Research Report – UCD-ITS-RR-11-27

Modeling Optimal Transition Pathways to a Low Carbon Economy in California: Impacts of Advanced Vehicles and Fuels on the Energy System

April 2011

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SUSTAINABLE TRANSPORTATION CENTER
of the Institute of Transportation Studies

Final Research Report [D04-4]

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EXECUTIVE SUMMARY

This research report describes the development of an energy-engineering-environmental-economic (4E) systems optimization (linear programming) model that represents the vast majority of energy and emission flows within, to, and from California. The CA-TIMES model, as it is called, is built within the well-established MARKAL-TIMES framework and is, thus, extremely rich in bottom-up technological detail. The main application of the model is to develop scenarios for how California's energy system could potentially evolve over the next several decades, in light of strong policies to reduce energy use and greenhouse gas emissions. The scenarios range from a business-as-usual Reference Case to a Deep GHG Reduction Scenario, in which a mixed-strategy, portfolio approach allows California economy-wide emissions to be reduced 80% below 1990 levels by 2050. Several variants of the Deep GHG scenario are then also developed, in order to explore important sensitivities related to the stringency of the emissions cap (i.e., less stringent than an 80% reduction) and the ultimate potential of key resources and technologies to contribute to greenhouse gas mitigation (e.g., sustainable biomass supply, nuclear power, carbon capture and storage, and electricity and hydrogen as transportation fuels).

In sum, this analysis shows that deep, economy-wide reductions on the order of 50% to 80% appear to be technically feasible at reasonable costs (e.g., 1.0% to 2.7% of California Gross State Product over the 2005-2055 time period, relative to the baseline scenario – considering only the transportation, electricity, and fuel conversion sectors). Policy cost estimates of this magnitude are in line with those of other studies for decarbonization of the U.S. and global energy systems (IEA, 2010; NRC, 2010). The bulk of the costs would be incurred in the medium to long term (between 2025 and 2050), as increasingly advanced technologies are used to make deeper and deeper reductions. The challenge for policy, however, is perhaps the next ten years (2010-2020). This analysis shows that whether policymakers ultimately decide to pursue a reduction target of 80% or something much less stringent (say, 50%), the types of technologies that need to be introduced in the near term are for the most part the same; hence, the emissions trajectories up to 2025 would be fairly similar. Furthermore, results of this study indicate that California's current target for 2020 – the AB32 goal of bringing emissions back down to 1990 levels – may not be stringent enough. To allow time for significant market penetration of the kinds of transformational technologies that will be needed in the long term (due to the inertia of energy system infrastructure and investments), advanced technologies must be introduced over the next ten years at a quicker rate than what the existing 2020 target is likely to motivate. More specifically, over the coming decade a significant expansion in, or at least the introduction of, the following mitigation options are likely needed: renewable electricity generation, specifically from wind, solar, and geothermal resources; advanced transportation technologies and fuels, including biofuels, hybrid-electric vehicles, plug-in hybrid electric vehicles, battery-electric vehicles, and hydrogen fuel cell vehicles; and a shift toward greater utilization of electricity as an end-use fuel in the industrial, commercial, residential, and agricultural sectors. Demand reduction is also likely to play an invaluable role in mitigating future emissions, both through energy efficiency and conservation efforts and reduced vehicle travel. The latter, which could be achieved by strong transit, land use, and auto pricing policies, deserves a considerably more attention in the development of energy and climate scenarios for California.

In terms of decarbonizing California's energy system, the transportation sector poses perhaps the biggest challenge and is therefore the most costly. Over half of the state's GHG emissions are attributable to transport at present, resulting primarily from the combustion of fossil fuels (gasoline, diesel, jet fuel, and residual fuel oil). Of course, because fossil fuels are relied upon so heavily, the potential for reducing transport GHGs via alternative fuel and vehicle technologies is quite huge. Biofuels are the most cost-effective option for making these emission cuts, both from the perspective of a single vehicle or when viewed at the energy systems level, the latter including fuel production and distribution infrastructure and considering competition for biomass from other sectors, such as electric generation and industry. The challenge with biomass is that total resources, while renewable on an annual basis, are actually rather limited. Only if California were to have access to biomass supplies far beyond its "fair share" of the national or global total (e.g., >30% of all U.S. consumption), would the state be able to fuel its entire transport sector with biofuels. This is perhaps unlikely in a future where other U.S. states and countries are also counting on biomass/biofuels to mitigate their GHG emissions. Given constraints on biomass resources, the results of this analysis indicate that the most optimal use of biofuels is in the non-light duty subsectors, namely in the form of bio-derived gasoline, diesel, jet fuel, and residual fuel oil. The reason for this is fairly intuitive: there are fewer alternative technological/fuel options to reduce GHG emissions in these other transport subsectors, hence the value of a tonne of biomass is higher. In fact, a marked advantage of light-duty vehicles is that there are quite a few alternatives for technology- and fuel-switching. Specifically, electric-drive vehicles could feasibly be used to satisfy a large portion of total VMT demand, whereas electricity and/or hydrogen are simply not realistic alternatives in some of the other subsectors, due to range limitations and refueling issues. The GHG reduction scenarios developed here rely heavily on HEVs and PHEVs (Gasoline and E-85), as well as Hydrogen FCVs to some extent, to make deep emission cuts in the light-duty subsector. In contrast, BEVs do not penetrate the LDV market to any significant degree, a result that may have more to do with model dynamics than anything else. BEVs are not favored by the model because of the various inputs that are currently assumed for the efficiencies and costs of vehicles and plug-in recharging infrastructure. The assumed costs for BEVs, for instance, are higher than for other advanced vehicle technologies because, in an effort to be fair, all vehicles in CA-TIMES are assumed to have roughly the same size, weight, range, power, etc. While this aggregated level of vehicle class representation for the most part makes sense within the modeling framework, it potentially disadvantages BEVs, which may be particularly well suited to the small car and small light truck markets or to urban driving, where travel distances are shorter. The current version of CA-TIMES is not able to capture this possibility, though future work may attempt to address this issue.

As the transport sector is decarbonized, emissions from the energy supply/conversion sector are likely to be reduced significantly as well, since the types of facilities that produce low-carbon transport fuels (e.g., bio-refineries, FT syn-fuels poly-generation plants, hydrogen plants, zero- and low-carbon electricity generation) tend to emit low levels of greenhouse gases, or at least they would in a low-carbon future. The exact carbon signature of these fuels, of course, depends on which energy resources are used for generating heat and electricity at these plants, and also whether or not carbon capture and storage is utilized. Bio-CCS technologies appear to be an especially attractive means by which to decarbonize the energy system, since they allow for negative emissions (i.e., permanently storing biomass carbon underground). In the scenarios developed in this study, bio-CCS play a major role in reducing GHG emissions while at the same time taking the burden off of other sectors, namely transport, which have higher abatement costs. When bio-CCS technologies are eliminated from the potential technology portfolio, however, the transport sector is forced to decarbonize much more significantly, and in the light-duty sector in particular, more advanced electric-drive vehicles (PHEVs and Hydrogen FCVs) become a preferred option for making these emissions cuts.

Emissions from the industrial, commercial, residential, and agricultural (ICRA) end-use sectors are reduced in this study through energy efficiency and fuel switching. In particular, drawing on other scenario studies by the IEA (2010), the Deep GHG Reduction Scenario assumes that an increasing share of energy demand is met by electricity and natural gas in the ICRA sectors in the future. How authentic these emission reductions actually are depends in large part on the simultaneous decarbonization of the electric sector, which also appears to be a likely outcome of stringent climate policy, as found in this and numerous other studies.

Comparatively, reducing emissions from electric generation is fairly straightforward and can be done at abatement costs that are lower than in the transport and energy supply sectors (IEA, 2010). Nonetheless, significant hurdles still remain, particularly with respect to spatial and temporal issues. For example, it could potentially be quite expensive to tap solar, wind, and geothermal resources in distant out-of-state locations, owing to the substantial capital investments required for long-distance transmission lines. In addition, it is still not entirely clear whether intermittent renewables, especially solar and wind, can be relied upon to contribute a majority share of total electric generation, unless significant storage and/or back-up capacity is built as well. For these reasons, the availability of nuclear power and fossil and/or biomass CCS is critical, so that low-carbon options for baseload generation remain in play. If nuclear and CCS are wholly absent from the technology portfolio, as one variant of the Deep GHG Reduction Scenario illustrates, then it will likely become considerably more difficult, and indeed more costly, to achieve a deep reduction target, if it is even possible. Other scenario variants lead to similar conclusions when biomass resources are significantly constrained or when the potential for electricity and hydrogen to be used in the transport sector is considerably limited.

An important caveat to this analysis is that it only does a partial economic accounting. In other words, it attempts to capture the total energy system *costs* of climate mitigation but largely ignores the significant economic *benefits* of pursuing this goal. For instance, the analysis does not consider the avoided costs (i.e., benefits) of climate change (e.g., more frequent extreme weather events, impacts on global agriculture and food production) or of climate adaptation (e.g., construction of sea walls, relocation of coastal populations). Similarly, the benefits accruing from reduced health expenditures and increased life expectancies, to the extent they can attributed to climate mitigation, have not been monetized here. Given this partial accounting, it is highly likely that the cost figures shown in this report are somewhat overestimated, a practice that is a known issue with integrated assessment models used to inform energy and climate policymaking (Nemet et al., 2010).

I. Introduction

The energy challenges facing society are as varied as they are great, and for this reason energy has become a key area to address in the twenty-first century. Central among these concerns is the specter of global climate change. The impact of energy production and consumption on the earth's climate system has been well documented, and scientific studies now suggest that annual greenhouse gas (GHG) emissions must be cut 50 to 80 per cent worldwide by 2050 in order to stabilize the climate and avoid the most destructive impacts of climate change (IPCC, 2007). Toward this goal, several governments have adopted emissions targets for 2050 (in many cases, they are still aspirational targets), including Germany, Australia, the UK, the European Union, and the state of California. The United States currently has no laws specifically designed to cut GHG emissions, but momentum is growing at both the national and state levels (Litz, 2008; Lutsey and Sperling, 2008; Pew, 2009). In fact, several climate change bills have been proposed in the US Congress over the past several years to set up a domestic emissions trading program with a declining cap on annual GHG emissions that would ultimately lead to economy-wide reductions in the range of 50-80% by 2050.[1,2] Climate change has also become a core issue at the international level. In 2009, for instance, the Group of Eight (G8) industrialized nations agreed to reduce global GHG emissions 50% below 1990 levels by 2050, with the intent to hold global warming to less than 2 degrees Celsius above pre-industrial levels (G8, 2009). The Copenhagen Accord later adopted

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[1] An 80% reduction in annual US GHG emissions (from all sources) below 1990 levels is equivalent to an 83% reduction below 2005. Annual GHGs in 1990 were 14% lower than in 2005 [EPA, 2008b. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. Environmental Protection Agency, Washington, DC.].

[2] "Comparison of Legislative Climate Change Targets," World Resources Institute (http://www.wri.org/publication/usclimatetargets) and (http://www.wri.org/chart/comparison-legislative-climate-change-targets-110th-congress-1990-2050)

the 2º C target. Here in California, *global* climate change could have a pronounced *local* impact, affecting the state's economy, natural and managed ecosystems, and human health and mortality (California Department of Environmental Protection, 2006).

Yet, despite the growing consensus for the need to reduce greenhouse gas emissions, the strategies for meeting these ambitious targets have not been clearly defined, and the technology and policy options are not well enough understood. For years, scenario analyses and energy modeling tools have been used widely to envision the potential evolution of energy systems over time. Until more recently, however, very few studies, had done detailed analyses of how *deep* cuts in greenhouse gas emissions could be made across all energy sectors in the long-term, using commercial or near-commercial low-carbon and advanced technologies and fuels. In particular, the literature lacked analyses focusing specifically on making deep cuts in transport sector emissions, whether in California or the United States or at the global level.

