Societal Benefits Topic Team Report

California 2010 Hydrogen Highway Network

March 2005

The Societal Benefits Topic Team Report was a collaborative effort by many people, some of whom contributed focused sections or passages involving specialized areas of expertise. The participation of and contributions from individuals represent neither an endorsement of the Report and its findings or recommendations, nor a verification of a review of the Report, by the individuals or the organizations they represent.

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Executive Summary

Societal Benefits Topic Team Organizational Structure

The Societal Benefits Topic Team comprises approximately 30 members and is divided into two subgroups, one focused on the technical assessment and the other focused on policy. The analysis of well-to-wheel emissions associated with the hydrogen production pathways was conducted by a contractor, TIAX, LLC.

The technical assessment subgroup reviewed the contractor's work and used it to develop the recommended emission reduction and renewable goals. The technical assessment group also evaluated renewable resources in California, fuel economy associated with hydrogen and conventional vehicles, and the impacts of near-total dependence on petroleum in the transportation sector.

The policy subgroup worked with other Topic Teams to develop a policy document that could be included in the broader California Hydrogen Blueprint Plan, and also completed an "inclusivity document." The inclusivity document is intended to highlight the benefits of non-hydrogen alternative-fuel vehicle technologies and the fact that these technologies contribute to the technological development and cost reduction of components used in hydrogen vehicles.

Mission Statement

The mission statement developed by the Societal Benefits Topic Team is as follows: This Topic Team will quantify the societal impacts of the pathways broadly defined to include those most likely to be commercially/technologically viable in California in the 2010 timeframe. The Societal Benefits Topic Team will also consider policies that would encourage pathways with greater societal benefits.

Goals Established

One of the most valuable attributes of hydrogen is that it can be produced from a myriad of production pathways, i.e., hydrogen can be produced from such pathways as natural gas steam reformation, electrolysis, and biomass, and can then either be used on-site or distributed to other locations. While all production pathways provide energy diversity benefits, there are differences in the greenhouse gas (GHG), criteria, and toxic pollutant emissions and differences in the amount of petroleum displaced for each pathway.

To ensure that the CA H2 Net results in environmental benefits spanning all pollutants, the Societal Benefits Topic Team recommended the following goals for the CA H2 Net. These goals are based on Scenarios A, B, and C as described in the Blueprint Plan:

1. The CA H2 Net should provide, in the aggregate, a 30 percent reduction in GHG emissions relative to conventional gasoline and diesel vehicles.

2. The CA H2 Net should utilize renewable resources comprising 20 percent of the total resources used in the production of hydrogen, and these renewable resources should be in excess of the 20 percent State's Renewable Portfolio Standard of 20 percent for the electricity sector.
3. The CA H2 Net should meet all of the aggressive goals and requirements currently established for criteria and toxic pollutants in the transportation and stationary source sectors. This includes the Air Resources Board's Low-Emission Vehicle II regulations, local and state regulations regarding stationary source emissions, and the Governor's Environmental Action Plan.

Emission Benefits Rating

Following the direction given in the Governor's Executive Order (EO) S-7-04 regarding both emission benefits and renewable resources, the Societal Benefits Topic Team developed a system for rating the environmental benefits of various hydrogen production pathways representative of a broad spectrum of possibilities for the 2010 timeframe.

As shown in Figures 1, 2, and 3 below, the various production pathways were rated according to their GHG emissions, criteria pollutant emissions, and petroleum usage rating. The results assume that the goals set by the Societal Benefits Team are achieved for renewable energy, GHG emissions, and criteria pollutant emissions. Achieving these goals will require the use of the lowest emission technologies for hydrogen production and delivery.

The GHG rating takes into account all carbon dioxide (CO_2), nitrous oxide (N_2O), and methane (CH_4) emissions associated with the production and distribution of hydrogen, as well as the emissions from the vehicle, weighted according to the GHG impact of each pollutant. It includes both in-state and out-of-state emissions. A variety of hydrogen production pathways and vehicle applications were analyzed, which affected comparative GHG rating.

In Figure 1, hydrogen passenger cars with either internal combustion engines (ICEs) or fuel cell power are compared with gasoline ICE vehicles. The comparison of hydrogen fuel cell buses to a diesel bus is also shown. The assumed fuel economy for each vehicle reflects the different GHG ratings for the same hydrogen production pathway. A lower value reflects lower GHG emissions and greater societal benefits.

The hydrogen production pathway is equally important in determining the GHG emission. A variety of water electrolysis, gas reforming, and solids gasification processes are shown in Figure 1. The effect of various categories of renewable power is illustrated for the electrolysis pathways, where electricity is the primary energy source. GHG emissions are lower when more renewable power is made available. The use of renewable power can be assured by either building a dedicated source of power (such as solar or wind) or through contracts that guarantee generation beyond the 20 percent New Renewable Portfolio Standard anticipated for grid power in California. Electricity inputs for all of the other hydrogen pathways assume a 20 percent renewable power component.

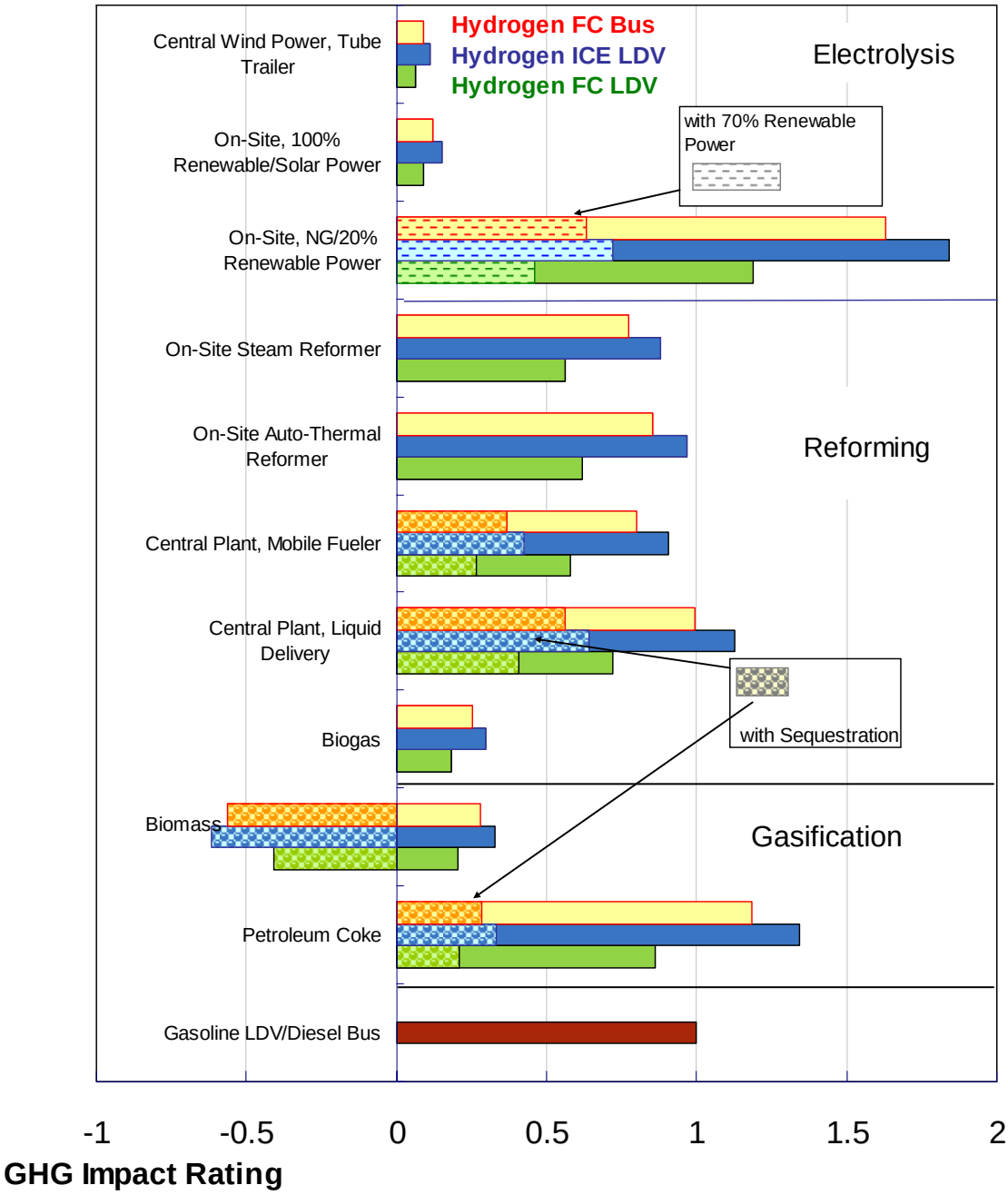

Figure 1. Greenhouse Gas Pollutant Rating

Other factors that affect the GHG rating are the energy inputs required for the production from natural gas or biomass through reforming or gasification. The carbon in renewable feedstocks such as biomass or biogas was recently captured from the atmosphere. This carbon will eventually enter the atmosphere either when the biomass is burned (i.e., agricultural burning) or if the feedstock is converted to hydrogen. Therefore the GHG impact of the CO_2 is zero. The electric power required for reforming or gasification, as well as the diesel fuel required for hydrogen delivery, also affect the total GHG emissions and rating of the various pathways.

Finally, concentrated CO_2 streams from central hydrogen production facilities can also be captured and stored underground (sequestration). In California, depleted oil wells can provide an opportunity for sequestration, provided that the CO_2 source is sufficiently close to the depleted oil well. This form of sequestration can even extend the life of oil reservoirs.

The criteria pollutant rating shown in Figure 2 is based on aggregate per-mile emissions of particulate matter (PM_{10} and $PM_{2.5}$), sulfur dioxide (SO_2), oxides of nitrogen (NO_x), non-methane organic gases (NMOG) and carbon monoxide (CO) for passenger cars and buses. Each pollutant is weighted according to the public health and environmental

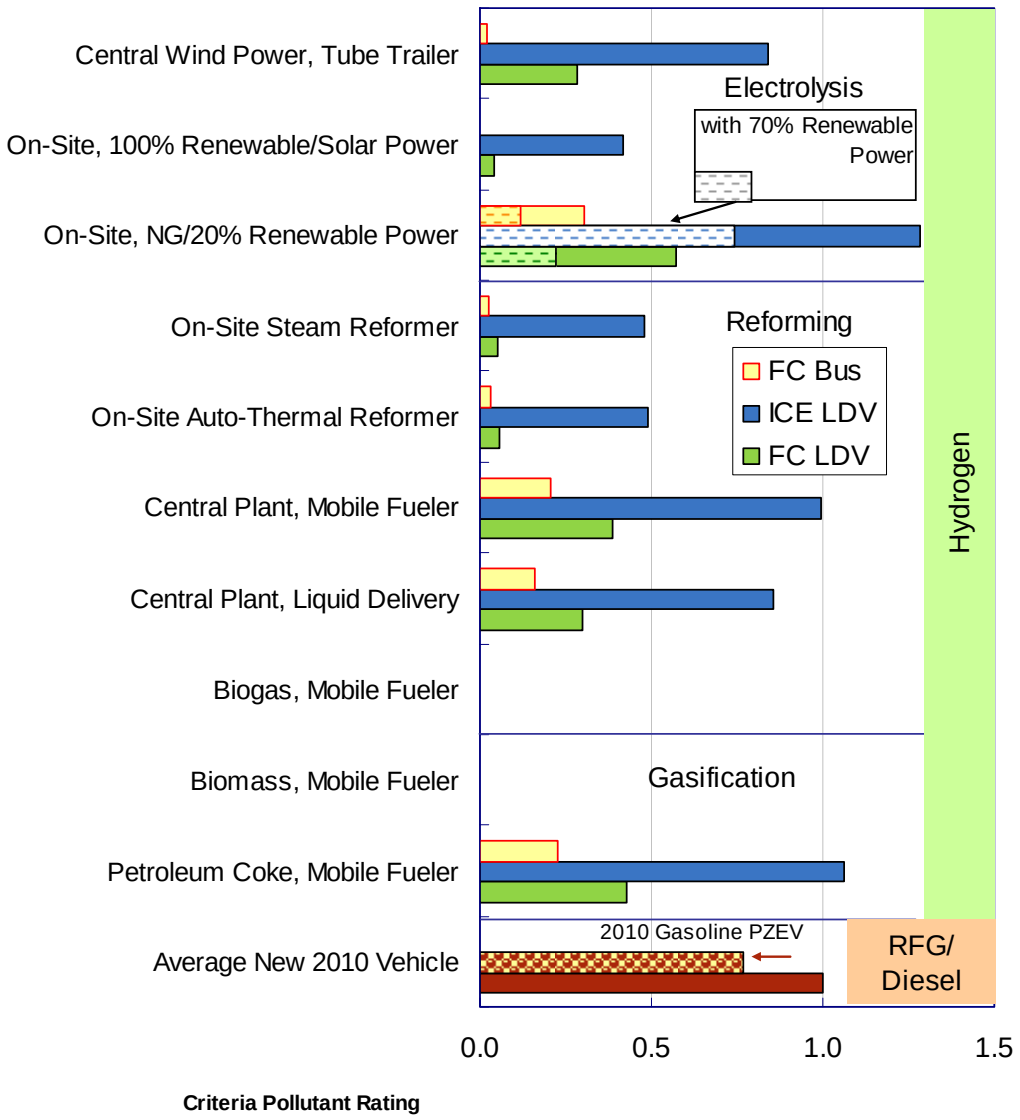

Figure 2. Criteria Pollutant Rating

damages associated with the pollutant as determined by the “Reducing California’s Petroleum Dependence Report, Joint Agency Report,” California Energy Commission and California Air Resources Board, July 2003 [1]. The criteria pollutant rating depends on the vehicle type and how the hydrogen is produced.

Vehicle NO_x represents a substantial portion of the total rating. Hydrogen vehicles have virtually no exhaust emissions except for NO_x from ICE vehicles. These vehicles were assumed to be certified at the partial zero emission vehicle (PZEV) level. By 2010, most of the new passenger cars will also be PZEVs. Tire and brake wear is another source of pollution from all vehicles.

Both renewable power and restrictions on new sources of power generation reduce emissions impact for hydrogen production. Electric power represents 9 to 100 percent of the energy input for the various hydrogen pathways. Diesel truck emissions for compressed hydrogen, either with a mobile fueler or tube trailer, result in NO_x and PM emissions that contribute to the criteria pollutant rating. The criteria pollutant rating is achieved only with diesel trucks that meet the most stringent emission standards. A limited number of fueling stations can also be located at or in close proximity to hydrogen production facilities. In this case, transportation emissions are eliminated.

Finally, some biomass and biogas feedstocks result in significant pollution if they are not processed and converted to fuels. For example, particulate emissions from burning agricultural residue far exceed those associated with processing the material, converting it to hydrogen, and transporting the hydrogen to the fueling station.

The petroleum usage rating shown in Figure 3 follows from the amount of petroleum used by each of the hydrogen production pathways. To the extent that hydrogen is transported or is produced using petroleum, a particular production pathway may rely on some amount of petroleum. Therefore, not all pathways provide 100-percent displacement of petroleum.

Energy inputs, other than petroleum are also analyzed in the report. These include primarily natural gas and renewable energy such as wind power and biomass. When comparing fuel cell passenger cars to conventional gasoline vehicles, the total energy inputs for hydrogen are comparable or lower than those for gasoline, except for electrolysis pathways that use less than 70 percent renewable power.

Renewable Power

EO S-7-04 calls for a significant and increasing use of renewable resources as well as a reduction in pollutants. Using renewable resources to generate hydrogen is consistent with a wide range of public health, environmental, and energy goals of California and the current administration. Therefore the Topic Team thoroughly assessed the different options for renewable power in California.

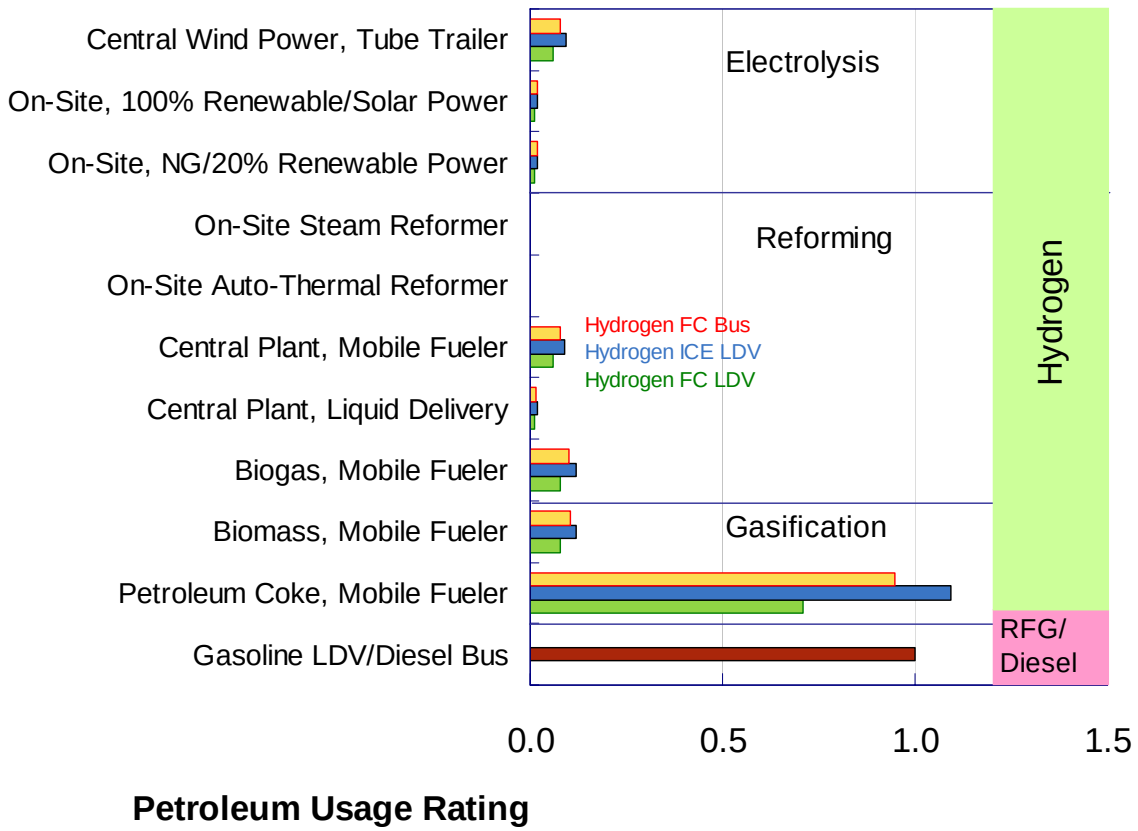

Figure 3. Petroleum Usage Rating

The assessment concluded that there are many differences between renewable resources that should be taken into account when planning to use them for hydrogen generation. Some of the key issues that should be taken into account are as follows:

- The use of Green Tags (tradable renewable credits) as opposed to Renewable Power Purchase Contracts (contracts guaranteeing that power is produced from renewable resources and that this renewable power is “excess” and not used to meet any other renewable obligation) can actually increase emissions and natural gas dependence in California if the renewable energy is not imported into California with the Green Tags

- The differences in intermittency and capacity factor of renewable resources can affect daily and seasonal availability of fuel

- There can be significant differences in operating and manufacturing emissions associated with various renewable energy sources, specifically NO_x emissions associated with biomass and waste resources, as well as CO_2 emissions associated with natural gas cofiring of solar thermal facilities

- Renewable resources should be used to offset energy in both the electricity and transportation sectors. However, unlike the diverse electricity sector, our near-total dependence on petroleum in the transportation sector is harmful both economically and environmentally.

- While analysis of quantitative differences may indicate the use of certain renewable resources for the production of hydrogen, the inclusion of auxiliary benefits, including reducing dependence on petroleum, could lead to a much wider scope of renewable hydrogen production options

All of these issues deserve attention in the development of a robust plan for utilizing renewable resources to meet California's hydrogen demand.

Inclusivity Section

The purpose of the inclusivity section of this document is to respond to comments made at some of the public meetings that, (1) the State of California should not be focusing solely on hydrogen-fueled vehicles, but should include consideration of other vehicle technologies and fuels; and/or (2) there are other vehicle technologies and fuels that can provide significant environmental and energy benefits comparable to those afforded by hydrogen-fueled vehicles, and can do so in a shorter time-frame, or at lower cost, or with greater energy efficiency.

The inclusivity section makes clear that, although the CA H2 Net effort is focused on hydrogen-fueled vehicles and related infrastructure, non-hydrogen vehicle technologies and fuels are a desired and necessary part of California's overall strategy to meet its environmental and energy goals. Non-hydrogen vehicles and fuels have been, and will continue to be, important and vital aspects of the State's broader environmental and energy strategy.

Recommendations

Based on the analysis contained in this Topic Team Report, the Societal Benefits Topic Team makes the following recommendations:

1. A goal of 30 percent reduction of GHG emissions, in the aggregate, for the CA H2 Net should be implemented.

2. A goal of 20 percent use of renewable resources to generate hydrogen for use in the CA H2 Net should be implemented. The renewable resource goal should ensure that any electricity generated from renewable resources and counted towards the CA H2 Net is not used to meet any other renewable obligation.

3. The CA H2 Net vehicles and refueling stations should comply with all local and state criteria and toxic pollutant goals and regulations currently in existence to ensure that there will not be increases in criteria or toxic pollutants as a result of the CA H2 Net. This includes the Air Resources Board's Low-Emission Vehicle II regulations, local

and State regulations regarding stationary source emissions, and the Governor's Environmental Action Plan.

4. To achieve the above three goals, it will be essential to determine how the State will ensure that the goals are met and who will be charged with that task.

5. Providers of hydrogen via electrolysis have indicated that they will strive to provide GHG emission reductions below what can be expected from conventional vehicles. As this will require significant use of renewable resources by the electrolysis production facility, we recommend that there be a specific GHG goal established for electrolysis. This goal should be established in cooperation with stakeholders.

6. Further assessment of the CA H2 Net on communities, specifically low-income and minority communities, is recommended. Although it is likely that such communities will benefit from the CA H2 Net, it will be important to more thoroughly evaluate the impacts in coordination with representatives from the communities.

7. During the policy development phase of the California Hydrogen Blueprint Plan, it will be essential that any policies or funding established to ensure the success of the CA H2 Net also ensure that the goals in Recommendations 1, 2, and 3 are met. In particular, as some of the renewable pathways may be more costly in the development phase, it may also be necessary to provide funding to offset a portion of the cost differential.

1. Well-to-Wheel Energy Emission Impacts of Hydrogen

1.1 Introduction

The myriad of hydrogen production options illustrates a key beneficial attribute: hydrogen can be produced from a variety of fuels, including natural gas, methanol, ethanol, biomass, and even water. There are a wide variety of "pathways" for hydrogen production, including the use of renewable feedstock and renewable energy resources. For example, the electrolysis process used to split water into hydrogen and oxygen requires electricity. Commercialization efforts are underway to supply this electricity from renewable energy sources such as solar and wind power. Not surprisingly, these types of processes and pathways for hydrogen production, which have the lowest environmental impact, generally entail the highest costs in today's early market stages.

The beneficial attributes of hydrogen go beyond its status as a clean fuel with diverse, environmentally sound production pathways. As an "energy carrier," hydrogen can be used to store and deliver energy. In particular, as the State moves towards energy independence, renewable energy sources such as solar and wind that cannot produce energy all the time can be used to generate hydrogen as a means to store energy. This hydrogen can then be moved to where it's needed, and can be particularly attractive in locations where electricity is scarce or the transmission process is not cost-effective. In remote locations, hydrogen can also be used to fuel vehicles.

The fact that hydrogen can be produced in so many different ways, although an attribute, also indicates a need to ensure that the production pathways relied upon are assessed to determine their relative societal benefits. The remainder of this section evaluates the various hydrogen production pathways considered the most likely in the 2010 timeframe. Criteria pollutants, greenhouse gas (GHG) emissions, and the extent to which a specific hydrogen production pathway provides an alternative to the current near-total dependence on petroleum are examined in this section.

Criteria pollutants[1] and greenhouse gases are emitted during vehicle operation as well as during fuel production and distribution, fabrication of fuel and vehicle production facilities, decommissioning of facilities, and vehicle scrapping/recycling. Non-vehicle emissions represent a significant fraction of the total vehicle cycle both in terms of local and GHG emissions, and are therefore an important consideration in assessing the environmental impacts of vehicle operation.

The purpose of this section is to provide a comparison of the environmental impacts of various hydrogen production options compared with those from conventional fueled alternatives. The primary focus of the analysis includes the ranking of:

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[1] Criteria pollutants from vehicles, discussed in Section 1.7, include NO_x, hydrocarbons (reactive organic gases [ROG]) or non-methane organic gases (NMOG), CO, PM, and SO_2.

- Well-to-wheel (WTW) global GHG emissions
- Energy impacts (petroleum usage)
- Criteria pollutants (in California and globally)

The Societal Benefits Topic Team developed specific goals for emission reductions in order to assure that hydrogen vehicles contribute towards improved air quality and reduced GHG emissions. These goals were based on the emission impacts expected from hydrogen and petroleum fueled vehicles in the 2010 timeframe.

This Section includes a technical discussion of the topics listed below. The analysis also relies on the assessment of renewables (Section 2).

1.1 Introduction
1.2 Scope of Analysis
1.3 Analysis Methods
1.4 Energy Impacts
1.5 Hydrogen Vehicle Energy Consumption
1.6 GHG Emissions
1.7 Criteria Pollutant Emissions
1.8 DG permitting in California

1.2 Scope of Analysis

The societal benefits analysis covers a range of hydrogen production pathways, uses of hydrogen, and environmental impacts. The extent of the analysis is described below.

1.2.1 Hydrogen Production

A variety of primary energy sources are potential feedstocks for hydrogen (Table 1-1).[2] These energy inputs include fossils fuels, renewable biomass feedstocks, as well as electric power derived from both fossil fuels and renewable/non-fossil resources. Hydrogen is currently produced on an industrial scale primarily through the steam reforming of natural gas. Most of the hydrogen is consumed in oil refineries and produced either on-site or in close proximity to the refinery. Other hydrogen users are fertilizer, chemical, food, and aerospace industries. The characteristics of different hydrogen production feedstock options and production technologies are incorporated into an assessment of energy efficiency, and GHG emissions and criteria pollutants.

The electrolysis of water is another commercially available technology for hydrogen production which competes with hydrogen delivered from central steam reforming facilities. The environmental impacts of hydrogen from electrolysis depend on the source of the electric power. The opportunities for obtaining renewable power for electrolysis and other hydrogen production options are discussed in Section 2.

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[2] See Roll Out Team, Production Report.

Table 1-1. Potential Hydrogen Feedstocks

	Feedstock	Energy Carrier
Non Fossil	Nuclear Solar	High temperature heat Electricity
	Geothermal Hydro Wind	Electricity
	Renewable contract Grid Power Mix	
Renewables	Biomass	
	Corn Waste sugar Sugar crops	Sugar, starch to ethanol or hydrogen
	Energy crops Switchgrass Forest residue Manure	Cellulose to ethanol, methanol or hydrogen
	Algae Sewage	Methane
Fossil Fuels	Coal	Coal
	Shale oil Tar sands Crude Oil	Petroleum coke LPG Naphtha Gasoline
	Pipeline natural gas LNG	Natural gas
	Remote natural gas	Methanol

[a] California grid power is produced from a variety of energy resources. On the margin, the grid mix is assumed to be derived 80 % from natural gas and 20% from renewables.

Figure 1-1 shows some of the numerous feedstock and existing production technologies that could be used to produce hydrogen. Such combinations of energy carriers are production technologies are referred to as “production pathways.” The solid lines represent the more common uses of primary energy and pathways for hydrogen production. The pathway, combined with the hydrogen application (vehicle type or stationary use) affects the overall energy inputs, GHG emissions, criteria pollutants, and other impacts of hydrogen use.

Hydrogen can be carried on-board the vehicle in a variety of storage modes including compressed gas, adsorbed on a metal hydride, as a cryogenic liquid, or bound in a chemical compound, which liberates hydrogen. This report focuses on the production of compressed hydrogen for vehicle applications with storage at 5000 psi (340 bar). Information in this report also supports the analysis of energy and emission impacts for:

- Hydrogen for stationary applications
- Liquid hydrogen for use on-board vehicles
- Compressed hydrogen for fueling metal hydride vehicles

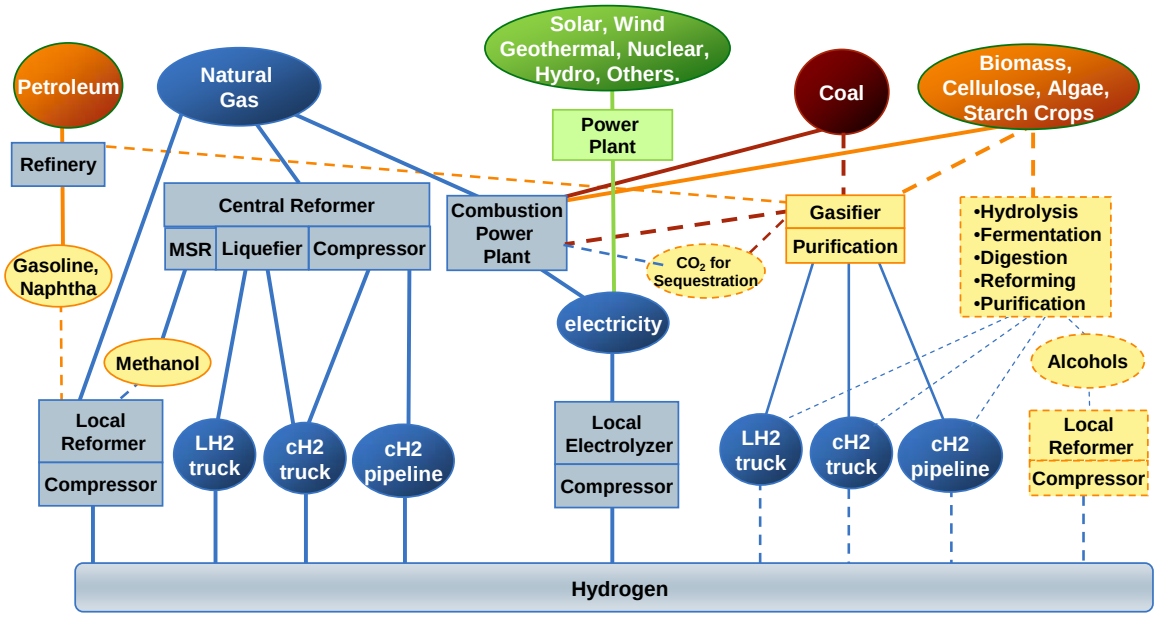

Figure 1-1. Potential Hydrogen Production Pathways

Not all of the production pathways are likely to provide hydrogen for California in the 2010 timeframe. Therefore, in order to narrow the analysis effort for this report, the Societal Benefits Topic Team developed an initial list of production pathways. This list is intended to be a "first cut" and will certainly grow as the CA H2 Net evolves.

The initial list of pathways allows for a thorough analysis of a broad range of hydrogen options while still limiting the scope of the effort in this report. Recognizing that there are hundreds of pathways, it is not tenable to evaluate them all. This list is intended to be diverse, encompasses those that are believed to be the most likely, and also was selected because many other pathways are similar enough to those listed here and, therefore, the same societal benefits would be applicable. Information is also provided in this report to develop the results for other pathways.

Table 1-2 includes a variety of electrolysis, reforming and gasification options. The range of feedstocks/energy carriers includes power from both fossil and renewable sources as well as natural gas, biomass/biogas, and petroleum coke, a byproduct of oil refineries. Both central plant production with delivery as a liquid or compressed gas are considered as well as on-site production where the energy carrier is available at the fueling station.

A variety of options for power generation are considered as energy inputs for electrolysis, including locating the electrolyzer at a wind farm where it can assist with load management, as well as using grid power and on-site solar power as an energy source. As discussed in the following section, growth in electric power in California is expected to be generated from natural gas or renewables. The sources of renewable power are discussed in Section 2 of this report. A discussion of the configuration of existing California fueling stations can be found in a recent CEC report [2].

Table 1-2. Baseline Hydrogen Pathways for Blue Print Plan

Energy Carrier	Central Plant Production	Delivery	On-Site Production	Consider Sequestration
Wind	Electrolysis	Tube trailer		—
Renewable Power		On-Site Solar	Electrolysis	
	CA Renewable Portfolio Standard			
Grid Power (natural gas with variable mix of renewable power)				—
Natural gas	Steam reforming, Existing LH2 plant	LH2 Truck		Yes
	Steam reforming	Mobile fueler		Yes
			Steam reforming	—
			Auto-thermal reforming	—
Petroleum Coke	Gasification to H_2	Mobile fueler		Yes
Biomass	Gasification to H_2	Mobile fueler		Yes
Biogas	Reforming to H_2	Mobile fueler		—

Baseline values are for vehicle fueling at 340 bar (5000 psi). Hydrogen is compressed to 420 bar for cascade pressure transfer.
Biomass = agricultural materials, forest residue, urban waste
Biogas = dairy, sewage treatment, landfill gas

The analysis of hydrogen from electrolysis, in this report, is based on the operator of fueling stations procuring a large fraction of power from new renewables. Information is presented to allow the calculation of the impacts for different fractions of renewable power.

Natural gas and biogas are feedstocks that can be combined with steam to produce hydrogen (reforming). A variety of production and deliver options are analyzed. Since the majority of hydrogen today is produced from natural gas, several production and delivery options were considered for this feedstock. Central plant delivery options include liquid hydrogen, compressed gas in tube trailers or smaller mobile fuelers, and by pipeline. The liquid and mobile fueler delivery pathways were analyzed with information provided for other delivery methods. On-site production with both steam reformers and autothermal reformers are also analyzed. The energy input requirements for these options differ, which affects the GHG emissions [3].

A wide variety of biomass materials have been considered as feedstocks for energy production. In many places in the world, including California, Forest materials, agricultural residue and urban wood waste have been used as fuel for power plants [4]. These and other biomass materials including waste paper and rice straw have also been considered as feedstocks for cellulose based ethanol production processes [5]. Such biomass material and other solid materials including petroleum coke, or even tires could be used as feedstocks for gasifiers that produce hydrogen. While the scale and configuration of gasification systems would vary with different feedstocks, the general

principle is similar. Solid material is reacted with steam, oxygen, or air to produce a gas stream. Components of this gas stream are further processed into pure hydrogen.

Gasification provides an opportunity to convert solid materials with low economic value to hydrogen or other fuels. However, the gasification pathways require more development than reforming and also represent higher capital costs per unit of hydrogen [6]. The feasibility of using solid materials as feedstocks is largely affected by the avoided cost of transporting or disposing of these materials.

1.2.2 Scope — Applications

This report compares the energy and emission impacts from hydrogen-fueled automobiles, medium-duty vehicles, and heavy-duty buses with those from conventional petroleum-fueled vehicles as indicated in Table 1-3. The analysis includes a WTW comparison of the global GHG emissions as well as the California petroleum and local emission impacts.

Table 1-3. Hydrogen Applications

Type	Car	Van	Bus
Hydrogen ICEV	✓	✓	—
Hydrogen FCV	✓	—	✓
Hydrogen FC PHEV	✓	—	—
Baseline Vehicle	MY2010 Car	MY2010 MDV	MY2010 Bus
Baseline Fuel	Gasoline	Gasoline	Diesel

All hydrogen vehicles could be hybridized, see Section 1.5.

ARB categories are Light-Duty Vehicle (LDV), Medium-Duty Vehicle with Catalyst (MDV-Cat, and Diesel Urban Bus (UB DSL).

The emission impacts for other applications in the CA H2 NET are also discussed. Emissions rates applicable to plug in hydrogen hybrid vehicles are presented. A discussion of the permitting benefits and constraints for distributed generation is included.

1.3 Analysis Methods

Figure 1-2 illustrates the steps in the total vehicle energy cycle. The boundaries of the cycle can include the production and burning of the fuel as well as the production and final fate of the fuel production facilities and vehicle. Fuel cycle emissions include emissions generated during the extraction of feedstocks, processing or refining, transport, and local distribution. Vehicle cycle emissions include vehicle evaporative and tailpipe emissions.

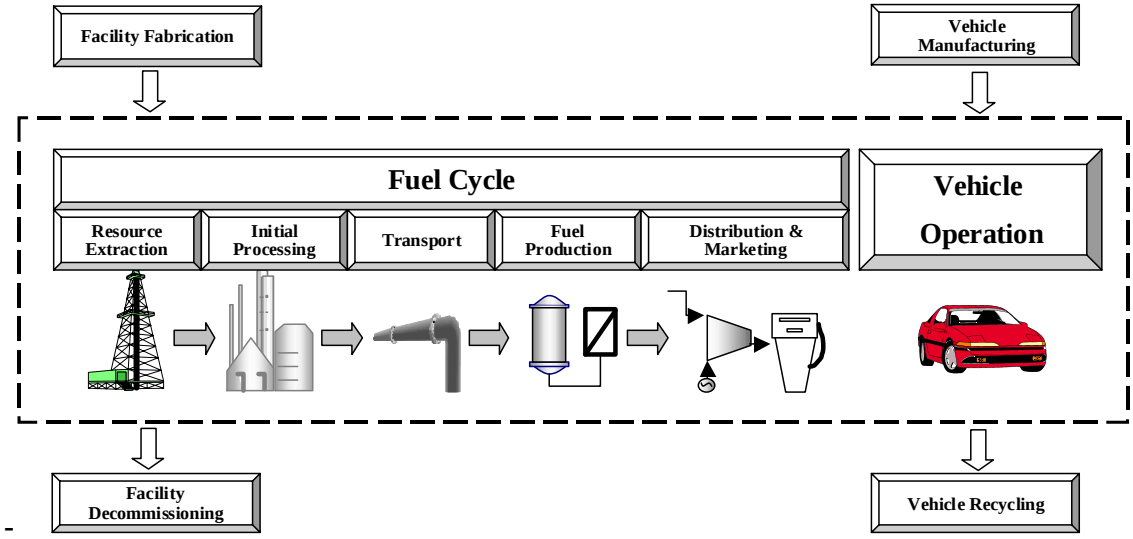

Figure 1-2. Total Vehicle Energy Cycle

This report focuses on GHG and criteria pollutant emissions. These emissions are examined on a total fuel cycle or WTW bases. A total energy cycle analysis (TECA) would include all of these emissions. For gasoline vehicles, vehicle use represents the largest source of emissions, followed by direct fuel production emissions, with vehicle production and recycling emissions being the smallest [7]. For example, a life cycle analysis from NREL shows that the energy inputs and GHG emissions associated with the manufacturing of a hydrogen plant correspond to 0.4% of the emissions associated with the production of hydrogen from natural gas at a central plant facility [67].

