductions would be greater. Higher petroleum prices would tend to favor the FCVs over the PHEVs since the FCVs reduce petroleum demand to a greater degree.

Producing and distributing hydrogen makes relatively small demands on the electric system, and consequently has relatively little impact on the structure and operation of the system. There is some interaction between the hydrogen production and the rest of the system in that the production of hydrogen is curtailed during peak hours in the summer.

The PHEVs obtain much of their energy from electricity and have a substantial effect on the electric generation system structure. The PHEVs charge largely at night when other demands are low. There is some charging during the day for much of the year, however, for the highest demand days in the summer there is no charging during the day. Since the peak demands on the electric system do not change, the total electric generation capacity does not change (compared to conventional vehicles). But there is a clear shift in the composition of the electric generators. The fact that the PHEVs charge at night increases the electric demand at night, though overall demand is still less than during the day. Consequently, the system shifts to a higher capacity of baseload generators. This allows for a reduction in the peaker capacity. By 2050 the baseload capacity increases about 18% compared to the conventional vehicle case, while the peaker capacity decreases about 26%.

The PHEVs within the model have a charging pattern that is highly coordinated with the conditions on the electric grid. This is easy to achieve within a model, however, to actually achieve such coordination in the real world will require a “smart grid” so that consumers get the correct signals to charge their vehicles at the best hours and the best rates to optimize the operation of the grid.

The introduction of the RPS does not change the overall costs appreciably. Although the total capital cost increases, the increase is offset by a reduction in the operating costs. The RPS does reduce overall CO₂ emissions by about 9 to 14% depending on the year and the vehicle scenario. It is not obvious that one type of vehicle or the other works better or worse with the RPS. The charging patterns for the PHEVs do change slightly depending on the availability of wind and solar energy—charging rates are higher in hours with ample wind generation compared to those same hours without the RPS. This further reinforces the conclusion that that the PHEV strategy will require a smart grid to manage the charging of the vehicles.

Models, such as the one upon which this analysis is based, are rarely “finished” as there are always improvements to be made that can improve the representation of or include another process or technology. This CAEP model will continue to improve its representation of H₂ infrastructure, vehicle charging patterns, and a host of other model additions and
improvements. Future work will incorporate these changes and run additional scenarios with different policies, such as carbon taxes and cap and trade, in order to improve our understanding of the impacts of advanced vehicles and fuels on our energy system.
5.0 Project Conclusions and Recommendations

The goal of the Advanced Energy Pathways project is to improve understanding of how the introduction of advanced vehicle technology and alternative fuels in California will impact the structure and operation of its energy system and resulting greenhouse gas (GHG) emissions. Many studies and assessments of advanced vehicle technologies do not take into account the effects of fuel production for these vehicles on the existing energy system. Instead, when comparing an advanced vehicle (such as a hydrogen FCV or PHEV) with a conventional vehicle, these studies simply calculate the average life-cycle emissions associated with gasoline and the equivalent amount of alternative fuel (e.g. ethanol, hydrogen or electricity) to go the same distance. This simple comparison is useful, but does not capture important impacts that would arise from a large penetration of advanced vehicles using alternative fuels, especially related to the interactions between the fuel and vehicle infrastructure and the rest of the energy system. This interaction will lead to changes in the composition, structure and operation of the entire energy system and influence the resulting costs, emissions and resource usage.

When additional electricity loads, such as vehicles, are added to the electricity grid, the grid dispatches existing electric power plants to generate the extra electricity needed to satisfy the additional demand. The power plants that are dispatched typically have very different characteristics than the system average. The timing of these additional demands is critical in determining the cost, resource use and emissions impacts associated these vehicles. Modeling of the energy system is essential for understanding how the energy system (especially electricity) would respond to the introduction of advanced vehicles and how the real-time interactions between the various sectors will influence and dynamically alter each sector.