A large number of studies have investigated different aspects of making transport sector GHG reductions, but very few have simultaneously included all transport subsectors in their analyses or have looked at scenarios for making deep emissions cuts. (At least this was true at the start of my dissertation project.) Most scenario analyses (e.g., (Bandivadekar et al., 2008; Grimes-Casey et al., 2009; Mui et al., 2007; NRC, 2008; Yeh et al., 2008)) concentrate only on light-duty vehicles (LDV) since they make up such a large share (60%) of US transport GHGs, whereas the few studies that do include additional on- and non-road subsectors (e.g., (IEA, 2008; WBCSD, 2004)) concentrate their analyses at the global level, meaning one cannot easily use them to assess the evolution of national and sub-national transportation systems, such as those in California and the US. Similarly, while several studies have looked at slight to moderate reductions from the LDV subsector (e.g., (Bandivadekar et al., 2008; Mui et al., 2007)), very few consider the feasibility of making deep carbon cuts in the long-term. For example, WBCSD (2004) develops a scenario that combines multiple GHG mitigation strategies in order to bring global annual road vehicle emissions back down to 2000 levels by 2050. In addition, a recent report by the National Research Council develops a "Hydrogen Success" scenario, in which LDV emissions are reduced 50% below 2005 levels by 2050, as well as a portfolio scenario, in which advanced biofuels and high efficiency internal combustion engine vehicles also achieve significant penetration, helping to reduce GHGs even further (85%).

Over the past two years, as energy and climate change have become even more prominent concerns, researchers and analysts have started to fill the void in the literature discussed above. In fact, some of the first major research in this area has been carried out by myself and colleagues in the STEPS Program at UC Davis – e.g., see the "80in50"studies by Yang, McCollum et al. (2009) and McCollum and Yang (2009), who analyzed scenarios for making deep cuts in emissions across all transport subsectors in California and the US, respectively.

While the *80in50* studies were successful in answering the types of research questions they were intended for, like any research project they had several important limitations.

Hence, to start to address these shortcomings and to further push our scenario analysis capabilities, our research group at UC-Davis undertook the development of an energy-engineering-environmental-economic systems optimization model. This type of work represents yet another method for developing energy scenarios. Well-known examples of such models include the US Energy Information Administration's NEMS model, the US Environmental Protection Agency's nine-region MARKet ALlocation (MARKAL) model for the United States, and the International Energy Agency's global MARKAL model. Each of these is capable of analyzing all transport subsectors simultaneously along with all other components of the energy system. However, until recently, none had been utilized to study in detail how deep emission reductions could be made in the long-term from all energy sectors, and in particular from all transport subsectors (e.g., see (Gallagher and Collantes, 2008)). Another problem with these models, at least for the purposes of my dissertation, is that because they are so broad in their geographic scope (in general, this is a good thing), they are not really conducive to carrying out California-specific analyses.

As described in this report, for a large part of my dissertation work, I have developed an early version of the CA-TIMES energy systems optimization model. In sum, CA-TIMES is a technologically-rich, energy systems model for California, along the lines of those models developed and maintained by the EIA, IEA, and EPA. It is a variant of the MARKAL and TIMES family of energy models, which focuses on the California energy system and contains California-specific data and assumptions. CA-TIMES represents a unique simulation tool in that it is the first publicly available model of its kind in the state. Other types of economic models have previously been used for near-term (2020) energy and climate policy analysis in California, for example, the Energy 2020 model by Systematic Solutions; an electricity and natural gas sector model by Energy and Environmental Economics (E3); and the Environmental Revenue Dynamic Assessment Model (E-DRAM) by UC-Berkeley, California Department of Finance, and California Air Resources Board. However, CA-TIMES is different from some or all of these models in that contains richer, bottom-up technological detail, covers all sectors of the California energy economy, is primarily focused on the medium to long term (2020-2050), and resides in the public domain. As California moves forward with a broad spectrum of carbon emissions reduction policies, there is a strong need for this kind of transparent, flexible, and accessible analysis tool to help inform policy decisions. My dissertation work begins this process by performing scenario analyses, evaluating policy, and presenting technological portraits for the future given the specific conditions that exist within the state. In this way, it fills an important void in the literature and research community, specifically in California. In addition, the CA-TIMES energy systems modeling project addresses some of the limitations of the *80in50* research by further expanding the scope of the analysis. First, since the CA-TIMES model is an energy-engineering-environmental-*economic* systems optimization model, it brings costs and prices into the analysis as decision variables. This means future technology-fuel combinations are selected endogenously by the model, rather than exogenously, as is done in the original *80in50* research. Second, whereas the *80in50* research looks at scenario "snapshots" in the year 2050, my analyses with CA-TIMES look at the transition pathway from now to 2050, allowing me to focus on important milestone years for policy (e.g., 2020). Third, all energy producing and consuming sectors are represented in the CA-TIMES *systems* model, as opposed to representation of only the transport sector. This permits an improved understanding of the potential responses of the entire energy system to a suite of energy and climate policies, since cross-sector linkages are accounted for. As an example, competition for limited primary energy resources can be more accurately modeled under the CA-TIMES framework (e.g., biomass for transportation fuels vs. biomass for electricity production).

The main objective in creating a MARKAL-TIMES model for California is to develop and analyze scenarios for meeting future energy and emissions reduction goals, with an eye toward the transportation, electricity, and energy supply and conversion sectors. In other words, this research is a direct extension of my previous *80in50* work (Yang, McCollum et al., 2009, and McCollum and Yang, 2009), though a bit more complex and comprehensive in nature. The aim is to provide insights on how economic drivers, such as cost considerations and an emissions trading program, and policies, like a renewable portfolio standard (RPS) for electricity, biofuels mandates, and vehicle tailpipe emissions standards, might affect future decisions on the investment of future energy technologies and utilization of resources under various scenarios.

The CA-TIMES research builds on several previous studies that have used a bottom-up energy systems optimization model approach for developing transportation scenarios. These include Schäfer and Jacoby (2006), IEA (2008), IEA (2010), and Yeh et al. (2008). For example, Schäfer and Jacoby (2006) combine MARKAL with a computable general equilibrium model and a modal split model in order to estimate the impact of advanced vehicle technologies on GHGs. They conclude that given an economy-wide reduction target, advanced vehicles will not be utilized in large numbers until gasoline prices rise to extremely high levels (US$9.50/gal, or $2.50/L). Similarly, Yeh et al. (2008) also find that, under an economy-wide target and because of relatively high marginal abatement costs, the transport sector will likely not contribute significantly to GHG reductions until less expensive mitigation options in other sectors (such as electricity production) have first been exhausted and the prevailing price of CO_2 has risen substantially. Moreover, the IEA's Energy Technology Perspectives (ETP) studies show that if deep (50-80%) economy-wide reductions are to be made in the long-term, all sectors of the energy system will eventually need to be significantly decarbonized. IEA finds that making deep reductions in global emissions will require an energy revolution, and they have estimated that in an optimistic case (their BLUE Map scenario), reducing global annual GHG emissions 50% below 2005 levels by 2050 (requiring 80% reductions in the U.S. and other industrialized countries) would involve the utilization of technologies with marginal abatement costs up to about $200/tonne CO_2. The IEA ETP studies show that if deep GHG reductions are to be made in the long term, the transport sector, which accounts for a significant 23% of global GHG emissions at present – in the US the corresponding figure is 29%, and in California 40% (CARB, 2008a; EPA, 2006; ITF, 2008) – will have to play a major role. Their analyses show, in particular, that the most important mitigation strategies are likely to be improved vehicle efficiencies, biofuels, and advanced technologies such as hydrogen and electric vehicles.

II. California Energy Use and GHG Emissions in the Base-Year 2005

In developing future energy scenarios for California, it is first necessary to take a historical perspective of energy use and greenhouse gas emissions in the state. The overview provided in this section paints a picture of California's energy landscape as it existed in 2005, which is used as the base-year throughout this study, since a considerable amount of data exists for 2005 and also because it is in the not-too-distant past.

1. End-Use Energy Demand in the Transportation, Industrial, Commercial, Residential, and Agricultural Sectors

California's energy system is largely reliant on fossil fuels, though a significant amount of energy is also sourced from nuclear, hydro, biomass, and various other types of renewable and non-renewable fuels. Much of this energy is either produced and/or converted to a finished fuel product within the state, in order to meet the ever-increasing demands of the five end-use sectors: Transportation, Industrial, Commercial, Residential, and Agricultural. Figure 1 depicts final energy consumption for each of these sectors in 2005. All values shown here and throughout this report reflect the use of higher heating values (HHV) when converting from native units (e.g., kg, scf, lbs) to energy units (e.g., PJ, MJ). In fact, all energy flows in CA-TIMES are estimated on a HHV basis.

It is important to note that according to the definition of *final* (i.e., *end-use*) *energy consumption* that is applied here, the numbers shown in the following figures do not include conversion of primary energy resources (e.g., crude oil, natural gas, coal, etc.) to final energy carriers (e.g., electricity, gasoline, diesel, etc.) at oil refineries, electric power plants, and other types of fuel conversion facilities. If primary energy consumption were allocated to each of the end-use sectors in fair proportions, the energy shares shown here would look quite a bit different indeed. (For example, the transport share would be significantly smaller.) In short, the greater the use of fuel combustion for the purposes of useful work (e.g., moving a vehicle) – as opposed to heat – the greater will be the end-use energy demand. Since work-related fuel combustion processes (e.g., internal combustion engines) are inherently inefficient, total energy consumption in, say, the transport sector is over-emphasized compared to the other end-use sectors where electrically-powered consumer devices and fossil fuel heaters/cookers play dominant roles. The major efficiency losses associated with, for example, electricity generation occur at the power plant stage – i.e., during the conversion from primary to final energy. (While there are certainly efficiency losses at refineries associated with converting crude oil to gasoline, diesel, jet fuel, and all other refined products, these losses are small in comparison to power plants and internal combustion engines.) Because these power plant efficiency losses are ignored, the results shown here for final energy consumption by end-use sector provide a different picture than one might expect if looking only at primary energy consumption.

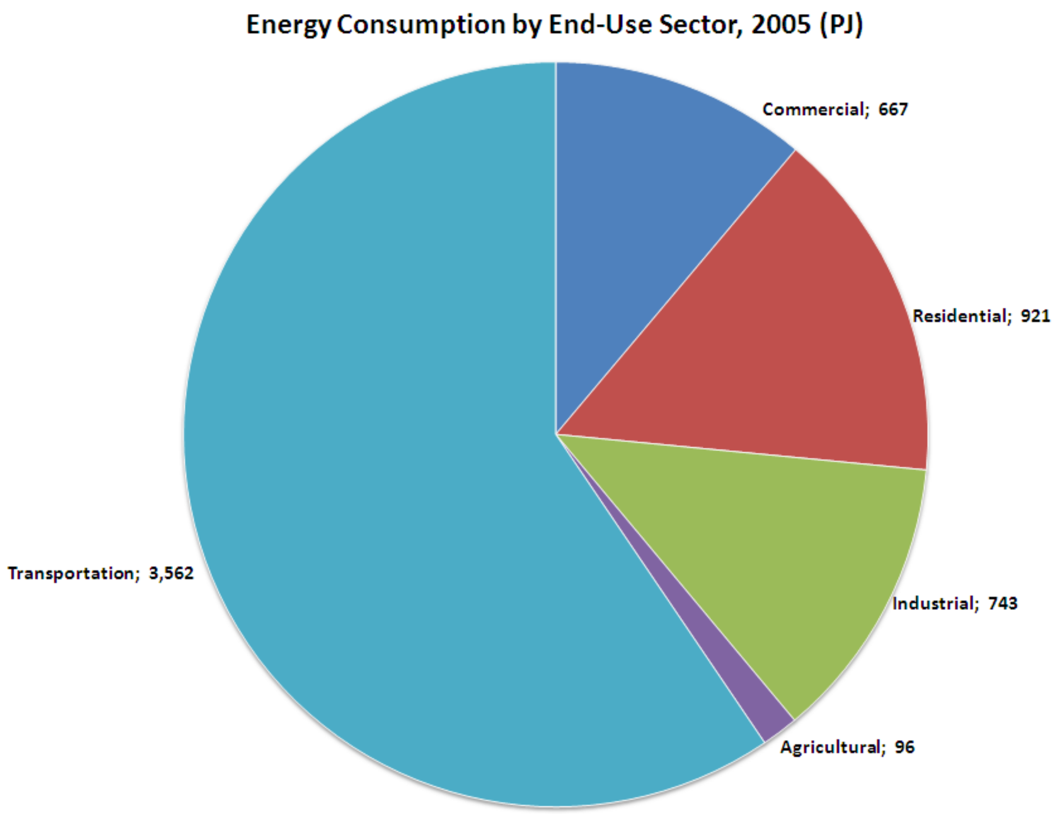


Figure 1 Final Energy Consumption by End-Use Sector, 2005

California's commercial sector accounts for about 11% of total energy demand in the state. The two most consumed fuels are, by far, electricity and natural gas (Figure 2). Certain other fuels, such as distillate, coal, kerosene, LPG, wood, gasoline, and geothermal energy, are used in far smaller quantities.