The results of this study include WTW energy, GHG emissions and criteria pollutants. WTW energy and emissions include both the fuel cycle (fuel production and distribution) and the vehicle cycle. WTW results are expressed on a per mile basis, which takes into account vehicle fuel consumption. Both WTW energy and GHG emissions are proportional to fuel consumption. In the case of hydrogen, all of the primary energy inputs are consumed in the fuel cycle. CO_2 emissions from gasoline and diesel as well as fuel cycle energy and GHG emissions depend on the amount of fuel burned[3]. Vehicle criteria pollutant emissions vary with vehicle type, emission control requirements. Engine type and exhaust aftertreatment affect N_2O and CH_4 emissions.

Fuel cycle energy and emissions are often referred to as well-to-tank (WTT) or well-to-pump. These values do not depend on the vehicle and are typically expressed per unit fuel (e.g. g/MJ). In some studies, the term WTT refers to only the fuel cycle while in other studies, the emissions associated with the energy in the fuel are presented along

[3] The GHG emissions, N_2O and CH_4 are also emitted from vehicles. These pollutants represent less than 3 percent of the GHG impact. These pollutants vary with factors other than fuel consumption. CO is not counted as a GHG gas. Therefore, for vehicles with high CO emissions, less of the carbon in the fuel is counted as a GHG. CO emissions are less than 2 percent of the carbon in the fuel and less than 0.5 percent for low emission vehicles.

with the fuel cycle and the values and expressed on a g/MJ basis. This report presents the WTT results along with the energy and emissions associated with the fuel cycle when it is helpful to illustrate how these values vary with fuel consumption. These energy and associated GHG emissions are shown per unit fuel[4]. These values are referred to as well-to-tank plus fuel (WTT_f) in order to distinguish from the stricter definition of WTT. The WTT_f emissions per J of fuel do not take into account vehicle efficiency but still reflect all of the GHG emissions that would be emitted during both the vehicle and fuel cycle.

In order to eliminate confusion the terms are used in the following manner in this report:

- Fuel cycle – fuel cycle energy and emissions expressed per unit fuel
- WTT_f – fuel cycle and vehicle emissions expressed per unit fuel.
- Vehicle cycle – vehicle emissions expressed per mile driven
- WTW – fuel cycle plus vehicle emissions expressed per mile driven. The split between vehicle and fuel cycle may be identified.

1.3.1 Fuel Cycle Boundaries

Global GHG Emissions

Energy inputs and emissions occur throughout the fuel cycle from resource extraction through processing and transport. Fuel production and distribution processes can occur throughout the world depending on the type of fuel and where the energy resources are available. Since the impact of GHG are global, they are counted on a global basis.

Local Criteria Pollutant Emissions

This report determines fuel cycle emissions for fuels consumed in California. Stringent stationary source emission standards in California limit the emissions associated with power production, fuel transport through marine terminals power generation, and other large stationary emission sources.

Growth projections for population and related trends in California gasoline consumption indicate a larger than 30-percent increase in gasoline demand over 2002 levels by 2030. Industry experts anticipate that in-state refinery capacity will not increase substantially and that all of the gasoline that would be displaced by petroleum reduction strategies considered in the AB 2076 petroleum displacement alternatives report [8] would be imported [9, 10]. Because of these constraints, the analysis in this study pertains to imported gasoline, diesel, and natural gas. Renewable fuels are produced in California. For liquid fuels, the emissions in urban areas in California consist mostly of exhaust from marine vessels and tanker trucks as well as hydrocarbon losses from fuel distribution. Figure 1-3 illustrates the principal steps involved in transporting liquid fuels to California, with darker shading indicating local emissions in California.

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[4] Per J of energy on a lower heating value basis (LHV) or per unit of fuel for standard units of commerce (gallon of liquid fuel, kg of hydrogen, 100 scf natural gas).

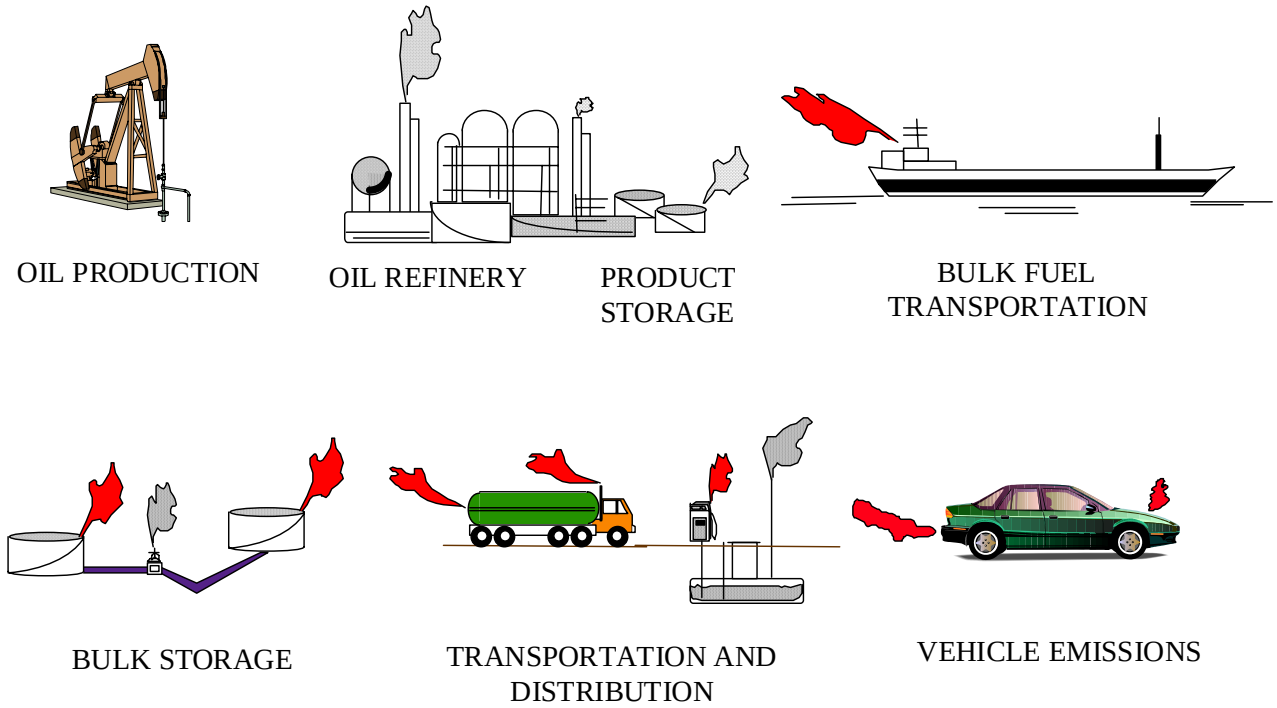

Figure 1-3. Fuel-Cycle and Vehicle Emission Sources – Gasoline and Diesel

Tanker ship emissions are counted for 100 nautical miles (kn) of travel. The pathways for delivering liquid fuels are similar, with the primary differences in local emissions resulting from the fuels vapor pressure and related fuel transfer emissions. Emissions associated with the rail transport of ethanol, a component of gasoline, are counted for 160 miles.

Figure 1-4 shows the emission sources for some of the leading hydrogen production and distribution options. For both natural gas distribution and hydrogen production, urban emissions are associated with pipeline transport, power plants, liquefiers, and hydrogen reformers. Significant quantities of electric power are also required for gaseous fuel compression and cryogenic fuel liquefaction. Electric power provides energy for hydrogen plant operation, compression, and electrolysis. Local emissions include those associated with natural-gas-fired power plants and gas pipeline transport to California.

As discussed earlier, many other pathways for hydrogen production are possible involving processes like gasifiers or other feedstocks like methanol or ethanol. Information on these pathways is also provided in this report.

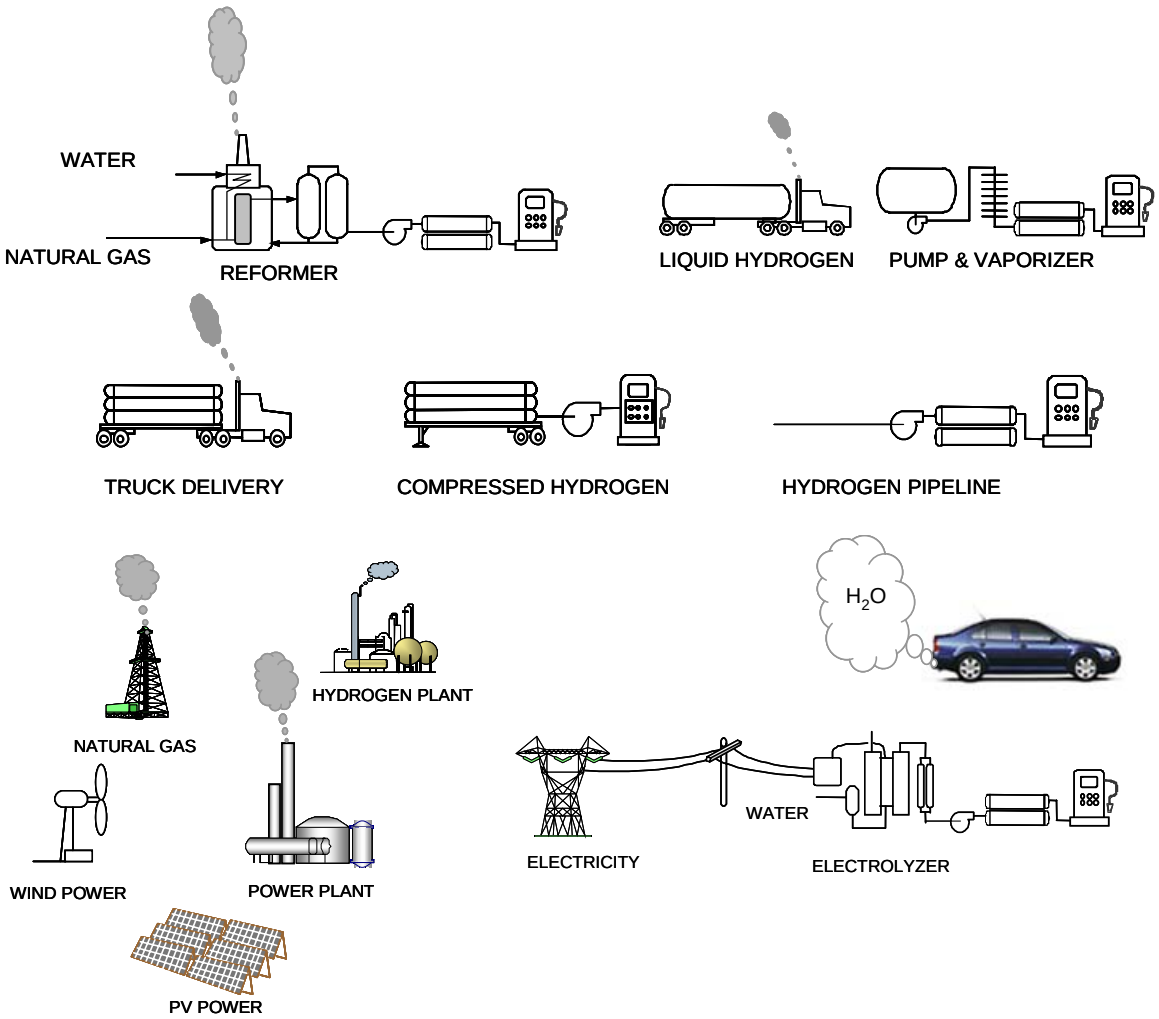

Figure 1-4. Fuel Cycle Emissions Sources for Hydrogen Production

1.3.2 Vehicle and Fuel Cycle Analysis

The analysis presented in this section quantifies the air emission impacts for each of the petroleum reduction options in the main report. This analysis accounts for the reduction in vehicle tailpipe and evaporative emissions, as well as emissions associated with fuel production, transport, and storage. The boundaries and approach to the fuel cycle analysis are discussed here.

The timeframe for the analysis is the year 2010 and corresponds to scenarios for a growing demand for gasoline beyond a demand of about 14 billion gallons per year in 2004. By the year 2020, baseline gasoline demand will be 19 billion gallons per year, according to the California Energy Commission's study on reduction of gasoline and diesel demand [1]. With the most aggressive petroleum reduction strategies analyzed by the Energy Commission, gasoline demand would drop to about 14 billion gallons per year, as illustrated in Figure 1-5. This consumption level plus demand from Nevada and Arizona would be sufficient to keep California refineries operating at capacity.

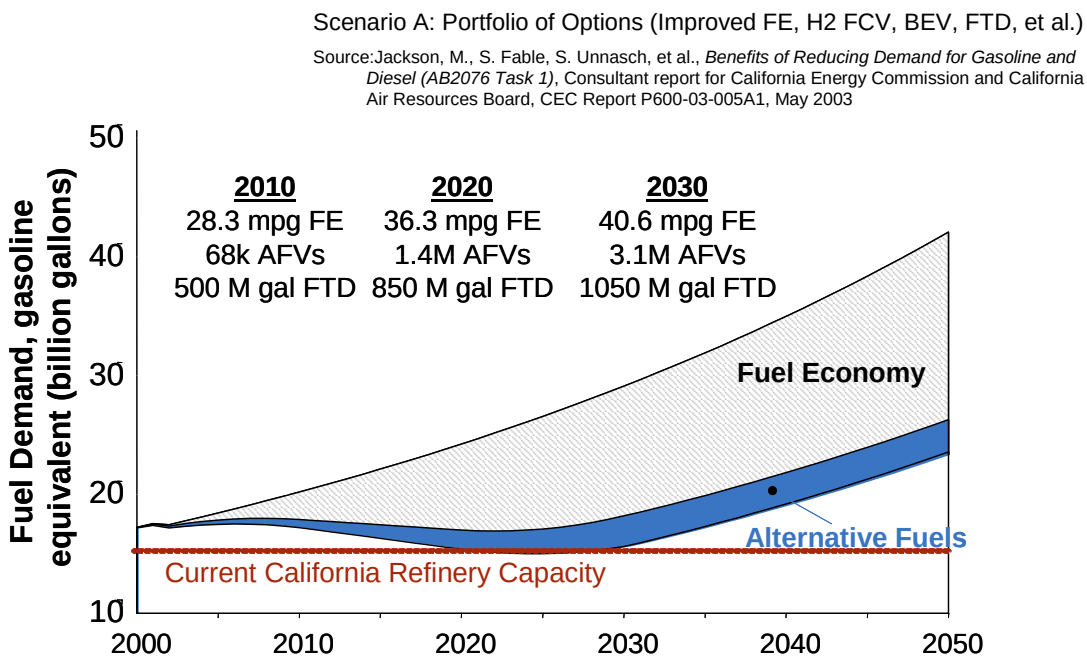

Figure 1-5. Fuel Demand and Refinery Output in California [1]

1.3.3 Marginal Emissions

This study is intended to evaluate global GHG and local emissions from marginal fuel production. The interpretation of which emissions correspond to marginal fuel production depends on several factors that are discussed in the following section.

The analysis presented here is aimed at identifying marginal emissions associated with large volume fuel distribution. In the view of the authors, production capacity in California and many other regions involved in the logistics of fuel supply are well enough understood that a first order estimate of the marginal sources provides a good basis for the study assumptions. In order to meet California and worldwide demand for most of the fuels considered in this study, new growth in production capacity will be required. Any increases in fuel production or power generation due to a reduction in petroleum use were assumed to come from new, more efficient plants built to meet growing demand.

A more rigorous economic analysis could provide more detail on marginal energy production impacts. An economic analysis would take into account the supply and demand elasticities where reductions in the usage of one fuel would affect its supply, price, and other aspects of the economy. Comments from industry experts indicated that future marginal gasoline supplies would clearly come from out of State sources[5].

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[5] The marginal source of gasoline was extensively reviewed with oil industry participants in prior ARB fuel cycle studies [9, 10].

The study looks at local emissions from the perspective of exposure to an individual in California. Although the total emissions from global fuel production and transportation are important, policy makers outside California can also address air quality goals with a variety of measures. Another consequence of a marginal analysis is that no hydroelectric or nuclear power is included in the electric generation mix. Reducing gasoline demand by increasing electric power demand for various hydrogen production or other electric transportation options does not increase the output from these types of generation facilities. The marginal source of electric power was assumed to be natural gas based on CEC's resource planning [11].

Substantial transportation distances were assumed for the natural gas used to produce hydrogen. Some analysts argue that natural gas resources in the U.S. are limited, and if hydrogen vehicles are used on a large-scale basis, additional natural gas would need to come from foreign sources of LNG. In this analysis, foreign sources of LNG were not included, but energy inputs and emissions and GHG emissions are consistent with long pipeline transportation distances (from Canada). This pipeline transportation results in greater energy inputs and GHG emissions for natural gas or natural-gas-derived fuels than those derived from California natural gas.

Some environmental groups and researchers consider the results of the marginal analysis in this study as optimistically low for gasoline production emissions in California. However, in the authors' view, marginal emissions represent the contribution to the air that we breathe. The analysis could also go through the exercise of calculating average emissions and then estimating secondary impacts due to offsetting, emission caps, and other regulatory constraints.

The emphasis on marginal emissions by industry groups was a key outcome of the 1996 ARB Fuel Cycle study [9]. Industry groups and State agencies ultimately agreed that a marginal approach was relevant in the context of a moderate usage of alternative fuels. Another point of view is that a very substantial use of alternative fuels could result in a reduction in refinery capacity. Given the limited refinery capacity and substantial growth in gasoline demand, this outcome is unexpected.

The emission impact of displacing a very large fraction of refinery capacity with alternative fuels is not analyzed here. Even if such a scenario were to occur, average emission rates would not reflect the impact on emissions, as the disposition of emission permits and offsets would need to be taken into account.

The principal assumptions that relate to these considerations include the following:

- Import liquid fuels to California
- Produce marginal electric power from fossil fuels projected to be natural gas with 20 percent of the power from new renewables
- Emissions from vehicles and stationary sources, such as fueling stations, are consistent with ARB rules
- Marginal natural gas originates outside California
- RECLAIM and other offset requirements limit NO_x and PM from power plants and large hydrogen production facilities (and oil refineries but reducing gasoline demand

displaces imported gasoline, so the impact on refinery emissions is minimal, at least in 2010)

1.3.4 Analysis Methods

In the study, local and regional emissions of criteria pollutants are calculated using in-use and rule-based emissions factors for the steps in the fuel cycle. Since the rules primarily govern fuel and vapor transfers on a volumetric basis, the local emissions are also tracked per unit of volume. GHG emissions, on the other hand, are calculated using energy efficiency factors for the fuel cycle, which are inputs to the GREET model, which was developed by Argonne National Laboratory [13]. A composite of several results from GREET provide the GHG values for hydrogen.

Determining fuel cycle emissions requires a detailed tracing of the steps involved in the production and distribution of fuels. Several studies consider these calculations [3, 7, 9, 12, 13, 14, 15] which include the following:

- Energy consumption is determined for all steps in the fuel cycle. Energy consumption and related combustion emissions are the principal source of GHG and criteria pollutant emissions in the fuel cycle

- The energy consumption in the full fuel cycle includes not only the direct energy consumption of fuel production and transport equipment but also the energy required to produce the fuel in the fuel cycle

- CO_2 emissions for combustion or fuel conversion are calculated from carbon content of the fuel or feedstock[6]

- CH_4 and N_2O emissions depend on the type of equipment and are based on emission factors or fuel combustion

Key assumptions that affect the fuel cycle energy and GHG emissions include feedstock extraction and refining efficiency, energy requirements for feedstock and fuel transport, and the feedstock resource mix and related carbon content. These input assumptions were modified in the baseline GREET model to reflect the assumptions discussed in the following section. The details of the fuel cycle analysis are considered in the GREET 1.6 model. This model was used to determine energy inputs and GHG emissions for the fuel cycle. The outputs of the GREET model were used to develop the results presented in this study.

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[6] In the case of fuel processes that involve a conversion of one feedstock to a fuel, the fuel cycle CO_2 emissions are typically determined using a carbon balance method. Carbon emissions = carbon in feedstock – carbon in product fuel – carbon in plant emissions. The carbon in the product fuel is converted to $_{CO2}$ in the vehicle. Vehicle CO_2 emissions = carbon in the product fuel – carbon in the form of CH_4, CO, or hydrocarbons. In the case of hydrogen, all of the carbon is used in the fuel cycle.

Some enhancements to the analysis and presentation of the results in the GREET 1.6 model were included in this study. These include the following:

- In addition to fuel cycle emissions, vehicle emissions are determined on a g_{GHG}/MJ_{Fuel} basis. This approach prevents an inadvertent decoupling of the vehicle and fuel cycle results by readers of this study. The fuel cycle results for a particular fuel often correspond to the fuel properties, which affect the vehicle GHG emissions.

- Results from GREET 1.6 were determined for several "primary fuels." The fuel cycle results for the primary fuels were used to determine the energy inputs and GHG emissions for fuels such as CNG where multiple feedstocks are required from different regions. For example CNG would be produced from natural gas distributed throughout the U.S. and electric power produced both inside and outside California[7].

- Detailed calculations of local fuel distribution emissions were used to determine emissions in California. This analysis allowed for a better tracking of the vapor pressure of blending components and delivered fuel products. The effect of ARB emission regulations was also tracked for each of the fuel distribution processes.

1.3.5 Energy and GHG Calculations

The approach for determining energy inputs and GHG emissions corresponds to the following steps:

1. Select fuel, feedstock, pathway, and vehicle combinations.

2. Determine California-specific assumptions for location of fuel production, transportation distance, emission rates, and fuel properties.

3. Steps 1 through 2 provide inputs to determine energy usage and GHG emissions from GREET 1.6. Determine fuel cycle values from GREET and calculate CO2 emissions from fuel combustion for "primary fuels" including:

    - Gasoline
    - Diesel
    - Natural Gas
    - Biomass
    - Biogas
    - Grid Power from natural gas
    - Renewable Portfolio Standard Power
    - Wind Power
    - Solar Power

---

[7] GREET1.6 does allow for fuels and feedstocks from different regions to be used in the analysis. However, combining the results off model provided for better transparency and also eliminated a calculation issue when both electric power and natural gas power were assumed for hydrogen liquefaction facilities. Off-model calculations also allow for a simple analysis of different hydrogen production scenarios.

- Petroleum Coke
- Methanol
- Ethanol
- LPG

5. Determine fuel production efficiency, energy inputs for fuel transportation, and hydrogen compression/liquefaction. Represent energy inputs in terms of J/J_{H2}.

6. Combine results for primary fuels with the energy inputs to produce hydrogen to determine energy inputs and GHG emissions per MJ of hydrogen.

7. Determine vehicle GHG emission CH_4, and N_2O, as CO_2 equivalents (CO_2e) on a $gGHG/MJ_{Feedstock}$ basis.

8. Calculate vehicle CO_2 emissions from fuel properties (in gCO_2/MJ_{fuel}). CO and HC emissions from combustion determine how much of the carbon in the fuel is converted to CO_2 (about 99.5 percent)

9. Estimate vehicle fuel consumption in MJ/mi.

10. Calculate vehicle CO_2 and fuel cycle GHG emissions from fuel economy and GHG factor (MJ/mi x g/MJ) and add vehicle CH_4 and N_2O emissions.

Other combinations of feedstocks and energy inputs can be calculated from the information in this section. However, the effort for hydrogen was limited to the baseline pathway identified by the topic team.

1.3.6 Urban Criteria Pollutant Calculations

A separate set of calculations outside the GREET model determine criteria pollutant and toxic emissions in California. GREET calculations were used to estimate emissions outside California. Regulatory requirements vary within California, other parts of the U.S., and throughout the world. Also, the details of local fuel distribution chain differ from the arrangement of input assumptions for GREET.

The approach for determining criteria pollutant emissions also combines the vehicles with fuel cycle emissions, including the following steps. Select fuel, feedstock, pathway, and vehicle combinations. Identify local California emissions. California specific assumptions for local fuel production are also an input to energy and GHG calculations. The parameters that affect urban emissions are location of fuel production facilities, rules governing fuel vapor emissions from storage facilities, fuel stations, stationary engines, power plants, as well as caps on power generation emissions.

Estimate transportation distances determine emissions for delivery trucks, rail car, pipelines, and marine vessels. Criteria pollutant emissions were counted for 100 kn of marine vessel operation was counted for liquid fuels imported to California. Determine combustion emissions for marine vessel, rail car, pipeline, and truck transport. These

emissions depend on energy consumption and cargo capacity for each transportation mode.

For hydrogen, determine natural gas and electricity inputs from the energy and GHG analysis. Calculate emissions from power plants taking into account the NO_x caps and offset requirements. Estimate impact of renewable power and assume fraction of renewable power. Assume that 75 percent of natural gas based power generation and hydrogen production require offsets for NO_x, ROG, and PM.

The constraints on emissions in California combined with the emissions assumptions affect the results of this analysis. The principal assumptions that affect the comparison of hydrogen vehicles with baseline vehicles are summarized here:

Vehicle Emissions

- Use CA EMFAC emission model results for vehicles built in 2010 over their useful life. The calculations were carried out over 150,000 mi for passenger cars. 2010 passenger cars include a mix of PZEVs and other certification levels.

- Assume hydrogen fuel ICEVs emit NO_x at the PZEV level. Hydrogen fuel cell vehicle emissions are zero.

Fuel Cycle Criteria Pollutant Emissions

- Within California, calculate emissions for imported gasoline, diesel, and natural gas. Assume 100 kn marine vessel transport counts for emissions in California, 160 miles for rail car, and 50 miles for tanker truck delivery.

- Use emission factors from prior ARB fuel cycle emission studies to estimate gasoline and diesel spills, marine vessel emissions, rail emissions [10].

- Assume lowest emission factors for new natural gas power plants and natural gas reformers.

- Assume that 75 percent of ROG, NO_x, and PM emissions from power plants and central hydrogen plants are offset and are therefore counted as zero.

- Assume gasoline, diesel, liquid hydrogen, and hydrogen in tube trailers is delivered by conventional tanker trucks. The emission rate corresponds to the trucks that are on the road (calculate average between 2010 and 2020).

- Assume that new 2010 trucks are used to haul mobile fuelers in order to minimize the emissions impact from fuel deliveries.

- Use values from GREET 1.6 to determine emissions outside California.

1.4 Energy Impacts

The results of this study include WTW energy and GHG emissions and criteria pollutants. Vehicle criteria pollutant emissions vary with vehicle type, emission control requirements. WTW GHG emissions depend on fuel consumption for CO_2 emissions. Engine type and exhaust after treatment affect N_2O and CH_4 vehicle emissions and contribute to the WTW emissions.

Primary energy inputs are first determined for each fuel. The WTT_f factor is then determined. The full fuel cycle emissions per joule (J) of fuel do not take into account vehicle efficiency but still reflect all of the GHG emissions.

1.4.1 Summary of Energy Inputs

Fuel cycle emissions include the full chain of fuel production emissions associated with producing finished fuels. A key factor in determining the energy inputs and related emissions is the type of feedstock (oil, natural gas, coal, etc.), as the resource mix affects the fuel cycle emissions associated with producing each feedstock. The composition of fuels determines the vehicle cycle CO_2 emissions, as most of the carbon in the fuel is burned to form CO_2.

Table 1-4 shows the primary energy inputs for each of the hydrogen pathways analyzed in this report. The primary energy includes feedstocks such as natural gas, petroleum coke, and biomass. Power for electrolysis can also be considered a feedstock/energy carries as it is the only source of energy for separating waster into hydrogen. Other electric energy inputs include power for the hydrogen plant as well as power for hydrogen compression.

The specific details of the energy inputs for hydrogen production have been evaluated in many studies [3, 6, 12, 14**,** 15]. These feedstock and electric power energy inputs are shown in Table 1-5 and the details of this analysis is not repeated here. The values in Table 1-4 reflect energy inputs for hydrogen production processes that could be built in the 2010 timeframe. The values used in the CA H2 Net analysis by the Economics team and those reported by Simbeck [6] reflect largely near term technology. Improvements in some technologies such as on-site reforming and electrolysis are expected in the long term. The energy inputs that can be expected with further technology development reflect values presented by DOE and part of their H2A effort as well as studies from ADL [3], and the National Academy of Sciences [16].

The energy required varies for the various hydrogen production processes represented in J of energy required per J of hydrogen. This value is the inverse of the feedstock energy ratio[8]. Several processes use natural gas as the primary energy input. Of these, central plant hydrogen production with steam reforming requires the least natural

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[8] The energy ratio equals hydrogen produced per unit of feedstock. While sometimes referred to as the efficiency, this value represents only the primary feedstock. A definition of efficiency is typically (hydrogen + waste heat)/(feedstock + electric power + heat input).

Table 1-4. Energy Inputs for Hydrogen Production

	Primary Energy , WTT_f (J/J H_2)				
	Natural Gas	Diesel	Petroleum Coke	Biomass	Electric[d]
Central Pet. Coke Gasifier, Mobile Fueler	—	0.114	1.33[a]	—	0.133
Sequestration Petroleum Coke[a]	—	—	—[a]	—	0.112[a]
Central Biomass Gasifier, Mobile Fueler	—	0.114	—	1.51[b]	0.19
Sequestration Biomass	—	—	—	—[b]	0.105[b]
Central Biogas SR, Mobile Fueler	—	0.114	—	1.47	0.160
Central NG SR, LH2 Truck	1.28	0.012	—	—	0.384
Central NG SR, Mobile Fueler	1.28	0.114	—	—	0.096
Sequestration Central NG SR	—[c]	—	—	—	0.054[c]
On-Site NG Autothermal Reformer	1.54	—	—	—	0.120
On-Site NG Steam Reformer	1.43	—	—	—	0.090
On-Site Electrolysis	—	—	—	—	1.80
Central Electrolysis, Wind, Tube Trailer	—	0.095	—	—	1.83

Note: These energy inputs represent the baseline pathways. Many other pathways will be part of the CA H2 NET. For example, some types of stations will provide hydrogen on-site and will not require delivery. The information in this table can be used to determine the energy and GHG factors for these and other pathways. The combinations of production and delivery methods are examples.

Sources: [3, 6], Economics Team Report

[a] 90 % of concentrated CO_2 is captured for sequestration. This CO_2 is captured in a concentrated stream from the PSA. Energy inputs for sequestration are added to the appropriate production pathways if sequestration is assumed.

18.7 kg CO_2 available/kg H_2, 4.36 kg O_2/kg H_2 for gasifier. O_2 requirement for gasification and power requirement for air separation unit based on SFA Pacific study [6]. Energy ratio for petroleum coke gasification is 75%. CO and PSA losses are 5%. The PSA off-gas is used to generate steam.

[b] 17.5 kg CO_2 available/kg H_2, 9.0 kg O_2/kg H_2 for gasifier. Energy ratio for biomass gasifier is 80%. 15% additional feedstock is assumed as fuel for fluid bed combustor for biomass drying. CO shift and PSA losses are 5%.

[c] 9.0 kg CO_2 available per kg H_2

[d] Electricity input includes power for central plant production and compression and/or on-site (forecourt) production and compression. Electric power values are for cascade storage at 420 bar (6250 psi).

Table 1-5. Comparison of Energy Inputs from Hydrogen Studies

Study	Time-frame	Parameter	Central NG SR, TT	Central NG SR, LH2	On-Site NG Steam Reformer	On-Site NG ATR	On-Site Electrolysis
CA H2 Net, 2010 Scenario [a]	2010	Combustion (J/JH2)	0.25	0.25	0.25	0.20	0
		Natural Gas (J/JH2)	1.28	1.28	1.43	1.54	0
		Efficiency (LHV,%)	72.5%	61%	66%	61%	55.6%
		Total Electric (J/JH2)	0.10	0.36	0.09	0.11	1.80
		Total Electric (kWh/kg H2)	3.21	12.0	3.0	4.0	60
Lasher/ADL [3]	Long-Term	Natural Gas (J/J H2)	1.26	1.26	1.32	1.40	0
		Total Electric (kWh/kg)	1.203	8.6	3.41	5.57	52.6
Simbeck/SFA Pacific [6]	2002	Natural Gas (J/J H2)	1.31	1.31	1.43	—	0
		Total Electric (kWh/kg)	3.74	12.0	2.19	—	54.8
H2A See detailed notes in xls	Long-Term plus some Mid-Term	Natural Gas (J/J)	~1.28	~1.28	1.37	—	1.32
		Total Electric (kWh/kg)	3.24	10.5	2.92	—	57.6
		LH2 Boil-off	—	0.07%	—	—	—
NAS [16]	Current Technology	Natural Gas (J/J)	1.31	—	1.42	—	0
		Total Electric (kWh/kg)	3.71	—	2.22	—	54.9
NAS [16]	Future Optimism	Natural Gas (J/J H2)	1.25	—	1.34	—	0
		Total Electric (kWh/kg)	3.57	—	1.70	—	50.2
Choudhury/ GM/LBST [14]	2010	Natural Gas (J/J H2)	—	1.42	1.44	—	0
		Total Electric (kWh/kg H2)	—	11.6	2.16	—	53.8

Efficiency = Hydrogen Produced/[Feedstock + Power (3.6 kWh/MJ]).
H2 Study Comparison Production v2.xls.
Energy inputs are same as those used in the Economics Team analysis.
TT= tube trailer, NG= natural gas, SR = steam reformer, ATR= autothermal reformer, LH2= liquid hydrogen

gas; however, additional energy is required to deliver the hydrogen to a local fueling station (other than limited cases where fuel can be provided at the central plant).

On site production with steam reforming or auto-thermal reforming will require somewhat more natural gas. Natural gas is delivered to these fueling stations. The accessory loads and compressors operate on electric power.

The energy inputs for gasification processes are also shown. The assumed energy ratio for petroleum coke gasification and biomass gasification are 75 and 66 percent, respectively. The difference is largely due to biomass being assumed as a supplemental fuel to raise steam for the gasification system. Both of the assumed gasification systems also require oxygen. The energy inputs for the oxygen plant are included in the electric energy requirements for the system. A variety of other reforming and gasification processes are candidates for hydrogen production. The details of these systems will vary and affect the amount of electricity required to operate the system as well as the energy ratio. For example, some gasification systems require not oxygen but the energy ratio is lower. For all of these thermo-chemical conversion processes, the energy ratio values typically can range from 65 to 80 percent (LHV).

The potential for CO_2 sequestration was also estimated for central plant steam reforming and gasification. In California, the captured CO_2 could be compressed and pumped into depleted oil reservoirs. In addition to avoiding emissions to the atmosphere, the CO_2 flooding could also extend the life of and oil reservoir. Energy inputs for CO_2 sequestration are also show in Table 1-4. The total WTT_f emissions would include those associated with hydrogen production minus the CO_2 captured plus the emissions associate with CO_2 capture.

Energy inputs for hydrogen compression were estimated for each of the pathways based on the values used in the Economy Team Report. In the case of on-site production, 3 kWh of electric power are assumed for hydrogen compression and steam reformer operation. This level of power consumption reflects an optimized system that takes advantages of efficiency improvements such as intermediate storage, hydrogen chilling, and booster compressors [3]. Some systems consume more power for compression. The actual power consumption for the various hydrogen production options should be monitored in order to update this analysis. The actual performance of both compressor systems as well as on-site fuel production should be evaluated over an extended period to determine actual feedstock and power consumption.

Table 1-6 shows the compression energy requirements for different hydrogen storage options. The energy input values are consistent with information provided by compressor vendors and modeling projections that take into account thermodynamic losses from the compression cycle as well as electric motors and power conversion losses. The impact of differ rent hydrogen storage strategies can be estimated by applying these values to the analysis in this report. For example, providing hydrogen for 10,000 psi storage could be accomplished by compressing all of the hydrogen into a cascade system with a storage pressure of 12,500 psi. If the compression energy were 4.5 kWh as indicated in Table 1-6, an additional 1.5 kWh of power would be needed for compression. The increase in GHG emissions would be 690 g CO_2e/kg H_2. Again, the actual power requirements are likely to different from these estimates. Motor, mechanical, Compressor losses may be higher for 10,000 psi systems. However, a

Table 1-6. Energy Inputs for Hydrogen Compression

On-site Compression Options	Energy Impact	Power Consumption		GHG (g/kg H_2)
		(kWh/kg)	(J/J H_2)	
6250 psi (420 bar) cascade	Baseline	3.0	0.090	1370
Metal hydride, 1,500 psi	Power savings	2.6	0.078	1190
Intermediate storage w. booster to 5,000 psi	Power savings	2.7	0.081	1230
12,500 psi cascade	Increased power use	4.5	0.135	2060
Intermediate storage w. booster to 10000 psi	about same as baseline	3.3	0.099	1510

GHG Emissions with 20% renewable power, 80% natural gas (457 g GHG/kWh), see Section 1.6.

variety of inter-stage cooling and gas chilling options as well as intermediate storage strategies have been proposed. These could mitigate the effect of mechanical losses in the compression equipment [3] for 10,000 psi.

The type of hydrogen delivery option also affects the energy inputs and emissions for hydrogen production. The baseline pathways analyzed in this report represent some of the combinations of production and delivery options. Table 1-7 provides a comparison of the energy inputs and GHG emissions for hydrogen delivery. These values are proportional to distance traveled and the amount of hydrogen carried by the delivery truck. The transportation energy can become a significant portion of the overall energy input for hydrogen for delivered compressed hydrogen. The economics of delivering compressed hydrogen will likely limit the practical driving range. There values in Table 1-7 can be used to determine the GHG emissions for other pathways that are not analyzed in this report.

Table 1-7. Energy Inputs for Hydrogen Delivery

Delivery Option	Fuel	Capacity (kg H_2)	H_2 Used (kg H_2)	Distance mi	Energy (J/J H_2)	GHG (g/kg H_2)
Pipeline	Natural Gas	Various	various	0.5 - 3	0.01 – 0.05	100-500
Tube Trailer	Diesel	300	240	50	0.095	1060
Mobile Fueler	Diesel	100	50	20	0.114	1280
LH2 Truck	Diesel	3700	3700	100	0.012	135

One-way transportation distance, energy and GHG based on round trip.

Pipeline distance for hydrogen fueling stations built in 2010. Future hydrogen pipeline networks could be much longer.

GHG emissions based on WTT_f GHG factor, 93.4 g/MJ, for diesel fuel (Section 1.6). Diesel GHG factor = J/JH_2 x 120 MJ/kg H_2 x 93.4 g/MJ =

1.4.2 Primary Energy Inputs

The primary energy inputs for hydrogen production are used to determine the WTT_f energy inputs and emissions for hydrogen production. Figure 1-6 illustrates the energy inputs from Table 1-4 for two hydrogen pathways compared to the primary energy inputs for gasoline production. Figure 1-7 shows how these energy inputs would compare on a per-mile basis for a hydrogen vehicle with a 2x improvement in fuel economy.

The primary energy inputs for hydrogen production are combined with WTT_f values that take into account both the use of the energy carrier/feedstock and the fuel cycle energy based on assumptions consistent with delivering feedstocks to California. The following section describes the assumptions related to the energy inputs and WTT_f GHG emissions for primary energy carriers. Note that that total WTT_f energy for hydrogen production is greater than the primary energy inputs in Figure 1-7.