Technical Assessments of Advanced Vehicle and Fuel Technologies

The first section of the report described a number of advanced vehicle and fuel technologies that may be used in California to help meet goals related to reducing criteria pollutants, greenhouse gas emissions and petroleum usage. This section and detailed chapters in Appendices C and D provide detailed technical information regarding these technologies and how they can help to achieve higher efficiency, reduce criteria emissions or lower GHGs. These sections provided information about costs, efficiency, emissions, and infrastructure and other important considerations about these technologies that could be widely employed in the state. A key finding from this analysis is that multiple vehicle options are available for improving efficiency of light-duty vehicle, but that the use of low-carbon fuels (such as cellulosic ethanol, hydrogen or electricity) is a critical element in trying to reduce GHG emissions. These advanced vehicles will tend to cost more than conventional vehicles, but fuel savings may lead to lower overall life-cycle costs. Key challenges from advanced vehicles are bringing down costs of hydrogen fuel cells and hydrogen storage as well as reducing battery costs. On the fuel side, key challenges include advancing technologies and obtaining sufficient biomass for the production of cellulosic ethanol, infrastructure challenges associated with hydrogen, and validating carbon capture and sequestration as a viable solution for fossil-based fuels and electricity production.

Energy Demand Scenarios
In order to understand the impact of advanced vehicles on the energy system, it is critical to understand the future energy system context in which their introduction and use would occur. The challenge of this, of course, is that knowing what this future context is like requires a prediction of the future. One solution to this issue is to develop scenarios for the energy system model so that multiple futures can be examined for the introduction of various kinds of advanced vehicles and alternative fuels. This section of the report included a number of energy demand scenarios for electricity, natural gas and transportation fuel that represent different energy futures. A wide range of population, activity and efficiency assumptions result in these differing energy futures. Beyond providing a basis for energy system modeling, energy demand scenarios such as these provide insights into the range of potential energy demands and the sensitivity of these demands to a number of input assumptions. Among the important results from these scenarios is that the activity drivers (population and energy service demand) are critical factors in determining the energy demand. While efficiency is important, when coupled with the baseline activity parameters, it has only a moderate effect on overall energy demand. The largest impact on total energy demand was a result of changes in assumptions about population and economic activity (such as GSP or other activity drivers). These drivers play a large role in determining the extent to which technologies (such as alternative fuels and advanced vehicles) will be needed in order to reduce future GHG emissions and the baseline set of assumptions impose a significant challenge for these technologies as energy demands are expected to increase, quite significantly, into the future.

These scenarios also include market penetration profiles for advanced vehicle technologies, which were obtained from a number of different literature sources. The vehicle scenarios contained two separate profiles for market penetration for flexible fuel vehicles (FFVs) that can run on ethanol, fuel cell vehicles (FCVs) and plug-in hybrid electric vehicles (PHEVs). These represent optimistic and aggressive rates of adoption for these vehicles in order to understand the potential for these vehicles and fuels to make a difference in total energy use, GHG emissions and other important parameters. Each of the vehicles is expected, given aggressive technology development and favorable policy support, to be able to make up more than 50% of new light-duty vehicle sales by 2050. FFVs, because they only require minor modifications of existing ICE vehicles, can achieve very high sales penetration fairly rapidly. FCVs can also achieve very high rates of adoption, if technical and cost targets are met and convenient refueling infrastructure development occurs concurrently. PHEVs scenarios also show rapid growth, though their adoption could be limited by lack of recharging infrastructure availability and high costs.

Energy System Modeling

The CAEPM model was used to analyze a future energy system in California based upon the energy demand and vehicle penetration scenarios. Several scenarios were examined, using the baseline energy demand scenario (for electricity and natural gas), with three different vehicle profiles (conventional vehicles, PHEVs and FCVs) and two different policy scenarios (with and without an RPS). The advanced vehicle scenarios are based upon the PHEV_high and FCV_high profiles which lead to these vehicles comprising 70% and 82% of total vehicles by 2050. The energy system model optimizes the appropriate composition and operation of infrastructure technologies to produce electricity and fuels to meet demand in the least cost manner. The model then assesses the emissions, costs and resource use of the energy system.
By comparing these metrics between the different scenarios, the model can determine the impact of the adoption of the RPS, the introduction of advanced vehicle technologies and their interaction.