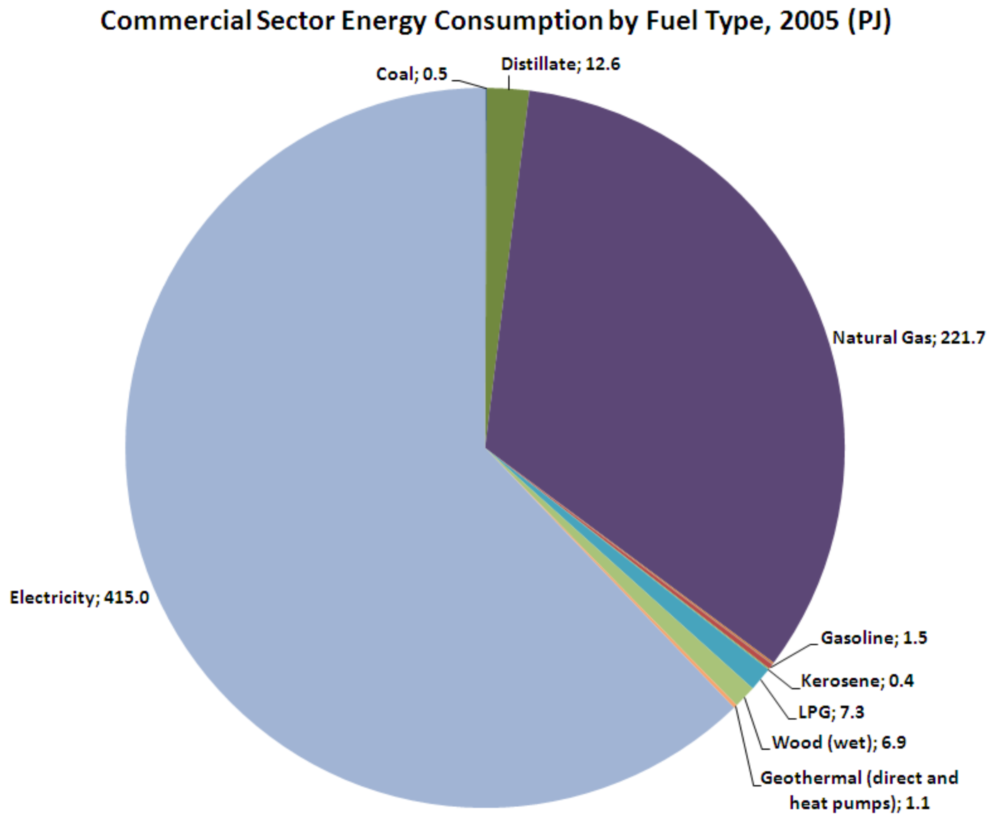


Figure 2 Commercial Sector Final Energy Consumption by Fuel Type, 2005

The residential sector is very similar to the commercial sector in its share of total end-use energy demand (~15%) and in that electricity and natural gas are the two dominant fuels (Figure 3). However, in this case the situation is actually reversed – natural gas is the principal fuel, and electricity assumes the minority role. Moreover, solar energy, in the form of rooftop solar photovoltaics and passive solar water heating, comprise a non-trivial share of residential energy supply.

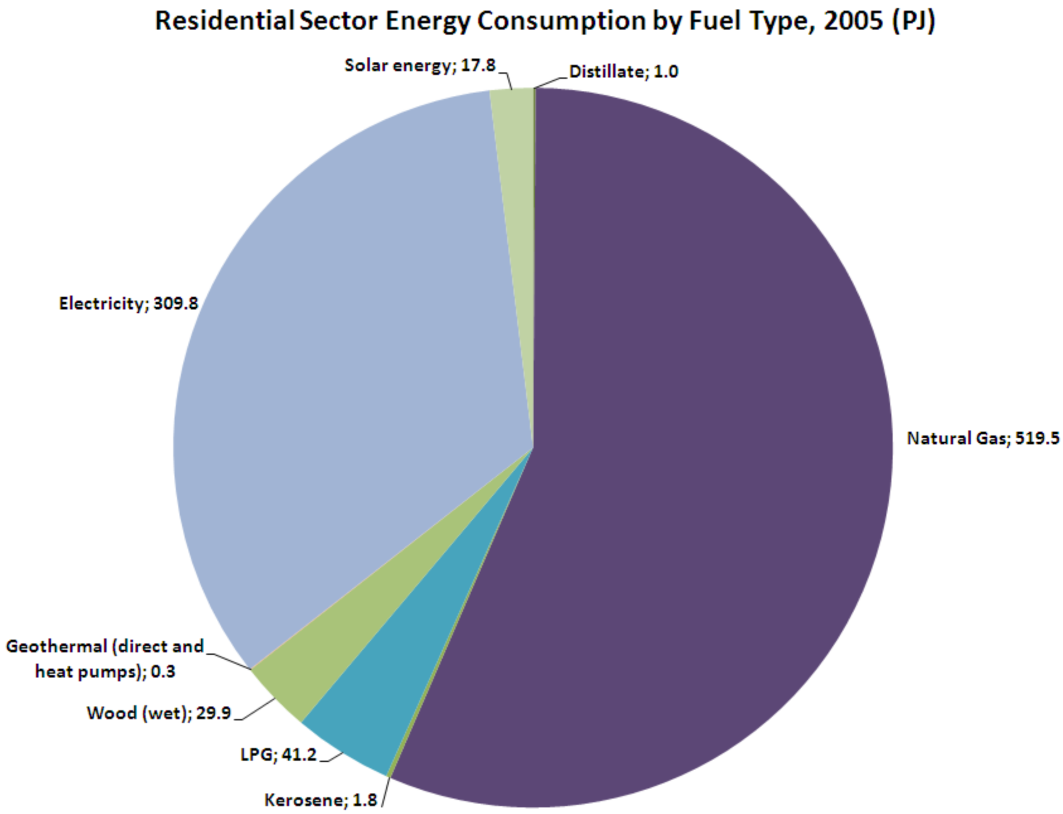


Figure 3 Residential Sector Final Energy Consumption by Fuel Type, 2005

The industrial sector accounts for about 12% of California's total end-use energy demand. When compared to some other states and countries, this is actually a relatively small fraction, though it should hardly be surprising given that heavy industry is not the basis for California's economy. That being said, the industries that do exist in California are relatively diverse; hence, the fuels consumed in the industrial sector are also quite diverse (Figure 4). Natural gas and electricity continue to play the two dominant roles, but a number of other fuels are also used in fairly significant quantities, for instance, coal, gasoline, distillate, and biomass, as well as niche fuels such as asphalt and road oil and lubricants, which according to the CARB GHG Inventory are actually combusted for energy purposes in California, thereby generating GHG emissions.

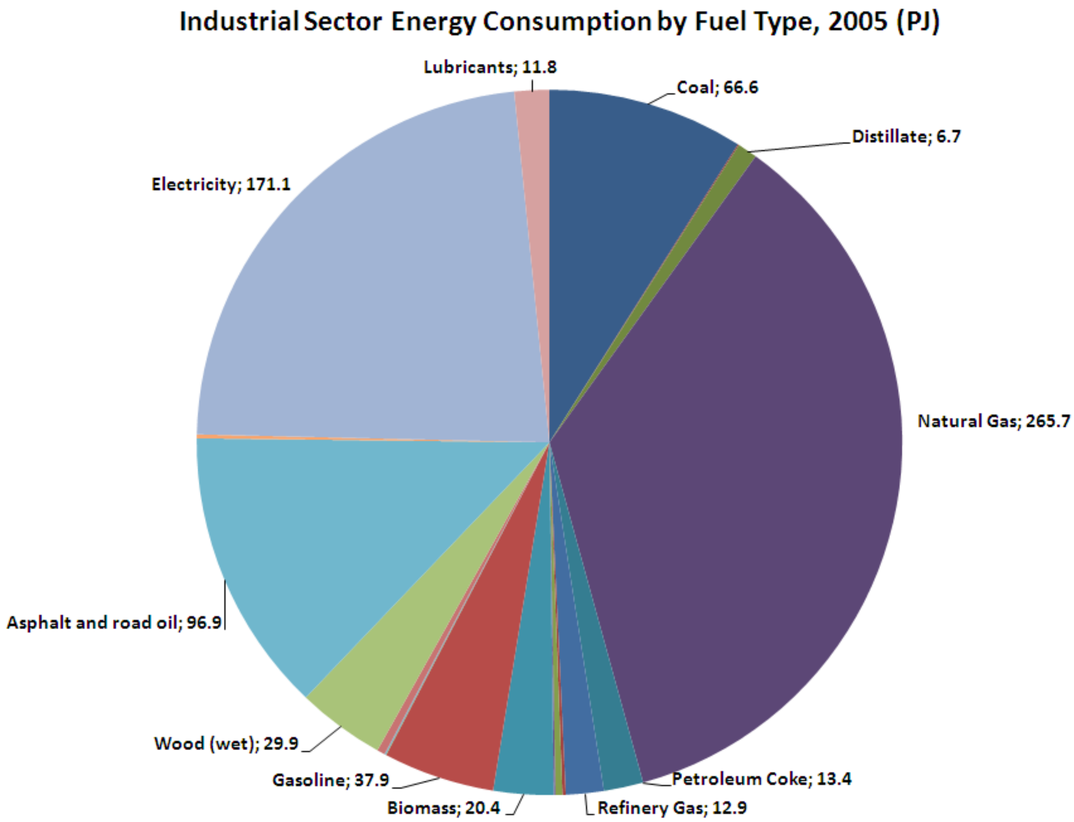


Figure 4 Industrial Sector Final Energy Consumption by Fuel Type, 2005

The smallest of California's end-use energy sectors is agriculture. It accounts for only 1.6% of the state's total energy demand, despite the fact that agriculture plays such an important role in California's economy and society. Note that although it may not be so clear from Figure 5, fuel consumption for agricultural vehicles is not included here, but rather in the transportation sector. Yet, even if energy demands for agricultural vehicles were included, total energy demand for the agricultural sector would still only amount to 2.3% of all end-use energy consumption in California.