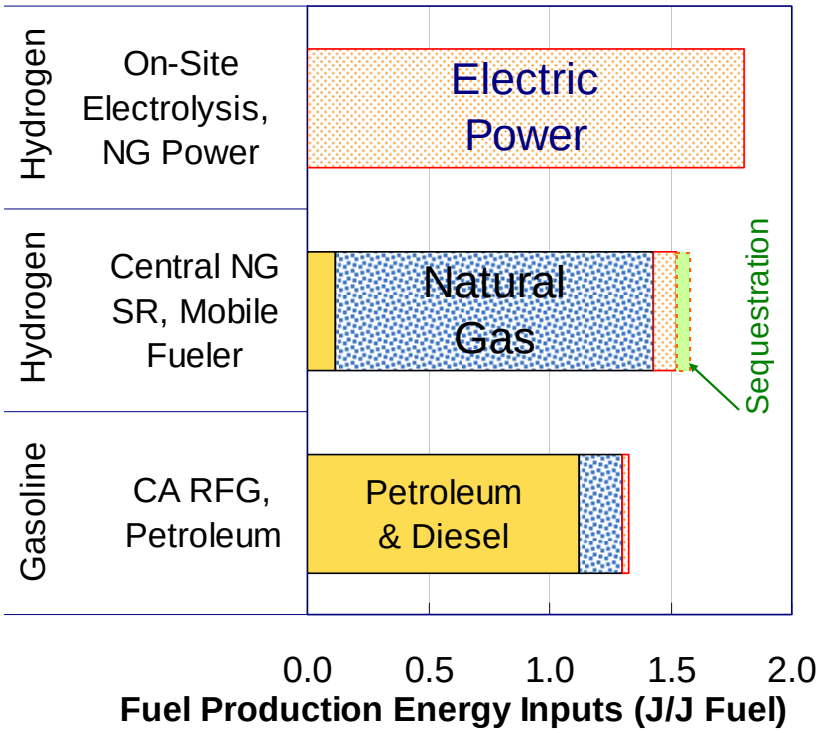

Figure 1-6. Example Primary Energy Inputs. (Values include energy in the fuel. Total energy required to produce 1.0 J of fuel.)

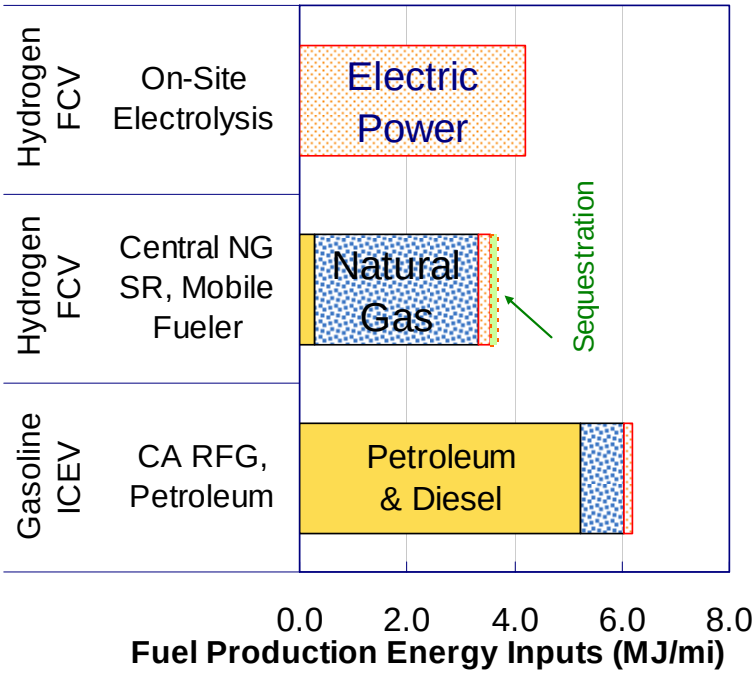

Figure 1-7. Example Primary Energy Inputs (g/mi) for passenger cars

The principal assumptions affecting the WTT_f energy and GHG inputs are shown in Table 1-8. The key factors that affect the energy inputs and GHG emissions are the following:

Refinery Energy The refinery energy is allocated to the production of gasoline, or in the case of California CARBOB. An estimate of the refinery operations associated with all of the refinery products is segregated by product slate. Energy inputs that are only

Table 1-8. Energy and GHG Assumptions for Fuels Imported to California

Parameter	Value
Petroleum Processes	
Petroleum Recovery Efficiency	97.7%
Tanker Ship Distances	
CARBOB, methanol	5400 nautical miles
Ethanol, Midwest	1200 miles
Ethanol, Caribbean	3200 nautical miles
Refining Assumptions	
CARBOB refining efficiency	84.5%
Supplemental hydrogen for CARBOB	150 scf/bbl
Sulfur content	10 ppm
Oxygenate, Ethanol	5.7 wt%
Diesel, 10 ppm S refining efficiency	88.5%
Supplemental hydrogen for low sulfur diesel	100 scf/bbl
LPG refining efficiency	93.5%
Petroleum coke refining efficiency	95%
Tanker Truck Distance	50 miles
Natural Gas Processing, Overseas	
Natural Gas Recovery	97.4%
Natural Gas Processing	97.8%
LPG Production	96.5%
NG Recovery Losses	0.35%
NG Processing Losses	0.15%
NG Transportation factor	0.27%/600 mi
NG Distribution factor	0.15%
Methanol production	29 GJ/tonne, 68.5%
Power Production	
Heat Rate, NG CC Mid Load	8500 Btu/kWh, HHV
Transmissions Losses	8%

associated with gasoline production (like alkylation) are assigned to gasoline, while crude oil distillation is assigned to all refinery products. Assumed a typical refinery efficiency allocation for 7 RVP gasoline plus an additional 150 scf/bbl of hydrogen for desulfurization. The baseline GREET analysis uses the same allocation scheme which results in fuel cycle GHG emissions of about 21 g/MJ gasoline. Other energy allocation schemes can result in a lower allocation of energy to gasoline production [12].

Fuel transportation distances associated with the marginal production of gasoline also affect total energy and GHG emission. A gasoline or CARBOB transportation distances of 5400 kn is assumed. This transportation distance reflects the import of refined product from locations such as Venezuela. Since Alaskan and Californian crude oil production are declining and California refineries are projected to remain at capacity even with extensive fuel efficiency improvements, these do not contribute to marginal sources of gasoline.

CA RFG is assumed to be made with 5.7 wt% ethanol which meets the 2-percent oxygenate requirement. 90 percent is assumed to be transported by rail from the Midwest and 10 percent by marine vessel from the Caribbean. The source for Caribbean ethanol is sugar cane.

The key factors that affect hydrogen production are the primary energy components diesel, natural gas, and electric power. Diesel is covered in the prior discussion. Factors that affect natural gas include:

- Transportation, processing, and extraction energy
- Transportation distances
- Methane losses
- The methane loss factor is critical
- Power plant heat rate
- Assume marginal heat rate of 8500 Btu/kWh
- Renewable fraction of power

Table 1-9 shows the key assumptions for fuels produced in North America. The values which have the most important impact on the GHG emissions from hydrogen include the following:

- Natural gas transmission distance and related methane loss
- Heat rate for marginal power production
- Fraction of power produced from renewables

The results of the fuel cycle analysis, presented as WTT_f energy inputs and GHG factors are presented in Section 1.6.

Table 1-9. Energy and GHG Assumptions for Fuels Produced in North America

Parameter	Value
Ethanol Production, North America	
Corn production yield	2.6 gal/bushel
Energy mix for processing	60% coal/40% NG
Processing energy after allocation to by-products	38,200 Btu/gal (LHV)
Corn farming energy	22,800 Btu/bushel
Power production	Baseline GREET
Natural Gas Processing, North America	
Natural Gas Recovery	97.5%
Natural Gas Processing	97.5%
Power Production	Baseline GREET
LPG production	96.5%
NG Recovery Losses, U.S.	0.1%
NG Processing Losses, U.S.	0.15%
California Power Production	
Renewable Power Fraction	20%
Fossil fuel	80% natural gas
Heat Rate, NG Combined Cycle Mid Load	8500 Btu/kWh, HHV
Transmissions Losses, 24 hr production	8%
Transmissions Losses, night time for PHEV	6%

1.5 Hydrogen Vehicle Energy Consumption

1.5.1 Baseline Fuel Economy

The purpose of this section is to provide baseline estimates for the comparative fuel consumption of hydrogen and baseline petroleum vehicles. The assessment of energy impacts and emissions in this report takes into account the energy consumption of hydrogen and comparable petroleum fueled vehicles. Vehicle energy consumption provides input to the following calculations:

- Vehicle and fuel cycle energy use
- Vehicle and fuel cycle GHG emissions
- Fuel cycle criteria pollutants
- Total hydrogen demand
- Petroleum fuel displaced
- Aggregate GHG emission reductions

The Societal Benefits Topic Team discussed a preliminary list of hydrogen vehicle applications and corresponding fuel usage presented in this section. The reason for developing this list of vehicle applications is the importance of a thorough analysis to evaluate a combination of pathways and end use applications that have the greatest probability of success. A variety of vehicle applications could operate as part of the hydrogen network. Candidate vehicle categories in the near term are ICE and fuel cell passenger cars and shuttle buses. Variants of these vehicle types with hybrid drive trains or auxiliary power units (APU). Table 1-10 shows the vehicle applications considered in this report.

Table 1-10. Hydrogen Vehicle Options Analyzed by Societal Benefits Topic Team

Category	Vehicle Type
Passenger Car (LD)	H2 FCV
	H2 ICEV/ICHEV
	H2 FC Plug-In HEV
Van (LD/MD)	H2 ICEV
Shuttle Bus (HD)	H2 FCV

LD= Light-Duty, MD=Medium-Duty, HD= Heavy-Duty

The list of applications reflects the fuel usage (achievable by 2010) for vehicles that represent a “fair” comparison to a gasoline vehicle with similar attributes. The Societal Benefits Topic Team recognizes that other hydrogen vehicle configurations may achieve better fuel economy by incorporating strategies such as weight reduction and hybridization which can result in even lower fuel consumption. The additional benefits of these vehicle configurations could be recognized on the basis of test data.

The environmental impacts of hydrogen depend on the source of the hydrogen and how much hydrogen is consumed by the vehicle application. The team developed a baseline ranking, which incorporates energy consumption values for hydrogen production equipment and vehicles. We believe that this ranking could be used for an initial assessment of energy and emission impacts.

The team held significant discussions about what fuel economy values to use for the baseline gasoline vehicle and hydrogen vehicle technologies with most favoring the comparison of a consistent set of gasoline ICE, hydrogen ICE, and hydrogen fuel cell technologies.

We analyzed hydrogen ICE vehicles that are 1.3 times more efficient than gasoline vehicles. If we consider a hybrid gasoline vehicle, then we would also consider a hybrid hydrogen vehicle, and the relative benefit would be the same. Should the hydrogen ICE vehicle employ technology above and beyond what is considered standard in the analysis that would be incorporated in the ranking system on a case-by-case basis.

A comparison issue arises when considering the hydrogen fuel cell vehicle. A variety of fuel economy improvements are projected for fuel cell vehicles depending on their technology maturity and degree of battery hybrid integration. When compared to a gasoline ICE, fuel cell vehicles could achieve a 1.8x to 2.5x improvement in energy efficiency. This relative ranking would be lower when compared to a gasoline HEV, however, not all gasoline vehicles will be HEVs. The baseline fuel efficiency improvement for hydrogen FCVs used in the analysis is 2.0 times that of the gasoline vehicle. Again, this value can be adjusted on a case-by-case basis with actual vehicle data. The energy consumption for electric drive vehicles may also need to be considered for plug-in hybrid vehicles. Again a wide range of energy consumption values are reported, depending on the vehicle technology, driving range, and other factors.

Figure 1-8 shows the comparison of fuel economy for a comparable compact passenger car. The range in fuel economy varies more with hybrid, hydrogen, and plug in applications due to a variety of vehicle, powertrain design, and engine efficiency parameters. These values are based on data presented in Sections 1.5.2 and 1.5.3.

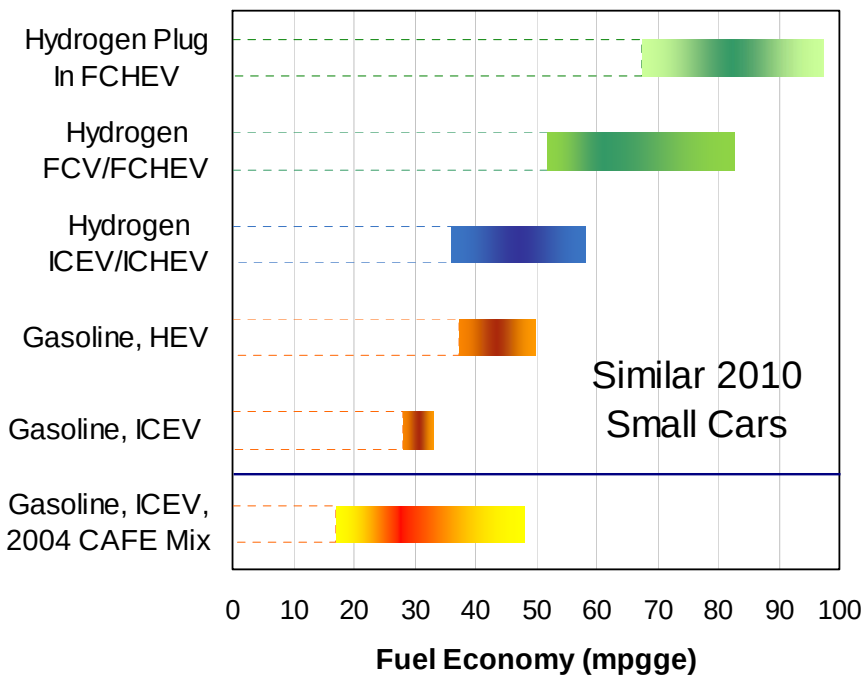

Figure 1-8. Range in Fuel Economy Estimates for Passenger Cars

Baseline Vehicle Fuel Economy

Baseline fuel economy estimates for passenger cars and shuttle buses are shown in Table 1-11. The ratio of gasoline energy consumption to hydrogen energy consumption, or energy economy ratio (EER) is used as a benchmark for assessing

energy consumption and emissions. The combination of EER and actual hydrogen consumption would be used in this analysis (See HERMIN, Section 1.6.3) once vehicles

Table 1-11. Assumed Fuel Consumption of Hydrogen and Baseline Petroleum Fueled Vehicles

Vehicle	On-Road Fuel Consumption (mi/gal or mi/kg)	Energy Economy Ratio, EER (J_G/J_{H2})
Passenger Car		
Gasoline ICEV	25.5	1
Hydrogen FCV	51.5	2
Hydrogen ICEV	33.5	1.3
Van/Shuttle Bus		
Gasoline ICEV	13	1
Hydrogen ICEV	17.1	1.3
Heavy-Duty Bus		
Diesel ICEV	5	1
Hydrogen FCV	6.6	1.5

are available. The purpose of developing a baseline EER value is to simplify the comparison with baseline gasoline vehicles or diesel buses.

The baseline EER also eliminates the issue of whether to compare a hydrogen vehicle to a gasoline ICE or HEV configuration. For example, a hydrogen ICE might achieve a 1.3x improvement in fuel economy over a gasoline ICE, while a hydrogen HEV might achieve a 1.3x improvement in fuel economy over a gasoline HEV. The EER value of 1.3 is at the high range of comparisons for non-hybridized hydrogen internal combustion engine vehicles (ICEVs) compared with gasoline ICEVs. Some developers argue that the hydrogen HEV should be compared with a gasoline ICEV while others argue the more appropriate comparison is with the gasoline HEV because the customer could have purchased the exact same HEV as a gasoline model. Using an EER value of 1.3 for hydrogen ICEV/HEVs is intended to represent a balance between these arguments. Automakers can provide data on vehicle comparisons if some vehicles for the hydrogen network exceed this fuel economy comparison for comparable vehicles.

There is a lack of consensus on the appropriate EERs, with some stakeholders believing a lower value is justified while others are supporting higher values. Since this ratio has real implications for quantifying the benefits of various pathways, we recommend a more comprehensive effort to gather real-world data on the various technologies with particular emphasis on the hydrogen technologies. By drawing on automaker data to the fullest extent possible, we hope to develop EERs that are represent the real world impact of hydrogen vehicles.

Advanced Technology Vehicles

Hydrogen vehicles could exceed the fuel economy projections shown in Table 1-12 with some of the following technological approaches:

- Large battery hybridization
- Plug-in hybrid operation
- Reduction in weight, size, and drag

To the extent that such improvements are not commercially available in gasoline ICEVs, an advanced hydrogen vehicle could achieve more favorable fuel economy comparisons than those shown in Table 1-12. For the purposes of counting vehicle

Table 1-12. Estimated Mileage and Range for a Collection of Vehicles

Vehicle	Storage Mode	Volume (liters)	H_2 (kg)[a]	Mileage[b] (mpgge)	Range (miles)	Reference
Ford P2000 – ICE [c]	3600 psi	87	1.5	36.8	70	[18]
Ford H2RV	5000 psi	122	2.8	45	125	[19]
BMW 750hL – ICE	Liquid	140	9.9	22	218	[20]
ECD/Quantum modified ICHEV [d]	MH	~100	3.0	44.3 - 54	132	[21, 22]
Ford Focus FCV	5000 psi	186	4.3	47	200	[23]
Toyota FCHV	5000 psi	136	3.1	57	180	[24,25]
Honda FCX[e]	5000 psi	157	3.6	67.9	210	[26,25,27]
Chrysler Natrium	$NaBH_4$	200	10	30	300	[28]
GM HydroGen3	Liquid	68	4.5 4.8	55 50	250 240	[28, 29] [29]
GM HydroGen3	10,000 psi	86	3.1	55	170	[30]
GM Hy-wire	5000 psi	88	2	40	80	[31]

[a] Hydrogen storage based on values in references. Methods for determining mass of hydrogen storage, which depend on fueling protocol and other parameters, differ among the range of information sources.

[b] Fuel consumption in miles per gasoline equivalent gallon. 1 gge ≅ 119 MJ. This value differs among the references cited. 1 kg hydrogen contains 120 MJ on and LHV basis. Basis for fuel economy including driving cycle vary among the references.

[c] City/Highway/Combined values are 31.4/46.7/36.8

[d] City/Highway/Combined values are 42.3/46.1/43.9 mi/kg. Vehicle was tested with antilock braking system disabled in order to enable testing on dynamometer. This modification also disabled the function of regenerative braking in the modified hydrogen vehicle. Developers estimate a 10 mi/kg improvement in fuel economy if regenerative braking were functioning during dynamometer test. Combined fuel economy of 49 mpg was achieved

[e] Fuel economy date from EPA Fuel Economy Guide. City/Highway/Combined values published in the Fuel Economy Guide are 62/51/57 (mi/kg). These values are adjusted (90% city, 78.8% highway) to reflect the lower fuel economy achieved during on road driving compared with dynamometer test results for the city and highway driving cycles. Fuel economy results without the adjustment factors is 67.3 mi/kg.

technologies that achieve a more favorable rating than the baseline values, vehicle developers can provide data and rationale to CalEPA for review.

As discussed in Section 1.5.2, EER comparisons for the most advanced vehicles might be as high as 1.8 for hybrid ICEVs and 2.5 for hybrid FCVs. In order to demonstrate such an improved fuel economy, an automaker could provide data for their hydrogen vehicle and their comparable gasoline vehicle or grouping of gasoline vehicles within a class. The data should also include a description of the vehicle attributes such as acceleration, storage capacity, passenger room, and other factors in order to demonstrate that the hydrogen to gasoline vehicle comparison is appropriate. The life-cycle impact of plug-in hydrogen HEVs would need to be calculated based on the combined hydrogen and electric power consumption. Appropriate calculations would also be required for other dual-fuel or bi-fuel hydrogen applications.

The EER values for hydrogen vehicles are an important part of the overall assessment of the hydrogen network. Section 1.6 shows how the EER values are used to develop GHG, criteria pollutant and energy use comparisons.

1.5.2 Hydrogen Vehicles — Range and Mileage

This section summarizes our survey of the estimated and projected mileage and range of hydrogen-fueled vehicles, all of which are in the demonstration stage of development. Since these are not production vehicles, and since in most cases, formal fuel economy testing has not been done, we assembled the information below from published papers, press releases, and private communication with manufacturer representatives.

Table 1-12 describes the storage, mileage, and range for a variety of hydrogen-fueled vehicles. The first three rows are vehicles powered by H_2-fueled engines; the Ford H2RV is a hybrid drivetrain, but the other two H_2-engine vehicles have conventional drivetrains. The rest of the vehicles are powered by H_2 fuel cells with hybrid-electric drivetrains. It is important to reemphasize that most of these vehicles are experimental prototypes developed to prove out new technologies, and in many cases, the vehicles have not been optimized for many of the functional characteristics of high volume production vehicles such as fuel economy, range, package space and other key customer attributes. Because most of these vehicles are development prototypes (some are one-of-a-kind prototypes), extreme care must be taken in drawing any conclusions regarding the capabilities of future production-intent vehicles, and in comparing one prototype in the matrix to another. In addition, few of these vehicles have been subjected to rigorous testing to confirm the characteristics shown in the matrix below. In most cases, the information should be treated, at best, as rough estimates.

The range of a vehicle depends on two factors: the mileage and the fuel storage. Values in the table that are taken from the references appear in bold; others are computed. In most cases, the referenced data are the range and the storage, the mileage is computed. For vehicles using gaseous storage, the computed values use Sandia's real-gas equation-of-state [26]. The conversion to miles-per-gallon on a gasoline equivalent basis uses the fact that 1 kg of H_2 has about the same heating

value as 1 gallon of gasoline. The quantity of H_2 stored in the Chrysler Natrium's sodium borohydride system is estimated from the stated range and mileage, as opposed to an analysis of the data given for the storage system.

The tabulated values have varying degrees of formality to the stated range or mileage. The Honda FCX city/highway mileage values are certified with the government [25], and these vehicles are now being placed in public service. The Ford P2000 H_2-ICE vehicle has mileages for the standard city and highway driving cycles, published in a reviewed technical paper; however, the vehicle is an experimental prototype that was made to test the viability of hydrogen-fueled IC engines and no significant effort was expended to maximize range. The city and highway mileages could be averaged into the composite value of 37 mpgge; however, for comparison of this vehicle to the others, we chose to use the highway value to compute the range. Since the other vehicles have only a single value reported for the range and there is no indication that real driving cycles were used, we assume that these are highway driving.

It may be of interest to note their relative size. The Toyota FCHV, and the GM HydroGen3 could be classified as small SUV body styles. The Ford vehicles are small cars; the P2000 is based on a Ford Contour with an aluminum body; the H2RV is a modified Focus wagon. The Honda FCX is the smallest vehicle, though still able to seat four persons. The largest vehicles are the Chrysler Natrium, which is a conventional minivan, and the BMW, which is a large sedan. The GM Hy-wire is a concept vehicle whose "skateboard" architecture is intended to support various body styles.

1.5.3 Fuel Consumption Modeling Projections — Hydrogen and Plug-In Vehicles

This section summarizes our review of modeling studies and projections of hydrogen fuel-cell-powered vehicles (FCVs) and ICEVs. A comparison of the fuel economy of hydrogen vehicle to baseline gasoline vehicle is also presented.

Today's hydrogen vehicles do not achieve the potential of modeling assessments for a variety of reasons. Most projections of hydrogen vehicle fuel consumption are based on their potential as fully developed vehicles. These estimates for future vehicles assume optimized integration of components like compressors, power electronics, and cooling systems. Ideal packaging and heat recovery from the fuel cell are also assumed. Other important factors such as the fuel cell operating voltage, pressure, and temperature capability affect the overall efficiency of the fuel cell and combined vehicle system.

Fuel Cell Vehicles

Figure 1-9 shows a comparison of hydrogen FCV and hybrid FCV (FCHEV) vehicles compared to gasoline vehicles from several studies. All of these results are based on modeling or surveys completed by the authors. The baseline gasoline ICEV is also comparable to the hydrogen vehicle. No additional body modifications were assumed for the hydrogen vehicles.

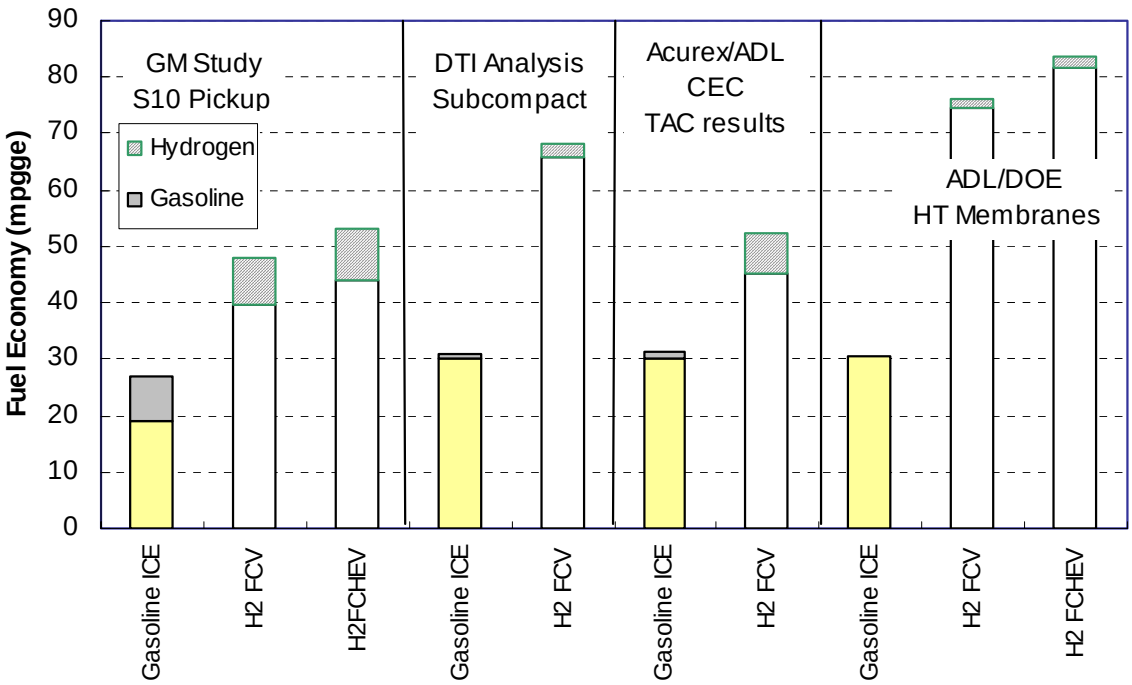

Figure 1-9. Model Predictions of Gasoline and Hydrogen FCV Fuel Consumption for Similar Vehicles

Figure 1-10 shows the comparison of energy consumption for the baseline gasoline vehicle divided by the hydrogen vehicle energy consumption. This EER is proportional to hydrogen vehicle fuel economy. The EER comparisons are similar among the studies cited even though the vehicle platforms differ. The most important factors that affect the relative differences are:

- Baseline gasoline engine technology
- Hybridization of FCV system
- Ideal weight for components (assumed in all the studies)

High temperature membranes, which reduce balance of system weight and improve FC efficiency.

Hydrogen ICEVs

Table 1-13 compares fuel economy projections for hydrogen ICE vehicles from various modeling studies. Both conventional drive vehicles and hybrids are included. Where available, the projected fuel economy for a comparable gasoline vehicle is given, as well.

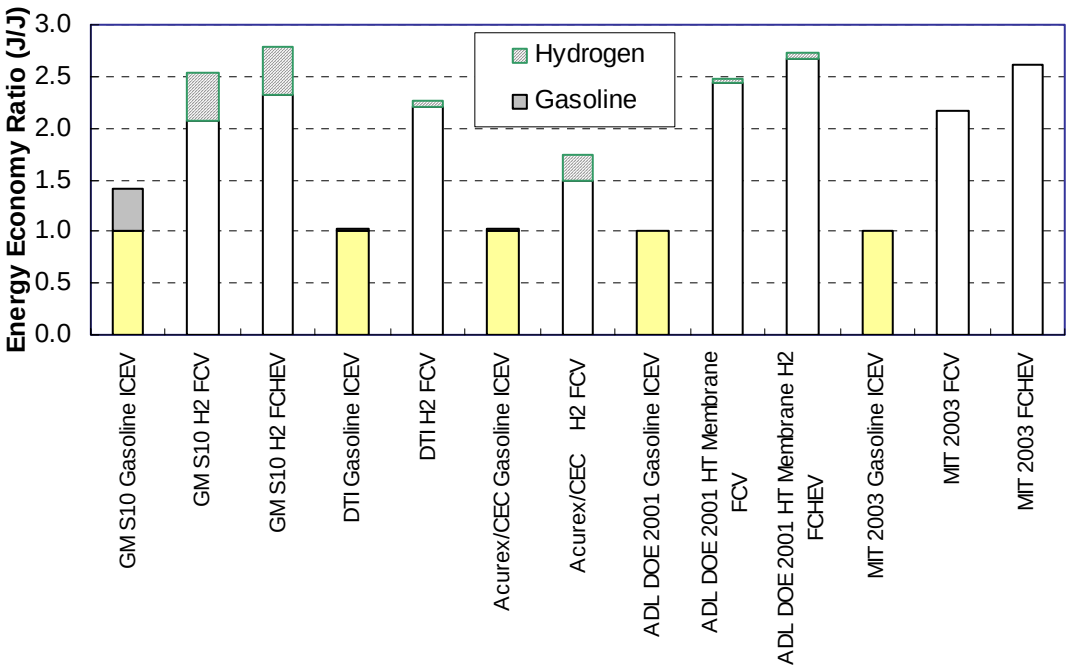

Figure 1-10. Energy Economy Ratio for Hydrogen FCV and Baseline Gasoline Vehicles [3, 15, 32, 35, 41]

Table 1-13. Fuel Economy Projections for Hydrogen ICE Vehicles

Study	Vehicle Description	Fuel Economy (mpgge)	Reference
GM European WTW	H_2 ICE, CD 1	36.9	[14]
	H_2 ICE, HEV	50.1	[14]
	Gasoline CD	30.7	[14]
	Gasoline HEV	41.9	[14]
Stromberger	H_2 ICE, CD 2005 - 2010 projection	41.2	[33]
	Gasoline CD 2005 - 2010 projection	46.5	[33]
Arthur D. Little (now TIAX)	H_2 ICE, CD	39.2	[3]
	Gasoline CD	30.6	[3]
Sandia	H_2 ICE, HEV	60	[34]
Directed Technologies	H_2 ICE, Load-Following Series Hybrid	~40	[35]
	H_2 ICE, Thermostat-Mode Series Hybrid	~38	[35]
	H_2 ICE, Parallel HEV	~ 50	[35]
	Gasoline vehicle, CD	~ 30	[35]
Lawrence Livermore	H_2 ICE, CD	35.8/51.8/41.6	[36]
	H_2 ICE, Parallel Hybrid	47.0/62.4/52.9	[36]
	H_2 ICE, Series Hybrid	57.4/70.0/62.5	[36]

CD = Conventional Drivetrain.

Fuel economy corresponds to driving cycle projection or EPA City/Highway/Combined

The fuel economy values in Table 1-13 vary quite noticeably. Three of the primary factors accounting for the variation are:

- The type of vehicle modeled
- The type of drivetrain modeled
- The driving cycle used in the study

The type of vehicle modeled dictates many performance characteristics and has a significant impact on fuel economy. The GM model uses a 2002 Opel Zafira minivan with projected improvements in 2010, Sandia uses a modified Toyota Prius, and Directed Technologies uses a Mercury Sable. The other two studies use seemingly similar vehicle types, but do not specify a particular make or model. Lawrence Livermore specifies the frontal area (2.04 m^2) and empty weight (1000 kg for the conventional vehicle) of its modeled vehicle, which are similar to figures of many mid- or full-sized sedans. The Arthur D. Little study is based on a "midsized" vehicle, which would be comparable to a Ford Taurus or Chevrolet Lumina. The FCV fuel economy was based on performance parameters for high-temperature PEM fuel cell stacks, which would result in improved fuel economy over today's fuel cell technology. Higher temperature fuel cells would also reduce the size and cost of radiators for the FCV.

The type of drivetrain used in the models also has significant implications for fuel economy. Presumably, studies modeling hybrid powertrains will predict greater fuel economy than studies investigating conventional drivetrains. The GM study includes both a five-speed conventional-drive vehicle and a parallel hybrid with a full-sized engine and nickel-metal hydride (NiMH) batteries sized to meet a 20 km zero emission vehicle (ZEV) range. Arthur D. Little considers a conventional-drive hydrogen ICE. Sandia's model uses a Toyota Prius (parallel/series hybrid) with a modified four-stroke, spark-ignited (SI) hydrogen ICE. Directed Technologies Inc. models three hybrid designs, two series configurations and one parallel arrangement. The Lawrence Livermore study considers three powertrains: conventional-drive, a parallel hybrid, and a series hybrid. The conventional vehicle uses a four-cylinder ICE, and both hybrids only use three cylinders and use flywheels for energy storage.

The drive cycle modeled also influences fuel economy projections. GM uses the European Driving Cycle (EDC). Arthur D. Little bases its results on a combination of city (Federal Urban Driving Schedule [FUD]) and highway (Highway Fuel Economy Test [HFET]) drive cycles. Sandia's model uses the FUDS. Directed Technologies uses a 1.25 times faster EPA 55/45 combined drive cycle. Finally, Lawrence Livermore uses both urban and highway drive cycles in their study. These results are not adjusted for differences between dynamometer testing and on-road driving. No further adjustments are made for differences between dynamometer cycles and on-road driving.

Plug-In Vehicles

Plug in hydrogen HEVs (PHHEVs) represent another option for the hydrogen network. These vehicles would be equipped with a sufficiently large battery pack to enable home

charging. Analyses by EPRI and a group of stakeholders indicate that an all-electric driving range over 20 miles is optimal from a cost, emission reduction, regulator incentive, and customer value proposition point of view for plug in HEVs [37, 38]. This all electric range is achieved by equipping the vehicle with a larger traction battery. The battery provides sufficient energy storage for the all electric driving range and sufficient power to achieve acceleration and top speed design parameters.

Experience with PHHEVs is evolving. DaimlerChrysler Corp. is in the midst of conducting a hybrid gas/electric van project with EPRI in Palo Alto, California, in which the vehicle runs on both gas and electric power or just electric.

The vehicle being tested is a Dodge Sprinter van. It comes with a small gasoline engine and a battery-operated electric motor that increases driving range, offers a power boost when needed and increases mileage while reducing emissions. Annuvu, an aftermarket upfitter in California, equips battery electric cars with PEM fuel cells in a range extender configuration.

EPRI has analyzed several options for gasoline plug in HEVs. These vehicles are configured as parallel hybrids with power provided by both the ICE engine and electric motor, except when in all electric mode. Hydrogen ICEVs could be similarly configured. Fuel Cell HEVs are series hybrids, equipped with an electric motor to drive the wheels. Fuel economy projections from gasoline plug in HEVs as well as assessments of the potential fraction of time driving on electric power were analyzed in the EPRI study. The plug in fuel economy and % of miles powered by plug in electric drive could serve as estimates of the potential performance of PHHEVs.

Table 1-14. Fuel Economy Projections for Plug-in Hybrid Vehicles

Vehicle Description	Fuel Economy (mpgge)		% Electric Operation[c]
	Gasoline	Plug-In[a]	
Midsize Car[b]			
Baseline	28.9	—	—
HEV0	41.9	—	—
HEV20	43.5	117.2	31 - 50
HEV60	45.4	113.8	63 - 74

[a] Source: EPRI [37]. Fuel economy based on modeling for combined city and highway driving cycle.
[b] 33.4 kWh/gge.
[c] The fraction of electric operation was estimated for situations where the plug-in vehicle is charged at home. The fraction of electric driving varies with the customers' diving patterns.

1.6 WTW Energy Inputs and GHG Emissions

Energy inputs and GHG emissions were calculated on a WTW basis, which represents the gram per mile impact of operating a hydrogen or conventional petroleum fueled vehicle. A comparison of vehicle and fuel cycle energy consumption on a per mile or km basis are calculated from WTT_f factors multiplied by fuel consumption[9] (for example g/MJ x MJ/mi). The WTT_f includes both the fuel cycle plus vehicle related impacts, which are identified separately here. In the case of gasoline, the carbon in the fuel is represented as a WTT_f factor.

The fuel cycle energy inputs and GHG emissions were determined using the GREET 1.6 model, with assumptions that represent future alternative fuels used in California as well as the gasoline that would be displaced. GHG emissions include CO_2 as well as CH_4 and N_2O, weighted for their lifetime global warming potential (GWP). CO_2 emissions were calculated directly from the carbon content of the fuel after accounting for fuel that is converted to CO, CH_4 and evaporative emissions[10].

The fuel cycle energy inputs and GHG emissions are affected by the mix of production resources, transportation, and delivery options. The sources of CO_2, emissions from fuel combustion in the fuel cycle include sources such as the following:

- Oil and gas extraction and processing
- Oil refining
- Natural gas transmission and distribution
- Petroleum and ethanol transportation
- Local fuel delivery
- Power production
- Hydrogen production and delivery

CH_4 and N_2O are also included in the fuel cycle GHG emissions. These include emissions from fuel combustion as well as CH_4 losses from natural gas distribution. Other sources of GHG emissions include N_2O from agricultural activities and N_2O from corona discharge from power lines. GHG emissions are represented on a CO_2 equivalent basis using the weighting factors in Table 1-15.

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[9] The comparison per mile will differ considerably among similar vehicles. For example the energy consumption for a hydrogen fuel cell vehicle could be about half that of a conventional gasoline ICEV, so the combined vehicle and fuel cycle emissions will be half that of a gasoline ICEV.

[10] This small amount of carbon conversion to pollutants other than CO_2 has a very small impact on the results.

Table 1-15. Global Warming Potential Weighting Factors for GHG Emissions

Pollutant	GHG Factor ($g\ CO_2e/g_{pollutant}$)
CO_2	1
CH_4	23
N_2O	296

IPCC 100 year GWP, also used in GREET 1.6, 2002.

1.6.1 Fuel Cycle GHG Emissions

The WTT_f values were first determined for primary energy carriers such as natural gas, diesel, and electric power. These were then combined with the energy inputs for hydrogen production. Table 1-16 illustrates total GHG emissions per unit energy delivered to the vehicle tank for the fuel considered in this report[11]. WTT_f GHG factors are grouped into vehicle/combustion and fuel cycle categories. Vehicle/fuel combustion includes both the CO_2 emitted when gasoline or diesel are burned as well as CH_4 and N_2O emissions from the vehicle. The CO_2 combustion factors for the primary energy inputs of hydrogen production (natural gas, etc.) are also shown in Table 1-17. Fuel cycle emissions are further grouped by those associated with the use of electric power in California, and all other fuel cycle emissions. Separating values associated with power production allows for the calculation of GHG emissions with different levels of renewable power.