One of the key model results relates to the change in the optimal composition of the electric sector with the introduction of advanced vehicles. The conventional (non-vehicle related) electricity demand exhibits a daytime peak and the electric sector is optimized to meet this electric profile in the least cost manner. The FCV case requires a significant amount of additional electricity (13% more than conventional case in 2050) and adds basically the same amount to the electric grid capacity requirements (13%). The PHEV case requires even more electricity (22% more than conventional case in 2050) but does not require much additional electricity capacity (1%). This is a result of the assumption that PHEVs are very flexible in their charging behavior and do not charge during the daytime peak and add to peak demands. PHEV-related electric demands are assumed to be more flexible than FCV-related electric demands. PHEVs are assumed to be able to charge anytime that the price is low and as a result exhibit the optimal load profile from a cost perspective. Some of the FCV electric demand is able to respond to price, but other components, such as those occurring at the refueling station, because of a fixed refueling profile, must occur when people are refueling their vehicles during the daytime. As a result, FCVs can add some additional load to peak electricity demands. The addition of demands that exhibit some flexibility in timing allows the system to arrange these demands in order to lower overall system cost by utilizing generators that have higher capacity factors, such as intermediate natural gas combined cycle plants. The added benefit is that these intermediate power plants are more efficient and produce lower emissions than peaker plants.

The model results show that the introduction of advanced vehicles reduced systemwide CO$_2$ emissions relative to a case with only conventional vehicles. FCVs reduce total vehicle CO$_2$ emissions by 27% and PHEVs reduce vehicle emissions by 20%. Even with the higher penetration assumed by FCVs relative to PHEVs (82% vs 70%), the CO$_2$ reduction per FCV is approximately 15% higher than per PHEV. And even with these reductions relative to the baseline, this still results in an increase in emissions over the modeling period (6% increase in the FCV case and 16% increase for PHEVs between 2010 and 2050). The model results show a significant reduction in emissions from the vehicle tailpipe and an increase in emission from the fuel (hydrogen or electricity) production. The model also shows that the RPS can reduce CO$_2$ emissions (5-8%), and but do not significantly impact total system costs and can even lower costs (slightly) in the advanced vehicle cases. This shows how flexibility in loads can help to enable the usage of intermittent renewables such as solar and wind.

Another model result shows that both types of advanced vehicles reduce the total energy infrastructure cost of refueling vehicles (with H$_2$ or electricity) relative to gasoline infrastructure. However, this result does not include the cost of vehicles only with supplying fuel. With respect to fueling costs (including additional infrastructure costs), PHEVs reduce refueling costs by a greater amount than FCVs (by more than twice the amount per vehicle). This is a result of the fact that in this analysis PHEVs are not assumed to require any additional refueling infrastructure. Additional electrical service to garages for many older homes and public charging infrastructure may be needed to encourage those without off-street parking.
Conclusion Summary

The use of advanced vehicles such as FCVs and PHEVs in California are expected to have wide-ranging impacts. These vehicles are significantly more efficient than conventional vehicles that use an internal combustion engine and they run on electricity and hydrogen, two energy carriers that are decarbonized and can be produced from a variety of domestic resources. These two factors can greatly reduce greenhouse gas emissions from light-duty vehicle transportation. These benefits are well documented. Other important impacts that are not as widely understood, but are still quite important, are the focus of this report and analysis. These impacts include the change in structure, cost, resource usage, and emissions of the electric sector. Because the energy system is moving towards more integration between the electric and transportation sectors, the addition of advanced vehicles and supporting infrastructure will influence the optimal structure of the overall energy system. In general, the addition of FCVs and PHEVs reduces GHG emissions and costs of providing energy from the energy system in California.
6.0 References


Knight, B. 2006. Personal communication with Ben Knight, vice president of R&D for American Honda Motor Company.