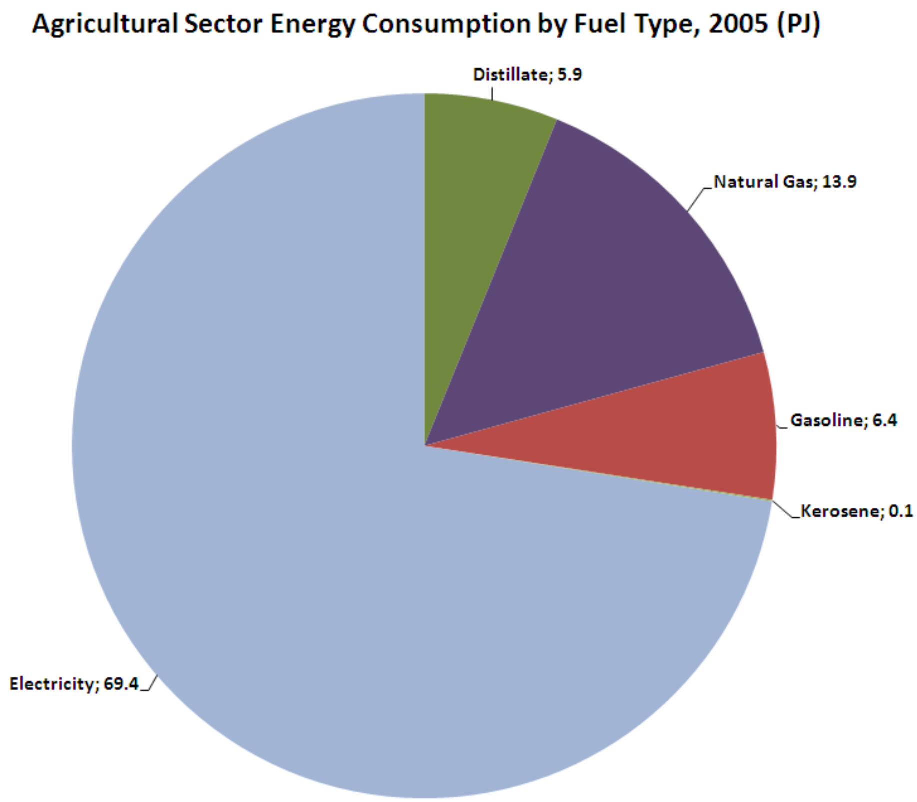


Figure 5 Agricultural Sector Final Energy Consumption by Fuel Type, 2005 (does not include energy consumption for agricultural vehicles)

The largest end-use energy sector in California is transportation, which by itself consumes more energy than all of the other end-use sectors combined, accounting for roughly 60% of the state's entire end-use energy demand (Figure 1). The most important transport sector fuels are petroleum-based: gasoline, diesel (i.e., distillate), jet fuel, and residual fuel oil. Natural gas, electricity, and ethanol are used as well, albeit at much lower levels.

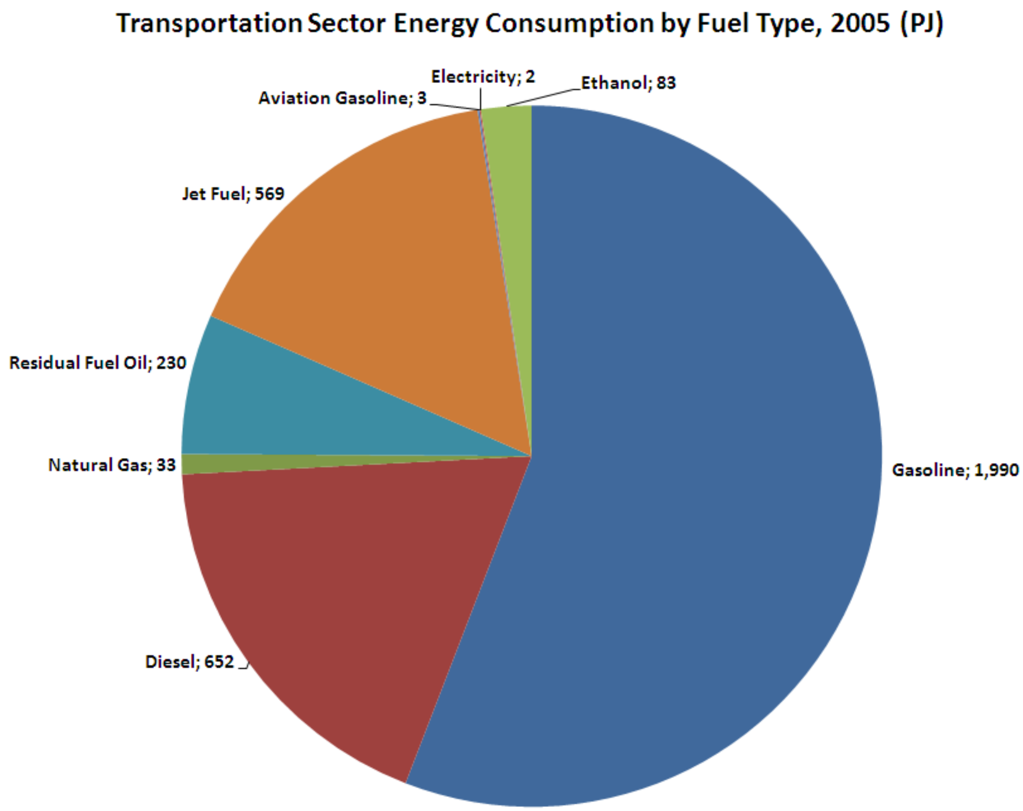


Figure 6 Transportation Sector Final Energy Consumption by Fuel Type, 2005

Like the other end-use sectors, transport is far from being a homogenous category. It is comprised of a number of distinct subsectors, each of which fulfills a unique role within California's energy economy. Perhaps not surprisingly, the most used transport fuel is gasoline (Figure 6), and the largest subsector is light-duty vehicles (Figure 7). Light-duty passenger cars and trucks account for a little more than half of all transport energy consumption in California. The other on-road subsectors (motorcycles, medium- and heavy-duty trucks, and buses) contribute an additional ~15%, while the aviation and marine subsectors comprise almost a quarter of all transport sector energy consumption. Off-road and construction devices, agricultural vehicles, and pipelines makes up the final ~6%.

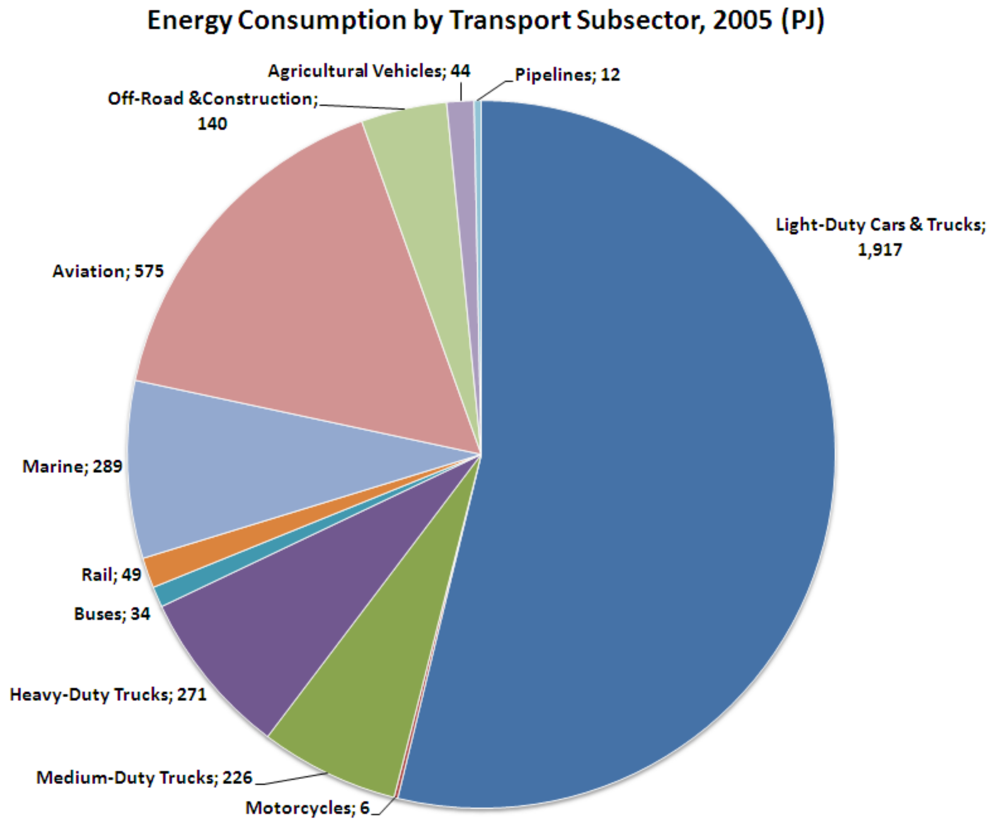


Figure 7 Final Energy Consumption by Transport Subsector, 2005

The fuel use estimates shown in Figure 7 include all energy consumption for any vehicles that purchase fuel within California, regardless of the destination of the trip – whether it be intrastate (within the state), interstate (to another state), or international (to another country). By this definition, the fuel consumption of a vehicle that starts its trip in another state or country and then terminates in California is not included, an issue that principally concerns the aviation and marine subsectors and is important because, in a relative sense, the vast majority of California's aviation and marine activity crosses state borders. It is also important from a policy perspective. Following guidelines published by the Intergovernmental Panel on Climate Change (IPCC), the California Air Resources

Board (CARB) calculates, but excludes, fuel use and GHG emissions resulting from aviation and marine fuel purchased in California and used for interstate and international trips (CARB, 2009a). Therefore, the energy and emissions estimates provided in this report will appear higher than those published by CARB in its official Greenhouse Gas Inventory. In order to do a fair comparison, when using the CARB numbers, one should make sure to add back in the energy and emissions estimates from their so-called "Excluded Emissions" category.

The reason I have chosen to include all transport activity, energy, and emissions in the estimates presented in this report, as well as in the CA-TIMES model itself, is quite simple: my objective is to model the entire California energy system, both present and future, in an effort to develop deep GHG reduction scenarios that allow the state to meet its long-term energy and environmental goals. While the policy process of today may not clearly specify which regulatory entities will eventually have jurisdiction over aviation and marine trips that cross state/country boundaries, it is quite likely that if a dramatic transformation of California's energy system is to ultimately take place, none of the state's energy sectors or subsectors can afford to be ignored. Therefore, I have made sure not to ignore them in my modeling.

2. Electricity Generation

The electricity sector is similar to oil refineries, bio-refineries, and hydrogen production facilities, in that power plants take a primary energy feedstock (e.g., natural gas, biomass, uranium, wind, hydro, coal) and convert it into a finished fuel product, in this case electricity, which can then be delivered and consumed within one of the five end-use sectors (industrial, commercial, residential, agricultural, and transportation). For this reason, these conversion facilities are often said to be a part of the "secondary" energy sector, where the "primary" sector refers to, for example, oil and natural gas production, coal and uranium mining, and biomass feedstock collection.

A variety of power plant types are used to produce electricity for the California market, the so-called "generation mix" (Figure 8). Natural gas, which actually encompasses several different plant technologies (combined-cycles, steam turbines, and gas turbines), is used to supply almost half of all electricity that is generated within California. The next largest categories are hydropower and nuclear, respectively. Production from other renewable and non-renewable sources comprises the remainder of in-state generation. However, a large share of California's electricity is actually supplied from outside the state. In fact, if it were classified as its own generation type, imports would represent the single largest source of electricity supply for California. In reality, imports are generated from a variety of fuel sources, and there are two different types of imports: firm and system. Firm imports refer to generation from power plants located outside of California but owned by in-state utilities (e.g., Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric). At present, these utilities operate plants that are located in Oregon, Arizona, Nevada, New Mexico, and Utah. System imports, on the other hand, refer to electricity produced by utilities in the Pacific Northwest (Oregon and Washington) or Desert Southwest (Arizona and New Mexico) that is only imported when available or needed – essentially the spot market for electricity. Because of fluctuating electricity demand and supply and annual rainfall levels (which impacts hydro availability), both within California and in these other states, the mix of imports changes from year to year. Figure 9 shows what the import mix looked like in 2005. Natural gas, hydro, and coal are the main fuel sources. Note that, although not shown, firm imports accounted for ~40% of the import total in 2005, while system imports made up the rest. (As discussed in a later section, Ryan McCarthy's dissertation is the source of most of the historical electricity sector data shown here and input to the CA-TIMES model for calibration between 2005 and 2010 (McCarthy, 2009).)