The fuel cycle factors for hydrogen are determined by combining the primary energy inputs from Table 1-4 with the WTT_f values for the primary energy carriers, natural gas, diesel, and electric power. The WTT_f values for a variety of other feedstocks are also shown. These values can be used to determine the WTT_f GHG factor for other hydrogen pathways.

The GHG factor for the hydrogen pathways consist primarily of the following:

- Primary energy input (such as natural gas)
- Diesel fuel for transportation
- Electric power for plant operation and compression
- CO_2 reductions and emissions associated with sequestration

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[11] Some readers take issue with applying the term WTW or TTW to the GHG emissions on an energy basis. However, these values do represent the total GHG emissions from fuel production and vehicle use. A small uncertainty is introduced with this approach. Different vehicle classes may emit different levels of N_2O and CH_4 per MJ. These values are often estimated as constant per mile for light-duty vehicles, which is no more accurate than the approach taken here. This method of presentation facilitates calculating GHG emissions from aggregate fuel use. In order to determine GHG emissions per mile, multiply by fuel consumption in MJ/mi.

Table 1-16. Well to Tank GHG Factors

Pathway	WTT_f GHG Emissions (g CO_2e/MJ)			
	Vehicle/ Fuel Combustion		Fuel Cycle Direct Emissions	Fuel Cycle CA Power
	CO_2	N_2O, CH_4		
CA RFG, Petroleum	72.6[a]	2.1	21.6	—
CA Low Sulfur Diesel	74.0[a]	2	17.2	—
Baseline Hydrogen Pathways (g/MJ H_2)				
Central Pet. Coke Gasifier, Mobile Fueler	0	b	149.1	16.9
Sequestration Pet. Coke [c]	—	—	-140.5	14.3
Central Biomass Gasifier, Mobile Fueler	0	b	15.3	24.1
Sequestration Biomass	—	—	-131.4	13.3
Central Biogas, Mobile Fueler	0	b	15.2	20.3
Central NG SR, LH2 Truck	0	b	88.0	48.8
Sequestration Central NG	—	—	-67.4	6.8
Central NG SR, Mobile Fueler	0	b	97.4	12.2
On-Site NG ATR	0	b	104.2	15.2
On-Site NG Steam Reformer[d]	0	b	96.7	11.4
On-Site Electrolysis, 100% NG Power	0	b	0	284.5
On-Site Electrolysis, 80% NG Power	0	b	0	228.5
On-Site Electrolysis, 30% NG Power	0	b	0	88.3
On-Site Electrolysis,100 % Renewable Mix	0	b	0	4.3
On-Site Solar, 100% Solar	0	b	0	17.1
Central Electrolysis, Wind, Tube Trailer	0	b	8.8	3.5

[a] Carbon factor for CA RFG, 5.7 wt% ethanol is 73 g CO_2/MJ; for CA diesel with 10 ppm sulfur, 74.4 g/MJ. Assume 99.5% of carbon in fuel is converted to CO_2.for vehicle emissions. GHG factor for CO and unburned hydrocarbons is zero.

[b] Assume 1.7 g/MJ for hydrogen ICEV based on N_2O proportional to fuel consumption. 0 g/MJ for hydrogen FCV.

[c] GHG emissions from sequestration are added to the appropriate pathway if sequestration is assumed.

[d] **Example Calculation: For On-Site NG Steam Reformer** (from Tables 1-4 and 1-17),
1.43 MJ NG/MJ H_2 x (57.3 + 10.4) g GHG/MJ = 96.7 g CO_2e/MJ H_2 from reformer combustion,
plus 0.090 MJ power/MJ H_2 x (102.6 + 24.3) g GHG/MJ = 11.4 g CO_2e/MJ H_2

Notes: 1 kg hydrogen contains 120 MJ, LHV basis. Multiply GHG factors by 120 to get g GHG/kg H2 values.

Also, all of the production options will use a mix of marginal natural gas and renewable power. The results for 100% natural gas and renewable power are shown in order to enable the calculation of different combinations of renewable power.

Table 1-17 Well to Tank GHG Factors for Electric Power and Feedstocks

Power Generation and Distribution	Heat Rate (Btu/kWh)	Transmission Loss	Fuel Cycle (g/MJ)	Power Plant (g/MJ)
Natural Gas CC Power Plant	7660[a]	8%	30.3	127.8
Natural Gas CC Power Plant, night time	7660[a]	6%	29.7	125.4
Wind	—	8%	2.4	0
On-Site Solar	—	0%	9.5	0
RPS Mix, 20% renewable, 80% NG[b]	—	8%	24.3	102.6[c]
RPS Mix, 20% renewable, 80% NG[b,] at night	—	6%	23.8	100.7

Primary Energy Inputs, (g CO_2e/MJ)	Combustion [d]		Fuel Cycle (g/MJ)	CA Power (g/MJ)
	CO_2	N_2O, CH_4		
Natural Gas to Plant	57.3	e	10.4	0
Petroleum Coke	95	e	8.8	0
Biomass, CA scenario [5]	81	e	-77.9	0
Biogas	65	e	-60	2
Methanol to Local Station	68.7	e	26	0
Ethanol (corn) to Local Station	70.8	e	-9	0
LPG to Local Station	65.7	e	11	0

[a] All energy values on LHV basis. 7660 Btu/kWh LHV = 8500 Btu/kWh HHV.
[b] Assumes that 20% of power is generated from new renewables and that sufficient demand for renewables exists to require growth in renewable power.
[c] 3.6 MJ/kWh. GHG factor is 457 g/kWh.
[d] Carbon factor represents CO_2 emitted from processing feedstock to make hydrogen. Carbon in fuel forms CO_2, CO, and hydrocarbon emissions. For a reforming process, over 99.5 % of carbon is converted to CO_2, which is reflected in the CO_2 factor. Note ethanol heating value is 27.0 MJ/kg. 52.1% carbon.
[e] N_2O and CH_4 emissions depend on the amount of fuel that is burned in the presence of air. For example, reforming hydrocarbons with pure oxygen or steam at high temperature sources produces no N_2O. For steam reformers, about 25% of the fuel energy is burned, usually as waste gas from the PSA. ATRs and MCFCs could produce different levels of N_2O emissions. The waste gas from these systems can be used for other processes.

The GHG factors for truck transportation depend on the factors described in Table 1-7. These values can vary substantially for various hydrogen fueling station options. Diesel transportation is included in the category of fuel cycle direct emissions.

The GHG factor is shown separately for hydrogen production pathways that could be combined with sequestration. The GHG factor for sequestration includes a negative value associated with CO_2 that would be sequestered and a positive value associated with power consumption for CO_2 capture and storage. The values for sequestration are added to the WTT_f values when sequestration is assumed.

GHG emissions associated with electric power used for hydrogen production or CO_2 sequestration are calculated from the electric energy inputs in Table 1-4 and the GHG factor for electric power in Table 1-17. The effect of renewable power is considered for the different hydrogen production pathways.

Renewable Power

GHG emissions associated with electric power depend on the resource mix and efficiency of power production. The GHG impact of renewable power is discussed in Section 2. The analysis in Section 2 takes into account the energy required for producing renewable power facilities as well as the emissions associated with fossil fuel-based power generation. A ratio of the GHG emissions from renewable power compared with natural gas power is used to determine the GHG factors for renewable power in Table 1-17.

GHG factors for hydrogen production are based electric power generated from 20 percent renewables due to a California Renewable. Natural gas fired power plants are assumed to provide the remaining 80 percent as the marginal generation resource [10]. The 20 percent renewable portion is attributed to power generation because any growth in power demand due to hydrogen production would need to meet the requirements of a renewable portfolio standard.

Operators of hydrogen production systems could also chose to obtain a higher fraction of power from renewables by entering into renewable power purchase agreements as described in Section 2. With a renewable portfolio standard in effect, additional demand for renewable power would require growth in production capacity. If the renewable portfolio standard is not in place or is relaxed due to shortages in power, then the effect of renewable purchase agreements on overall GHG emissions becomes less clear.

The results for different sources and fractions of renewable power are shown for the electrolysis options in Table 1-16. The reader can calculate the result for any mix of renewables based on the values shown in this table. Note that the central plant electrolysis option also includes emissions from hauling the hydrogen by tube trailer. This value is shown as a direct fuel cycle emission rather than fuel cycle power. The mix of renewable power for electrolysis is a parametric calculation and does not imply an actual level of renewable power except where dedicated power production is associated with electrolysis (such as wind and solar). Even when dedicated power production is built for hydrogen production, supplemental grid power may be needed for electrolysis systems. The actual mix of renewable power for electrolysis systems will depend on the type of arrangements made to guarantee that the renewable fraction as described in Section 2.

Plug in Hybrid Hydrogen Vehicles

The impact of hydrogen PHEVs depends on both the energy consumption when operating on plug in power and hydrogen as well as the proportion of distance traveled for each energy carrier. The emission impacts from PHEVs can be determined from the WTT_f factor for electric power from Table 1-16. Some developers expect that plug-in vehicles will be charged in home garages largely at night. Electric power line losses are slightly lower at night because less power is consumed and transmitted at night. This effect can also be considered for plug-in vehicle charging.

Vehicle GHG Emissions

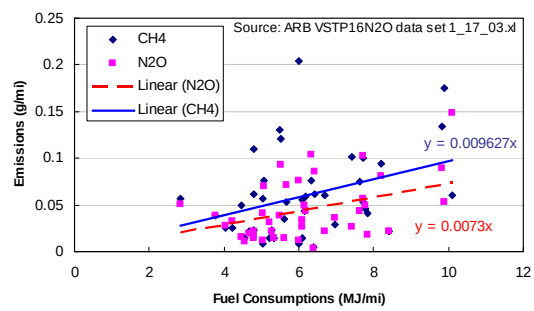
Table1-18 shows CH_4 and N_2O data from gasoline cars and trucks complied by ARB. In order to simplify the analysis of GHG emissions, these pollutants were assumed to be proportional to fuel consumption. For the purposes of this report, N_2O from hydrogen ICEVs was assumed to be proportional to the factor for gasoline. With improved fuel efficiency, the overall N_2O emissions would be lower than that of the gasoline fueled vehicle. A refinement of the GHG analysis can be performed with additional data for both hydrogen ICE and gasoline vehicles.

Table 1-18. N_2O and CH_4 Emissions Data from Light-Duty Gasoline Vehicles [17]

Vehicle	N_2O	CH_4	Units
Gasoline ICEV	1.9	0.2	g/MJ
Gasoline ICEV	0.03	0.04	g/mi
H2ICE	1.9	0	g/MJ
H2ICE	0.02	0	g/mi

Data for gasoline ICEVs from ARB. Emission factors for gasoline based on ARB data from 60 cars VSTP16 N_2O data set.xls. Emissions proportional to fuel consumption appears to be a better correlation than constant per mile emissions.

Assumed N_2O is proportional to fuel economy for hydrogen ICE vehicle.



1.6.2 Energy Inputs

The WTW energy inputs for hydrogen were calculated for the baseline pathways. These inputs include energy for feedstock production, processing, transport, and vehicle use and are shown on a per unit fuel (WTT_f) basis in Table 1-19. These values include both the energy consumed in the fuel cycle as well as the energy in the fuel. The fuel cycle portion is simply 1 J/J less than the WTT_f value. The calculation approach is the same as that for GHG emissions where the sum of feedstock, diesel, and electric power are combined with the energy inputs for hydrogen production.

Fuel cycle energy inputs for natural gas, diesel, and other inputs for hydrogen production were determined from GREET 1.6. The energy required for hydrogen production, from Table 1-4, was multiplied by the appropriate values in the lower portion of Table 1-19 in order to determine the total energy inputs for hydrogen production. The energy inputs for other feedstocks (ethanol, methanol, and LPG) are also shown in order to facilitate the analysis of other hydrogen production pathways.

WTW energy inputs were determined by multiplying energy consumption values from Table 1-11 by the values in Table 1-19. The results are shown for passenger cars in Table 1-20 and ICE shuttle buses and FC transit buses in Table 1-21. The energy inputs are broken out according to petroleum, other fossil fuels, and non-fossil fuels.

Table 1-19. Well to Tank Energy Inputs

Pathway	WTT_f Energy impacts (J/Jfuel)		
	Petroleum	Other Fossil	Non Fossil
Petroleum Fuels			
CA RFG	1.094	0.173	0.063
CA Diesel	1.087	0.119	0.00
Hydrogen Pathways			
Sequestration Petroleum Coke [a]	0.002	0.235	0.022
Central Pet. Coke Gasifier, Mobile Fueler	1.552	0.292	0.060
Sequestration Biomass [a]	0.002	0.219	0.021
Central Biomass Gasifier, Mobile Fueler	0.169	0.410	1.547
Central Biogas, Mobile Fueler	0.168	0.347	1.502
Sequestration Central NG [a]	0.001	0.113	0.011
Central NG SR, LH2 Truck	0.024	2.193	0.076
Central NG SR, Mobile Fueler	0.130	1.603	0.019
On-Site NG ATR	0.007	1.918	0.024
On-Site NG Steam Reformer	0.007	1.735	0.018
On-Site Electrolysis, NG Power/20%RPS	0.028	3.76	0.355
On-Site Electrolysis, 70% Renewable/30%NG Power	0.028	1.452	1.241
On-Site Electrolysis,100 % Renewable Mix	0.028	0.070	1.773
On-Site Solar, 100% Solar	0.028	0.281	1.692
Central Electrolysis, Wind, Tube Trailer	0.131	0.068	1.808
Energy Inputs/Feedstocks			
Natural Gas to Plant	0.0036	1.083	0.00
Petroleum Coke	1.07	0	0.025
Biomass, CA scenario [5]	0.028	0	1
Biogas	0	0.05	1.02
Methanol to Local Station	0.05	1.47	0
Ethanol (corn) to Local Station	0.5	0.4	1.4
LPG to Local Station	1.04	0.1	0
Electric Power [b] , 100 % natural gas, 8500 Btu/kWh	0.0157	2.60	0
Electric Power [b], 80 % natural gas, 8500 Btu/kWh/ 20% renewable (20% RPS)	0.0130	2.09	0.2
Electric Power [b], 100 % renewable, wind	0.00023	0.039	1

[a] Additional energy required if the concentrated CO_2 steam is sequestered. CO_2 from these sources is not sequestered today and the feasibility of sequestration depends on the availability and economics of a suitable storage options.

[b] Energy required to deliver electric power to fueling station including 8% transmission losses representing 24-hour operation. 40.1% efficient generation (HHV basis).

Table 1-20. Well to Wheel Energy Inputs — LDVs

MJ/mi	Vehicle	Fuel	WTW Energy Inputs (MJ/mi)		
			Petroleum	Other Fossil	Non Fossil
4.7	ICEV	CA RFG, Petroleum	5.10	0.80	0.29
		Hydrogen Vehicles - Various Pathways			
3.6	ICEV	Sequestration Petroleum Coke	0.01	0.84	0.08
3.6	ICEV	Central Petroleum Coke Gasifier, Mobile Fueler	5.56	1.05	0.21
3.6	ICEV	Sequestration Biomass	0.01	0.79	0.07
3.6	ICEV	Central Biomass Gasifier, Mobile Fueler	0.61	1.47	5.55
3.6	ICEV	Central Biogas, Mobile Fueler	0.60	1.25	5.39
3.6	ICEV	Central NG SR, LH2 Truck	0.09	7.86	0.27
3.6	ICEV	Sequestration Central NG	0.00	0.40	0.04
3.6	ICEV	Central NG SR, Mobile Fueler	0.46	5.75	0.07
3.6	ICEV	On-Site NG ATR	0.03	6.88	0.08
3.6	ICEV	On-Site NG Steam Reformer	0.02	6.22	0.06
3.6	ICEV	On-Site Electrolysis, 80% NG Power/20%RPS	0.10	13.47	1.27
3.6	ICEV	On-Site Electrolysis, 70% Renewable/30%NG Power	0.10	5.21	4.45
3.6	ICEV	On-Site Electrolysis,100 % Renewable Mix	0.10	0.25	6.36
3.6	ICEV	On-Site Solar, 100% Solar	0.10	1.01	6.07
3.6	ICEV	Central Electrolysis, Wind, Tube Trailer	0.47	0.24	6.48
2.3	FCV	Sequestration Petroleum Coke	0.00	0.55	0.05
2.3	FCV	Central Petroleum Coke Gasifier, Mobile Fueler	3.62	0.68	0.14
2.3	FCV	Sequestration Biomass	0.00	0.51	0.05
2.3	FCV	Central Biomass Gasifier, Mobile Fueler	0.39	0.95	3.60
2.3	FCV	Central Biogas, Mobile Fueler	0.39	0.81	3.50
2.3	FCV	Central NG SR, LH2 Truck	0.06	5.11	0.18
2.3	FCV	Sequestration Central NG	0.00	0.26	0.02
2.3	FCV	Central NG SR, Mobile Fueler	0.30	3.74	0.04
2.3	FCV	On-Site NG ATR	0.02	4.47	0.06
2.3	FCV	On-Site NG Steam Reformer	0.02	4.04	0.04
2.3	FCV	On-Site Electrolysis, 80% NG Power/20%RPS	0.07	8.75	0.83
2.3	FCV	On-Site Electrolysis, 70% Renewable/30%NG Power	0.07	3.38	2.89
2.3	FCV	On-Site Electrolysis,100 % Renewable Mix	0.07	0.16	4.13
2.3	FCV	On-Site Solar, 100% Solar	0.07	0.65	3.94
2.3	FCV	Central Electrolysis, Wind, Tube Trailer	0.31	0.16	4.21
1.6	Plug In[a]	Plug-in power, 20% RPS, night time charging	0.025	3.18	0.30

[a] Energy impact for plug in vehicle with assumed EER of 3.0. These results represent the miles driven on plug in power. Grid power could represent 30 to 70% of the miles driven, depending upon battery capacity and other factors.

Table 1-21. Well to Wheel Energy Inputs — MDVs and HDVs

MJ/mi	Vehicle	Fuel [a]	WTW Energy Inputs (MJ/mi)		
			Petroleum	Other Fossil	Non Fossil
9.1	ICE Bus	CA RFG, Petroleum	10.00	1.58	0.57
7.0	ICE Bus	Sequestration Pet. Coke	0.01	1.65	0.16
7.0	ICE Bus	Central Pet. Coke Gasifier, Mobile Fueler	10.92	2.05	0.42
7.0	ICE Bus	Sequestration Biomass	0.01	1.54	0.15
7.0	ICE Bus	Central Biomass Gasifier, Mobile Fueler	1.19	2.88	10.88
7.0	ICE Bus	Central Biogas, Mobile Fueler	1.18	2.44	10.56
7.0	ICE Bus	Central NG SR, LH2 Truck	0.17	15.42	0.53
7.0	ICE Bus	Sequestration Central NG	0.01	0.79	0.07
7.0	ICE Bus	Central NG SR, Mobile Fueler	0.91	11.27	0.13
7.0	ICE Bus	On-Site NG ATR	0.05	13.49	0.17
7.0	ICE Bus	On-Site NG Steam Reformer	0.05	12.20	0.12
7.0	ICE Bus	On-Site Electrolysis, 80% NG Power/20%RPS	0.20	26.41	2.49
7.0	ICE Bus	On-Site Electrolysis, 70% Renewable/30%NG Power	0.20	10.21	8.73
7.0	ICE Bus	On-Site Electrolysis,100 % Renewable Mix	0.20	0.49	12.47
7.0	ICE Bus	On-Site Solar, 100% Solar	0.20	1.97	11.90
7.0	ICE Bus	Central Electrolysis, Wind, Tube Trailer	0.92	0.48	12.72
27.3	ICE Bus	CA Diesel	29.62	3.24	0.00
18.2	FC Bus	Sequestration Pet. Coke	0.03	4.26	0.40
18.2	FC Bus	Central Pet. Coke Gasifier, Mobile Fueler	28.20	5.30	1.08
18.2	FC Bus	Sequestration Biomass	0.03	3.99	0.38
18.2	FC Bus	Central Biomass Gasifier, Mobile Fueler	3.07	7.44	28.10
18.2	FC Bus	Central Biogas, Mobile Fueler	3.05	6.31	27.29
18.2	FC Bus	Central NG SR, LH2 Truck	0.44	39.84	1.38
18.2	FC Bus	Sequestration Central NG	0.02	2.05	0.19
18.2	FC Bus	Central NG SR, Mobile Fueler	2.35	29.12	0.34
18.2	FC Bus	On-Site NG ATR	0.13	34.85	0.43
18.2	FC Bus	On-Site NG Steam Reformer	0.12	31.52	0.32
18.2	FC Bus	On-Site Electrolysis, 80% NG Power/20%RPS	0.51	68.24	6.44
18.2	FC Bus	On-Site Electrolysis, 70% Renewable/30%NG Power	0.51	26.39	22.55
18.2	FC Bus	On-Site Electrolysis,100 % Renewable Mix	0.51	1.27	32.21
18.2	FC Bus	On-Site Solar, 100% Solar	0.51	5.10	30.74
18.2	FC Bus	Central Electrolysis, Wind, Tube Trailer	2.39	1.24	32.85

[a] Comparison of medium duty shuttle buses with baseline gasoline engines. Hydrogen pathways correspond to those in Table 1-19.

The other fossil fuels category is primarily natural gas except for a small fraction of coal used in processing ethanol and as an input for electric power for natural gas production in the Midwest. The non-fossil fuels category includes renewables such as ethanol used in gasoline, renewable power for hydrogen production, as well as biomass and biogas energy. The energy inputs for a plug-in vehicle are also shown. These results reflect the miles traveled on plug-in power. The results for other vehicle comparisons are directly proportional to the EER value discussed in Section 1.5. A further discussion of the implications of displacing petroleum in included in Section 3.

A relative ranking of WTW energy inputs was calculated for passenger cars in Figures 1-11 and 1-12. The energy inputs are shown for hydrogen ICEV and FCV passenger cars as well as for a gasoline vehicle. The WTW energy input for each category of energy, petroleum, other fossil fuels (primarily natural gas), and renewables is shown in the figure. The energy inputs for each category of hydrogen vehicle are divided by the total petroleum usage for a gasoline vehicle. The petroleum usage for a gasoline vehicle is then assigned a value of 1.0. The results are proportional to the EER assumptions discussed in Section 1.5.

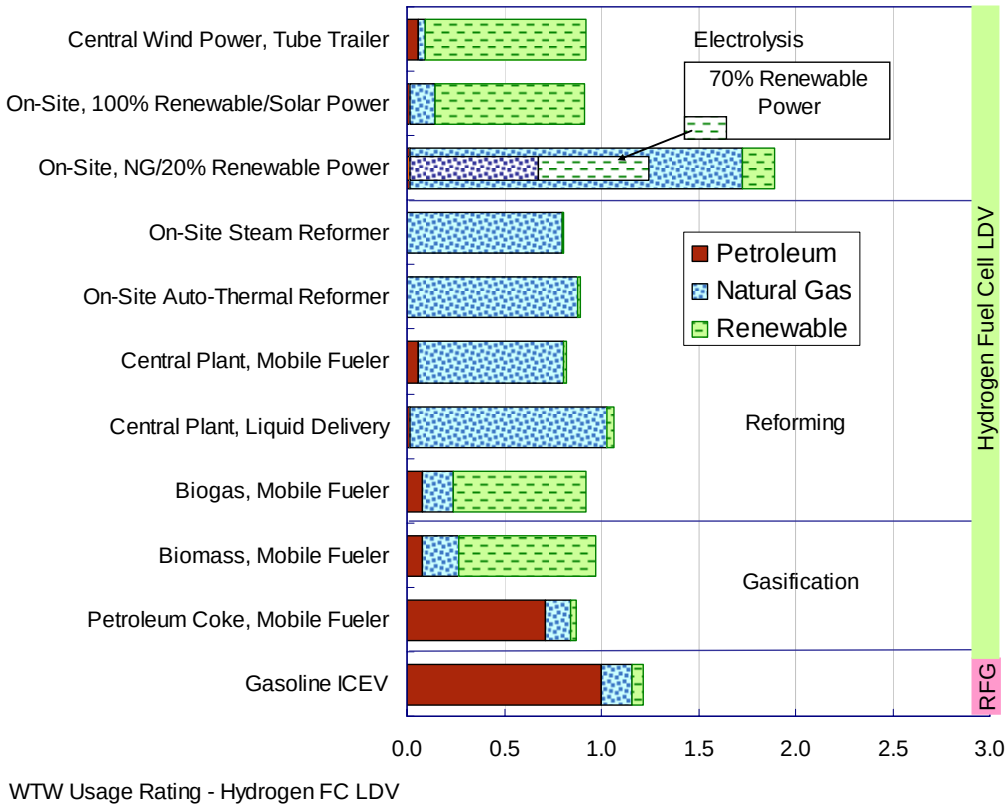


Figure 1-11. WTW Energy Rating for Hydrogen Fuel Cell Passenger Cars

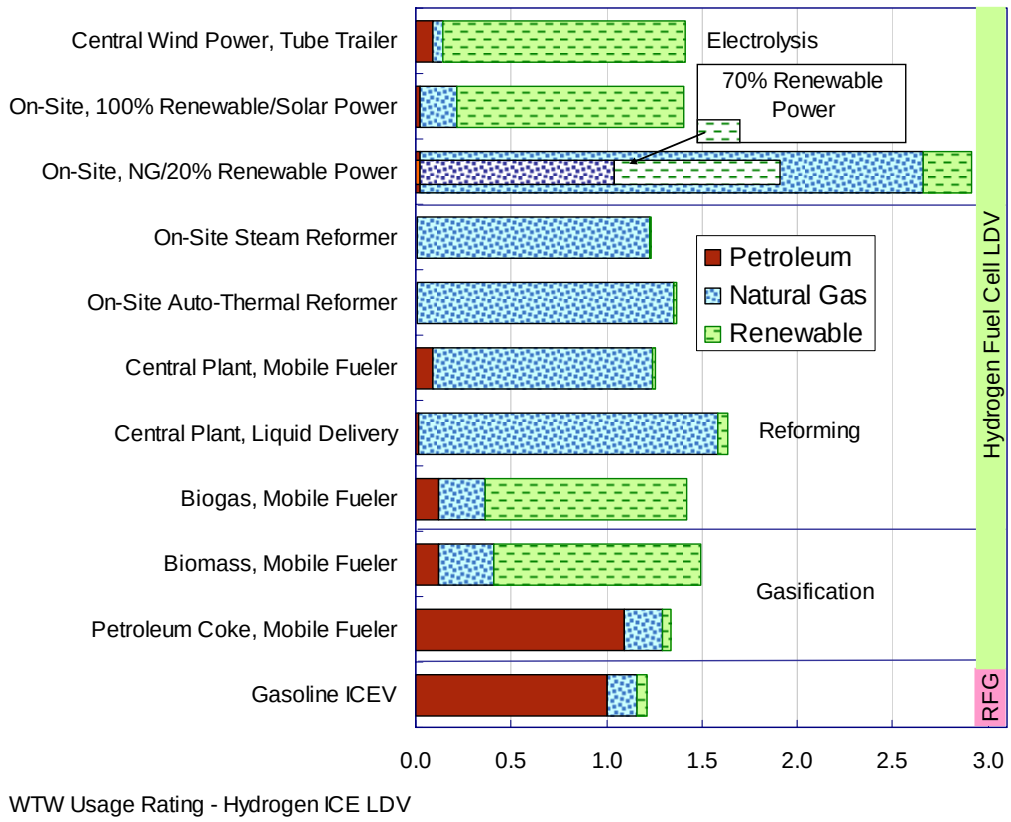


Figure 1-12. WTW Energy Rating for Hydrogen ICE Passenger Cars

1.6.3 WTW GHG Emissions — Cars and Buses

Tables 1-22 and 1-23 show the WTW GHG emissions for passenger cars, medium duty buses and heavy-duty buses. The WTW emissions are determined by combining WTT_f GHG factors with vehicle fuel consumption to determine WTW GHG emissions. Other WTT_f values from Table 1-17 can be used for different pathways and scenarios using the approach outlined in this report.

Emissions are broken out according to:

- Direct vehicle emissions
- Fuel cycle combustion and other fuel cycle emissions
- Indirect fuel cycle emissions associated with power production

Showing the fuel cycle power as a separate value enables the analysis of a variety of other pathways with different fuel use (energy ratio or 1/"efficiency") and power consumption values. The effect of 10,000 psi storage, use of renewable power, or other energy inputs can be determined by adjusting the values in the following tables. For example, emissions associated with electric power for on-site natural gas steam reforming are 41 g/mi for a hydrogen ICEV. The power mix is assumed to correspond to a 20 percent RPS requirement. If 100 percent of the power were derived from

Table 1-22. Well to Wheel GHG Emissions for Baseline Pathways — LDVs

Small Passenger Car	Fuel	WTW GHG Emissions (gCO_2e/mi)			
		Vehicle	Direct Emissions	CA Power	Total
ICEV	CA RFG, Petroleum	348	100.5	0	449
ICEV	Sequestration Pet. Coke	0	-504	51.2	-453
ICEV	Central Pet. Coke Gasifier, Mobile Fueler	5.9	534	60.7	601
ICEV	Sequestration Biomass	0	-471	47.8	-423
ICEV	Central Biomass Gasifier, Mobile Fueler	5.9	54.9	86.4	147
ICEV	Central Biogas, Mobile Fueler	5.9	54.4	72.8	133
ICEV	Central NG SR, LH2 Truck	5.9	315	174.8	496
ICEV	Sequestration Central NG	0	-242	24.6	-217
ICEV	Central NG SR, Mobile Fueler	5.9	349	43.8	399
ICEV	On-Site NG ATR	5.9	374	54.6	434
ICEV	On-Site NG Steam Reformer	5.9	345	41.0	393
ICEV	On-Site Electrolysis, 80% NG Power/20% RP	5.9	0	819	825
ICEV	On-Site Electrolysis, 30% NG Power/70% RP	5.9	0	317	323
ICEV	On-Site Electrolysis,100 % Renewable Mix	5.9	0	15.3	21
ICEV	On-Site Solar, 100% Solar	5.9	0	61.2	67
ICEV	Central Electrolysis, Wind, Tube Trailer	5.9	31.7	12.4	50
ICEV	CA RFG, Petroleum	348	100.5	0	449
FCV	Sequestration Pet. Coke	0	-327	33.3	-294
FCV	Central Pet. Coke Gasifier, Mobile Fueler	0	347	39.5	387
FCV	Sequestration Biomass	0	-306	31.1	-275
FCV	Central Biomass Gasifier, Mobile Fueler	0	35. 7	56.2	92
FCV	Central Biogas, Mobile Fueler	0	35.4	47.3	83
FCV	Central NG SR, LH2 Truck	0	205	114	319
FCV	Sequestration Central NG	0	-157	16.0	-141
FCV	Central NG SR, Mobile Fueler	0	226	28.5	252
FCV	On-Site NG ATR	0	243	35.5	278
FCV	On-Site NG Steam Reformer	0	225	26.6	252
FCV	On-Site Electrolysis, 80% NG Power/20% RP	0	0	532	532
FCV	On-Site Electrolysis, 30% NG Power/70% RP	0	0	205.8	206
FCV	On-Site Electrolysis,100 % Renewable Mix	0	0	10.0	10
FCV	On-Site Solar, 100% Solar	0	0	40.0	40
FCV	Central Electrolysis, Wind, Tube Trailer	0	20.6	8.1	29
FC/PHEV[a]	Plug-in power, 20% RPS, night time charging	0	0	193	193

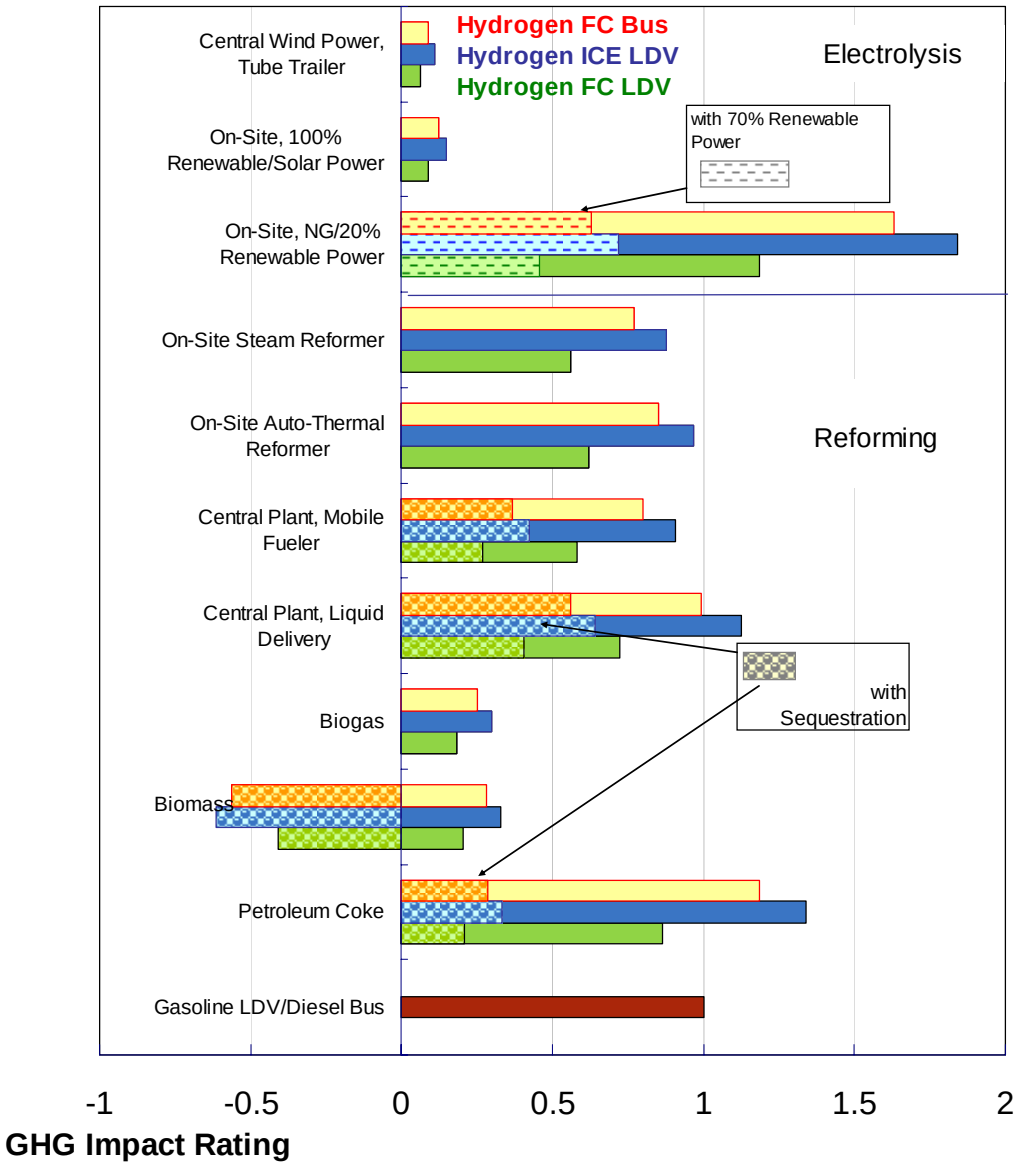
[a] Energy impact for plug in vehicle with assumed EER of 3.0. These results represent the miles driven on plug in power. Grid power could represent 30 to 70% of the miles driven, depending upon battery capacity and factors such as how frequently the vehicle is plugged in. The balance of driving could be accomplished with a hydrogen fuel cell. Other vehicle configurations are also possible.

Table 1-23. Well to Wheel GHG Emissions for Baseline Pathways — MDVs and HDVs

Vehicle	Fuel	WTW GHG Emissions (gCO_2e/mi)			
		Vehicle	Direct Emissions	CA Power	Total
ICE Bus	CA RFG, Petroleum	683	197	0	880
ICE Bus	Sequestration Pet. Coke	0	-988	100	-888
ICE Bus	Central Pet. Coke Gasifier, Mobile Fueler	12	1048	119	1179
ICE Bus	Sequestration Biomass	0	-924	94	-830
ICE Bus	Central Biomass Gasifier, Mobile Fueler	12	108	169	289
ICE Bus	Central Biogas, Mobile Fueler	12	107	143	261
ICE Bus	Central NG SR, LH2 Truck	12	619	343	973
ICE Bus	Sequestration Central NG	0	-474	48	-426
ICE Bus	Central NG SR, Mobile Fueler	12	701	86	782
ICE Bus	On-Site NG ATR	12	733	107	852
ICE Bus	On-Site NG Steam Reformer	12	680	80	772
ICE Bus	On-Site Electrolysis, 80% NG Power/20% RP	12	0	1607	1618
ICE Bus	On-Site Electrolysis, 30% NG Power/70% RP	12	0	621	633
ICE Bus	On-Site Electrolysis,100 % Renewable Mix	12	0	30	42
ICE Bus	On-Site Solar, 100% Solar	12	0	120	132
ICE Bus	Central Electrolysis, Wind, Tube Trailer	12	62	24	98
ICE Bus	CA Diesel	2078	468	0	2546
FC Bus	Sequestration Pet. Coke	0	-2553	259	-2293
FC Bus	Central Pet. Coke Gasifier, Mobile Fueler	0	2708	308	3016
FC Bus	Sequestration Biomass	0	-2387	242	-2145
FC Bus	Central Biomass Gasifier, Mobile Fueler	0	278	438	716
FC Bus	Central Biogas, Mobile Fueler	0	276	369	645
FC Bus	Central NG SR, LH2 Truck	0	1598	886	2484
FC Bus	Sequestration Central NG	0	-1225	124	-1101
FC Bus	Central NG SR, Mobile Fueler	0	1769	222	2033
FC Bus	On-Site NG ATR	0	1893	277	2170
FC Bus	On-Site NG Steam Reformer	0	1756	208	1964
FC Bus	On-Site Electrolysis, 80% NG Power/20% RP	0	0	4150	4150
FC Bus	On-Site Electrolysis, 30% NG Power/70% RP	0	0	1605	1605
FC Bus	On-Site Electrolysis,100 % Renewable Mix	0	0	78	78
FC Bus	On-Site Solar, 100% Solar	0	0	310	310
FC Bus	Central Electrolysis, Wind, Tube Trailer	0	161	63	224

renewables, the emissions would be 0.7 g/mi[12]. Similarly the effect of acquiring a larger fraction for renewable power for electrolysis or other processes can also be determined.

WTW emissions for grid based electrolysis are shown for 70-percent renewable power. This is approximately the level needed to help achieve GHG emission goals described in the following section.



[a] Rating represents ratio of g/mi GHG emissions for hydrogen vehicle to baseline gasoline LDV or diesel bus. CO_2 sequestration options would need to be developed. Electric power input for all hydrogen options reflects 20% RPS unless indicated.

Figure 1-13. GHG Rating for Hydrogen Vehicle Applications [a]

[12] 41.0 g/mi GHG x (4.3/228.5) from Table 1-16.