Lamont (1994), Lamont, A.D., User’s guide to the META•Net economic modeling system, Lawrence Livermore National Laboratory, 1994, UCRL-ID-122511


# 7.0 Glossary

<table>
<thead>
<tr>
<th>Acronym/abbreviation</th>
<th>Original term</th>
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<tbody>
<tr>
<td>BEV</td>
<td>battery electric vehicle</td>
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<tr>
<td>Btu</td>
<td>British thermal unit</td>
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<td>CCS</td>
<td>carbon capture and sequestration</td>
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<tr>
<td>CI</td>
<td>compression ignition</td>
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<td>CIDI</td>
<td>compression-ignition direct injection</td>
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<td>CO</td>
<td>carbon monoxide</td>
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<td>CVT</td>
<td>continuously variable transmission</td>
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<td>DPF</td>
<td>diesel particulate filter</td>
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<td>EMAT</td>
<td>electro-mechanical automatic transmission</td>
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<td>g</td>
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<td>GETF</td>
<td>Global Environment and Technology Foundation</td>
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<td>GHG</td>
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<td>GSP</td>
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<td>GWh</td>
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<td>H₂</td>
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<td>HCCI</td>
<td>homogeneous charge compression ignition</td>
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<td>HEV</td>
<td>hybrid electric vehicle</td>
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<td>ICE</td>
<td>internal combustion engine</td>
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<td>IGCC</td>
<td>integrated gasification combined cycle</td>
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<td>LCFS</td>
<td>low-carbon fuel standard</td>
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<td>LNT</td>
<td>lean NOx trap</td>
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<td>liquefied petroleum gas</td>
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<td>MJ</td>
<td>megajoule</td>
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<td>MM</td>
<td>million</td>
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<tr>
<td>MMgal</td>
<td>millions of gallons</td>
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<tr>
<td>MMgge</td>
<td>millions of gallongs gasoline equivalent</td>
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<tr>
<td>MMkg</td>
<td>millions of kilograms</td>
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<td>mpg</td>
<td>miles per gallon</td>
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<td>mpgge</td>
<td>miles per gallon gasoline equivalent</td>
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<td>Mt</td>
<td>megaton</td>
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<td>NiMH</td>
<td>nickel metal hydride</td>
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<td>NOx</td>
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<td>PEM</td>
<td>proton exchange membrane</td>
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<td>PHEV</td>
<td>plug-in hybrid electric vehicle</td>
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<td>PM</td>
<td>particulate matter</td>
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<td>R&amp;D</td>
<td>research and development</td>
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<td>Short Form</td>
<td>Full Form</td>
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<tr>
<td>rpm</td>
<td>revolutions per minute</td>
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<td>RPS</td>
<td>renewable portfolio standard</td>
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<tr>
<td>SCR</td>
<td>selective catalytic reduction</td>
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<tr>
<td>SI</td>
<td>spark ignition</td>
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<td>SIDI</td>
<td>spark-ignition direct injection</td>
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<tr>
<td>SIPI</td>
<td>spark-ignition port injection</td>
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<td>SMR</td>
<td>steam methane reformation</td>
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<td>U.S. DOE</td>
<td>U.S. Department of Energy</td>
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<td>VVT</td>
<td>variable valve timing</td>
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Appendix A. Advanced Vehicle Technology Assessments

Appendix B. Fuels and Production Assessments

Appendix C. UC Davis Grid Dispatch Model

Appendix D. Energy Demand Scenario Descriptions

Appendix E. Transportation Sector Scenarios

Appendix F. Model Description For California Advanced Energy Pathways Model (CAEPM)

Appendix G. Global Business Network Scenarios Report