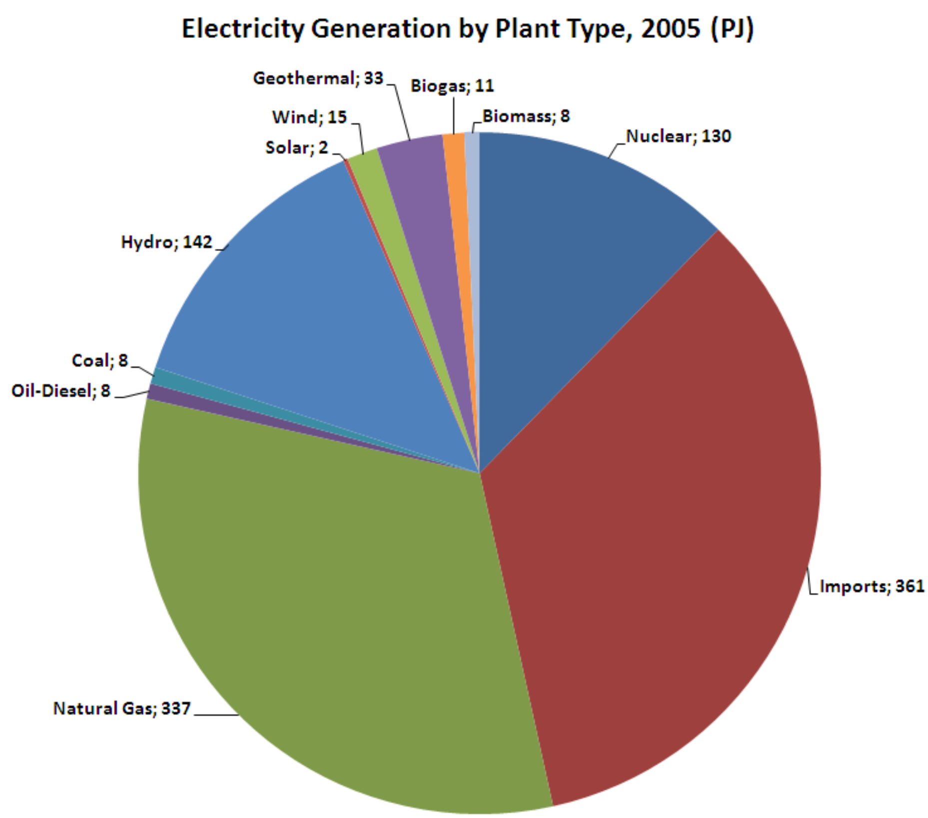


Figure 8 Electricity Generation by Plant Type, 2005

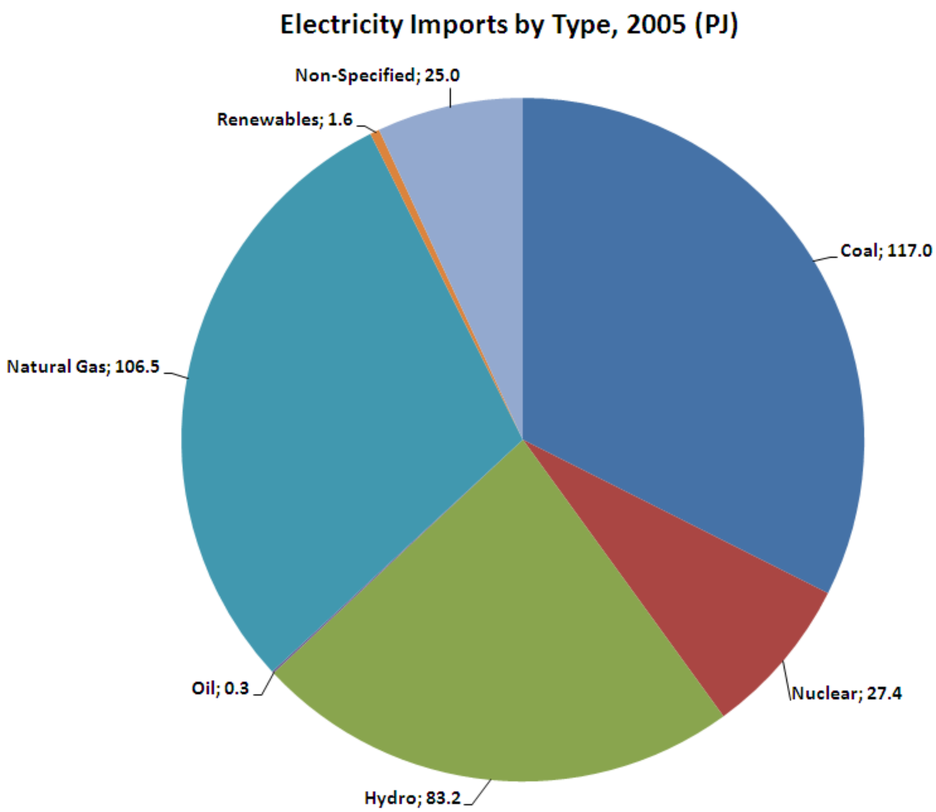


Figure 9 Electricity Imports by Type, 2005

Continuing a previous discussion, it is interesting to note that, as required by the Global Warming Solutions Act of 2006 (AB 32), the energy use and emissions related to electricity imports *are* included in CARB's official GHG Inventory (CARB, 2009a). Thus, in the CA-TIMES model and in the data and results presented in this report, I also follow this same convention, attributing energy and emissions from electricity imports to the CA-Combustion in-state category.

3. Greenhouse Gas Emissions

California greenhouse gas emissions are a by-product of fuel combustion in the electricity, refining, transport, industrial, commercial, residential, and agricultural sectors, as well as due to a host of other non-fuel combustion activities, including, but not limited to, industrial processes (e.g., cement and lime production, manufacturing of electronics equipment), livestock enteric fermentation and manure management, forest lands, crop burning, solid waste disposal and wastewater treatment, to name just a few (CARB, 2009a). This non-fuel combustion (i.e., non-energy) category partly includes high-GWP (Global Warming Potential) gases, such as hydrofluorocarbons (HFC), halocarbons, and sulfur hexafluoride (SF6). In addition, a small, but non-significant quantity of GHG emissions are annually sequestered (i.e., stored) in California's vast forests and rangelands.

According to the California Air Resources Board's official GHG Inventory (CARB, 2007a, 2010a), the state's total emissions of greenhouse gases from all sources amounted to 518 million tonnes carbon dioxide-equivalent (Mt CO_2-eq) in 2005, a figure that was up 6.7% from 486 Mt in 1990 (Figure 10). These totals include emissions from interstate and international aviation and marine activity, what CARB refers to as "Excluded" emissions, a category that contributed 59 and 45.5 Mt CO_2-eq in 1990 and 2005, respectively. Also included in the official CARB statistics are non-energy GHGs, which contributed 35.8 and 55.4 Mt CO_2-eq in 1990 and 2005, respectively.

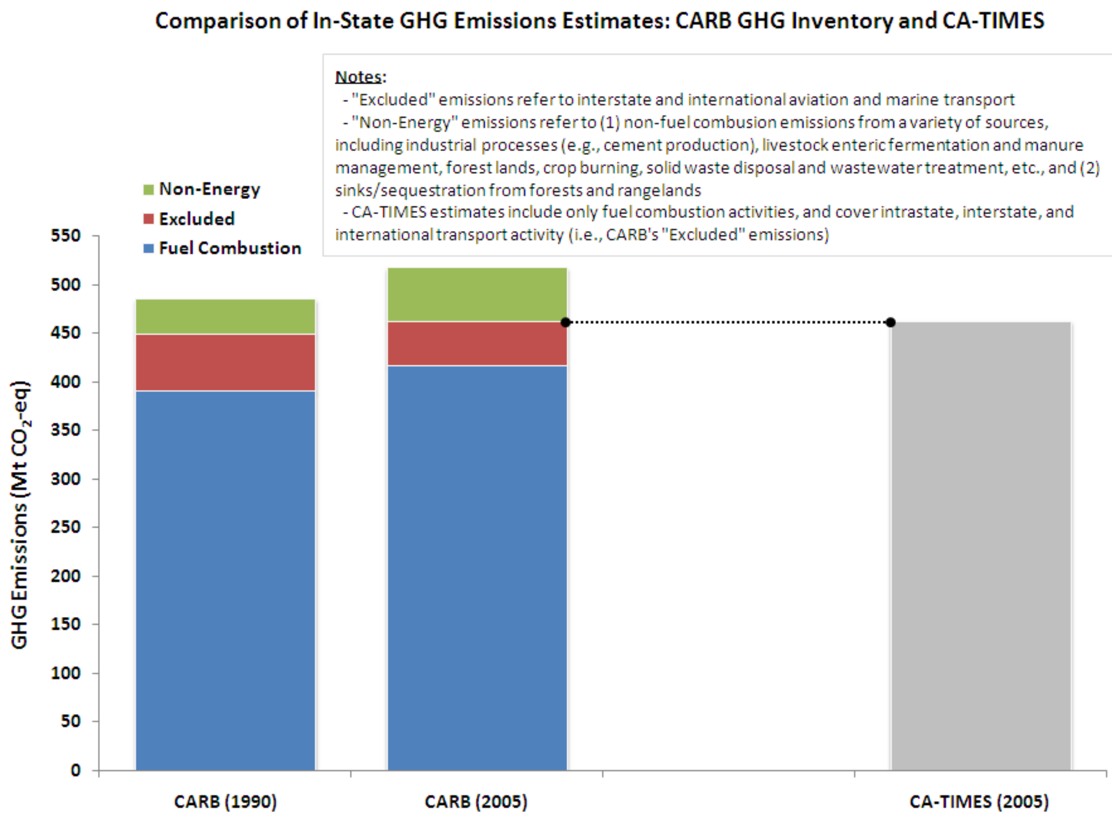


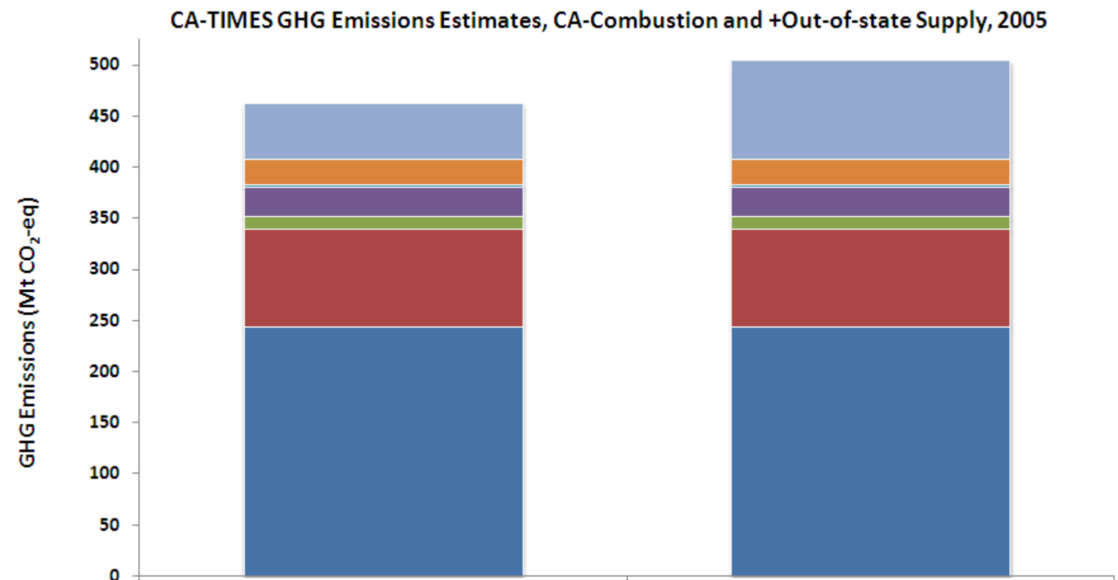
Figure 10 Comparison of GHG Emissions Estimates: CARB GHG Inventory and CA-TIMES

Unlike the CARB GHG Inventory, the current version of the CA-TIMES model only covers emissions from fuel combustion activities. Non-energy GHGs (which accounted for just 11% of total emissions in 2005) are not modeled at the present time, though there are plans to do so at a later date by other members of our research team. Moreover, as discussed earlier in this report, the model covers intrastate, interstate, and international aviation and marine activities. Therefore, the emissions estimates from CA-TIMES are directly comparable to the sum of the "Fuel Combustion" and "Excluded" emissions categories from the CARB GHG Inventory. Figure 10 clearly illustrates this comparability and at the same time indicates how closely the CA-TIMES model (comprised of hundreds of technologies – each with unique fuel inputs, efficiencies, and costs – which are spread over the various primary, secondary, and end-use energy sectors) is able to replicate the energy system of California in the base-year 2005. The statistical difference between the CA-TIMES model output and the 2005 data is less than 0.1%. In total, the current version of the CA-TIMES model captures 89% of all GHG emissions currently produced by the California energy system. Such broad coverage becomes especially important when developing deep GHG reduction scenarios, since the emissions reductions required in the future depend in large part on the historical baseline.