Vehicle emissions include CO_2 from fuel combustion as well as GWP weighted CH_4 and N_2O emissions. CO_2 emissions relate directly to the amount of fuel burned while CH_4 and N_2O emissions are not always directly proportional to fuel consumption. CO_2 emissions were calculated from the carbon content of the fuel while CH_4 and N_2O emissions were estimated from vehicle emissions data.[13]

1.6.4 Aggregate GHG Goals

In order to meet the requirements of the executive order and also address the concerns of the environmental community, a composite estimate of the GHG emissions for the CA hydrogen Highway net was developed. The aggregate accounting of GHG emissions shows that a 30-percent reduction in GHG emissions and a 20-percent increase in new renewables are achievable with a wide range of vehicle and production technology options.

Aggregate GHG emissions were determined according to the procedure described in the next subsection. The inputs combine the fuel economy for the hydrogen vehicles and an estimate of petroleum displaced. An aggregate GHG emission factor for the hydrogen production was also determined. A combination of the vehicle fuel economy, petroleum displaced, fraction of renewable power, and other renewables affects the overall GHG impact. The overall GHG emission reductions reflect the combined impact of all of the vehicle fuel providers.

Aggregate GHG Emissions — HERMIN

Aggregate GHG emissions are calculated through three steps:

1. Estimate hydrogen consumption and petroleum displaced
2. Estimate mix of production pathways and mix of renewable power
3. Combine hydrogen consumption and petroleum displacement with GHG factors for hydrogen and gasoline

These calculations are for aggregate GHG emissions are set up in the Hydrogen Emission Reduction Model Including N_2O (HERMIN). The spreadsheet was distributed to enable the Societal Benefits Topic Team to assess the impact of different vehicle and hydrogen production options.

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[13] CH_4 and N_2O emissions were estimated to be proportional to fuel consumption. While hydrocarbon emissions are controlled and therefore typically assumed to be constant on a per mile basis, methane and N_2O emissions are not. Emissions data indicate that estimating these pollutants proportional to fuel consumption is somewhat more accurate than assuming these pollutants are constant per mile.

Aggregate Fuel Consumption

Aggregate fuel consumption is determined by estimated the hydrogen vehicle fuel consumption and displaced gasoline as indicated in Table 1-24. The total hydrogen consumed for Scenario C is estimated for 20,000 passenger car and 400 bus applications. The mix of vehicle corresponds to the values assessed in the overall Blueprint Plan. Two thirds of the passenger cars are ICE vehicles and on-third fuel cell vehicles. The mix of vehicles and fuel economy estimates are not prescriptive of any technology or vehicle size mix. Rather, they form the details for a scenario used to estimate overall GHG impacts.

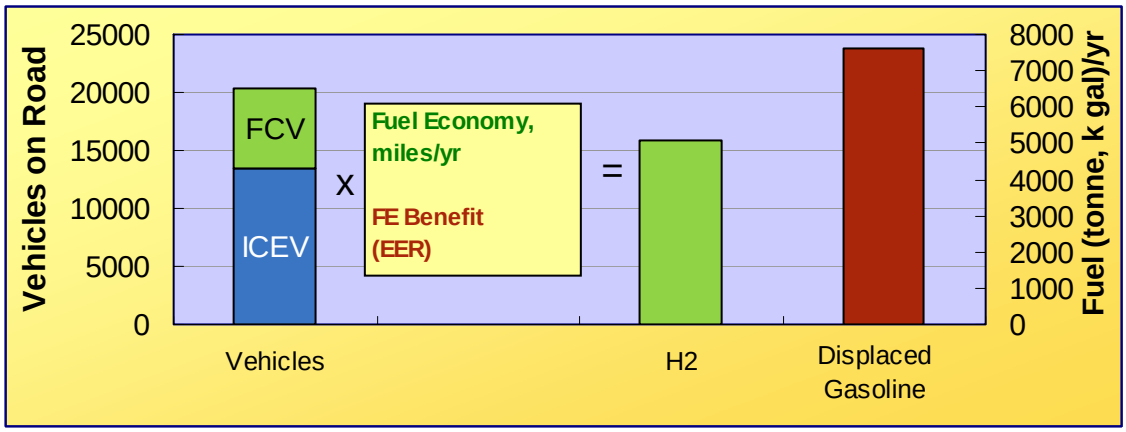
Table 1-24. Aggregate Hydrogen Consumption — Scenario C

Type	Number of Vehicles	FE (mi/kg)	FE Improved (EER)	Baseline Gasoline FE (mpgge)	Annual Mileage	Displaced Gasoline (gal/yr)	Hydrogen (kg/yr)	Power (gge/yr)
ICE LDV	13,332	42	1.3	32.0	10,000	4,166,535	3,174,286	0
ICE Bus	160	16	1.3	12.2	15,000	196,888	150,000	0
FC LDV	6,667	55	2	27.2	10,000	2,447,843	1,212,182	0
FC Bus	140	8	1.5	5.3	30,000	908,716[a]	525,000	0
FCPHEV H2	1[b]	55	2	27.2	5,000	184	91	0
FCPHEV-elect	1[b]	82	3	27.2	5,000	184	0	61
Total H2ICE	66%	—	—	—	—	4,363,424	3,324,286	0
Total H2FC	34%	—	—	—	—	3,356,742	1,737,273	0
Total Plug In	0%	—	—	—	—	184	0	61
Total	20,300	—	—	—	—	7,720,350	5,061,558	61

Step 1 of HERMIN.xls

[a] 795,000 gal of diesel fuel would be displaced. In order to simplify the example, the energy equivalent quantity of gasoline is shown here.

[b] For plug-in vehicle, miles driven on hydrogen and plug-in power are counted separately in order to determine hydrogen and power consumption. Calculations are shown for 1 PHEV as an example.



One of the fuel cell vehicles is shown as a plug in configuration to illustrate the calculation procedure. These values correspond to a hydrogen demand of 5.0 million kg per year displacing 7.7 million gallons of gasoline and diesel. One vehicle of each type with corresponding fuel consumption was assumed in Table 1-24. An example for a plug-in vehicle is also included. Half of the miles are assumed to be from plug in driving.

The procedure requires estimating the on-road fuel consumption of the hydrogen vehicle and also using a factor for the improvement in fuel economy over the baseline vehicle. The baseline fuel economy values Section 1.5 were used for this purpose. As the CA H2 Hwy Net evolves a variety of vehicle applications will be used and their fuel economy and will differ from the baseline values used here. For advanced vehicle options, which could combine a combination of hydrogen technologies and other features, to improve fuel economy, automakers can propose a comparison of hydrogen fuel consumption data and the appropriate comparison to gasoline vehicles.

The fuel economy values for hydrogen vehicles are inputs to HERMIN on a mi/kg basis. These values are slightly lower than miles per gasoline equivalent gallon (gge) due to the difference in heating value (MJ/kg vs MJ/gal). Fuel consumption for electric transportation is entered in gasoline equivalent gallons. The fuel economy improvement or energy economy ratio is a non dimensional value representing the ratio of gasoline energy consumption divided by hydrogen vehicle energy consumption.

Hydrogen Production

The next step in assessing GHG emissions is to estimate the mix of hydrogen production pathways and the fraction of renewable power used in each pathway. The HERMIN model includes the well-to-tank GHG factors for the principal baseline pathways discussed in Section 1.2. The mix of supply options is based on an overall station mix scenario (SMS) described in the Blue Print Plan. The mix of hydrogen production capacity in the HERMIN model is group by resource type and production technology. The station type, production capacity, and resource mix for Scenario C are shown in Figure 1-14. The total production capacity also corresponds to a scenario for 250 fueling stations, grouped by forecourt configuration, used in the economic analysis.

An aggregate GHG factor is determined in the HERMIN model based on the fraction of production resources in Figure 1-14 and the total hydrogen demand from Table 1-24. The amount of hydrogen consumed from each generation source is an input to

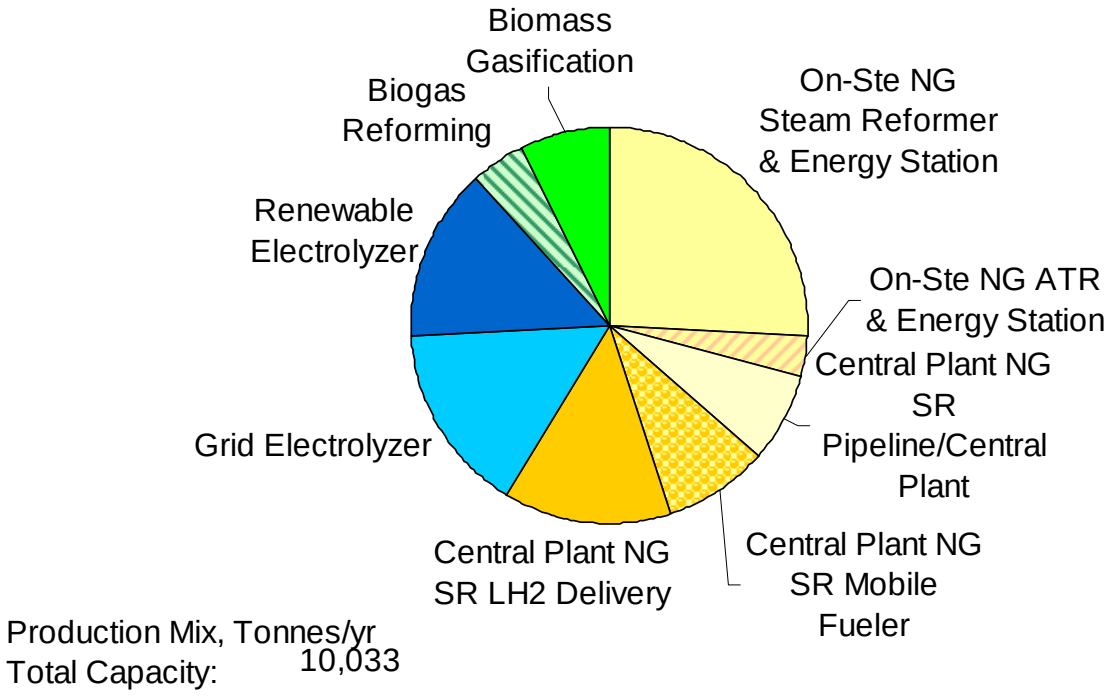


Figure 1-14. Mix of Hydrogen Production Pathways, Grouped by Resource

the second step in the HERMIN model in Table 1-25. The procedure is also repeated for plug-in power in the HERMIN spreadsheet. The GHG factors in Table 1-25 are shown in g/kg based on the values in Table 1-16 (multiplied by 120 MJ/kg).

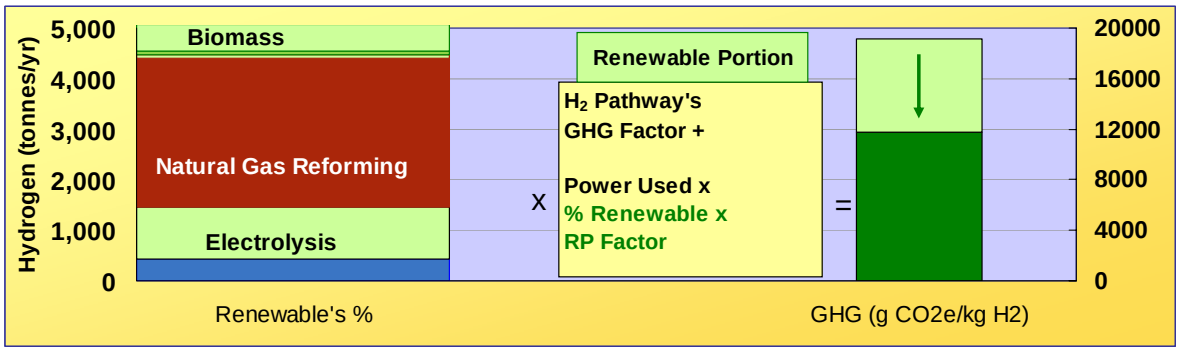
Another input is the fraction of renewable power. The assumed mix of renewable power for electrolysis options can be achieved by a combination of dedicated renewable production like solar and wind, purchasing excess power associated with renewable generation, or purchasing renewable power credits as described in Section 2. A baseline value of 20 percent renewable power was assumed for all other hydrogen applications. This assumption is based on a combination of marginal power generation from natural gas and 20-percent renewable power corresponding to a renewable portfolio standard.

The GHG factors in g/kg in Table 1-25 identify combustion and power consumption separately. This allows for the calculation of the impacts associated with any mix of renewable power. The impact of renewable power on the overall GHG factor is shown in the bar chart at the bottom of the table. The top of the bar shows the GHG factor with no renewable power and the bottom of the bar reflects the assumed renewable power mix in Table 1-25. GHG factors for other pathways and other feedstocks can readily be incorporated into the HERMIN model. The GHG factors for other feedstocks are identified in Section 1.6.1. The mix of feedstock, diesel fuel, and electric power for hydrogen production can be used to estimate a GHG factors for HERMIN.

Table 1-25. Aggregate Hydrogen Consumption and Renewable Power

Hydrogen Source	GHG Factor (g CO_2e/kg H_2)				Hydrogen (kg/yr)
	Combustion	Power	%RP	Total	
Grid Electrolyzer	0	34,140	70%	10,601	787,500
Solar Electrolyzer	0	2,048	70%	9,658	682,500
On-site SMR	11,601	1,707	20%	12,972	1,312,500
On-site ATR	12,506	2,276	20%	14,334	189,000
NG SR Central Plant	10,831	1,827	20%	12,297	409,500
NG SR Mobile Fueler	11,958	1,827	20%	13,425	420,000
NG SR, LH2	10,831	7,288	20%	16,683	682,500
Biogas Reforming	1,822	3,035	20%	4,259	210,000
Biomass Gasification	1,837	3,601	20%	4,728	367,500
Total					5,061,000

Step 2 of HERMIN.xls



GHG Reductions and Goal

The overall GHG reductions are calculated in Step 3 of HERMIN. Vehicle N_2O and methane emissions are also estimated. The N_2O from hydrogen ICEV is assumed to be proportional to fuel use. However, since some ICEVs may achieve NO_x reductions through very lean operation, N_2O emissions could be lower. Automakers could provide actual N_2O emissions as an input for HERMIN.

Figure 1-15 shows the aggregate GHG emission reductions for Scenario C. The mix of vehicle technologies, hydrogen production options, and mix of renewable power results in an overall GHG reduction of over 30 percent. Achieving this GHG reduction included the use of 20 percent new renewables, above and beyond the 20 percent required by RPS. The new renewables include both electric power and biomass energy inputs.

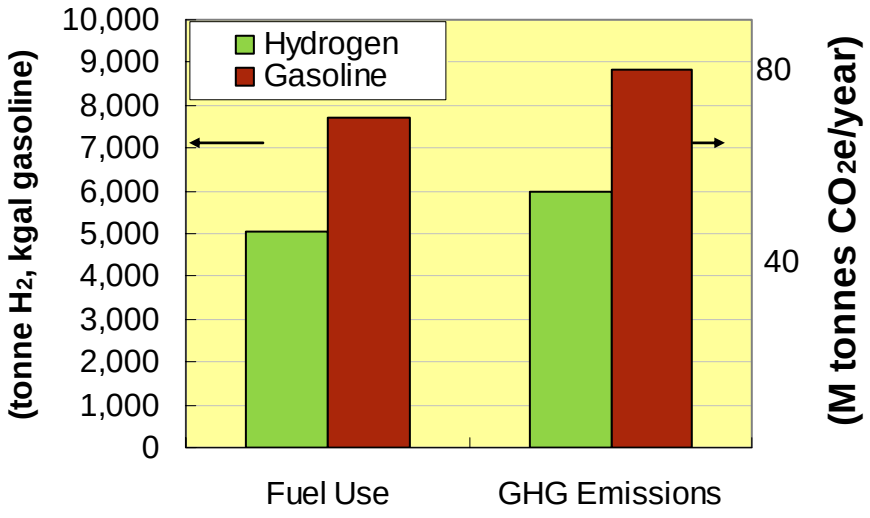


Figure 1-15. GHG Reductions from CA H2 Net

1.6.5 Stationary Applications and Energy Stations

Stationary fuel cell applications are intended to either operate more efficiently than conventional natural gas power generation or provide a power distribution benefit, which would also support an overall improvement in efficiency; a specific goal for stationary power generation was not evaluated. The improvements in efficiency for base-loaded molten carbon fuel cells (MCFCs) or proton exchange membrane fuel cells (PEMFCs) operating under a variety of load profiles would consume less natural gas and provide waste heat. The reduced fuel consumption for power generation and displacing natural gas or other fuels for heating will result in a reduction in GHG emissions from these applications.

Energy stations can impact GHG emissions because several operating parameters differ from conventional hydrogen production or power generation. Some of these parameters include:

Power Generation Efficiency

- Generate power on-site to eliminate transmission losses
- Operate at different efficiency than central power plants
- 7500 Btu/kWh for high temperature fuel cells which is lower than the heat rate for marginal grid power
- 9000 to 10,000 Btu/kWh for PEM systems, which is lower than the heat rate for peaking turbines
- Enable peak shaving operating modes which displace 10,000 to 18,000 Btu/kWh grid power

- Produce combined heat and power (cooling, heating, and power [CHP]). The use of waste heat displaces natural gas for hot water heaters and boilers

Hydrogen Production

- Enable more steady reformer operation for PEMFC/SR systems which reduces startup heat losses
- Capture unused hydrogen from a MCFC

1.7 Criteria Pollutant Emissions

Achieving healthful air quality continues to be a challenge in California. Figure 1-16 illustrates that despite several decades of improvement, ambient air quality still needs improvement. More than 90 percent of Californians breathe unhealthful air over part of the year.

California's air quality programs have resulted in steady reductions in pollutant emissions as illustrated in Figure 1-17. The emission advantages of hydrogen fueled vehicles combined with stationary source emission controls over fuel production processes can help make hydrogen part of the solution for achieving improved air quality.

Because hydrogen vehicles produce no virtually no emissions except for NO_x from hydrogen ICE vehicles, they can help contribute to on-going reductions in air pollutant emissions in California.

This section evaluates the impact of hydrogen applications on criteria pollutant emissions. Hydrogen can contribute to reduced emission reductions in California.

Criteria pollutant emissions were also calculated for various fuel production pathways. These pollutants include hydrocarbons, NO_x, PM, SO_2, and CO. Hydrocarbons are reported as NMOG which include aldehydes, alcohols, and other organic components. NMOG is a pollutant category that applies to vehicle standards in California. For liquid fuel distribution, SO_2 is emitted from fuel combustion in marine vessels. For gaseous fuels and electric power, SO_2 is emitted from pipeline engines and power plants. Toxic pollutants associated with local fuel distribution were also determined.[14]

[14] Refer to ARB listed toxic air contaminants. Those associated with fuel production include benzene, 1-3, butadiene, formaldehyde, and acetaldehyde. See toxic emissions per unit fuel in [8].

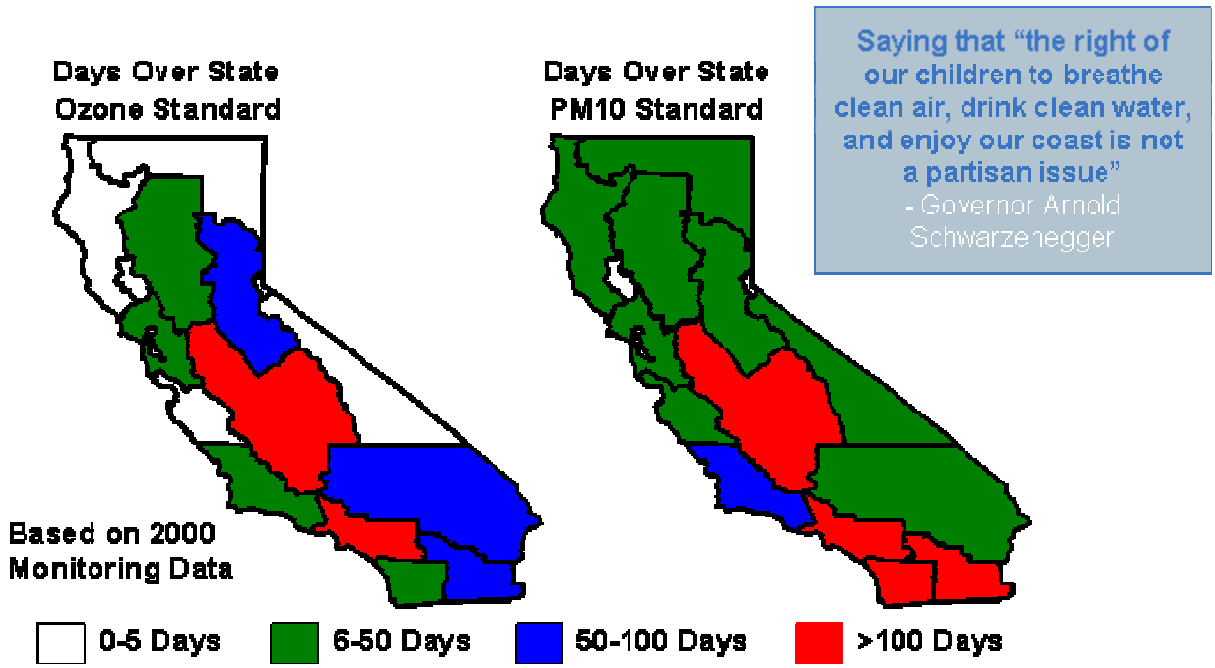


Figure 1-16. Many Regions in California are not in Attainment of Ozone or PM_{10} Standards

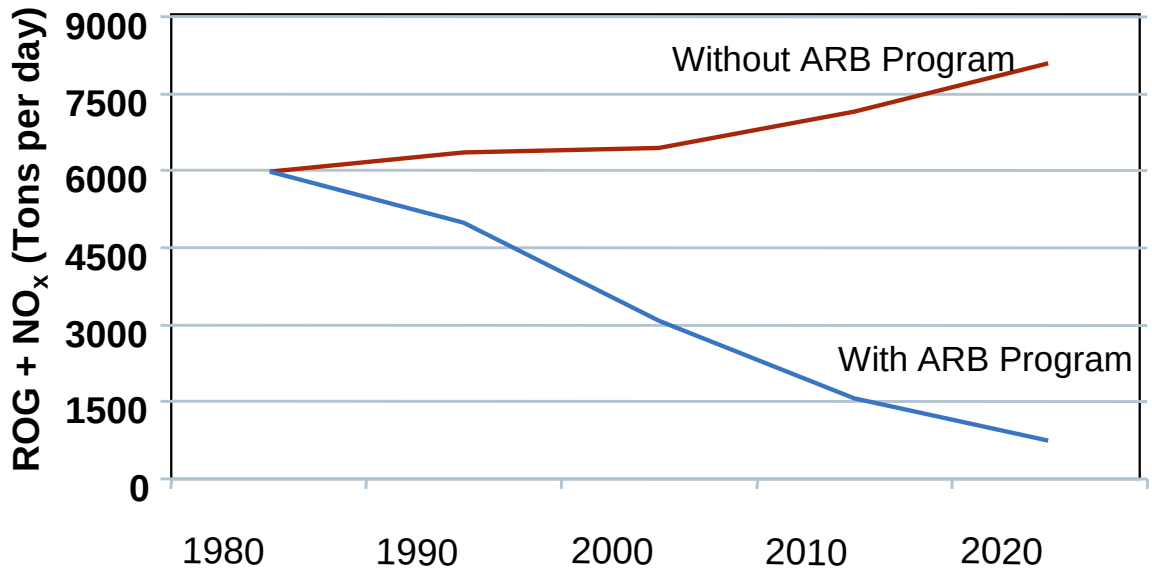


Figure 1-17. ARB's Air Quality Programs Have Achieved a Steady Reduction in Criteria Pollutant Emissions

1.7.1 Vehicle Criteria Pollutants

Table 1-26 shows the emissions from passenger cars, medium duty vehicles, urban buses, and diesel trucks. These exhaust emissions were estimated for a variety of vehicles to compare conventional and hydrogen fueled vehicle emissions and also determine the fuel cycle emissions related to hauling gasoline, diesel, and hydrogen. The groupings in **bold** were used for the analysis in this report. The other values are provided for comparison.

Table 1-26. Vehicle Exhaust and Evaporative Emissions

Vehicle[a]	Grouping	ROG Exhaust	ROG Evap.	CO	NO_x	PM Exhaust	PM_{10} Tire/Brake	SO_2
Baseline Petroleum Fueled Vehicles								
Gasoline LDV Total	**2010 PZEV, 150k mi**	0..0050	0.020	0.40	0.024	0.0017	0.021	0.0037
	MY 2010, 150k mi [b]	0.0136	0.0242	0.541	0.0367	0.0017	0.021	0.0037
	2010 Fleet [c]	0.180	0.176	3.57	0.306	0.0017	0.021	0.0037
Gasoline MDV Cat	**MY 2010 12 year life[b]**	0.0281	0.0358	1.14	0.0647	0.0194	0.021	0.0064
	2010 Fleet [c]	0.303	0.274	5.64	0.805	0.028	0.021	0.0064
Urban Diesel Bus	**MY 2010 12 year life**	0.174	0.0055	1.05	0.528	0.063	0.048	0.027
	2010 Fleet [c]	0.937	0.0055	3.88	19.4	0.347	0.022	0.027
Hydrogen ICE Vehicles								
LDV	**MY 2010, 150k mi**	0	0	0	0.024[d]	0	0.021	0
MDV	**MY 2010 12 year life**	0	0	0	0.05[d]	0	0.022	0
Vehicles for Gasoline, Diesel, and Hydrogen Transportation								
HD Diesel Truck[e]	**MY 2010 12 year life**	0.174	f	1.00	1.7	0.063	0.048	0.022
	MY 2010, first year[g]	0.079	f	1.09	0.545	0.035	0.0488	0.022
Diesel Tanker Truck[e]	2010 Fleet [c]	0.59	f	2.60	13.0	0.24	0.058	0.026
	2020 Fleet	0.31	f	1.64	4.3	0.11	0.058	0.026
	Weighted Average	0.43	f	2.04	7.9	0.16	0.059	0.026

[a] Gasoline LDV and MDV equipped with exhaust catalyst. Urban Bus and Tanker Truck operate on diesel. Emissions provided by ARB from inventory model EMFAC2002 V2.2 Apr 23 2003 [17]. Vehicles in **bold** used for analysis in this report. Other values are supporting information for reference.
[b] Refers to a new vehicles built in 2010, operating over their useful life (for this analysis).
[c] Refers to the inventory of all vehicles on the road in 2010
[d] Assume NO_x emissions from hydrogen ICEVs emit at the PZEV level. Assumption is based on lean combustion approach being less subject to degradation over time.
[e] Assumed new diesel truck meeting 2010 standards hauls mobile fuelers. Conventional tanker truck haul gasoline, LH2 and hydrogen tube trailers. Emissions adjusted from HD Truck value to reflect GVW
[f] ARB inventory assumes negligible value for diesel evaporative emissions. Assuming that evaporative emissions are 10% of vapor space, the emissions would be 0.0006 g/mi.
[g] The new diesel truck has about on-half of the ROG, NO_x, and PM compared to the vehicle over its life.

The exhaust, evaporative, and tire and brake wear emissions correspond to values from ARB's EMFAC model. The model estimates emissions on a tons/year basis taking into accounts factors such as driving patterns, trips per day, and deterioration of the vehicle's emission control system. The model output is typically used to determine the emissions "inventory" for a year with a mix of vehicle types and vehicle ages or model years (MY). Emission rates in g/mi were determined for a set of inventory runs by dividing total annual emissions by miles driven. The following groupings of emission rates were determined:

- New MY 2010 vehicle in 2010 – to enable reader to compare the inventory to emission standards

- MY 2010 vehicle over its life analyzed in this report (150,000 miles for passenger car, 12 years for buses) – Baseline gasoline or diesel vehicle used to compare with hydrogen vehicle. Also new diesel truck assumed to haul mobile fuelers.

- 2010 and 2020 on-road tanker truck fleet – Used to determine emissions from trucks hauling gasoline, diesel, LH2, and tube trailers.

The EMFAC model allows for the analysis of a single model year vehicle. These values were developed over the life of MY 2010 vehicles to determine the average emissions over the life of the vehicle. The inventory results take into account projections in declining vehicle population and annual mileage over time as well as increasing emissions over time as emission control systems deteriorate. An important observation from these emission results is the substantial reduction in NO_x and PM emissions from diesel trucks and buses that are expected as new emission controls standards take effect. These emissions are important for the comparison of diesel buses to hydrogen applications. They also represent a significant fraction of the local fuel cycle emissions for delivered hydrogen.

1.7.2 Fuel Cycle Criteria Pollutants

This study focuses on determining emissions in urban areas in California. The steps associated with the transportation, storage, blending, and vehicle filling are individually calculated for each fuel.[15]

Table 1-27 illustrates fuel cycle criteria pollutant emissions in California for baseline petroleum fuels as well as the energy inputs for hydrogen production. The local emissions depend largely on the conditions affecting fuel delivery to California and related study assumptions. Since all of the fuels except for hydrogen and electricity are imported to California, the emissions from fuel production facilities are not counted in the California. The emissions for liquid fuel correspond to combustion emissions from tanker ships and delivery trucks and losses (ROG) from fuel distribution. For liquid fuels,

[15] The molecular weight and vapor density of fuel blends do not vary in a linear fashion with blends like M85 or reformulated gasoline. Estimating the emissions from vapor transfer for each product represents an accurate method of tracking fuel transfer emissions.

Table 1-27. California Fuel Production and Distribution Criteria Pollutant Emission Factors (Fuel Cycle Emission Factors)

Fuel Cycle Component	ROG	CO	NO_x	PM Exhaust	PM Tire/Brake	SO_2
Fuel Cycle Emission Factor						
Baseline Petroleum Fuels (g/GJ_{fuel})						
CA RFG	4.79	0.26	1.49	0.054	0.0061	0.039
CA Diesel Fuel	2.55	0.24	1.39	0.055	0.0061	0.041
Energy Inputs for Hydrogen (g/GJ_{H2})						
LPG	8.6	0.46	2.4	0.046	0.0067	0.054
Ethanol , corn – imported to CA	2.25	1.06	5.22	0.084	0.0094	0.029
Methanol	2.12	0.49	2.89	0.12	0.013	0.087
Natural Gas	0.032	0.27	0.040	0.0011	0	0.00036
Petroleum Coke	0.44	0.022	0.47	0.037	0	0.035
Biomass, Residue [5]	-8	-330	-14	-41	0.01	0.032
Biogas	-10	-50	-10	-5	0	0.0001
Electric Power, 100% NG	2.81	13.0	8.3	7.6	0	0.33
Electric Power, Renewable	0.034	0.16	0.10	0.92	0	0.00001
Electric Power, Solar	0.17	0.78	0.50	0.46	0	0.020
Reformate Combustion	0.86	2.2	4.3	0.86	0	0
Diesel Tanker Plus Fuel Cycle	18.6	75.1	290	4.0	2.2	1.0
Clean Mobile Fueler Plus Fuel Cycle	5.6	37.1	63.7	2.4	1.8	0.8
Fuel Cycle Emission Factor for Liquid Fuels (g/gal)						
CA RFG	0.179	0.032	0.575	0.006	0.0007	0.0047
CA Diesel Fuel	0.186	0.032	0.342	0.007	0.0008	0.0055
LPG	0.210	0.041	0.751	0.005	0.0006	0.0048
Ethanol	0.418	0.085	0.180	0.007	0.0007	0.0023
Methanol	0.173	0.029	0.127	0.007	0.0008	0.0052
Power Production Emission Factors						
NG CC Plant (lb/MMBtu NG)	0.02	0.09	0.06	0.056	0	0.0026
NG CC Plant (g/kWh_e)	0.0091	0.041	0.027	0.026	0	0.0012
WTT_f NG Power (g/kWh_e)	0.010	0.047	0.030	0.028	0	0.0012
Transportation Emissions						
Marine Vessel (g/1000 ton mi)	8.3	2.1	186	14.4	0	13
Tug Boat (g/1000 ton)	374	750	2000	156	0	74
Rail (g/1000 tone-mi)	70	113	610	8.7	0	2.6

Emissions in California. Effect of renewable power and emission offsets are not included in these values.

Natural gas power plant emissions correspond to EPA AP-42 emission factors for new combined cycle power plant combined with 8500 Btu/kWh (HHV) heat rate and 8% transmission loss. Transmission loss based in inputs from electric utilities as reported in [10].

100 kn of marine vessel transportation for diesel, methanol, and ethanol. Assume 160 mi travel in urban areas for ethanol or LPG by rail. Emission factors reported in [10]

Emissions from liquid fuel delivery corresponds to tanker trucks traveling 50 miles to a delivery plus the return trip. Emissions correspond to average of 2010 and 2020 Fleet of tanker trucks.

ROG emissions correspond primarily to spills and evaporative losses associated with fuel transfers.

The energy requirements for hydrogen production in Table 1-4 were multiplied by the emission factors in Table 1-27 to determine the fuel cycle emission factors (in California) for hydrogen on a g/GJ basis. The fuel cycle factors reflect the production resources and constraints on stationary sources in California including the following:

- Fuel delivery trucks meet ARB emission standards.
  - Average 2010-2020 tanker truck assumed for gasoline, diesel, and LH2
  - New 2010 heavy-duty truck assumed for compressed hydrogen delivery
  - Low truck emissions are needed to achieve emission goals since the amount of hydrogen carried in compressed form is 50 to 300 kg compared to 8000 gal in a gasoline tanker truck
- Refineries in California operate at capacity so gasoline and diesel refining emissions are counted outside California
- With continued reductions in emissions from electric power generation, the emissions associated with electric power correspond to the Best Available Control Technology (BACT)
- Load growth from power plants is assumed to achieve BACT requirements. The electric power is used for hydrogen compression as well as an energy input for production. In addition, it was assumed that 75% of the electric power would need to offset NO_x, ROG, and PM emissions. Adjustments reflecting these offsets are included in Table 1-29 and 1-30 (see example calculations).
- Reformers for hydrogen plants are assumed to achieve BACT requirements. These emission levels might only correspond to expanded capacity for existing hydrogen plants. For central plant reformers, it was assumed that 75% of the NO_x, ROG and PM emissions associated with the new capacity would need to be offset.
- Emissions from biomass and biogas production take into account the avoided emissions from burning agricultural residue and avoided forest fire risk [10] and avoided landfill gas emissions [10].
- Emissions associated with power production are adjusted for the fraction of renewable power. The energy inputs and corresponding emissions are described in Section 2.
- All of these factors are very important in achieving continued emission reductions in California. Assuring that these emission reductions apply to hydrogen production is important for achieving emission reduction goals.

The fuel cycle factors in Table 1-28 reflect emissions that occur outside of California. These include the following sources:

- Oil and gas production and petroleum refining
- Petroleum product transport except for 100 nautical miles in California

Table 1-28. Fuel Production and Distribution Criteria Pollutant Emission Factors Outside California (Fuel Cycle Emission Factors, g/GJ)

Fuel Cycle Component	ROG	CO	NO_x	PM Exhaust	SO_2
CA RFG	11	41	14	3.5	16.8
Natural Gas at Station	0.57	9.4	4.6	0.32	2.3
CA Diesel Fuel	5.2	38	11.5	2.4	11.3
Petroleum Coke	3.7	26.2	8.2	1.7	8.0

Fuel cycle factors for gasoline and diesel distribution and hydrogen production in California are shown in Tables 1-29 through 1-31. For each pollutant, these emission sources are broken out according to:

- Diesel truck emissions for fuel transport
- Combustion emissions associated with hydrogen production (reforming or gasification)
- Emissions associated with power production
- Other fuel cycle emissions

The category "other fuel cycle emissions" primarily includes the fuel cycle emissions associated with producing natural gas or diesel for hydrogen production and delivery. In the case of sequestration, stored CO_2 is included in the "other fuel cycle" category. The weighted criteria pollutant values in Table 1-31 are discussed in the following section.

Emissions from electric power generation have been the subject of considerable analysis and debate. Electric power primarily contributes to EV and PHEV charging, electrolytic hydrogen production, CNG and hydrogen compression, and cryogenic fuel liquefaction.[16] Emissions associated with operating electric fuel pumps for gasoline are included in the analysis but represent an insignificant contribution to total emissions. Emissions associated with lighting and operating fueling stations are considered outside the fuel cycle and are not analyzed here. For natural gas delivery and electric power, the emissions correspond to power plant emissions and compressor engines for pipeline distribution.[17]

[16] Even though some refineries may import electric power, the assumption for this study is that the liquid fuels are imported on the margin, and power consumption from refineries is not counted towards urban emissions in the SoCAB.

[17] Local emissions in this study are estimated to be those from marginal fuel production. Key assumptions in the analysis of marginal emissions are that gasoline and diesel are imported to California. Emissions from power production correspond to the most stringent requirements.

Table 1-29. California Fuel Cycle Emission Factors for ROG and NO_x (g/GJ_{fuel})

Pathway[a]	ROG[e]					NO_x[e]				
	Total Fuel Cycle	Other Fuel Cycle	Diesel	Combust	Power	Total Fuel Cycle	Other Fuel Cycle	Diesel	Combust	Power
CA RFG, Petroleum	4.8	4.3	0.5	0	0	1.5	0	1.5	0	0
Sequestration Petroleum Coke	0.06	0	0	0	0.06	0.19	0	0	0	0.187
Central Pet. Coke Gasifier, Mobile Fueler	1.36	0.58	0.64	0.06	0.08	8.4	0.631	7.2	0.301	0.222
Sequestration Biomass[b]	0.06	0	0	0	0.06	0.17	0	0	0	0.175
Central Biomass Gasifier, Mobile Fueler	-11.4	-12.2	0.64	0.06	0.11	-13.9	-21.7	7.2	0.301	0.316
Central Biogas, Mobile Fueler[b]	-11.1	-11.9	0.64	0.06	0.09	-13.4	-21.2	7.2	0.301	0.266
Central NG SR, LH2 Truck	0.54	0.04	0.23	0.05	0.22	4.56	0.053	3.60	0.269	0.639
Sequestration Central NG	0.03	0	0	0	0.03	0.090	0	0	0	0.090
Central NG SR, Mobile Fueler	0.80	0.04	0.64	0.06	0.05	7.7	0.053	7.2	0.290	0.160
On-Site NG ATR	0.29	0.05	0	0.17	0.07	1.12	0.062	0	0.86	0.199
On-Site NG Steam Reformer[c]	0.31	0.05	0	0.22	0.05	1.28	0.058	0	1.08	0.150
On-Site Electrolysis, NG Power/20%RPS[d]	1.02	0	0	0	1.02	3.0	0	0	0	2.99
On-Site Electrolysis, 70% Renewable/30%NG Power	0.39	0	0	0	0.39	1.16	0	0	0	1.16
On-Site Electrolysis,100 % Renewable Mix	0.02	0	0	0	0.02	0.056	0	0	0	0.056
On-Site Solar, 100% Solar	0.08	0	0	0	0.08	0.224	0	0	0	0.224
Central Electrolysis, Wind, Tube Trailer	0.55	0	0.53	0	0.02	6.1	0	6.03	0	0.045

[a] Emissions for the fuel cycle are the same per GJ for all vehicle applications using the same fuel.

[b] The use of biomass and biogas as feedstocks for hydrogen result in a net emission reduction because the assumed use of these feedstocks results in avoided emissions from agricultural burning or forest fire risk. The potential emission savings are described in a CEC report on ethanol from biomass [10].

[c] **Example Calculation for on-site steam reformer:** (Table 1-27) 4.3 g NO_x/GJ x 25% of energy for hydrogen combusted (Table 1-5) x 1.08 g/GJ H_2

[d] **Example Calculation for on-site electrolysis with 20% RPS:** (Table 1-27) 0.030 g NO_x/kWh_e x 1,000,000 x 1h/3600s x 0.803 x 25% = 1.67 g/GJ_e
228.5/284.5 = 0.803 represents the fraction of emissions from an RPS mix compared with 100 % NG power from Table 1-16 and Section 2.
1.67 g NO_x/GJ_e x 1.8 J/JH2 from Table 1-4 = 3.0 g/GJ H_2.

[e] Emission factors for ROG and NO_x assume that 75% of emissions are offset from large central plant facilities and power plants.

Table 1-30. California Fuel Cycle Emission Factors for CO and PM (g/GJ_{fuel})

Pathway	CO					Exhaust/Combustion PM[a]					Tire/Brake
	Total Fuel Cycle	Other Fuel Cycle	Diesel	Combust	Power	Total Fuel Cycle	Other Fuel Cycle	Diesel	Combust[a]	Power[a]	Diesel Truck
CA RFG, Petroleum	0.26	0	0.26	0	0	0.05	0	0.05	0	0	0.0061
Sequestration Pet. Coke	1.17	0	0	0	1.17	0.17	0	0	0	0.17	0
Central Pet. Coke Gasifier, Mobile Fueler	6.23	0.03	4.21	0.60	1.39	0.58	0.05	0.27	0.06	0.20	0.204
Sequestration Biomass	1.10	0	0	0	1.10	0.16	0	0	0	0.16	0
Central Biomass Gasifier, Mobile Fueler	-498	-505	4.2	0.60	1.98	-61.3	-61.9	0.27	0.06	0.29	0.204
Central Biogas, Mobile Fueler	-485	-492	4.2	0.60	1.67	-60	-60.3	0.27	0.06	0.25	0.204
Central NG SR, LH2 Truck	5.81	0.35	0.92	0.54	4.00	0.69	0.0014	0.05	0.05	0.59	0.027
Sequestration Central NG	0.56	0	0	0	0.56	0.08	0	0	0	0.08	0
Central NG SR, Mobile Fueler	6.14	0.35	4.21	0.58	1.00	0.48	0.0014	0.27	0.06	0.15	0.204
On-Site NG ATR	1.66	0.41	0	0.00	1.25	0.36	0.0016	0	0.17	0.18	0
On-Site NG Steam Reformer	1.85	0.38	0	0.54	0.94	0.35	0.0015	0	0.22	0.14	0
On-Site Electrolysis, NG Power/20%RPS	18.8	0	0	0	18.75	2.76	0	0	0	2.76	0
On-Site Electrolysis, 70% Renewable/30%NG Power	7.25	0	0	0	7.25	1.07	0	0	0	1.07	0
On-Site Electrolysis,100 % Renewable Mix	0.35	0	0	0	0.35	0.05	0	0	0	0.05	0
On-Site Solar, 100% Solar	1.40	0	0	0	1.40	0.21	0	0	0	0.21	0
Central Electrolysis, Wind, Tube Trailer	3.79	0	3.5	0	0.28	0.27	0	0.22	0	0.04	0.170

[e] Emission factors for ROG and NO_x assume that 75% of emissions are offset from large central plant facilities and power plants (does not include combustion emissions from on-site ATR and steam reformers.

Table 1-31. California Fuel Cycle Emission Factors for SO_2 and Weighted Pollutants (g/GJ_{fuel})

Pathway	SO_2					Weighted Criteria Pollutants, $PM_{2.5}$=1				
	Total Fuel Cycle	Other Fuel Cycle	Diesel	Combust	Power	Total Fuel Cycle	Other Fuel Cycle	Diesel	Combust	Power
CA RFG, Petroleum	0.04					0.44				
Sequestration Pet. Coke	0.03	0	0	0	0.03	0.22	0	0	0	0.22
Central Pet. Coke Gasifier, Mobile Fueler	0.18	0.05	0.10	0	0.04	2.8	0	2.1	0	0.26
Sequestration Biomass	0.03	0	0	0	0.03	0.21	0	0	0	0.21
Central Biomass Gasifier, Mobile Fueler	0.19	0.05	0.10	0	0.05	-65	-68	2.15	0.14	0.37
Central Biogas, Mobile Fueler	0.19	0.05	0.10	0	0.04	-63	-66	2.15	0.14	0.32
Central NG SR, LH2 Truck	0.12	0.0005	0.01	0	0.10	1.85	0.02	0.98	0.12	0.76
Sequestration Central NG	0.01	0	0	0	0.01	0.11	0	0	0	0.11
Central NG SR, Mobile Fueler	0.12	0.0005	0.10	0	0.03	2.49	0.02	2.15	0.13	0.19
On-Site NG ATR	0.03	0.0006	0	0	0.03	0.36	0.02	0	0.10	0.24
On-Site NG Steam Reformer	0.02	0.0005	0	0	0.02	0.32	0.02	0	0.12	0.18
On-Site Electrolysis, NG Power	0.48	0	0	0	0.48	3.67	0	0	0	3.55
On-Site Electrolysis, NG Power	0.19	0	0	0	0.19	1.42	0	0	0	1.37
On-Site Electrolysis,100 % Renewable Mix	0.01	0	0	0	0.01	0.07	0	0	0	0.07
On-Site Solar, 100% Solar	0.04	0	0	0	0.04	0.27	0	0	0	0.27
Central Electrolysis, Wind, Tube Trailer	0.09	0	0.08	0	0.01	1.82	0	1.77	0	0.05

Emissions also occur from the extraction, production, and delivery of fuels and feedstocks produced outside California. With the marginal emission assumptions applied to this analysis, all of the emissions associated with oil and gas production occur outside of California. Oil refining, tanker transport as well as natural gas pipeline emissions also occur outside California. The fuel cycle emission factors are shown in Table 1-28. The emission factors represent grams of pollutant per GJ of fuel. For hydrogen production, the fraction of energy input from Table 1-4 is combined with the out of state emission factors to determine the emissions per GJ of hydrogen. The appropriate mix of natural gas and renewables is also included for electric power production.

The emission factors in Table 1-28 were determined from the GREET 1.6 model with the energy input assumptions presented in this report. The emission factors correspond to the difference between total worldwide emissions identified in the GREET model and the values within California (Table 1-27).

1.7.3 WTW Criteria Pollutants — Cars and Buses

Fuel cycle criteria pollutant factors were multiplied by vehicle energy consumption to determine the fuel cycle portion of WTW emissions. The WTW results for passenger hydrogen ICE passenger cars and baseline gasoline ICE vehicles are shown in Table 1-32. These values in include both the fuel cycle emissions from hydrogen production plus NO_x from the hydrogen vehicle. The emissions associated with power consumption for hydrogen sequestration are shown for the appropriate pathways.

Hydrogen fuel cell vehicles produce no criteria pollutant emissions. The fuel cycle results are 65 percent of the values shown in Table 1-32 for hydrogen ICE vehicles and shown in Table 1-33. The sum of vehicle and fuel cycle emissions are also shown here.

California WTW emissions were also calculated for heavy-duty hydrogen fuel cell buses and baseline diesel buses. The results are shown in Table 1-34 and 1-35.

This study focuses on emissions in urban areas in California. The resource limitations and constraints on fuel supplies for California result in the assumption that most of the finished fuels or natural gas feedstocks will be imported to California. Therefore, most fuel production emissions will occur outside the state. Baseline estimates for urban emissions in the GREET model provide the calculations for criteria pollutant emissions outside of California. These calculations take into account emission rates from production facilities, processing and transport equipment. These values from the GREET model, with the assumptions presented in this study are indicated in Table 1-36. Urban emission estimates in GREET take into account assumptions the proximity of fuel production facilities to urban. The fuel cycle emissions outside California are larger for gasoline and diesel because the assumption for this report was hydrogen vehicles displace gasoline and diesel that are imported to California.

Table 1-32. WTW Criteria Pollutant Emissions in California for Hydrogen ICE Passenger Cars (mg/mi)

Fuel	ICE Vehicle Emissions				ICEV Fuel Cycle Emissions[a]			
	ROG	CO	NO_x	PM	ROG	CO	NO_x	PM
CA RFG, Average New 2010 Passenger Car	38	54.1	37	1.7	22.3	1.2	6.9	2.5
CA RFG 2010 PZEV	25	40	2.4	1.7	22.3	1.2	6.9	2.5
Sequestration Petroleum Coke	—	—	—	—	0.23	4.20	0.67	0.62
Central Pet. Coke Gasifier, Mobile Fueler	0	0	24	0	4.8	22	30	2.09
Sequestration Biomass	—	—	—	—	0.21	3.93	0.63	0.58
Central Biomass Gasifier, Mobile Fueler	0	0	24	0	-41	-1800	-50	-220
Central Biogas, Mobile Fueler	0	0	24	0	-40	-1700	-48	-210
Central NG SR, LH2 Truck	0	0	24	0	1.9	21	16.3	2.6
Sequestration Central NG	—	—	—	—	0.11	2.0	0.32	0.30
Central NG SR, Mobile Fueler	0	0	24	0	2.8	22	27.8	1.7
On-Site NG ATR	0	0	24	0	1.04	7.5	4.0	1.28
On-Site NG Steam Reformer	0	0	24	0	1.12	6.6	4.60	1.27
On-Site Electrolysis, 80% NG Power, 20% Renewable Power	0	0	24	0	3.6	67	10.7	9.9
On-Site Electrolysis, 30% NG Power, 70% Renewable Power	0	0	24	0	1.41	26	4.15	3.83
On-Site Electrolysis,100 % Renewable Mix	0	0	24	0	0.07	1.26	0.20	0.18
On-Site Solar, 100% Solar	0	0	24	0	0.27	5.0	0.80	0.74
Central Electrolysis, Wind, Tube Trailer	0	0	24	0	1.91	13.6	21.8	0.95

[a] Sum of vehicle and fuel cycle emissions are shown in Table 1-33. Fuel cell vehicle fuel cycle emissions are also shown in Table 1-33.

Table 1-33. Total WTW Criteria Pollutant Emissions in California for Hydrogen Passenger Cars

Fuel	ICEVs[a] (mg/mi)				Fuel Cell Vehicles[a] (mg/mi)			
	ROG	CO	NO_x	PM	ROG	CO	NO_x	PM
CA RFG, Average New 2010 Passenger Car	60	540	43.7	1.95	—	—	—	—
CA RFG 2010 PZEV	47	400	31	1.95	—	—	—	—
Sequestration Petroleum Coke	0.23	4.20	0.67	0.62	0.15	2.73	0.44	0.40
Central Pet. Coke Gasifier, Mobile Fueler	4.80	22	54	2.09	3.12	14.52	19.5	1.36
Sequestration Biomass	0.21	3.9	0.63	0.58	0.14	2.55	0.41	0.38
Central Biomass Gasifier, Mobile Fueler	-41	-1800	-26	-220	-27	-1160	-32.3	-143
Central Biogas, Mobile Fueler	-40	-1700	-24	-210	-26	-1130	-31.2	-139
Central NG SR, LH2 Truck	1.93	20.81	40	2.58	1.25	13.5	10.6	1.7
Sequestration Central NG	0.11	2.01	0.32	0.30	0.07	1.31	0.21	0.19
Central NG SR, Mobile Fueler	2.8	22	52	1.71	1.80	14.3	18.0	1.11
On-Site NG ATR	1.04	7.49	28	1.28	0.67	4.87	2.62	0.83
On-Site NG Steam Reformer	1.12	6.65	29	1.27	0.73	4.32	2.99	0.83
On-Site Electrolysis, 80% NG Power, 20% Renewable Power	3.64	67	35	9.9	2.4	44	7.0	6.44
On-Site Electrolysis, 30% NG Power, 70% Renewable Power	1.4	26	28	3.8	0.91	16.9	2.7	2.49
On-Site Electrolysis,100 % Renewable Mix	0.07	1.26	24	0.18	0.04	0.82	0.13	0.12
On-Site Solar, 100% Solar	0.27	5.02	25	0.74	0.18	3.26	0.52	0.48
Central Electrolysis, Wind, Tube Trailer	1.91	13.6	46	0.95	1.24	8.8	14.2	0.62

[a] Total includes vehicle and fuel cycle emissions. For ICEVs see Table 1-32. For fuel cell vehicles, vehicle emissions are zero, so all of the emissions are from the fuel cycle.

Table 1-34. WTW Criteria Pollutant Emissions in California for Gasoline ICE and Hydrogen ICE Shuttle Buses

Fuel	Vehicle Emissions (g/mi)				Fuel Cycle Emissions (g/mi)			
	ROG	CO	NO_x	PM	ROG	CO	NO_x	PM
Gasoline Shuttle Bus	0.064	1.14	0.065	0.019	0.044	0.002	0.014	0.000
Hydrogen Pathways					0.000	0.008	0.001	0.001
Sequestration Pet. Coke	—	—	—	—	0.009	0.044	0.059	0.004
Central Pet. Coke Gasifier, Mobile Fueler	0	0	0.05	0	0.000	0.008	0.001	0.001
Sequestration Biomass	—	—	—	—	-0.080	-3.500	-0.098	-0.430
Central Biomass Gasifier, Mobile Fueler	0	0	0.05	0	-0.078	-3.41	-0.094	-0.420
Central Biogas, Mobile Fueler	0	0	0.05	0	0.004	0.041	0.032	0.005
Central NG SR, LH2 Truck	0	0	0.05	0	0.000	0.004	0.001	0.001
Sequestration Central NG	—	—	—	—	0.005	0.043	0.054	0.003
Central NG SR, Mobile Fueler	0	0	0.05	0	0.002	0.015	0.008	0.003
On-Site NG ATR	0	0	0.05	0	0.002	0.013	0.009	0.002
On-Site NG Steam Reformer	0	0	0.05	0	0.007	0.132	0.021	0.019
On-Site Electrolysis, 80% NG Power, 20% Renewable Power	0	0	0.05	0	0.003	0.051	0.008	0.008
On-Site Electrolysis, 30% NG Power, 70% Renewable Power	0	0	0.05	0	0.000	0.002	0.000	0.000
On-Site Electrolysis,100 % Renewable Mix	0	0	0.05	0	0.001	0.010	0.002	0.001
On-Site Solar, 100% Solar	0	0	0.05	0	0.004	0.027	0.043	0.002
Central Electrolysis, Wind, Tube Trailer	0	0	0	0	0.044	0.002	0.014	0.000

Table 1-35. WTW Criteria Pollutant Emissions in California for Heavy-Duty Diesel and Hydrogen Fuel Cell Buses

Fuel	Vehicle Emissions (g/mi)				Fuel Cycle Emissions (g/mi)			
	ROG	CO	NO_x	PM	ROG	CO	NO_x	PM
Urban Diesel Bus	0.174	1.06	0.528	0.063	0.070	0.0065	0.038	0.0015
Hydrogen Pathways								
Sequestration Pet. Coke	—	—	—	—	0.0012	0.0213	0.0034	0.0031
Central Pet. Coke Gasifier, Mobile Fueler	0	0	0	0	0.024	0.11	0.15	0.011
Sequestration Biomass	—	—	—	—	0.0011	0.020	0.003	0.0029
Central Biomass Gasifier, Mobile Fueler	0	0	0	0	-0.21	-9.0	-0.25	-1.1
Central Biogas, Mobile Fueler	0	0	0	0	-0.20	-8.8	-0.24	-1.1
Central NG SR, LH2 Truck	0	0	0	0	0.0098	0.11	0.083	0.013
Sequestration Central NG	—	—	—	—	0.0006	0.010	0.0016	0.0015
Central NG SR, Mobile Fueler	0	0	0	0	0.014	0.11	0.14	0.0087
On-Site NG ATR	0	0	0	0	0.0053	0.038	0.020	0.0065
On-Site NG Steam Reformer	0	0	0	0	0.0057	0.034	0.023	0.0064
On-Site Electrolysis, 80% NG Power, 20% Renewable Power	0	0	0	0	0.018	0.34	0.054	0.050
On-Site Electrolysis, 30% NG Power, 70% Renewable Power	0	0	0	0	0.0071	0.13	0.0210	0.0194
On-Site Electrolysis,100 % Renewable Mix	0	0	0	0	0.0003	0.0064	0.0010	0.0009
On-Site Solar, 100% Solar	0	0	0	0	0.0014	0.026	0.0041	0.0037
Central Electrolysis, Wind, Tube Trailer	0	0	0	0	0.0097	0.069	0.11	0.0048

Table 1-36. Passenger Car WTW Criteria Pollutant Outside of California (g/mi)

	Vehicle/Pathway	ROG	NO_x	CO	PM	SO_2
ICEV	CA RFG, Petroleum, PZEV and 2010 mix	0.052	0.191	0.066	0.0781	0.0069
ICEV	Sequestration Pet. Coke	0.000	0.008	0.004	0.00185	0.00002
ICEV	Central Pet. Coke Gasifier, Mobile Fueler	0.018	0.134	0.044	0.04064	0.00623
ICEV	Sequestration Biomass	0.000	0.007	0.003	0.00173	0.00002
ICEV	Central Biomass Gasifier, Mobile Fueler	0.001	0.013	0.006	0.00313	0.00003
ICEV	Central Biogas, Mobile Fueler	0.001	0.011	0.005	0.00264	0.00002
ICEV	Central NG SR, LH2 Truck	0.004	0.069	0.034	0.01691	0.00029
ICEV	Sequestration Central NG	0.000	0.004	0.002	0.00089	0.00001
ICEV	Central NG SR, Mobile Fueler	0.003	0.049	0.025	0.01216	0.00025
ICEV	On-Site NG ATR	0.004	0.060	0.030	0.01468	0.00029
ICEV	On-Site NG Steam Reformer	0.003	0.054	0.027	0.01326	0.00027
ICEV	On-Site Electrolysis, NG Power/20%RPS	0.007	0.121	0.060	0.02969	0.00026
ICEV	On-Site Electrolysis, 70% Renewable/30%NG Power	0.003	0.047	0.023	0.01148	0.00010
ICEV	On-Site Electrolysis,100 % Renewable Mix	0.000	0.002	0.001	0.00055	0.00000
ICEV	On-Site Solar, 100% Solar	0.001	0.009	0.004	0.00222	0.00002
ICEV	Central Electrolysis, Wind, Tube Trailer	0.000	0.002	0.001	0.00045	0.00000
FCV	Sequestration Pet. Coke	0.000	0.005	0.002	0.00121	0.00001
FCV	Central Pet. Coke Gasifier, Mobile Fueler	0.012	0.087	0.028	0.02642	0.00405
FCV	Sequestration Biomass	0.000	0.005	0.002	0.00113	0.00001
FCV	Central Biomass Gasifier, Mobile Fueler	0.001	0.008	0.004	0.00204	0.00002
FCV	Central Biogas, Mobile Fueler	0.000	0.007	0.003	0.00172	0.00001
FCV	Central NG SR, LH2 Truck	0.003	0.045	0.022	0.01099	0.00019
FCV	Sequestration Central NG	0.000	0.002	0.001	0.00058	0.00001
FCV	Central NG SR, Mobile Fueler	0.002	0.032	0.016	0.00790	0.00016
FCV	On-Site NG ATR	0.002	0.039	0.019	0.00954	0.00019
FCV	On-Site NG Steam Reformer	0.002	0.035	0.017	0.00862	0.00017
FCV	On-Site Electrolysis, NG Power/20%RPS	0.005	0.079	0.039	0.01930	0.00017
FCV	On-Site Electrolysis, 70% Renewable/30%NG Power	0.002	0.030	0.015	0.00746	0.00007
FCV	On-Site Electrolysis,100 % Renewable Mix	0.000	0.001	0.001	0.00036	0.00000
FCV	On-Site Solar, 100% Solar	0.000	0.006	0.003	0.00144	0.00001
FCV	Central Electrolysis, Wind, Tube Trailer	0.000	0.001	0.001	0.00029	0.00000

1.7.4 Criteria Pollutant Weighting

The comparison of criteria pollutant impacts is based on the weighting approach developed in the AB 2076, Petroleum Dependency report [1]. The valuations of criteria pollutant emissions are intended to reflect the cost of the damages associated with pollution. The valuations shown in Table 1-37 are taken from the AB 2076 report and used as the weighting factors, shown in Table 1-38, in this analysis. The method for determining the values takes into account population and potential for exposure, so the value would differ as population changes in California. Because of population would be eliminated. The effect of population would be more important when considering the

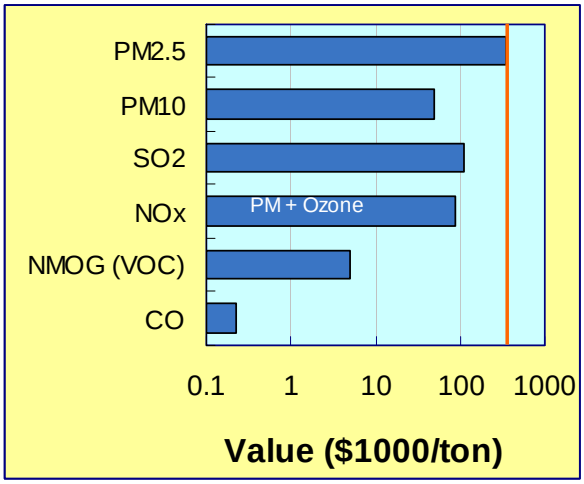
Table 1-37. Cost of Pollution Damages

Pollutant	Valuation ($/ton)
CO	220
NMOG (VOC)	5000
NO_x - PM Precursor	12,000 - 157,000
NO_x - Ozone Precursor	1000 - 20,000
NO_x Combined	88,000
$PM_{2.5}$	352,000
PM_{10}	48,531
SO_2	109,265
CO_2	$15/ton
Gasoline Spillage	0.009 $/gal gasoline

Source: AB2076 Report, [1,8]

Table 1-38. Weighting Factors for Criteria Pollutant Emissions in California

Pollutant	Valuation ($/ton)	Weighting Factor
CO	220	0.00063
NMOG (VOC)	5,000	0.014
NO_x	88,000	0.25
SO_2	109,265	0.31
PM_{10}	48,531	0.14
$PM_{2.5}$	352,000	1.0



actual $ valuations. The AB2076 damage valuations were used only to develop a criteria pollutant rating. The valuations for CO_2 and petroleum spillage are shown for reference.

The weighting factors for criteria pollutants were used to determine a rating system for hydrogen vehicles. The weighting factor was multiplied by WTW emissions for hydrogen vehicles and baseline petroleum vehicles. The total for the petroleum vehicle was set to 1.0 and the ratio of the hydrogen vehicle result to the gasoline or diesel vehicle represented as a criteria pollutant rating. The rating for hydrogen ICE and FC passenger car compared with gasoline passenger cars as well as hydrogen fuel cell buses compared with diesel buses are shown in Figure 1-18. The results are shown for the average new 2010 vehicle as well as PZEV vehicles.

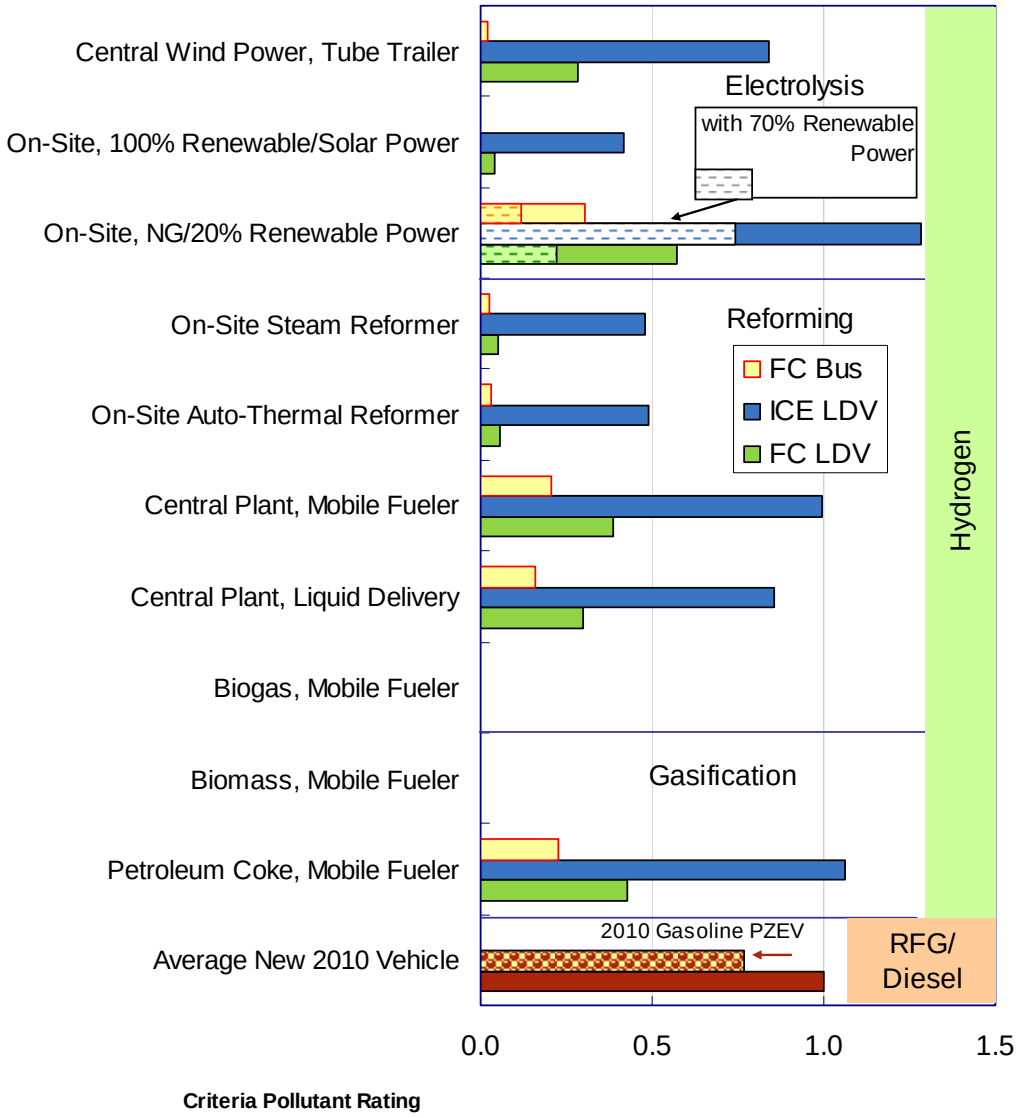


Figure 1-18. Criteria Pollutant Weighting

As indicated previously, the analysis is based on electric power production from natural gas and 20 percent renewables. The results for electrolysis with dedicated renewable power (solar and wind) are also shown. The operator of an electrolysis system could also chose to purchase a higher fraction of renewable power from the grid; therefore, the results with 70 percent renewable power are also shown.

1.7.5 Criteria Pollutant Goals

In order to meet the requirements of the executive order and support the Governor's Environmental Action Plan, hydrogen vehicles need to contribute to an overall improvement in criteria pollutant issues. Criteria pollutant impacts differ among each of the hydrogen production pathways and they also differ among the hydrogen vehicle technologies. This section describes the range in criteria pollutants and describes factors than can help assure a reduction in criteria pollutant emissions.

As discussed earlier, criteria pollutants are emitted both during vehicle operation and the production and distribution of fuel. Other than trace levels of CO and PM related to engine oil, hydrogen ICE vehicle produce only NO_x emissions. Some ICEV configurations may operate in a lean mode with virtually no NO_x. Hydrogen FCVs produce no criteria pollutant emissions. (All vehicles are assumed by the ARB emissions inventory to include PM from tire and brake wear and GHG emissions from air conditioning systems). Fuel cycle emissions from hydrogen depend on the fuel consumption for the hydrogen vehicle. Fuel cycle emissions decrease in inverse proportion to vehicle fuel economy.

Table 1-39 shows the range in well to wheel criteria pollutant emissions for MY 2010 passenger car over its life and for hydrogen cars. The fuel cycle emissions represent the range associated with different production pathways. The following discussion focuses on criteria pollutant emissions in California. As discussed previously, these emissions correspond to the marginal production of gasoline as well as energy inputs for hydrogen production. Many of the energy inputs for hydrogen production in California would be related to electricity generation. For natural gas based electricity generation the impact of these emissions will depend on local constraints such as offset requirements and emission caps.

In addition, emissions attributed to hydrogen depend on local air quality constraints. All new stationary sources in areas that do not meet federal attainment standards are required to obtain offsets for non-attainment pollutants. For example if an area is in non attainment for ozone, new sources must offset ROG and NO_x emissions. If an area is non attainment for PM, new sources must provide PM offsets. Most of Los Angeles, eastern San Diego, San Bernardino, Riverside, San Joaquin and Sacramento are non attainment for federal ozone and PM standards. Local districts can place further restrictions on new stationary sources and require offsets if the district is non attainment for the more stringent state standards. The assumption in this report was that 75 percent of the ROG, NO_x and PM emissions associated with natural gas fired power plants and hydrogen reformers were reduced by offset requirements.

Table 1-39. Well to Wheel Criteria Pollutant Emissions in California (g/mi)

Emission Source	ROG	CO	NO_x	PM Exhaust	PM_{10} Tire/Brake	SO_x
MY2010 Gasoline Passenger Car						
Vehicle	0.036	0.54	0.037	0.0017	0.021	0.004
Fuel Cycle	0.022	0.001	0.0069	0.00025	0.0021	0.0001
Total	0.06	0.54	0.044	0.002	0.0227	0.0038
Hydrogen Passenger Car						
FCV	0	0	0	0	0.021	0
ICEV	0	0	0.024	0	0.021	0
Fuel Cycle	0-0.005	0- 0.07	0.0002-0.03	0 - 0.01	0-0.02	0-0.001
Total	<0.005	<0.07	<0.03	< 0.01	0.022	<0.001

Note: Mobile fueler NO_x is as high as 0.1 g/mi but quantities of fuel delivered are small.

The impact of electricity generation and hydrogen production also depends on the fraction derived from renewables. As discussed in Section 2, the emissions impact for wind power production is very low compared to conventional power plants. Renewable emission credits can also result in pollution reductions however, the regional impact of these credits would need to be considered.

Many of the fuel production emissions do not occur in California. These fuel cycle emissions are presented in Table 1-36. Gasoline production outside California results in refinery emissions, oil field, storage tank, and tanker ship emissions. Producing natural gas for hydrogen would also result in emissions from gas fields, gas processing facilities and pipeline compressors. Whereas, many of the marginal fuel production processes for hydrogen production occur in California. The effect of this fuel switching is to place more of the fuel production emissions under the stricter stationary source emission controls in the State.

Hydrocarbons (ROG)

Hydrocarbon emissions from gasoline vehicles include exhaust and fuel cycle losses. Most ROG emissions in the fuel cycle correspond to vapor losses from storage tanks, vehicle fueling, and spillage. Because hydrogen is produced largely from pathways that do not involve liquid fuels, other than diesel for distribution, hydrogen would provide a reduction in ROG emissions in California.

Carbon Monoxide (CO)

CO emissions in the hydrogen fuel cycle correspond to reformer emissions, power plant emissions, natural gas compressor emissions, and truck exhaust. CO emissions are relatively low for most steps in the hydrogen fuel cycle when compared to gasoline vehicle exhaust emissions.

Oxides of Nitrogen (NO_x) and Particulate Matter (PM)

As in the case of other pollutants, NO_x and PM emissions vary with the hydrogen production pathway, the use of renewable power, and the vehicles' hydrogen consumption, and emission offset requirements. The most significant sources of these emissions include:

- Reformers and other stationary combustion sources
- Power plants
- Diesel trucks
- Hydrogen ICEs

Combustion Emissions

Hydrogen reformer and gasifiers would come in a range of sizes. The largest facilities operate under a complex set of permitting constraints. Modifications to these facilities would require a substantial environmental review process, and potentially mitigation of any NO_x or PM emissions. The most significant sources of these emissions include:

- Oil refineries
- Central hydrogen plants with liquefier
- Gasifiers
- Industrial gas plants
- On-site fueling stations with steam reformers or autothermal reformer
- Energy stations (molten carbonate, solid oxide, steam reformer, autothermal reformer)

Emissions from reformers and gasifiers are often lower than those from other combustion sources per unit of energy because the reformer is fired with a mixture of CO and hydrogen, which are a residue from the hydrogen separation process.

Electric power for hydrogen production would be derived from natural gas and renewable resources on the margin in the 2010 timeframe. New combined cycle power plants are equipped with emission controls such as selective catalytic reduction (SCR). The overall emissions associated with hydrogen production would be reduced with the use of new renewable power sources that would likely be from wind.

Table 1-40 shows the range of emission estimates associated with combustion sources. The table shows calculations of the emissions associated with fuel combustion only for a variety of hydrogen pathways. A range of emission estimates is shown when emission offsets may be required. In the case of refineries, offsets will be required so marginal emissions are zero. The results are also expressed on a g/kg of hydrogen basis and also shown on a per mile basis assuming a 50 mi/kg hydrogen vehicle.

Table 1-40. Combustion Emissions for Hydrogen Production

Emission Source	Refinery	Large Scale Reformer	Biomass Gasifier	On-Site Reformer	NG CC Power Plant (for electrolysis)
Emission Factors					
NO_x (g/GJ)	4.8	14.4	14.4	3	3.4
PM (g/GJ)	2	2	2	1	3.2
Emission Controls	SCR	lean combustion	lean combustion	lean combustion	SCR
Emission Limits	RECLAIM, Offsets, local review	Offsets, local review	Offsets, local review, displaced burning	Local review	RECLAIM, Offsets, local review
Combustion J/J H_2	0.25	0.25	0.28	0.25	1.80
% Renewables	0	0	0	0	70%
NO_x Estimate					
(g/GJ combusted)	0	0 to 14.4	10	3	0 to 1.10
(g/kg H2)	0	0 to 0.432	0.34	0.097	0 to 0.241
(g/mi) for 50 mi/kg	0	0 to 0.0086	0.0067	0.0019	0 to 0.005
PM Estimate					
(g/GJ combusted)	0	0 to 2	Reduced burning	1	0 to 1.038
(g/kg H2)	0	0 to 0.060	<0	0.032	0 to 0.227
(g/mi) for 50 mi/kg	0	0 to 0.0012	<0	0.0006	0 to 0.005

0.01 lb/MMBtu = 4.8 g/GJ.

The following set of emission constraints contribute to a range of NO_x and PM emission estimates:

- Oil refineries are subject to RECLAIM or other emission caps. Growth in NO_x or PM emissions from these facilities is unlikely.

- Capacity additions to existing hydrogen plant outside oil refineries would be subject to offset requirements. Emissions would need to meet best available control technology requirements. Emissions would be higher if older plants had idle capacity.

- Biomass gasifiers may be subject to offset requirements depending on where they are sited. Consuming biomass feedstock often eliminates substantial emissions associated with agricultural burning or forest fire risk [4, 5]. The reduced PM emissions are much lower than those for the gasifier. The overall benefit is not

calculated. Some NO_x emissions would also be avoided by processing biomass in a gasifier.

- NO_x and PM emissions from small scale reformers can be very low for a variety of reasons. First, all of the reformer fuel or combustion products are waste gas from the PSA. A combination of CO and hydrogen burns with very low PM emissions. Limited NO_x emissions data are also available [62].

- New combined cycle power plants are subject to extensive emissions review. In many regions, NO_x and PM offsets will be required. The assumption in this report is that 75 percent of power plants and hydrogen reformers will require offsets.

Distribution Emissions

Hydrogen from central plants will be primarily delivered by diesel trucks. The largest hydrogen carrying capacity is in an LH2 truck, followed by a tube trailer, and mobile fueler. Truck emissions are proportional to the carrying capacity of the hydrogen, distance traveled and truck emission factor as shown in Table 1-41.

Table 1-41. Emissions from Hydrogen Delivery

	Tube Trailer	LH2 Truck	Mobile Fueler
Capacity (kg)	300	3700	100
Fuel Used (kg)	240	3700	50
One Way Distance (mi)	50	100	20
NOx Emissions			
(g/kg H2)	3.7	0.47	5.57
(g/mi @ 50 mi/kg)	0.07	0.009	0.11
PM Emissions			
(g/kg H_2)	0.018	0.0012	0.056
(g/mi @ 50 mi/kg)	0.0004	0.00002	0.001

- In order to minimize emissions from mobile fuelers and tube trailers, the cleanest diesel engines were assumed for these applications. These engines would need to exceed an engine manufacturer's requirement for low emission engines in order to result in actual emission reductions.

- Truck emissions from hauling LH2 are about the same per mile as those from gasoline. A gasoline truck hauls 8000 gal which is about twice that of and LH2 truck. Depending on the hydrogen vehicle fuel consumption, truck emissions would be comparable.

- The low carrying capacity of tube trailers and mobile fuelers results in higher emissions. These emissions would be much lower for shorter transportation distances which might be possible with some configurations of the hydrogen highway.

Summary of Criteria Pollutant Goals

- ROG and CO emissions should be lower than those for comparable gasoline vehicles

- NO_x and PM emissions depend on permitting constraints. Under some siting scenarios many emissions would need to be offset. Capacity limitations and constraints on refinery emissions result in no net emission in California. Similarly, many of the stationary emissions associated with hydrogen would be limited by local permit constraints.

- The use of renewable power reduces the impact of power generation

- NO_x and PM emissions are a significant contribution from gaseous fuel delivery and the lowest emission trucks should be used for mobile fuelers and tube trailers.

1.8 Permitting Distributed Generation in California

After January 1, 2003, all DG units exempt from permitting by local districts must be certified by ARB. The certification standards are provided in Table 1-42. The standards for 2007 are essentially equivalent to emissions from a new natural gas fired combined cycle power plant.

Although the 2007 standards are perhaps unattainable for standard combustion equipment without the CHP credit, they really only apply to a handful of devices; only those DG units exempt from local permitting must comply. Table1-43 provides size thresholds below which DG units are exempt from permitting for a sample of the largest air districts. We can conclude that most engines (those greater than 50 hp) and many combustion turbines (> 200 kW) must go through permitting with the local air district.

Local permitting of new sources includes consideration of best available control technology (BACT) and emission offsets. BACT requirements for new DG sources are fairly predictable since ARB has issued BACT guidance for electrical generation equipment [63]. Tables 1-44 and 1-45 provide ARB's assessment of BACT for combustion turbines (< 50 MW) and reciprocating engines. These emission levels are achievable today with SCR and oxidation catalysts.