Given that California's transportation sector is the single largest energy-consuming category in the state, as discussed previously, it is perhaps not surprising that transport is also the greatest emitter, comprising a little more than half of all greenhouse gas emissions in 2005 (Figure 11). The second largest polluter is the electricity sector, followed by the combined industrial/supply sector. The residential, commercial, and agricultural sectors emit relatively low quantities of GHGs since electricity makes up such a large share of fuel consumption in each of these sectors, and emissions from electric generation are accounted for in the "Electricity" category in Figure 11. Viewed another way, Figure 12 allocates electric sector emissions to the various end-use sectors – i.e., each end-use sector is assigned an additional quantity of emissions in proportion to the share of electricity it consumes in total economy-wide production. The sectors most affected by this allocation are residential, commercial, agricultural, and industrial. Because the transport sector in California only consumes a small amount of electricity at present (mostly for rail and certain bus applications), its emissions are essentially unchanged. Note that because the transport, electricity, and supply sectors account for

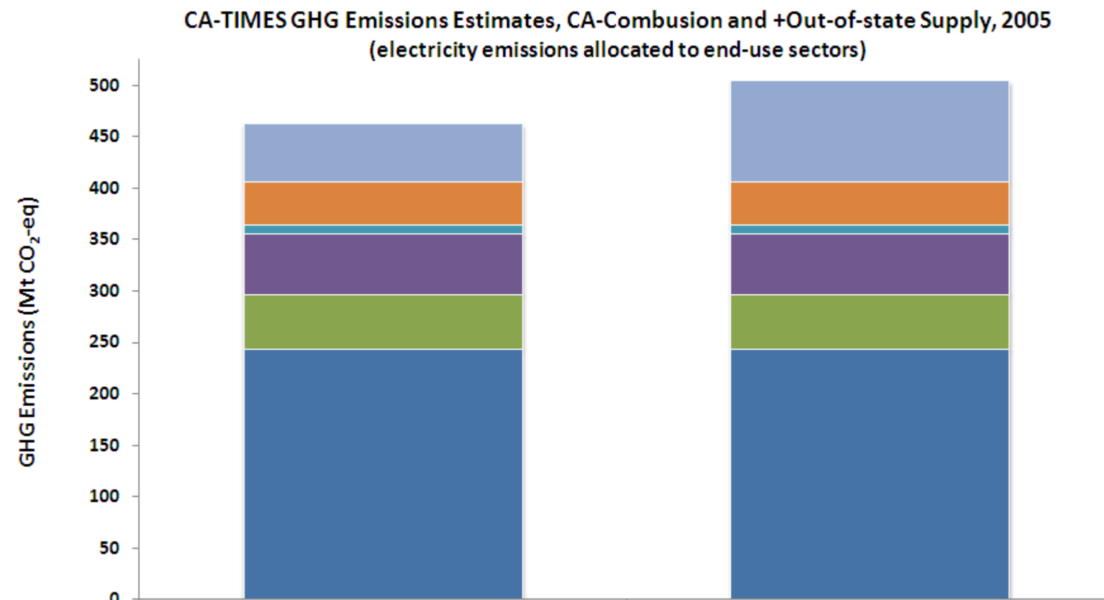
85% of all emissions related to fuel combustion, these are the sectors that receive the most attention in this dissertation research and are, thus, modeled with the greatest bottom-up technological detail in the current version of the CA-TIMES model.

At this point, the reader should note a small, but important, accounting detail that concerns industrial and supply sector emissions. Officially, there is no "Supply" category in the CARB GHG Inventory. Within the CA-TIMES modeling framework, however, the supply sector covers certain industrial activities, including petroleum refining, oil and gas extraction and production, biomass feedstock collection and transport, coal and uranium mining, and delivery of finished fuel products; in future model years, bio-refineries, hydrogen production facilities, and a few other types of conversion plants are included as well. Therefore, the combined industrial/supply category in CA-TIMES is synonymous with the conventional meaning of the "Industrial" sector, as might be found in the CARB GHG Inventory or elsewhere. Naturally, care has been taken not to double-count energy use and emissions in the industrial and supply sectors of CA-TIMES.



	CA-Combustion	+Out-of-state Supply
Supply	54.4	96.2
Industrial	25.7	25.7
Agricultural	1.6	1.6
Residential	28.8	28.8
Commercial	12.6	12.6
Electricity	95.6	95.6
Transportation	243.6	243.6

Figure 11 CA-TIMES GHG Emissions Estimates, CA-Combustion and +Out-of-state Supply, 2005



	CA-Combustion	+Out-of-state Supply
Supply	55.8	97.6
Industrial	42.3	42.3
Agricultural	8.3	8.3
Residential	59.0	59.0
Commercial	53.1	53.1
Transportation	243.9	243.9

Figure 12 CA-TIMES GHG Emissions Estimates, CA-Combustion +Out-of-state Supply, 2005 (electricity emissions allocated to end-use sectors)

Figure 11 and Figure 12 both show two types of emissions estimates, *CA-Combustion* and *+Out-of-state Supply*. CA-Combustion emissions are fairly self-explanatory: they include all emissions produced from fuel combustion activities within the boundaries of California's energy system, which in this analysis is defined to also include emissions from interstate and international aviation and marine trips whose origin is California and from all power plants whose electricity is destined for the California market, even if those plants are located in neighboring states. (The latter procedure is consistent with the CARB GHG Inventory, wherein only the "California share" of emissions from electricity imports is counted.) For the base-year 2005, the CA-Combustion designation does not include emissions that result from transporting primary energy feedstocks (e.g., crude oil, natural gas, coal, uranium, biomass) or finished fuels (e.g., refined petroleum products, biofuels) from outside of the state into California, nor are the upstream lifecycle ("well-to-tank") emissions resulting from production/conversion of these feedstocks/fuels outside of California considered, except for combustion emissions related to electricity imports. Nevertheless, from a modeling standpoint, it would be quite useful to be able to calculate the full lifecycle GHG emissions (both "well-to-tank" and "tank-to-wheel") for all of the fuels consumed within the California energy system, including emissions from the upstream supply stages that occur outside the state or even in another country (e.g., crude oil production in the Middle East). For this reason, the CA-TIMES model also tracks the vast majority of upstream emissions related to imported energy commodities and assigns these out-of-state emissions to the *+Out-of-state Supply* emissions total. In particular, the emissions are allocated to the supply sector category. The upstream emission factors for each type of resource/fuel generally come from the California-specific version of Argonne National Laboratory's Greenhouse gases, Regulated Emissions and Energy Use for Transportation (GREET) Model (CARB, 2007b). Figure 11 and Figure 12 illustrate that total emissions including out-of-state supply are, as expected, slightly larger than CA-Combustion emissions in the base-year 2005. This is due entirely to total supply sector emissions being about 75% greater than in the CA-Combustion case. In other words, a large portion of the upstream emissions that are generated while producing final energy carriers for end-use consumption in California actually occur outside of the state's borders. Emissions from the non-supply sectors are, by definition, the same in both the CA-Combustion and +Out-of-state Supply cases. Therefore, one should not think of the figures as showing the well-to-wheel emissions of each energy sector. This calculation would require the careful allocation of total supply and electric sector emissions to each of the end-use demand sectors, which incidentally has been done separately, as discussed below.

The average lifecycle carbon intensities of several fuels commonly used in California in 2005 are shown in Figure 13 (technically speaking, electricity is an energy carrier). Both upstream (well-to-tank) and fuel combustion (tank-to-wheel) emissions are highlighted. The carbon intensities of the refined petroleum product fuels (gasoline, diesel, residual fuel oil, and jet fuel) are roughly similar, ranging from 78 to 88 gCO_2-eq/MJ_{HHV}, with most of their emissions being attributable to the fuel combustion stage. Natural gas is less carbon-intensive than these fuels; in fact, natural gas is the least carbon-intensive of all commonly used fossil fuels. Interestingly, the most carbon-intensive fuel shown in the figure is electricity (based on California's average grid mix), whose emissions are attributed entirely to the upstream stages, because electricity is not actually combusted. One must keep in mind, however, that electric motors tend to be more efficient energy conversion devices than internal combustion engines, boilers, and gas turbines (efficiencies can be up to four times greater). Therefore, the true carbon intensity of electricity is actually quite a bit less than the other fuels shown, if one takes as the boundary the useful work (i.e., energy service) that is supplied by an energy conversion device.

In comparing the fuel carbon intensities shown here to those of other studies, it is important to note that I estimate all carbon intensities on a higher heating value (HHV) basis. (In fact, all energy flows in CA-TIMES are estimated on a HHV basis.) Utilization of a HHV for a fuel's heat content (in units of, say, MJ/gal) has the effect of lowering a carbon intensity estimate on a lower heating value (LHV) basis by about 7 to 11%, depending on the particular fuel (except for electricity, of course, for which LHVs and HHVs are the same). This is important because the convention adopted by the GREET model, the California Low Carbon Fuel Standard (LCFS) regulations, and most other lifecycle analysis studies is to use a LHV basis for estimating fuel carbon intensities. Our research group has chosen to adopt a HHV basis throughout the CA-TIMES model because it represents a more accurate treatment of energy flows (from primary resource supply through conversion to end-use) and because it is the approach adopted by the U.S. Energy Information Administration (EIA) in its National Energy Modeling System (NEMS) energy forecasting and scenarios model.

Taking this LHV/HHV conversion issue into account, the average lifecycle carbon intensities calculated within the CA-TIMES framework match up quite well to what one would expect to see, based on other studies. In truth, the CA-TIMES values are a little on the low side, if only slightly, say by about 2% to 4%. This is due to inherent limitations with trying to capture every single process and emission flow related to the lifecycle production of a particular resource/fuel commodity. Entire careers have been devoted to developing modeling tools to do just that (e.g., Argonne's GREET and Delucchi's LEM). The lifecycle analysis (LCA) model used in conjunction with CA-TIMES is simply an Excel-based tool that I developed (somewhat tangentially to the core model development), in order to post-process the results produced by CA-TIMES. The tool takes the output of a given CA-TIMES model run/scenario and allocates all of the energy and emission flows to the various production stages for the numerous fuel products. Great care is taken to apportion these flows in the correct way. The LCA calculations definitely do *not* occur internally within the current version of the CA-TIMES model, which is a very important point since this limits one's ability to impose dynamic constraints on carbon intensities while the model is running, something that might be desirable if one were to want to analyze an LCFS policy. Future work by other members of the CA-TIMES research team may attempt to address this important limitation of the model. In any case, various other types of energy and environmental constraints can be feasibly implemented within the model framework, including carbon caps, vehicle fuel economy standards, renewable portfolio standards, and so on (as discussed in greater detail in later sections).