Offset requirements are triggered if the source has a potential to emit (PTE) greater than a certain threshold. Thresholds for emission offset requirements for several large districts are shown in Table 1-46. It would be difficult for a single BACT equipped DG

Table 1-42. January 1, 2003, Emission Standards (lb/MW-hr)

Pollutant	2003 Standard, lb/MWh		2007 Standard, lb/MWh
	DG Unit, no CHP	DG Unit with CHP	
NO_x	0.5	0.7	0.07
CO	6.0	6.0	0.10
VOC	1.0	1.0	0.02
PM	NG with S < 1 gr/100scf	NG with S < 1 gr/100scf	NG with S < 1 gr/100scf

Table 1-43. Examples of Engines and Turbines Exempt from Local Permitting

CA Air District	Engines	Combustion Turbines
BAAQMD	< 50 hp (37 kW)	< 50 hp (37 kW)
SMAQMD	< 50 hp (37 kW)	< 3 MMBtu/hr heat input (~200kW)[a]
SCAQMD	< 50 hp (37 kW)	< 2.975 MMBtu/hr heat input (~200 kW)[a]
SDAPCD	< 50 hp (37 kW)	< 300 kW or < 1 MMBtu/hr heat input (67 kW)[a]

[a] Assuming 23% efficiency on HHV basis.

Table 1-44. Summary of DG BACT for Combustion Turbines (lb/MWh)

Category	NO_x	VOC	CO	PM
< 3 MW	0.5 (9 ppm[a])	0.1 (5 ppm[a])	0.4 (10 ppm)	NG with S < 1 grain/100 scf
3 – 12 MW				
Combined Cycle	0.12 (2.5 ppm[a])	0.04 (2 ppm[a]*)	0.2 (6 ppm[a])	
Simple Cycle	0.25 (5 ppm[a])	0.04 (2 ppm[a])	0.2 (6 ppm[a])	
> 12 and < 50 MW				
Combined Cycle	0.10 (2.5 ppm[a])	0.03 (2 ppm[a])	0.15 (6 ppm[a])	
Simple Cycle	0.20 (5 ppm[a])	0.03 (2 ppm[a])	0.15 (6 ppm[a])	
Waste Gas Fired	1.25 (25 ppm[a])	X	X	

[a] dry, 15% O_2. 23% efficiency for < 3 MW category to arrive at ppm value.

Table 1-45. Summary of DG BACT for Reciprocating Engines (lb/MWh)

Category	NO_x	VOC	CO	PM
Fossil Fuel Fired	0.5 (0.15 g/bhp-hr or 9 ppm[a])	0.5 (0.15 g/bhp-hr or 25 ppm[a])	1.9 (0.6 g/bhp-hr or 56 ppm)	0.06 (0.02 g/bhp-hr)
Waste Gas Fired	1.9 (0.6 g/bhp-hr or 50 ppm[a])	1.9 (0.6 g/bhp-hr or 130 ppm[a])	7.8 (2.5 g/bhp-hr or 300 ppm[a])	X

[a] dry, 15% O_2. 23% efficiency for < 3 MW category to arrive at ppm value.

Table 1-46. Example Thresholds for Triggering Offset Requirements

District	NO_x	VOC	CO	SO_2	PM
BAAQMD	15 tpy	15 tpy	—	—	—
SMAQMD	7500 lb/qtr	7500 lb/qtr	49,500 lb/qtr	13,650 lb/qtr	2,500 lb/qtr
SCAQMD	4 tpy	4 tpy	29 tpy	4 tpy	4 tpy
SDAPCD	25 tpy	25 tpy	—	—	—

operating 8760 hours per year to trigger offset requirements in any of these districts. For example, a 1 MW DG unit emitting 0.5 lb/MWh permitted to operate 8760 hours/year has a PTE of 2.2 tpy. This unit would not trigger offset requirements in any of the districts listed in Table 1-46. Similarly, an on-site reformer would not trigger offset requirements.

2. Renewable Energy Sources for Hydrogen — Identifying Societal Benefits

2.1 Introduction

There are many different types of renewable resources available in the state of California for the production of electricity and/or hydrogen. The purpose of this section is to provide background information on some of the ways in which renewable resources differ from one another and from conventional electricity generation resources. It also discusses the implications that these differences might have for their potential use in the electricity and transportation markets. Examples of these differences include emissions associated with providing a new renewable resource both in terms of manufacturing energy and operating energy, the manner in which a resource is purchased, the intermittency and capacity factor characteristics of the resource, and any added benefits that may not be readily apparent when the resources are compared on simply an energy cost basis.

The primary focus of this section is the differences among renewable electricity options for producing electrolytic hydrogen in order to understand their implications for the well-to-wheels analysis.

This is not to infer that the future of renewable energy for production of hydrogen is limited to electrolytic hydrogen at vehicle refueling sites, or that our analysis was restricted to this supply option. It is recognized, for instance, that biomass gasification can present a compelling and attractive option for the production of hydrogen. However, for the nascent period of hydrogen commercialization before us, production of hydrogen at refueling sites using grid-supplied electricity faces an existing practical set of limitations and opportunities that must be considered together with the character of each of the renewable energy technologies feeding the electrical grid. There can be wide differences in the environmental benefits of renewable hydrogen depending not only on the character of the renewable resource but also on its relationship to all other resources and demands that make up the existing electrical grid.

This section provides a comparison of environmental impacts and benefits mostly for new renewable grid-connected electricity resources dedicated to the provision of renewable hydrogen.

2.2 Attribution of Renewable Power

This section identifies the differences between renewable energy purchasing mechanisms in terms of their true benefit to California citizens. There are many different ways which renewable energy can be procured to produce hydrogen, some of which have multiple benefits and some of which are solely benefits on paper. A methodology is developed to allow a Well to Wheels analysis which will differentiate between various types of power purchases using a calculated vector to represent the relative “greenness” of that renewable purchase.

2.2.1 New Versus Existing Renewables

The first question to ask when looking at the use of renewable power for hydrogen production is whether the renewable electricity is from a “New Renewable” or an “Existing Renewable.” The CEC’s RPS Eligibility Guidebook defines “New Renewable” as being installed after January 1st, 2002 [39], while the Center for Resource Solutions defines “New Renewable” as being installed after 1997 [40]. Resources that were built before 1997 in California were typically financed by the utilities with the costs being added into the rate base. As a result, paying a little more for the attributes of those projects now would not result in any new capacity being built, and as new electricity demand came on-line, the end result would be a heavier reliance on fossil fuels in the electricity mix.

For the purpose of producing hydrogen, it is important to require that any “renewable hydrogen” be produced from new renewables rather than existing renewables. Production from existing renewables does not make sense because these sources are already a part of the existing grid supply. By adding a new demand source in the hydrogen electrolyzer, we add demand to the grid, above that which is already planned for based on load forecasts. The result of this additional load will likely be either increased reliance on marginal gas resources or new combined cycle gas plants as long as natural gas maintains an economic advantage over renewables. As a result, the environmental value of using existing renewables to produce hydrogen should be given the full emissions value associated with a marginal California natural gas fueled electricity generation facility. A typical heat rate for such a facility is on the order of 8500 Btu/kWh[3], which results in approximately 450 kg CO_2/MWh being generated from direct combustion.

2.2.2 In-State Generation Versus Out of State Generation

The work done on the state RPS defines eligible resources as being located within California, or out of the state but bound by contract to deliver the energy to California, and being able to deliver that power to an Investor Owned Utility (IOU) designated in-state hub [42], as well as meeting a separate set of delivery requirements. For the purposes of generation of hydrogen, those out of state resources that meet this definition will be considered out of state power purchases. For purchases of resources that do not supply energy to the California market, we can effectively consider these to be equivalent to Green Tags.

The purchase of energy from a renewable resource that does not actually supply that energy to California results in additional natural gas generation occurring in California, as described before. Because of this, these renewable energy attributes that would be used to generate “renewable” hydrogen would be resulting in criteria pollutant emissions in California equivalent to a typical natural gas plant here. The greenhouse gas emissions from this sort of arrangement would net to zero if the resource was offsetting natural gas generation in the state it was occurring. Natural gas is the likely marginal source in most Western states due to the high fuel cost and wide range of operation possible with most natural gas electricity generation technologies. For Green Tags purchased from states where coal would be offset, we can see that there would actually

be a GHG *reduction* as a result of the renewable generation and sale of the Green Tags. On the other hand, in the event that nuclear facilities were being curtailed to allow entry of the renewable resource, we can see that there could be an increase in greenhouse gas emissions as a result of the Green Tag purchase. These two scenarios would require extensive research to determine the feasibility of either case, and will not be addressed further as part of this effort. Rather, Green Tag, or attribute only purchases will be considered net-zero GHG energy, but will count for the full emissions value of a typical California natural gas fired generation facility. If the Green Tags are created from renewable power that is generated in California however, they would not be assigned the criteria pollutant penalty.

In addition to the negative environmental impacts, the purchase of out of state Green Tags may put California further at risk to natural gas price and supply fluctuations, which can have significant negative consequences on residential gas and electricity rates in California. Because risk and economics are not considered in the well to wheels analysis, no factor will be developed for this area. It is important however to recognize the danger of increased reliance on a single fuel for meeting California's energy needs, as is the case for transportation. It is also worth mentioning that should Green Tags be used, the resulting natural gas generation will consume more natural gas and produce more criteria pollutants than would natural gas reforming for hydrogen production, so this method makes very little sense except as a near term bridge to a renewable electrolysis future.

2.2.3 On-Site Generation Versus Distributed Generation

Because of issues of wind "curtailment," it may be necessary to consider collocating the hydrogen generation with the wind farm. Other renewable energy sources typically do not experience the intermittency associated with the wind resource, and therefore are not subject to the curtailment issues associated with wind farms. Because wind farms occasionally produce electricity at undesirable times for the grid, and can experience output swings at unpredictable rates, their output may be "curtailed," meaning their energy production is not accepted onto the grid. Additionally, utilities may accept wind electricity onto the grid when they do not need it to avoid paying curtailment charges, but the added wind may only end up raising the grid voltage, with no real benefit in terms of fossil fuel reduction. As a result, siting of the hydrogen generation at the wind farm may be a desirable way to capture wind energy that occurs during off-peak times. Because of the capture of power that would otherwise have been wasted, these on-site generators are effectively increasing the amount of renewable energy that can be captured, and when compared to a distributed generation scenario, are effectively decreasing the amount of natural gas generation required by the amount of wind energy that would otherwise be curtailed.

In order to estimate the amount of wind energy that could conceivably be curtailed, it is necessary to consider what the hours are in which California generating facilities are base-loaded. In California, the grid peak occurs in the late afternoon, and between the hours of midnight and 4 or 5 a.m. most of the grid is base-loaded. Wind generated during this time would have the highest likelihood of being curtailed. In Solano County wind generation peaks at midnight [43], which means that there is a good amount of

energy that falls during this time that could be curtailed. While these morning hours represent 21 percent of the day, the amount of energy that is generated during this time is roughly 25 percent of the average annual total for Solano. Curtailment might be a small portion of this 25 percent, depending on the utility, and the amount of wind penetration. For this case, we will assume that 20 percent of the energy that falls during these morning hours is curtailed, resulting in a 5-percent bonus for onsite generation over distributed generation in terms of criteria pollutants and greenhouse gases. Determining whether the on-site should receive a bonus, or the distributed generation should receive a penalty is the main difficulty here. It is anticipated in many regions that as the amount of installed wind power reaches 15 to 20 percent of the total grid capacity, the amount of curtailment may become quite significant.

2.2.4 Summary

Any hydrogen that is produced and results in increased electricity demand in California will be attributed the full criteria pollutant emissions value of an average marginal natural gas generation facility in California unless it clearly comes from a renewable resource. We take an average plant because a good deal of the required increased generation will come from existing marginal resources in California in addition to new natural gas plants that are built to meet steadily increasing demand. If the electricity demand is met through power purchase agreements with renewable energy producers in or bordering California, the hydrogen producer can legitimately call the hydrogen zero-emission. However, if the hydrogen is produced from grid electricity and out of state Green Tags are purchased to offset the emissions, the hydrogen will only be credited with the offset GHG's, not the offset criteria pollutants. In the event that the hydrogen is produced at the site of generation, (in particular at a wind or Hydro spill site), the emissions associated with the hydrogen should be considered negative, or some sort of credit should be given as a reward for utilizing an under-utilized renewable resource. The current estimate for this credit value for California is ~5 percent.
Table 2-1 shows the emissions and energy savings ratings associated with various

Table 2-1. Renewable Energy Rating System for WTW analysis

Type of Renewable Energy Purchase	Types of Renewable Energy Benefits to California			
	Greenhouse Gas[a]	Criteria Pollutant[a]	Energy	Overall
Green Tags/Attribute Only Purchase	0.00	1	1	0.7
Renewable Power Purchase Agreement	0.00	0.00	0.00	0.00
On-Site Generation (Wind)[b]	-0.05	-0.05	-0.05	-0.05
Existing Renewable (Pre-2002)	1	1	1	1

Rating represents fraction of emissions from an 8500 Btu/kWh natural gas generation facility

[a] Emissions will differ based on the type of renewable energy procured. Wind is effectively considered a zero emission source, however all other renewables have some small but quantifiable emissions value associated with them. See Section 2.3.

[b] The on-site generation has received a credit because it is harvesting power that would otherwise be lost if the production was located off-site.

renewable energy purchases. The difficulty lies in determining whether this should be a credit, or whether the other purchasing methods should take a penalty.

2.3 Renewable Power Growth and the California Power Grid

This section will look at how renewable power is expected to grow in California as a result of the Renewable Portfolio Standard (RPS), and whether using renewables for hydrogen will be feasible considering resource projections. It will also discuss the question of offsetting electricity generation or transportation fuel in terms of societal benefits to California.

2.3.1 The Renewable Portfolio Standard Versus the Renewable Hydrogen Standard

As California looks at requiring the electric utility industry to move towards a 20-percent RPS by 2010, and a 33 percent RPS by 2020, it is important to consider the availability of renewable resources and their best use in terms of offsetting emissions and maximizing their societal benefit. In addition, when considering availability, a look at the overall state resource assessment is necessary to ensure that the State has adequate renewable resources to meet the rising demand in both the electricity and transportation sectors. According to the Renewable Resources Development Report put out by the CEC, the state has a total potential renewable generation capacity of 262,000 GWh per year [44]. This compares to the state's total electricity demand in 2003 of roughly 256,000 GWh [45]. The estimated potential done by the CEC does not include off-shore wind power or wave power, both of which could become feasible before California begins to exhaust its land-based renewable energy options, and both of which represent huge potential energy sources for California. In addition, the WECC technically has a significant surplus of renewable resources outside the state of California that could provide power to California's grid if there was a need for additional procurement of renewable power. Based on these assessments, it seems unlikely that a shortage of renewable power would force a choice between its use for either the electricity or transportation market.

As has been mentioned, the benefits of renewable energy sources range from reduction of greenhouse gases, criteria pollutants, and energy dependence, as well as the encouragement of supply diversity and economic development. These benefits apply regardless of whether the power is used to offset the electricity grid demand or the transportation demand in California. However, the magnitude of each of these categories of benefits differs depending on the market in which they are being consumed.

In looking at decisions for 2010, the question is of little significance considering the scale of the demand for hydrogen. For a very aggressive assumption of a 10,000-vehicle fleet in 2010, entirely fueled by electrolytic renewable hydrogen, this would represent three tenths of one percent of our current renewable electricity production in California. When looking further to the future, there are increased difficulties in projecting efficiency improvements in various technologies, although it is likely that

newer technologies have the greatest room to improve in efficiency. These issues should be considered when examining this analysis.

In the electricity market, a new renewable will be offsetting natural gas fired generation in California. This is because the nuclear and hydroelectric resources will be fully utilized as a result of their price signals. The gas resource is the primary marginal resource in California, and for this analysis, an average assumed value of 8500 Btu/kWh for the marginal natural gas heat rate was used. On the transportation side, a 2:1 fuel economy improvement was assumed for a fuel cell vehicle over a gasoline vehicle. Emissions of NO_x were based on current emissions controls capabilities, using ARB and eGrid2002 numbers for California and comparing the values to the emission factors in the WTW GHG analysis in Appendix W. The analysis considered the best use of 1 MWh of renewable energy, for each of the areas mentioned above. The results of the comparison are shown in Table 2-2.

Table 2-2. Comparing Offset Options for 1 MWh of Renewable Electricity

Offset Market	Greenhouse Gases (kg/MWh)		NO_x (g/MWh)	Fossil Fuel Offset	Market Diversity Impact
	CO_2	GHG			
Transportation[a]	370	388	37	Petroleum	High
Electricity 80% NG, 20% RPS[b]	433	456	27	Natural Gas	Medium

[a] For Transportation, assumptions included a 2x fuel efficiency improvement for FCVs over gasoline vehicles (60 mi/kg), an electrolysis power consumption of 60 kWh/kg. 1 MWh produces 16.7 kg of hydrogen or displaces 33.5 gal of gasoline. The displaced CO_2 from the gasoline vehicle is 370 kg (WTW). This corresponds to 290 g CO_2/mile direct emissions plus 80 g/mi of CO_2 from the fuel cycle. (From WTW, 30 mpg, 11,030 g CO_2/gal gasoline) and 0.037 g NO_x/mile (MY2010 vehicle over 150,000 miles EMFAC 2002). Assuming 50 kWh/kg and 2.5X fuel economy results in 20 kg of hydrogen produced, 50.3 gal of gasoline displaced and 555 kg of CO_2 displaced.

[b] Direct power plant or vehicle emissions only. For electricity, the gas plant was assumed to have a heat rate of 8500 Btu/kWh (42.3% efficiency, HHV) and a NO_x emissions rate of 0.027 kg NO_x/MWh (Both consistent with mid-1990's combined cycle or a newer combined cycle plant operating at part load). Direct CO_2 emissions are 460 kg CO_2/MWh or 544 kg CO_2/MWh on a "well to plug" basis. Assuming a heat rate of 6500 Btu/kWh for newer power plants results in 432 kg/MWh of displaced CO_2. With a 20% RPS, the impact of displacing 1MWh would be 347 kg/MWh of CO_2 or 371 kg/MWh of total GHG emissions.

Significant here is the fact that the transportation offsets are better for reducing NO_x and petroleum dependency, though not necessarily for CO_2, depending on the efficiency of the power plant and fuel cell vehicle. The CO_2 difference will likely close as older gas plants are retired, moving the gas heat rate towards 6000 to 7000 Btu/kWh and electrolysis efficiency improves towards the 50 kWh/kg range. The other categories offer some significant insights. In looking at criteria pollutants, offsetting transportation, even clean 2010 vehicles, is a better option than offsetting power-plants. In terms of offsetting fossil fuels, petroleum is clearly of greater significance given our near total dependence on it for transportation. Petroleum provides 94 to 96 percent of our

transportation energy needs in California, while natural gas provides only 40 to 50 percent of our electricity needs.

If we examine the quantities of renewables that are consumed in each market, it becomes apparent that a significant disparity exists in both the fuel diversity and the overall size of each market in terms of energy. On an energy basis, the amount of gasoline consumed for transportation in California is 120 percent more than the amount of natural gas consumed for electrical generation, as shown in Figure 2-1. Further, natural gas consumed for electrical generation makes up just over a third of the total natural gas consumption in California, as shown in Figure 2-2. So in the short run, attempts to reduce the portion of natural gas used for electricity consumption through the use of renewables would have a relatively small impact on the overall total.

When considering whether renewables would have a larger impact on the electricity or transportation market, it is useful to examine the diversity of fuel supplies in each of these markets. In the transportation market, gasoline makes up 94 percent of the fuel used for passenger vehicles in California [1]. On the other hand, in the electricity market, natural gas generation made up roughly 50 percent of the in-state electricity in 2000(eGrid 2002)

the significant improvements being made in both the hydrogen production areas and the natural gas generation areas, it appears that the maximum societal benefit could be achieved by encouraging the use of renewables in the transportation market as a first priority and the electricity market second. While this may not be true for other states, considering the fact that California's grid mix is as clean as it is, and that natural gas is its marginal resource, point towards gasoline and the transportation market as the primary area for cleanup of emissions.

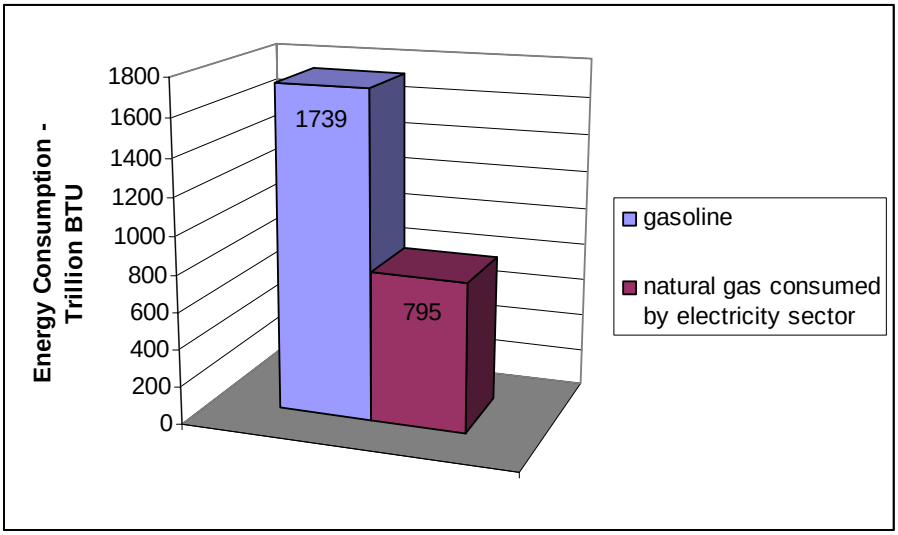


Figure 2-1. Gasoline and Natural Gas Consumption in California in 2002 (Source: EIA and CEC)

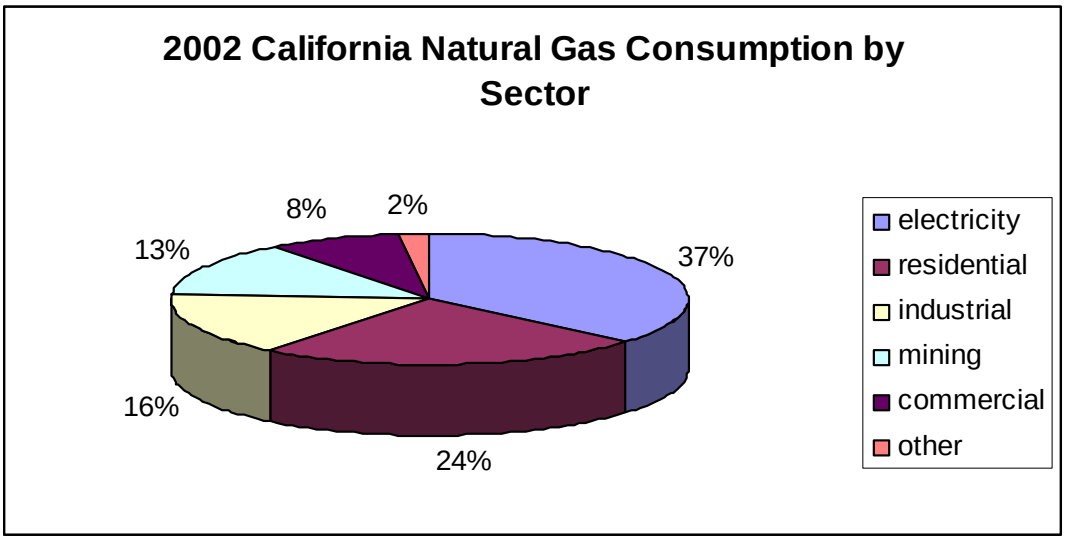


Figure 2-2. Breakdown of Natural Gas Consumption in California (Source: CEC)

Figure 2-3 shows the transportation sector being responsible for more than 50 percent of the CO_2 emissions in California. This suggests the use of renewable energy sources might best be targeted at this sector in order to minimize our state's greenhouse gas emissions. In addition to CO_2, mobile sources account for as much as 70 percent of Ozone precursor emissions in the Sacramento Metropolitan AQMD [46]. The use of renewable hydrogen to offset CO_2 and NO_x emissions in the transportation market would have the maximum benefit for those renewable resources.

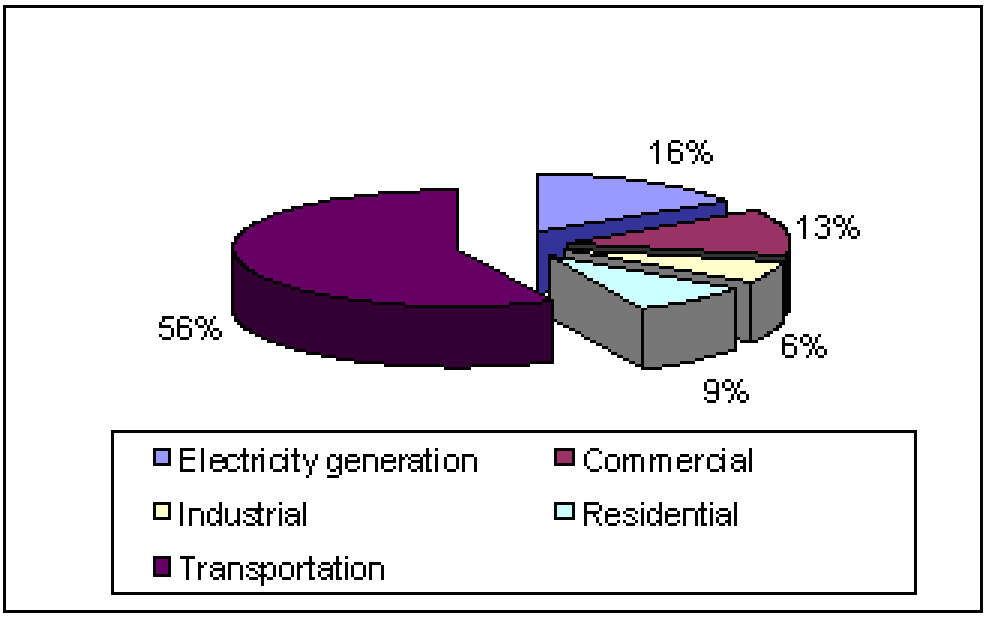


Figure 2-3. CO_2 Emissions in California by Sector (1999) (Source: CEC)

2.3.2 Existing Grid Constraints and Impacts on Peak Demand Versus Hydrogen Availability

One of the challenges of simply connecting electrolyzers to the electricity grid for the production of hydrogen is the question of existing grid generation and transmission capacity. The electricity grid in California has experienced several Stage 1 alerts in recent years in which we have come within 7 percent of our upper limits for grid demand. The addition of significant amounts of electrolysis onto the grid must be done with full consideration of its impacts on grid reliability to ensure that its presence adds to grid stability rather than worsening our current situation.

Renewables can add stability to the grid, however they can also cause difficulty for schedulers because of their intermittency. For example, a wind resource that was scheduled to deliver power could fail to do so during a peak demand time. For this reason, wind is often looked at as an undesirable addition to the grid from the perspective of a power scheduler. On the other hand, load following of a wind resource with an electrolyzer may not necessarily be much easier. Depending on the size and design of the electrolyzer, ramp up and ramp down rates may prevent the electrolyzer from load following in an optimal manner.

One way in which renewable hydrogen can add benefit to the grid reliability is to utilize the energy storage characteristic of hydrogen. For instance, electrolyzers could plan to shut down during the grid peak demand or to utilize “spill” power in the late night hours to make hydrogen for the following day’s business. By designing this capability into the stations, the renewable power plants that are dedicated to supplying power to these electrolysis units effectively become peaking units when the electrolysis load shuts off on a hot summer afternoon, but provide stabilizing load during the off-peak hours. In this manner, the grid scheduler is no longer forced to accept power when they don’t want it, but have load on the system when nature makes power available.

2.3.3 Summary

Renewable electricity sources that are dedicated to the production of hydrogen can bring significant societal benefits to California. This can be done in addition to using renewables to supply electricity demand in California. There are potentially more than enough regional renewable sources to provide California’s entire electricity and transportation markets for the foreseeable future. While the question is frequently asked as to whether renewables are better used to offset electricity emissions in California, the question should be how can we most fully utilize our renewable resources to offset as much of our energy needs as possible? Renewables used to produce hydrogen for fuel cell vehicles offer a huge benefit in terms of NO_x emissions. They can also offer the most significant CO_2 emissions reductions for California’s largest source of greenhouse gases, transportation. Finally, by using renewable electrolysis in cooperation with the grid schedulers, renewables can be used to stabilize the electricity grid by providing a renewable peak power source.

2.4 Renewable Technology and Energy Inputs

This section compares the different renewable resources, the state of the technology, and likely future public benefits to choosing one or another. The differences in emissions of the various renewable technologies are also examined in order to understand whether or not they can be considered equivalent or whether they must be considered separately. Life cycle energy use, or manufacturing energy necessary for manufacturing will also be examined.

2.4.1 Attributes of Renewable Sources

The Renewable Portfolio Standard and the Western Renewable Energy Generation Information System both currently consider energy sources that meet the definition of "renewable" to be equivalent to one another. Qualifying renewable energy sources include:

- Biomass
- Biodiesel
- Fuel cells using renewable fuels
- Digester gas
- Geothermal
- Landfill gas
- Qualifying Municipal solid waste
- Ocean wave, ocean thermal, and tidal current
- Photovoltaic
- Small hydroelectric (30 megawatts or less)
- Solar thermal
- Wind

Looking at the list, there are several areas that renewable energy sources differ from one another. These include criteria pollutants, greenhouse gas offsets, intermittency and capacity factor issues, and life cycle energy use for the renewable technologies themselves.

In terms of criteria pollutants, biomass sources including landfill gas, MSW, and agricultural residues all produce NO_x emissions. Several of these biomass sources also result in some non-biogenic CO_2 emissions as a result of fossil content and fuel transportation. Figure 2-4 gives a comparison of several of the technologies in terms of the CO_2 emissions associated with their manufacture and operations. The emissions from the transportation of the biomass materials is not quantified however, as it varies widely depending on the resource. Figure 2-5 shows the NO_x emissions associated with the manufacture and operations of each of the technologies[18]. From the plots, it is clear that the best renewable electricity sources to use for hydrogen production would be

[18] This comparison reflects only the direct emissions from power plants. The benefits of avoided agricultural burning are not included in the values for biomass as they were in Section 1.

geothermal, wind and solar, while biomass and biogas options would be better suited for direct conversion to hydrogen through gasification and steam methane reforming in order to minimize emissions.

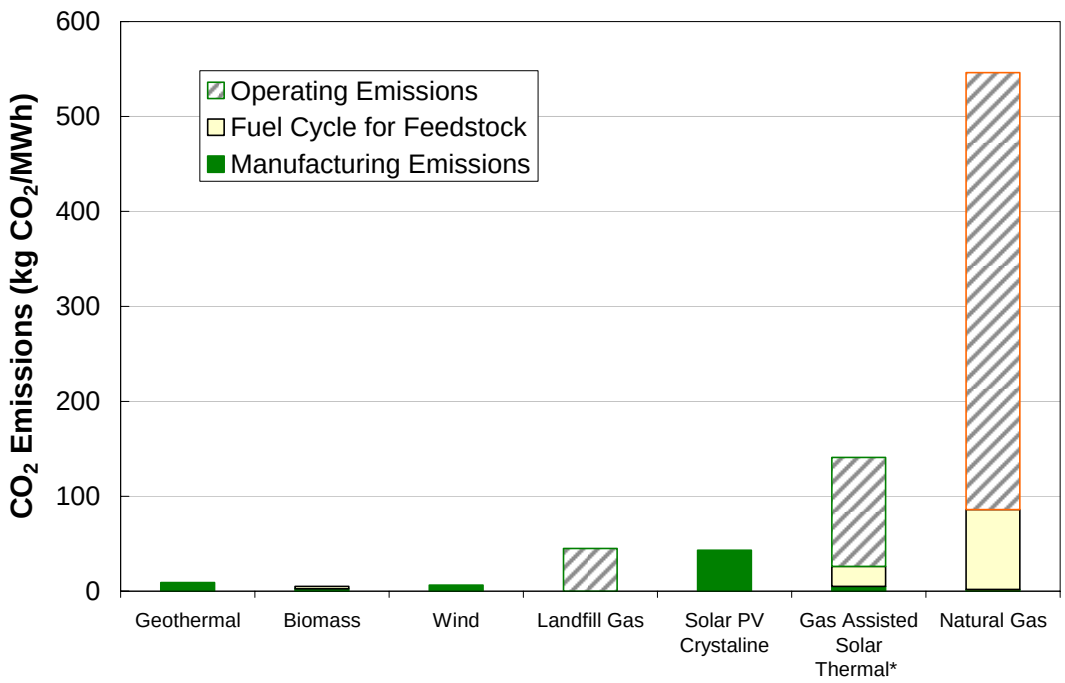


Figure 2-4. Manufacturing and Operating CO_2 Emissions for Various Renewable Energy Sources, Compared to Natural-Gas-Based Electricity, Sources: [47, SEGS 2000 Operating Data]

Table 2-3. Direct Emissions and Manufacturing Energy Required for Renewable Facilities (kgCO_2/MWh)

Renewable Energy Source	Manufacturing	Fuel Cycle for Feedstock	Operational	Overall
Geothermal	9.10	0	0	9.10
Biomass	2.60	3.2[a]	0	5.80
Wind	6.46	0	0	6.46
Landfill Gas	0.07	0	45	45.07
Solar PV Crystaline	43.00	0	0	43.00
Gas Assisted Solar Thermal	5.00	21	115	141.00
Natural Gas	2	84	460	546.00

[a] Includes energy for diesel equipment to collect and transport biomass residue.

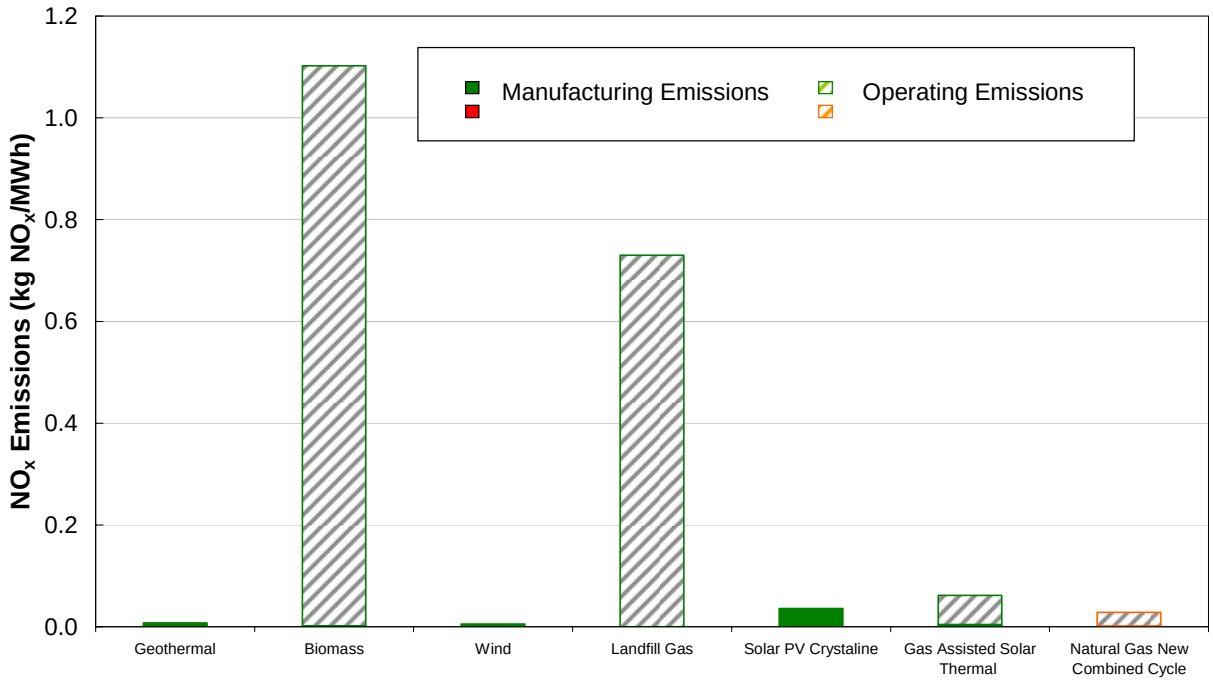


Figure 2-5 Manufacturing and Operating NO_x Emissions for Various Renewable Energy Sources, Compared to Natural-Gas-Based Electricity [47]

While it is possible to compare these technologies as they exist today, the truth is that many of them are emerging technologies and their emissions values and energy intensiveness will likely improve in the future. Because of this, it is difficult to look very far into the future to compare each of these technologies to one-another, as the differences will likely be even smaller. However, at the same time, it is important to realize that these "renewable" resources do not all have the same characteristics, and by using some of them to produce hydrogen, we may very well be creating a fuel which actually increases NO_x emissions, depending on the feedstock and way that it was made. It is important to identify these emissions, and ensure that they are minimized and that the hydrogen is produced from the cleanest possible feedstocks.

2.4.2 Intermittency and Capacity Factor Issues with Renewable Sources

Another issue that frequently separates renewable energy technologies is their intermittency and annual capacity factor. The capacity factor of a resource refers to the percentage of the year that a resource is operating at its rated capacity. The intermittency of a resource is more of a measure of the predictability of a resource for scheduling generation. Typically, solar facilities, unless coupled with storage or with a natural gas assist, have the lowest capacity factors, while wind resources have the highest intermittency.

Intermittency and capacity factor typically impact the cost of integrating these resources onto the grid, but can also play a large role in the availability of hydrogen, if production

is tied to the output of a facility. In particular, swings between seasonal capacity factors could result in hydrogen shortages in the winter months if the output is tied to solar or to certain wind resources. This would limit the size of a hydrogen production facility to the average output for the smallest month, or week, or even 2 to 3 days, depending on the storage available. In the case of Solano Wind, this would result in a hydrogen production facility being sized for 5 percent of rated wind capacity or less, as opposed to the annual wind capacity factor of approximately 30 percent. These sizing issues would need to be considered in any situation where the hydrogen production is tied directly to the output of a single renewable resource. Attempts to assess both Capacity Factor and Intermittency have lead to the concept of the Relative Capacity Credit that is being developed at the CEC. Table 2-4 shows the average capacity credit assigned to various resources as part of California's RPS integration costs analysis [48].

Table 2-4. Relative Capacity Credit of Various Renewable Technologies and Natural Gas

Resource	Medium Gas	Biomass	Geothermal	Solar Thermal with Gas Assist	Wind (Altamont)	Wind (Tehachapi)	Wind (San Georgino)
Relative Capacity Credit	100%	97.8%	88%	56.6%	26%	23.9%	22%

Source: California RPS Cost Analysis Phase 1: One Year Analysis of Existing Resources

* Note that the Solar resource in this case is from the SEGS plants, which utilize a natural gas assist for as much as 25% of the overall energy.

While these numbers look very difficult for the wind resources from either the perspective of producing hydrogen or electricity, the integration of the electrolysis control with the grid scheduler might allow increased installation of wind turbines in California. This integration would allow the scheduler to control the load of the electrolyzers based on the output from the wind resource and the grid demand.

2.4.3 Summary

While there are many different types of renewable electricity that can be used to produce hydrogen, some types are far better than others in terms of the environmental benefits to Californians. In particular, development of new wind, geothermal and solar resources for the production of electricity and hydrogen should be encouraged. Combustion of biomass and landfill gas should be encouraged to shift to cleaner technologies to minimize NO_x emissions for electricity production. For hydrogen production though, biomass and landfill gas resources are better used through a direct gasification and steam methane reforming process to minimize emissions and maximize efficiency. While manufacturing and operating emissions were considered here, other factors such as emissions offset from avoided forest-fires or ag-residue burning or

methane escape should be considered and applied when considering the benefits of biomass resources.

In terms of intermittency, solar and wind are the most difficult to deal with from the perspective of hydrogen production while wind is the most difficult to deal with from the perspective of electricity production. By allowing the option of hydrogen production integrated with grid scheduler control, intermittency could be sufficiently mitigated to allow an increase in the amount of renewable allowed on the grid.

2.5 Auxiliary Benefits of Renewable Energy Technologies

Finally, we examine the benefits to the existing electricity grid that various renewable resources could provide, as well as the possible benefits they might provide if coupled with hydrogen production. These benefits may be difficult to quantify, particularly when we are looking at reliability, however it is important to identify which resources have added value and which should just be taken at face value.

2.5.1 Wind Auxiliary Benefits

While it is clear that the intermittency effects of wind resources are not desirable for a utility grid operator, it should be noted that for the most part, both the wind and solar resources are desirable from a seasonal availability perspective [48]. Both of these resources peak in the summer, which coincides with the peak electricity demand in California. Looking at both resources on a diurnal basis, depending on the wind resource, the output of a wind resource may peak as late as midnight, while solar output peaks in the middle of the day. As a result, the solar resource is more desirable in order to meet peak demand, while wind must be accommodated as demand for power is dropping. This coincidence with peak electricity demand is an auxiliary benefit of the solar resource, and points towards using this resource primarily to meet electricity demand rather than using it for hydrogen production. Wind resources that peak at midnight however, have very little auxiliary benefit to a grid operator, and might be better suited for off-peak hydrogen production.

2.5.2 Biomass Auxiliary Benefits

Biomass resources provide an added benefit of being the most dispatchable of any of the resources. Depending on fuel availability, biomass facilities can be operated at near a 100 percent capacity factor , or may be operated solely to meet peak demand for electricity. This allows a built in diurnal and seasonal storage capability that none of the other resources have, and enhances biomass benefits both for producing electricity and for producing hydrogen. This is dependent however, on having a variety of feedstocks available for the biomass generation facility, or on having a consistent feedstock that does not vary in seasonal availability.

Biomass resources also provide auxiliary benefits in terms of enhanced utilization of the waste product that they typically are generated from. In the cases of0dairy waste and landfill gas, eliminating methane emissions by combustion or conversion to hydrogen greatly reduces GHG emissions. When looking at forest trimmings, utilization for

electricity and hydrogen production provide an enhanced revenue stream as part of otherwise required forest fire prevention activities.

Xxx elaborate on avoided emissions

2.5.3 Geothermal Auxiliary Benefits

Geothermal resources provide a level of consistency that is typical of a base-loaded electricity generation facility, which is also desirable both for grid electricity and hydrogen production. The use of geothermal energy of course would be limited to new installations, or repowering of old installations.

2.5.4 Solar PV Auxiliary Benefits

Solar photovoltaics (PV) provides added value in several ways. Primarily, PV can be deployed in a distributed fashion on the grid, providing clean generation sources where they are needed. This can be of benefit to both electricity and hydrogen production, as no transmission of the energy is required for either case, eliminating problems of grid congestion and fuel transportation. In addition, PV can offset the embodied energy and cooling demands of the structures it is attached to through the use of insulated, or enhanced roofing building integrated PV (BIPV). Another use of PV that has added benefit is integration into shade structures for covered parking. This can reduce the heat buildup of the cars that park under the structures, which can in turn reduce the startup emissions resulting from intensive air conditioning use as the vehicles leave the parking facility. These factors provide some offset to the energy requirements for producing the PV modules, which are shown in Section 2.3, are not trivial. These are also factors that may not show up in the technical analysis of using PV to create hydrogen from a public benefit perspective, however they should be considered as potential attributes of PV systems.

2.6 Conclusions

There are many differences between renewable resources that should be taken into account when planning to use them for hydrogen generation. Some important issues to note include:

- The use of Green Tags as opposed to Renewable Power Purchase Contracts can actually increase emissions and natural gas dependence in California if the Renewable Energy does not get imported into California with the Green Tags

- The differences in intermittency and capacity factor of renewable resources can affect daily and seasonal availability of fuel

- There can be significant differences in operating and manufacturing emissions associated with various renewable energy sources, specifically NO_x emissions

associated with biomass and waste resources, as well as CO_2 emissions associated with natural gas co-firing of solar thermal facilities

- Renewables should be used to offset both electricity and transportation, but we should recognize that transportation in California faces big problems given its complete dependency on petroleum, and also is a cause of many of our environmental problems considering it accounts for a majority of both CO_2 and NO_x emissions in California

- While analysis of quantitative differences may point to the use of certain renewables for the production of hydrogen, the inclusion of auxiliary benefits could lead to a much wider scope of renewable hydrogen production options

All of these issues deserve attention in developing a robust plan for utilizing renewable resources to meet California's hydrogen demand.

3. Challenges of California's Petroleum Dependence

3.1 Petroleum Dependency Background

According to the California Energy Commission, growing demand for gasoline and diesel fuels in California is expected to increase by almost 35 percent over the next 20 years, exacerbating the already strained transportation fuel market [1]. A combination of refinery constraints, market competition issues and unique fuel specifications have lead to volatile fuel prices that are consistently among the highest in the nation. Over the long term, crude oil production capacity is expected to peak worldwide and will likely to cause further upward pressure on fuel prices.

If California is to have a market that provides adequate, and cost-effective transportation fuels, it must over time decrease demand for petroleum fuels by transitioning to non-petroleum fuels and improve vehicle efficiency. Hydrogen, along with other fuels, can provide options to reducing petroleum and can be produced as a clean, domestically-derived fuel source.

The principal problems California faces from its increasing reliance on petroleum are sources of supply, economics and environmental quality.

The capacity at California's refineries has not kept up with the growing demand for transportation fuels. As a result, the state has become a major importer of petroleum products. This, in combination with marine and distribution infrastructure limitations, has made the California fuel market increasingly unstable and dependent on importations. As long as demand for transportation fuel continues to grow, California's gasoline and diesel supply will be subject to price volatility.

Unless consumers are given viable fuel options, the state could continue to face significantly higher gasoline and diesel prices. Non petroleum fuel options, such as hydrogen and others, could reduce demand for petroleum and temper price fluctuations.

Rising petroleum prices can have a significant impact on the U.S. and California economies. In addition to reducing the real income of consumers through higher fuel prices directly, oil price hikes drive up the cost of production and transportation of goods and services throughout the economy. The result is a negative impact on the State's economy (gross State product). The significant petroleum price hikes in 1973-74, 1979-80, and 1990 led to or worsened recessions in the U.S. [1]. High fuel prices have harmed the state's economy by costing consumers and businesses billions of dollars annually. [19]

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[19] Assuming California uses approximately 15 billion gallons of gasoline per year, an increase of $0.50/gallon equals $7.5 billion in additional costs to consumers and businesses.

In 2002, the average price for crude oil was $24.09 per barrel and $28.50 per barrel in 2003 [67]. Crude oil has risen in excess of $50 per barrel in late 2004, setting records for crude prices (nominal). High crude oil prices have a direct impact on both gasoline and diesel prices.

California's heavy reliance on petroleum also results in increased greenhouse gas emissions and challenges efforts to improve air quality. Substantial scientific evidence points toward the link between increasing greenhouse gas emissions and climate change. The potential for severe climate change impacts our ecosystems, economy, and health. For example, changes in climate can affect mountain snow packs, critical for water storage in much of the state, as well as bring more frequent and more severe storms. Furthermore, a warming climate could exacerbate urban smog.

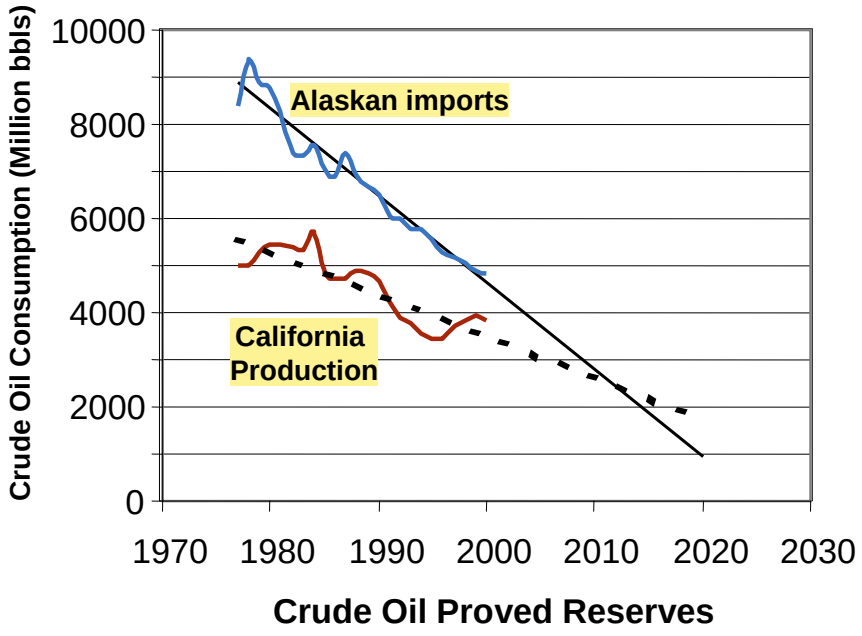

Figure 3-1. California Oil Production and Alaskan Imports

Depending on feedstocks and how fuels are produced, measures to increase the use of non-petroleum fuels will reduce California's GHG emissions. This is critical because of the significant role vehicle emissions play in the state's greenhouse gas emissions. ZEVs, such as fuel cell vehicles operating on hydrogen, result in no smog-forming emissions or greenhouse gases from the vehicle.

Furthermore, supporting the use of non-petroleum fuels should allow for a smooth transition away from petroleum dependence in the transportation sector. There are steps that government can take in the near-term to stimulate the use of non-petroleum fuels. The most effective strategies to reduce demand for petroleum, however, require long lead times to fully implement. Therefore, urgent focus on these issues is needed now.

3.2 Hydrogen Applications — Petroleum Use

A comparison between the petroleum inputs for gasoline and hydrogen passenger cars is shown in Figure 3-2. The WTW petroleum inputs on a g/mi basis are compared for comparable passenger cars. The petroleum inputs include gasoline derived from crude oil as well as diesel and bunker fuel used in the transportation and distribution of fuels.

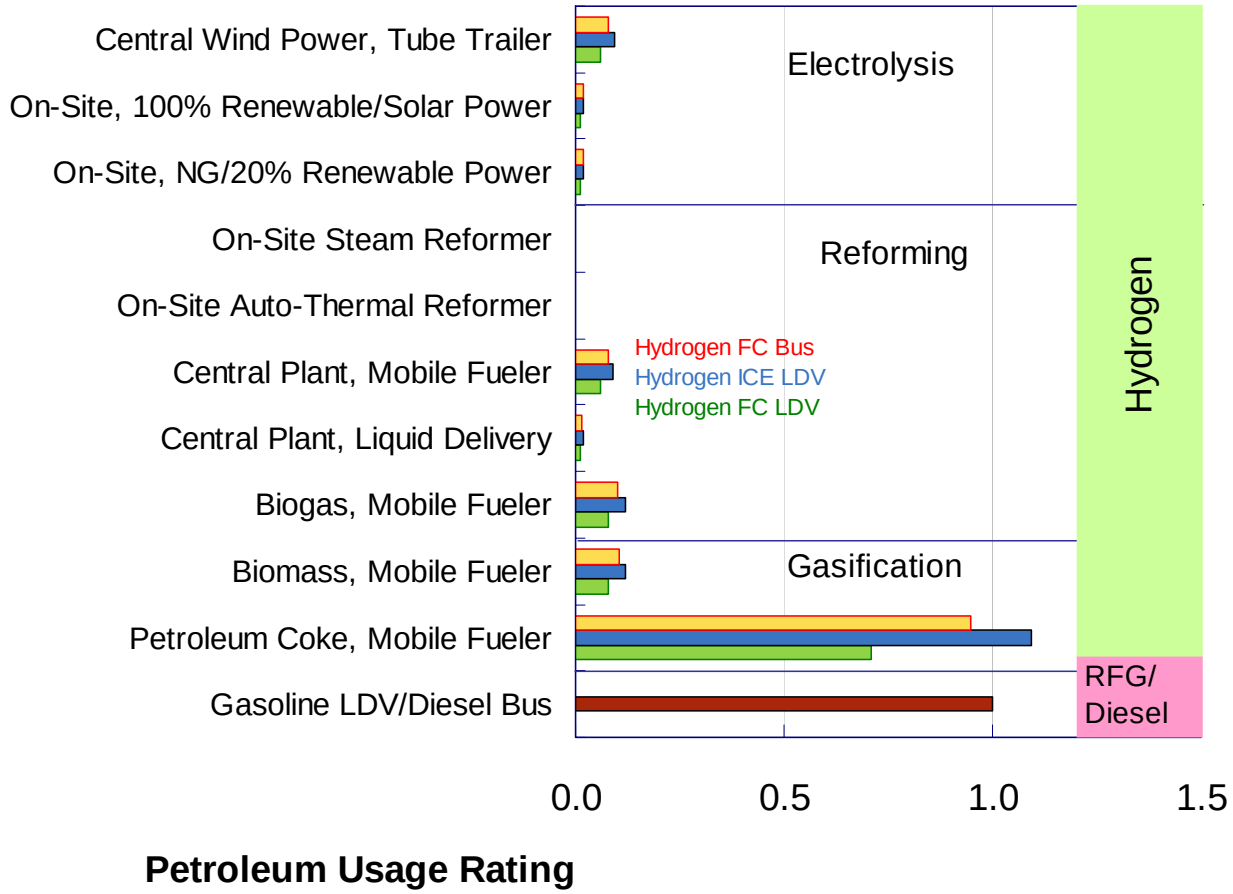

Figure 3-2. Comparison of Petroleum Usage for Different Hydrogen Pathways

Relatively little petroleum is used in most hydrogen pathways. Diesel fuel used for transportation can represent about 10 percent of the energy for compressed hydrogen delivery in mobile fuelers and tube trailers. If petroleum coke is used as a feedstock for

gasification, most of the energy would be derived from petroleum. However, petroleum coke from California refineries is not used as a feedstock for transportation energy.

The petroleum consumption from hydrogen applications depends on both the petroleum input for hydrogen production as well as the vehicle's fuel consumption. The relative petroleum consumption is proportional to fuel consumption as reflected by the baseline fuel consumption comparison values for hydrogen ICEVs and FCVs (See Section 1.5).

4. Inclusion of Non-Hydrogen Vehicle Technologies and Fuels in California's Energy and Environmental Strategy

4.1 Introduction

The California Hydrogen Economy Blueprint Plan (Blueprint Plan) is only one part of a broader energy and environmental strategy for our State [50]. This strategy must, by necessity as well as per public policy preference, include other vehicle technologies and fuels, in addition to hydrogen vehicles and infrastructure, in order to meet the State's energy and environmental goals.

Air quality in California has improved dramatically over the past 30 years. However, more than 90 percent of all Californians breathe unhealthy levels of one or more air pollutants during some part of the year. Governor Arnold Schwarzenegger has pledged to cut air pollution statewide by up to 50 percent, to meet or do better than minimum federal and state standards for healthy air.

The Governor has also pledged to restore independence from foreign oil, including the increased use of alternative fuels. His Action Plan for California's Environment specifically states:

> I will direct the California Energy Commission and California Environmental Protection Agency to ensure that California's fuel marketplace offers producers and consumers a real choice of fuels that are more plentiful, cost-effective and at the same time reduce harmful pollutants and greenhouse gases. Fuel choices should include compressed natural gas (CNG), liquefied natural gas (LNG), ethanol, hydrogen, electric, low-sulfur and non-petroleum diesel blends [51].

In an August 2003 Report, the ARB and the CEC unanimously adopted aggressive goals for reducing petroleum dependence [52], including:

- Reducing demand for on-road gasoline and diesel to 15 percent below the 2003 demand level by 2020 and maintaining that level for the foreseeable future
- Increasing the use of non-petroleum fuels to 20 percent of on-road fuel consumption by 2020 and 30 percent by 2030

Additionally, in September 2004 the California Air Resources Board unanimously approved regulations that achieve the maximum feasible and cost-effective reduction of GHG emissions from motor vehicles [64].

The California Performance Review independent report on reforming and revitalizing State government specifically called for the development of a comprehensive and coordinated transportation fuel strategy, with particular emphasis on alternative fuels [53]. The report specifically stated that:

> First, to create a healthy and diverse fuel market, California should create a coherent policy that encourages a diversified supply and directs the many departments with roles in fuels to work together to support research and coordinate environmental management functions…. Second, the Governor should also encourage the use of alternative and emerging fuels.

Hydrogen-fueled vehicles are expected to contribute to meeting all the above policies and goals, primarily in the long term. But California will clearly need improvements in other non-hydrogen vehicle technologies and fuels, as well as other measures in the short- to mid-term.

For the purposes of this paper it is useful to categorize these other non-hydrogen technologies and fuels, as follows:

1. **"Bridging" technologies:** Vehicle technologies and fuels that contribute to the technological development and cost reduction of components used in hydrogen fuel cell and hydrogen internal-combustion-engine (ICE) vehicles. In other words, developments in these technologies will help to ease and facilitate the commercialization of hydrogen vehicles**.**

2. **Vehicle technologies with similar or significant societal benefits:** Vehicle technologies and fuels that provide similar or significant societal benefits in comparison to both conventional and hydrogen-fuel vehicles.

These two categories of other vehicle technologies and fuels are discussed in detail below.

4.2 Bridging Technologies

As summarized above, these are vehicle technologies and fuels that contribute to the technological development and cost reduction of components used in hydrogen fuel cell and hydrogen ICE vehicles. These technologies include: propulsion systems, drivetrains, energy storage systems, and other components that are similar to those used in hydrogen fuel cell and hydrogen ICE vehicles.

California policy makers clearly understand and support these bridging technologies, as noted in the introduction and also underscored in a recent Q&A interview with CalEPA Secretary Terry Tamminen [54]:

> Question: Do you consider hybrid electric vehicles to be a bridge to ubiquitous use of fuel cell electric vehicles? What is the link between the use of today's electric drive technologies and the technology and infrastructure to support the widespread commercialization of fuel cell electric vehicles?

> Answer: I'm glad you asked this question because it gives me the opportunity to stress that the state views hydrogen vehicles as our future but we will NOT sacrifice the interim opportunities with hybrids and alternative fuels. Vehicles that promote the development of electric drive train technologies are clearly advancing the base of knowledge that is necessary to commercialize hydrogen fuel cell vehicles (HFCVs). There is no one clear pathway to the widespread acceptance of HFCVs but it will naturally include hybrids and distributed generation to produce the fuel. The Blueprint Plan is looking into these obvious links and is not ruling any of them out.

Hybrid-electric vehicles (HEVs) are part of a broader family of "electric drive" vehicles, which includes:

- **Hybrid-Electric Vehicles** – Two types of light-duty hybrid-electric vehicles are in the market today. The first type has a larger battery or energy storage system and can provide propulsion energy to operate the vehicle by battery alone, or via battery/engine combination. The second type typically has a smaller-sized energy storage system and provides better vehicle efficiency by reducing the load on the engine during launch and allows the engine to shut down when the vehicle is stopped. Automobile manufacturers are planning a variety of hybrids in the near future, all of which provide an opportunity for creation of a broader supply base for components that are utilized by both types of hybrids and are likely to be used by hydrogen vehicles as well.

- **"Plug-In" Hybrid Electric Vehicles** – sometimes called "grid-connect" hybrids. These are hybrids which may have a larger battery pack than the HEVs and which have the capability to be recharged from standard household current (120 VAC), getting 20 to 60 miles of all electric range before the IC engine comes on.

- **Battery-Electric Vehicles** – vehicles that operate exclusively on battery power. These are zero-emission vehicles and can be recharged at home. However, they do require up to 6 hours to fully recharge and are not currently able to be "fast charged," i.e., charged in 15 minutes or less.

An August 2003 report by Dr. Timothy Lipman and Roland Hwang, examining the link between hybrid electric and fuel cell vehicles, noted that today's electric-drive vehicles are widely recognized as "bridging technologies" to HFCVs, and explain [55]:

> HEVs are emerging as a key technology that can act as a "stepping stone" to FCVs or battery-electric vehicle commercialization by producing a technological "spillover" effect on critical components. The primary reason for this strong linkage is that they are all "electric-drive" vehicles; that is, they derive some or all of their primary motive power from electric motors. Depending on the specific design, HEVs and FCVs share many components that are either the same or closely related, namely electric motors, power inverters/controllers, and wiring systems for high power

circuits. This relationship is further strengthened by the likelihood of "hybridizing" FCV designs with battery systems, and this adds batteries and regenerative braking systems to the list of common components.

The Lipman/Hwang report quotes automakers themselves which support the concept of and recognize that hybrid-electric vehicles provide a technical pathway and bridging strategy to HFCVs [56].

In addition to a technical pathway, HEV's may also provide an economic pathway should the cost of the fuel cell stack remain greater than the cost of advanced batteries and "plug-in" capability. It may be attractive to substitute these components and downsize the fuel cell without reducing performance.

All of these electric drive technologies provide environmental benefits in comparison to conventional gasoline vehicles (which are discussed in greater length in the next section). Further, all of these options result in reduced petroleum consumption. As a result, to the extent that California encourages these technologies as a bridging strategy to HFCVs, the state will realize the environmental and energy-related benefits in a cost-effective manner. It's a win-win strategy in the short-, mid-, and long-term.

Another category of bridging technologies involves on-vehicle storage of gaseous fuels, in particular compressed natural gas (CNG) vehicles. Relative to hydrogen vehicles, CNG vehicles use similar storage tanks and materials, and face similar challenges involving tank size and placement in the vehicles. The infrastructure for CNG vehicles shares many similarities with hydrogen infrastructure as well. The experience with installing the first hydrogen fueling stations has shown that in communities where CNG refueling stations currently exist, the task of working with the community and the permitting requirements is less onerous than in communities where no CNG refueling infrastructure exists.

Honda Motor Company has announced their intent to produce CNG passenger cars with home refueling for sale in California. The sale of these vehicles and the home refueler will provide insight into the potential to accomplish the same for hydrogen-powered vehicles.

Liquefied natural gas (LNG) vehicles are now widely used in heavy-duty applications in California. This application provides clear bridging benefits to hydrogen vehicles. The on-board storage issues of a cryogenic fuel, as well as transport and refueling issues associated with this fuel can provide valuable insight into the same issues as they pertain to liquefied hydrogen.

Lastly, some of these bridging vehicle technologies and fuels could be mixed and matched, such as an alternative-fuel hybrid. Medium- and heavy-duty hybrid-electric vehicles that use gasoline, diesel or an alternative fuel are also currently being developed.

4.3 Vehicle Technologies with Similar or Significant Societal Benefits

These are other vehicle technologies and fuels that provide societal benefits that are significant, in comparison to both conventional and hydrogen fueled vehicles. In some cases, the benefits may not be as great as those of hydrogen-fueled vehicles, but they may cost less or have other attributes that make them attractive from a societal perspective. Some vehicle technologies and fuels provide greater societal benefits than hydrogen vehicles, depending upon how the respective fuels are produced.

As stated in the introduction, the Blueprint Plan is one part of a broader energy and environmental strategy for California. Although the focus of the Blueprint Plan effort is on hydrogen-fuel vehicles and related refueling infrastructure, the participants recognize that there are other vehicle technologies and fuels that can make significant contributions (particularly in the near- and mid-term) to the same goals and values that were developed for the Blueprint Plan. The core values driving the Blueprint Plan are:

- Energy Independence
- Energy Security & Diversity
- Reducing Air Pollution
- Reducing Global Warming Emissions
- Protecting Public Health
- Economic Competitiveness
- Job Creation

These goals and values also mirror the more specific statutory and agency-adopted goals described above.

Alternative-fuel vehicles, including those that run on LPG, CNG, electricity, and ethanol and other biofuels, can contribute to greater energy independence, security and diversity, by reducing our reliance on petroleum fuels, much of which come from regions in the world that are often politically unstable. Many alternative-fuel vehicles can also achieve large reductions in air pollution and global climate change gases.

More efficient petroleum-fuel vehicles, such as hybrid-electric vehicles or “plug-in” hybrid-electric vehicles, can also make large contributions to energy independence, as well as reduction in air pollution and global warming gases.

Further, it is possible to produce bi-fuel (or “two-fuel”) vehicles that use combinations of two low-emission fuels, such as a plug-in hybrid vehicle that uses an alternative fuel for the combustion-engine drive cycle [57]. A plug-in fuel cell vehicle that combines the torque and cold-start benefits of grid-supplied electric power and energy storage with a fuel cell is another option that takes advantage of the benefits inherent to each different fuel.

California recognizes the benefits of these other on-road vehicles and fuels, and supports their development, commercialization and use. They are a needed part of our broader energy and environmental strategy.

The evaluation of societal benefits that has been done as part of the Blueprint Plan is very detailed and comprehensive; it includes a WTW analysis of GHG emissions, criteria pollutants, and petroleum reduction. Non-hydrogen vehicle technologies and fuels have not been evaluated in this way as part of this report. However, other analysis conducted recently illustrates the relative benefits of these other non-hydrogen vehicles/fuels in comparison to conventional gasoline vehicles. The relative benefit of these vehicles in reducing GHG emissions is contained in the Air Resources Board Staff Report on climate change. This report illustrates potential reduction in GHG emissions from the vehicles and fuels listed in Table 4-1.

Table 4-1. Reduction in Greenhouse Gas Emissions from Selected Passenger Vehicles and Fuels (well-to-wheels analysis) [58]

Vehicle Type	Total CO_2 Equivalent Emissions (g/mi)	Percent Reduction from Conventional Gasoline Vehicle
Conventional Vehicles	449	0%
Compressed Natural Gas	378	16%
Liquid Petroleum Gas	364	19%
Ethanol (E85)	344	23%
Moderate Hybrid-Electric	319	29% [59]
Advanced Hybrid-Electric	210	54% [60]
Plug-In Hybrid 20	171	62%
Electric Vehicle	150	67%

This table illustrates the substantial benefits of these other on-road vehicles and fuels in reducing GHG emissions in comparison to conventional gasoline vehicles.

Several of the alternative-fuel and advanced technology vehicles mentioned above now meet very low emission standards for criteria pollutants. Currently, the CNG light-duty passenger car built by Honda meets or exceeds the SULEV (Super Ultra Low Emission Vehicle) emission standard for vehicles. Heavy-duty vehicles using LPG, LNG or CNG also provide emission benefits relative to their diesel counterparts. Battery electric zero-emission vehicles provide significant reductions in criteria and toxic pollutants and, although production of these vehicles in the passenger car applications has diminished significantly, fleet and neighborhood battery electric vehicles are still available in the marketplace. Hybrid-electric vehicles meet California's stringent AT-PZEV (Advanced Technology Partial Zero Emission Vehicle) standard. And plug-in hybrid vehicles are expected to reduce NO_x and ROG emissions an additional 25 to 55 percent below the AT-PZEV standard.

All of the alternative fuel and advanced technology vehicles mentioned above can provide significant reductions in petroleum dependency. The Joint Agency Report of the California Energy Commission and the California Air Resources Board, "Reducing

California's Petroleum Dependence", August, 2003 [61], (Petroleum Dependence Report) identified and quantified the three major problems that California faces due to its increasing reliance on petroleum: economic, sources of supply, and environmental. The largest impact of petroleum dependence, by far is economic. The Report said:

> Unless consumers are given viable options, California could continue to face significantly higher gasoline and diesel prices. Such options could dampen demand for petroleum and moderate price fluctuations.
>
> Rising petroleum prices can have a significant impact on the US and California economies. In addition to reducing the real income of consumers through higher fuel prices, oil price increases drive up the average cost of production of goods and services throughout the economy. The result is a negative impact on the state's economy (gross state product). In fact, the significant petroleum price hikes in 1973-74, 1979-80, and 1990 all lead to US recessions.

The cost of petroleum dependence is estimated in the literature to range from $0.10 to $0.33 per gallon. To the extent that the alternative-fuel and advanced technology vehicles also reduce criteria and GHG pollutants and toxic air contaminants there will be further savings to society as a result of avoided costs associated with damages to public health and the environment. These savings vary according to pollutant and the actual value associated with these cost savings can be found in the Petroleum Dependence Report (due to the complexity of the issue the Petroleum Dependence Report did not monetize toxic air contaminants).

The analysis done for the Petroleum Dependence Report is not directly comparable with the evaluation in the Hydrogen Highways Blueprint Plan because that analysis is more comprehensive and uses different assumptions. However, it clearly indicates that these alternative-fuel vehicle technologies and fuels provide substantial societal benefits that are needed to meet California's public health, energy and environmental goals.

Of particular interest to California policy makers are those vehicle technologies and fuels that are hydrogen bridging technologies and which provide large societal benefits as described in this section. These technologies and fuels would provide substantial benefits for California in the short-term and beyond.

4.4 Conclusion

The California Hydrogen Economy Blueprint Plan is only one part of a broader energy and environmental strategy for our State. This strategy must, by necessity as well as public policy preference, include other vehicle technologies and fuels, in addition to hydrogen vehicles and infrastructure, in order to meet the State's energy and environmental goals.

Bridging technologies and fuels, particularly those that also provide significant environmental and energy benefits, provide a win-win situation which not only facilitates

the development of hydrogen-fueled vehicles but also contributes to our near- and mid-term environmental and energy goals. Separate from the Blueprint Plan, but in a coordinated and consistent manner, California should continue to support and develop policies, programs, and incentives for these technologies and fuels.

5. Recommendations

Based on the analysis contained in this report, the Societal Benefits Topic Team makes the following recommendations:

1. A goal of 30 percent reduction of GHG emissions, in the aggregate, for the CA H2 Net should be implemented.

2. A goal of 20 percent use of renewable resources to generate hydrogen for use in the CA H2 Net should be implemented. The renewable resource goal should ensure that any electricity generated from renewable resources and counted toward the CA H2 Net has not been used to meet any other renewable obligation.

3. A goal that ensures that there will not be increases in criteria or toxic pollutants as a result of the CA H2 Net and that the CA H2 Net will comply with all local and State criteria and toxic pollutant goals and regulations currently in existence. This includes the Air Resources Board's Low-Emission Vehicle II regulations, local and state regulations regarding stationary source emissions and the Governor's Environmental Action Plan.

4. To achieve the above three goals, it will be essential to determine how the State will ensure the goals are met and who will be charged with that task.

5. Providers of hydrogen via electrolysis have indicated that they will strive to provide GHG emission reductions below what can be expected from conventional vehicles. As this will require significant use of renewable resources by the electrolysis production facility, we recommend that there be a specific GHG goal established for electrolysis. This goal should be established in cooperation with stakeholders.

6. Further assessment of the CA H2 Net on communities, specifically low-income and minority communities, is recommended. Although it appears that such communities will benefit from the CA H2 Net it will be important to more thoroughly evaluate the impacts in coordination with representative from the communities.

7. During the policy development phase of the California Hydrogen Blueprint Plan, it will be essential that any policies or funding established to ensure the success of the CA H2 Net also ensure that the goals in Recommendations 1, 2, and 3 are met. In particular, as some of the renewable pathways may be more costly in the development phase, it may also be necessary to provide funding to offset a portion of the cost differential.

6. Glossary

Definitions

Autothermal reformer	A fuel processor which converts air, steam, and natural gas (or other feedstocks) to hydrogen.
Biomass	Plant material used as a feedstock for hydrogen or other fuel/energy production. Biomass materials include forest material, agricultural residue, urban waste paper, and crops grown as feedstocks for energy production.
Green Tags	Tradable renewable credits
Electrolysis	Hydrogen production process involving the separation of water into hydrogen and oxygen with an electric current
Feedstock	The energy carrier
Forecourt	At the fueling station
Model Year	The year a vehicle was built. An emissions inventory contains the aggregate emissions for a mix of model year vehicles.
Production pathways	The cycle of hydrogen production from feedstock to delivery, e.g. hydrogen produced from natural gas via steam reformation that is trucked to a mobile refueler
Renewable power purchase contracts	A contract guaranteeing that power is produced from renewable resources and that this renewable power is “excess” and not used to meet any other renewable obligation
Steam Reforming	The process of reacting steam with natural gas or other feedstocks to make hydrogen
Ullage	Liquid fuel tank vapor space

Acronyms, Abbreviations, and Units of Measure

ADL	Arthur D. Little
ANL	Argonne National Laboratory
ARB	California Air Resources Board
API	American Petroleum Institute
AP-42	EPA document on emission factors
atm	1 atmosphere = 14.7 psi
AT-PZEV	Advanced Technology Partial Zero Emission Vehicle
ARB	California Air Resources Board
ATR	Autothermal reformer
bar	= 100,000 Pascals, 14.9 psi, unit of measure for pressure.
bbl	barrel of crude oil (42 gal)
Bcf	billion standard cubic feet
bhp-hr	brake horsepower hour (dynamometer measurement)
bsfc	brake specific fuel consumption
Btu	British thermal unit = 1.055 kJ
CA	California
CalEPA	California Environmental Protection Agency
CARBOB	California Reformulated Gasoline Blendstocks for Oxygenate Blending
CA H2 Net	California Hydrogen Highway Network
CEC	California Energy Commission
CHP	Cooling, heating and power
CNG	compressed natural gas
CH_4	methane
CO	carbon monoxide
CO_2	carbon dioxide
CO_2e	GHG emissions expressed as CO_2 equivalent. CO_2=1 and other GHG emissions are weighted by their GWP.
DG	Distributed Power Generation
DOE	United States Department of Energy
DWT	dead weight ton
E100	ethanol, 100 percent with no blending components
EER	Energy economy ratio
EMFAC	ARB vehicle emissions factor model
EO	Executive Order
FCV	Hydrogen fuel-cell-powered vehicle
FUDS	Federal Urban Driving Schedule
EVs	electric vehicles
FE	Fuel economy
g	gram
gal	gallon = 3.785 Liter
g/bhp-hr	grams per brake horsepower-hour
GHG	Greenhouse gas
GJ	giga Joule = 1,000,000,000 J
GREET	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) Model from Argonne National Laboratory

GVW	gross vehicle weight
GWP	global warming potential
H2A	DOE working group on hydrogen cost analysis
HD	Heavy-Duty
HERMIN	Hydrogen Emission Reduction Model Including N_2O and methane
HEV	Hybrid Electric Vehicle
HFET	Highway Fuel Economy Test
HHV	higher heating value of fuel or feedstock
hp	horsepower
hp-hr	shaft horsepower hour
H_2	hydrogen
IC	internal combustion
ICE	internal combustion engine
ICEV	IC engine vehicle
IOU	Investor Owned Utility
J	Joule
kg	kilogram
kJ	kilo Joule
kWh	kilowatt hour = 3.6 MJ = 3,412 Btu
kn	nautical mile, 2000 yards
lb	pound mass = 453.5 g
LD	light-duty
LDV	Light-duty vehicle
LHV	lower heating value, HHV less heat of vaporization of water vapor in combustion products
LH2	liquid hydrogen
LNG	liquefied natural gas
LPG	liquefied petroleum gas
MCFC	Molten carbon fuel cell
MD	medium-duty
MDV	Medium-duty vehicle with catalyst
mi	mile
MJ	Mega Joule = 3.6 kWh
MWh	megaWatt hour
M100	methanol, 100 percent with no blending components
MMBtu	million Btu
MMscf	million
mpg	miles per gallon
MW	molecular weight
MY	model year
NAS	National Academy of Sciences
NG	natural gas
NGV	natural gas vehicle
NMOG	non-methane organic gases
NO_x	oxides of nitrogen
N_2O	nitrous oxide

NREL	National Renewable Energy Laboratory
NSPS	new source performance standards
OEM	original equipment manufacturer
O_2	oxygen
PEMFC	proton exchange membrane fuel cell
PHEV	Plug-In Hybrid Vehicle, a hybrid vehicle with a battery that can be charged from both an on-board engine/fuel cell as well as by plugging into the vehicle into a wall outlet or electric charger.
PHHEV	Plug-In Hydrogen Hybrid Electric Vehicle
$PM_{2.5}$	particulate matter smaller than 2.5 μm
PM_{10}	particulate matter smaller than 10 μm
PSA	Pressure Swing Adsorption, a process for purifying hydrogen. For example, some SR systems use a PSA to separate hydrogen from the other gases produced by the SR
psi	pressure, lb/in^2, 14.7 psi = 1 atm
PTE	potential to emit
PV	photovoltaic
PZEV	Partial zero emission vehicle
RECLAIM	Regional Clean Air Incentive Market
RFG3	reformulated gasoline, current California requirement
ROG	Reactive Organic Gases, hydrocarbons except for methane
RVP	Reid vapor pressure
SCAQMD	South Coast Air Quality Management District
scf	standard cubic feet of gas, at 60°F and 1 atm
scfm	standard cubic feet per minute
SCR	selective catalytic reduction
SMS	station mix scenario
SO_2	sulfur dioxide
SO_x	oxides of sulfur
SULEV	Super Ultra Low Emission Vehicle
SR	steam reformer
t/d	tons/day
TECA	total energy cycle analysis
TOG	total organic gases
ton	United States short ton, 2000 lb
tpd	ton per day
TTW	Tank to Wheels, energy or emissions associated with vehicle operation, usually expressed in g/mi or MJ/mi
TVP	true vapor pressure
UB DSL	Diesel Urban Bus
UCD ITS	University of California Davis, Institute for Transportation Studies
U.S. EPA	United States Environmental Protection Agency
WTT	Well to Tank, energy or emissions associated with fuel production. WTT emission results are usually expressed in g/MJ, g/gal, g/kg. The energy inputs are represented in J/J of fuel produced.
WTT	Well to Tank

WTT_f	Well to tank plus fuel, showing the vehicle cycle emissions in g/MJ
WTW	Well to Wheel, energy or emissions associated with fuel production and distribution, and vehicle operation. WTW results are usually expressed in g/mi or MJ/mi.

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