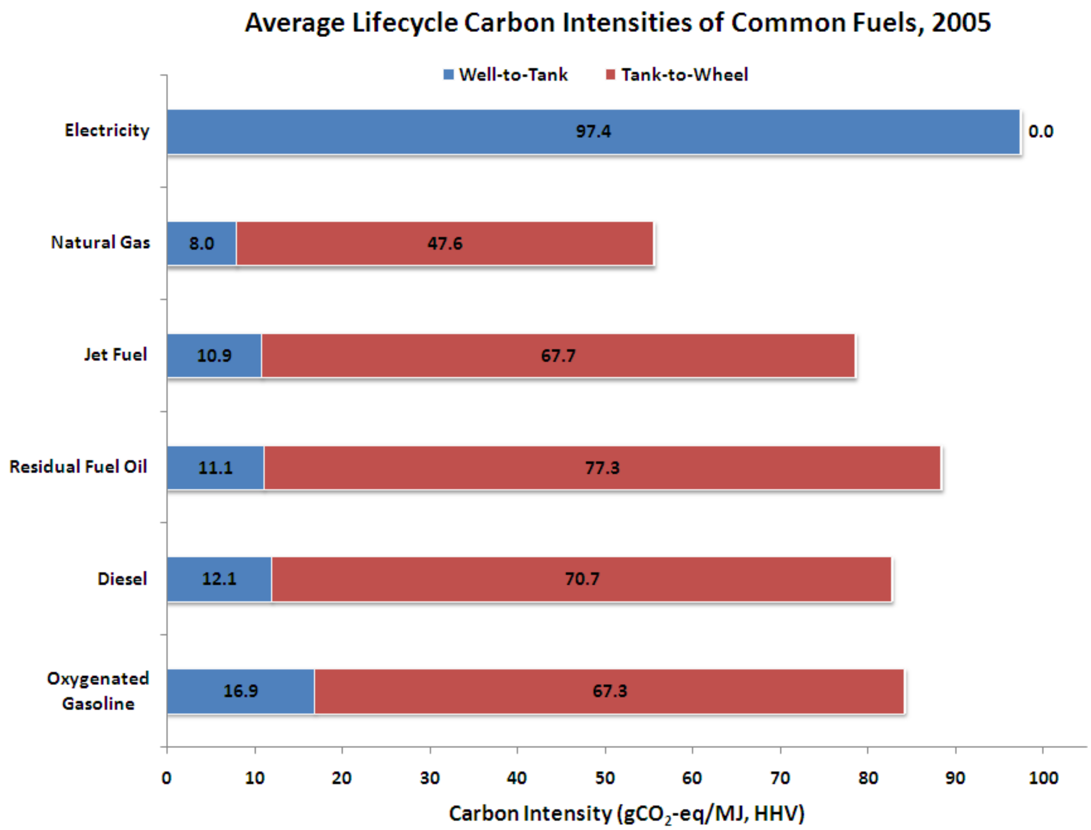


Figure 13 Average Lifecycle Carbon Intensities of Common Fuels, 2005

By comparison, California's energy system is less carbon-intensive than other US states and other countries. For instance, as shown in Figure 13, the CA-TIMES model estimates that the average carbon intensity of California's electricity grid – taking transmission line losses into account – was 97.4 gCO_2-eq/MJ (351 gCO_2-eq/kWh) in 2005, a value confirmed by McCarthy (2009). This is significantly less than U.S. average electric generation, which achieved a carbon intensity of 170 gCO_2-eq/MJ (612 gCO_2-eq/kWh) in 2005 (EIA, 2006; EPRI, 2007). The reason for this large difference is fairly straightforward: the vast majority of California's electricity comes from relatively low-carbon sources, such as nuclear, hydro, natural gas, and other renewables, whereas a significant portion of US electric generation (~50%) is derived from coal power.

Other similar metrics also indicate that California's economy and energy system are less carbon-intensive than the rest of the country. Table 1 presents California GHG emissions relative to the state population and the state's gross domestic product (GDP/GSP) in 1990 and 2005. For comparison, average values for the U.S. are shown as well. The emissions estimates shown here include all types of in-state GHGs (or in the case of the U.S., all domestic GHGs), i.e., emissions from fuel combustion, non-energy emissions, and forestry/rangeland sinks, etc. that occur within California, excluding interstate and international aviation and marine emissions. The statistics show that the carbon intensity of California's economy has decreased significantly since 1990. In fact, California was less carbon-intensive in 1990 than the entire U.S. was fifteen years later in 2005.

Table 1 Indicators of Economy-Wide GHG Emissions in California and the U.S.

	California		United States*	
Year	**1990**	**2005**	**1990**	**2005**
tCO_2-eq per Mill$ GDP	477	305	640	490
$ GDP per tCO_2-eq	2,097	3,281	1,563	2,040
tCO_2-eq per capita	17.4	14.0	19.9	20.1

Data sources: CARB (2007a), CARB (2010a), UN (2010)*

* *Notes: U.S. emissions estimates are taken from the United Nations Framework Convention on Climate Change (UNFCCC) statistics, rather than from the Carbon Dioxide Information Analysis Center (CDIAC)*

III. Methodology

The model developed in this project has been named CA-TIMES. It is a technologically-rich, integrated energy-engineering-environmental-economic systems model that is a variant of the MARKAL and TIMES family of energy models, focusing on the California energy system and containing California-specific data and assumptions.[3] CA-TIMES is a unique simulation tool, in that it will represent the first publicly available model of its kind in the state, when it is fully developed. Unlike other economic models that have previously been used for California energy and climate policy analysis[4], CA-TIMES is a bottom-up, optimization model, which covers all sectors of the California energy economy, including primary energy resource extraction, imports/exports, electricity production, fuel conversion, and the residential, commercial, industrial, transportation, and agricultural end-use sectors. Over the next several years, CA-TIMES will be used by UC-Davis researchers and the California Air Resources Board to generate and analyze scenarios for meeting California's long-term (2020-2050) GHG emission reduction goals. My dissertation work begins this process by performing scenario analyses, evaluating policy, and presenting technological portraits for the future given the specific conditions that exist within the state.

[3] An alternative way of viewing MARKAL and TIMES is that they are model "shells". We take this shell, which contains hundreds of embedded equations and algorithms, and input the data for California, thereby creating a California-specific energy systems model. In this sense, the modeling is data-driven, and we avoid wasting excessive time tinkering with the model code.

[4] For example, the Energy 2020 model by Systematic Solutions; an electricity and natural gas sector model by Energy and Environmental Economics (E3); and the Environmental Revenue Dynamic Assessment Model (E-DRAM) by UC-Berkeley, California Department of Finance, and CARB.

1. Solution Framework of the CA-TIMES Model

The MARKet ALlocation (MARKAL) model and its next-generation extension, The Integrated MARKAL-EFOM1 System (TIMES), are comprehensive energy-engineering-environmental-economic (so-called "4E") modeling frameworks used by the U.S. DOE National Laboratories, the U.S. DOE Energy Information Administration (EIA), the U.S. Environmental Protection Agency (EPA), the International Energy Agency (IEA), and most UNFCCC Annex I governments. In fact, over the past 30 years, MARKAL-TIMES models have been utilized by more than 250 institutions in some 70 countries worldwide (Goldstein, 2009). While there are at present two national-level U.S. MARKAL models used for government energy forecasting and analysis, there are none, quite surprisingly, that are specific to the state of California. In fact, there are no publicly available bottom-up energy-engineering-environmental-economic models that cover all sectors of the state's energy system. As California moves forward with a broad spectrum of carbon emissions reduction policies, there is a strong need for this kind of transparent, flexible, and accessible analysis tool to help inform policy decisions.

MARKAL-TIMES models are partial-equilibrium models that solve iteratively in GAMS (General Algebraic Modeling System) via optimization of an objective function (Loulou et al., 2005).[5] The standard solution method is linear programming (LP), though mixed-integer and stochastic programming are also possible. An interior point solver using CPLEX or XPRESS is normally chosen. The objective of a typical model is to supply energy services at minimum global cost (or more accurately, at minimum loss of

[5] Documentation of the TIMES model framework can be found at http://www.etsap.org/documentation.asp

consumer and producer surplus, by reaching a supply-demand equilibrium with endogenous energy service demands)[6] subject to a larger set of technical and policy constraints (Figure 14, Figure 15).[7] Importantly, the technological supply curves in TIMES are not assumed by the modeler; rather, they are built endogenously within the model. The modeler inputs a host of data and assumptions for individual technologies, and then TIMES implicitly constructs the supply curves internally. These supply curves are not fixed in any given time period and/or across different model runs: rather, they shift and vary, as the model continuously makes decisions in an effort to maximize total consumer and producer surplus. Demand curves, on the other hand, may be input exogenously by the modeler or built endogenously within the model, depending on whether the demand commodity in question is an energy service demand or energy carrier or material. In the latter case (e.g., for a fuel such as gasoline), it is not necessary for the modeler to specify an exogenous demand because the demand for the commodity will be calculated endogenously within TIMES – i.e., TIMES chooses whether or not to consume the fuel/material based on whether or not it is a cost-effective to do so from a *systems level* perspective. In the case of energy service demands (e.g., for light-duty vehicle-miles traveled), either the modeler exogenously specifies a demand trajectory for each year of the model time horizon or she specifies a demand trajectory and in addition a constant own-price elasticity for the demand in each year.[8] In the latter case, the TIMES

[6] Total surplus is maximized at the point where the quantities and prices of the model's various commodities (energy carriers, demands, materials, and emissions) are in equilibrium, i.e., their prices and quantities in each time period are such that the suppliers produce exactly the quantities demanded by the consumers.

[7] The basic equations of the model are commodity balances, transformation equations, input/output shares on process flows, activity definitions, utilization constraints, and market share constraints.

[8] An own-price elasticity of demand is a measure of the responsiveness of the quantity demanded of a good or service to a change in its price. It is typically represented as a percentage change in quantity demanded

model internally constructs a demand function, using the demands and elasticities as inputs. Note that if the modeler specifies fixed demands (not demand functions), then the optimization problem is essentially transformed from the maximization of total consumer and producer surplus to the minimization of total system costs. In this situation, the model becomes more of a supply model, as its ability to flexibly adjust demands is reduced. Figure 16 diagrammatically illustrates the alternative supply-demand equilibrium in TIMES when fixed energy service demands are exogenously specified by the modeler. The capability of specifying elastic demands is a special feature of MARKAL-TIMES models; however, not all modeling groups choose to run their models in “elastic mode” due to the problems that can potentially arise if reliable elasticity data is not able to be found for all demands of interest.

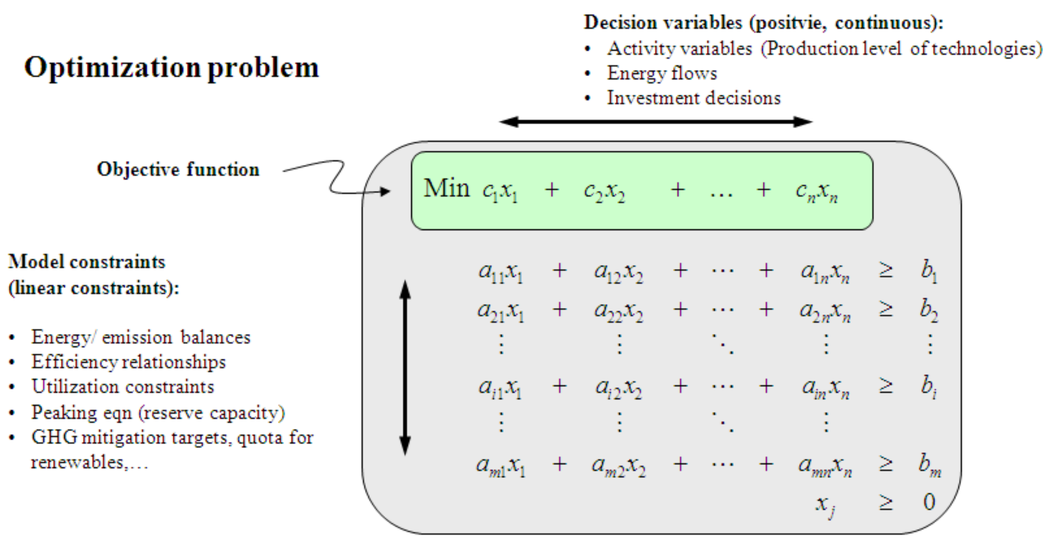


Figure 14 Simplified Representation of the Linear Programming Optimization Problem in TIMES
* *Figure source: Uwe Remme, University of Stuttgart and International Energy Agency*

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in response to a one percent change in price (holding constant all the other determinants of demand, such as income).

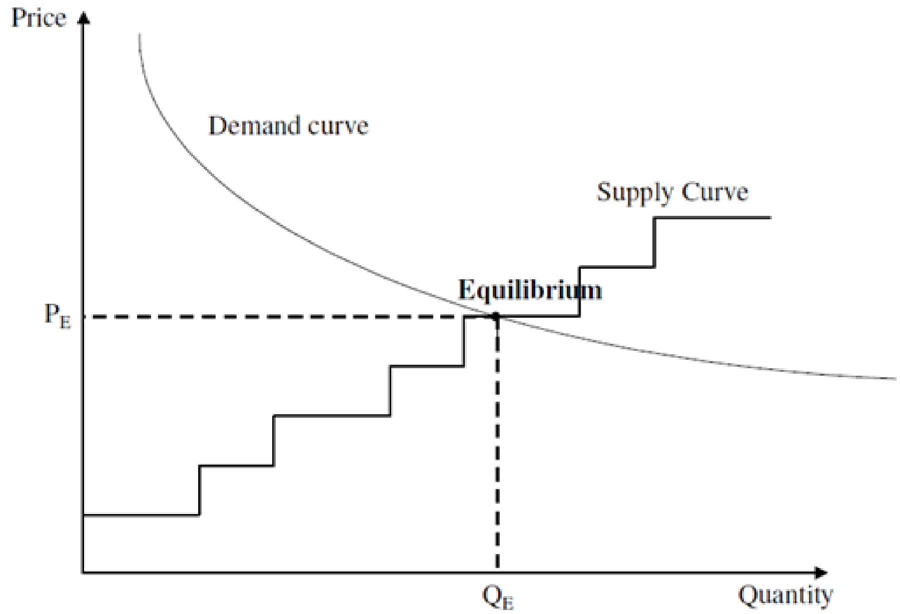

Figure 15 Supply-Demand Equilibrium in TIMES for an Endogenous Energy Carrier, Material, Emission, or Service Demand
* *Figure source: Loulou et al. (2005)*

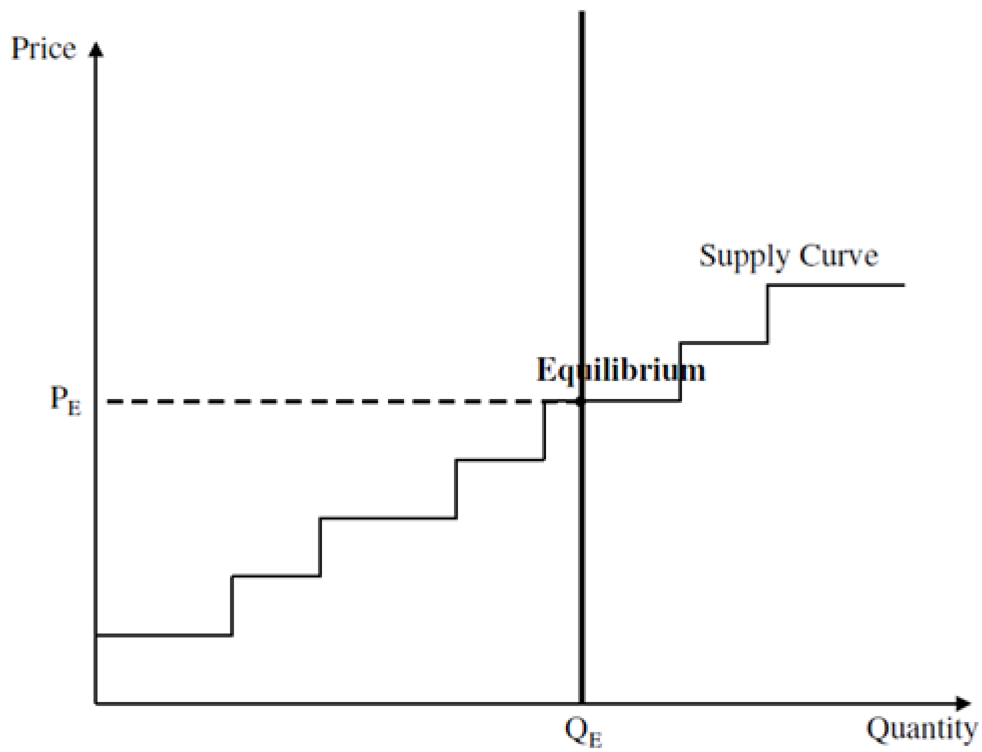

Figure 16 Supply-Demand Equilibrium in TIMES for an Exogenous Energy Service Demand
* *Figure source: Loulou et al. (2005)*

The TIMES objective function sums the discounted net present values (NPV) of capital costs, fixed and variable O&M, import and export costs, delivery costs, taxes and subsidies, salvage values, and welfare losses (resulting from reduced end-use demands), as well as other cost terms, for all years and regions within the model.[9] Basically, the consumption and production of every demand, energy carrier, material, and emission within the model has a cost associated with it – all vehicles, fuel conversion devices, and power plant technologies, all primary energy resources, and so on – and the total discounted NPV of these costs is minimized. In doing so, the model attempts to replicate the kind of rational economic behavior that, in theory, we should see exhibited by consumers and firms in a perfectly competitive market. Of course, in reality many markets are imperfect (e.g., consumers of private transportation, oil suppliers, etc.), and consumers and firms often exhibit irrational behavior from purely an economic perspective (when considering only private costs). It, therefore, becomes necessary to depart from the perfectly competitive market framework, and this is possible in TIMES through the introduction of taxes, subsidies, and explicit user-defined constraints (e.g., limits to technological growth and penetration, constraints on emissions, technological hurdle rates, demand elasticities, etc.).

A strongpoint of MARKAL-TIMES models is that they have the capacity to represent technologies in considerably rich, bottom-up detail, thereby allowing for the characterization of energy system dynamics over a long-term, multi-period time horizon

[9] A global discount rate of 4% is used in the CA-TIMES model. However, certain process have technology-specific discount rates (i.e., hurdle rates), which may be considerably higher.

(e.g., from 2005 to 2050). A given model contains a large database with hundreds to thousands of technologies, and each technology is characterized by technical, financial and environmental parameters (e.g., efficiencies, capital and O&M costs, and emissions factors). These databases are written in Excel spreadsheet tables and are, thus, easily accessed and transferable. Technological progress[10] is accounted for in the model, and the future availability of new, advanced technologies is considered. The main decision variables are investment choices (e.g., new capacities, extension, and retirement) based on annualized costs (capital, variable, fuel, O&M, and emissions prices), activities, energy/emission flows, storage, demand, and trade. Shadow prices of the decision variables, representing the marginal system values of the constraints, are determined by the dual equations. Note that in the TIMES model, demands can be decision variables as well, if they are specified to depend on energy prices (i.e., if they have elasticities associated with them).

The current version of CA-TIMES can be described as a perfect foresight model with a single decision-maker (sometimes referred to as the “social planner”). The model has perfect information over the entire model planning horizon and complete knowledge of the market’s parameters, both now and in the future. In other words, the model knows in 2010 what the total electricity demand and cost of a particular power plant will be in 2030, 2040, and 2050; therefore, it can make the best possible investment and operating decisions in each year, in order to optimize costs over the entire model time horizon.

[10] Technological progress is captured via exogenous specification of future technology cost and performance assumptions, investment in new technologies, and early retirement of inefficient technologies. The model also has the potential to represent technological progress endogenously through learning and experience curves (i.e., a progress ratio approach), although the current version of the CA-TIMES model does not make use of this feature.

Alternately, a non-standard, myopic version of the TIMES model also exists, though I have chosen not to use it for the purposes of my dissertation. (The myopic version may be used in the future by other members of the research team.) Perfect foresight models are preferred for scenario development and when conducting so-called "what if" exercises because they allow a researcher to answer questions, such as, "What is the best way for society to get from where we are today to where we want to be in the future?" Myopic models, in contrast, are typically used for forecasting and predicting and are better geared to answer questions such as, "What is likely to happen in the future given current policies and how we think energy prices and technologies will develop over time?" While the differences between these two modeling approaches may be subtle, they are nevertheless important.

Box 1
In layman's terms: How CA-TIMES makes fuel use and investment decisions

This box provides a straightforward explanation of how the CA-TIMES model makes its fuel use and investment decisions, hundreds of thousands of which are made in parallel during a single model run. Supply of light-duty car demand over the multi-period time horizon is taken as an example.

First, the modeler specifies an exogenous trajectory of light-duty car demand (in units of vehicle-miles traveled) over the next several decades. These growth projections are typically taken from other studies or official government forecasts. The model can choose to meet this demand in a number of different ways. For instance, it can choose to invest in gasoline internal combustion engine (ICE) vehicles or hybrid-electric vehicles (HEV), diesel ICEs or HEVs, biofuel ICEs or HEVs, battery-electric vehicles (BEV), hydrogen fuel cell vehicles (FCV), or a number of other options. It can also choose some combination of all these vehicle types. The decision criterion for investment is the vehicle-fuel combination with the lowest total discounted net present value cost over its entire life (say, 15 years). The costs considered are the annualized stream of capital costs, fuel costs, and variable and fixed O&M costs. However, some of the more advanced vehicle technologies are quite unfamiliar to consumers; thus, there is a certain risk associated with them. This manifests itself as a cost premium and is formulated in the model as assigning a higher hurdle rate (i.e., technology-specific discount rate) to these advanced technologies.

While the investment cost of each of the vehicle technologies is exogenously specified by the modeler for each year of the model (typically, by using results from techno-economic studies as a basis for the assumptions), the fuel costs are constantly varying, as the model solves for them endogenously using supply curves that it calculates internally. These curves depend on (1) the cost of the technologies supplying the particular fuels (e.g., oil refineries, bio-refineries, hydrogen production facilities, electric generation plants), and (2) the cost of primary energy resources that are fed to the fuel conversion sector. The cost trajectories of each of the electric generation and fuel conversion technologies are exogenously specified by the modeler for each year of the model (unless the endogenous technological learning function is used), and the costs and quantities of the various primary energy resource commodities (e.g., coal, oil, natural gas, uranium, biomass, and imports of finished fuel products) are represented with supply curves or price trajectories for future years. As before, common practice is for these input assumptions to be based on the findings of other reliable studies.

Here, one can begin to see the indirect link between investment and fuel use decisions in seemingly unrelated sectors, such as transport and electric generation. For instance, the decision of whether or not to invest in a BEV depends on the full lifecycle costs of this technology, which itself depends, at least in part, on how much it costs to install new electric generation and transmission capacity and, if there is a carbon cap or tax, the carbon intensity of the electricity that is produced. The decision to install new generation capacity depends on the demand for electricity in each of the other end-use sectors and the cost of primary energy resources that are consumed to generate the electricity. Similar decisions are continuously being made for other types of light-duty car technologies, as well as all of the other technologies in the other transport subsectors and the electricity, supply, industrial, commercial, residential, and agricultural sectors. The ability to represent a multitude of simultaneous decisions across a wide range of sectors is at the heart of *systems level* modeling, and this is certainly what makes it an attractive and useful tool for conducting energy analyses.

2. CA-TIMES Reference Energy System

The concept of the Reference Energy System (RES) is fundamental to the craft of energy systems modeling. The RES describes the entire structure and network of a particular system via three types of entities (Loulou et al., 2005):

- Technologies: these encompass all technologies including mining, import, export, fuel conversion, electric generation, transportation, and other end-use demand technologies;
- Commodities: these consist of energy carriers, energy services, materials, monetary flows, and emissions.

- Commodity flows: these are the links between processes and commodities.

The CA-TIMES RES represents California's energy system as it exists today, and it provides full descriptions for potentially available technologies, energy resource potentials, and service demands for future years out to 2055. The energy flows and energy balances are calibrated to 2005, and then optimized for all future years (generally at 5-year time steps). The RES essentially connects all processes (i.e., energy production, conversion, and end-use technologies) with commodity flows (i.e., fuels, materials, emissions, demands) of the model. As one might imagine, this ultimately leads to a fairly complex network, with seemingly unrelated processes and commodities (say, gasoline-powered light-duty vehicles and electric-powered industrial equipment) all depending on and/or reacting to each other in some way. Such complexity is representative of the real world, as economic actors in various sectors of the economy each make decisions based on information (prices, costs, quantities, etc.) that simultaneously depend on the decisions of others. The CA-TIMES model attempts to capture these decisions, at an aggregated level, within the California energy system, and therefore the RES is built to reflect, as accurately as possible, the system as it exists today and the potential pathways it could take in the future.

Figure 17 shows an extremely simplified schematic of the CA-TIMES Reference Energy System. The diagram is helpful for illustrating the model's main components in a linear fashion; however, it fails to represent the numerous feedbacks and the complex web of interdependencies that exist within the model. For instance, progressing from left to right, one sees how the model takes primary energy resources (e.g., crude oil) and feeds them to the fuel conversion sector where the primary resources are turned into final energy commodities (e.g., gasoline, electricity) with varying degrees of efficiency, dependent on technology.[11] These final energy commodities are then consumed by technologies in the various end-use sectors, in order to produce enough useful energy to meet the required energy service demands (e.g., VMT, PMT, TMT).

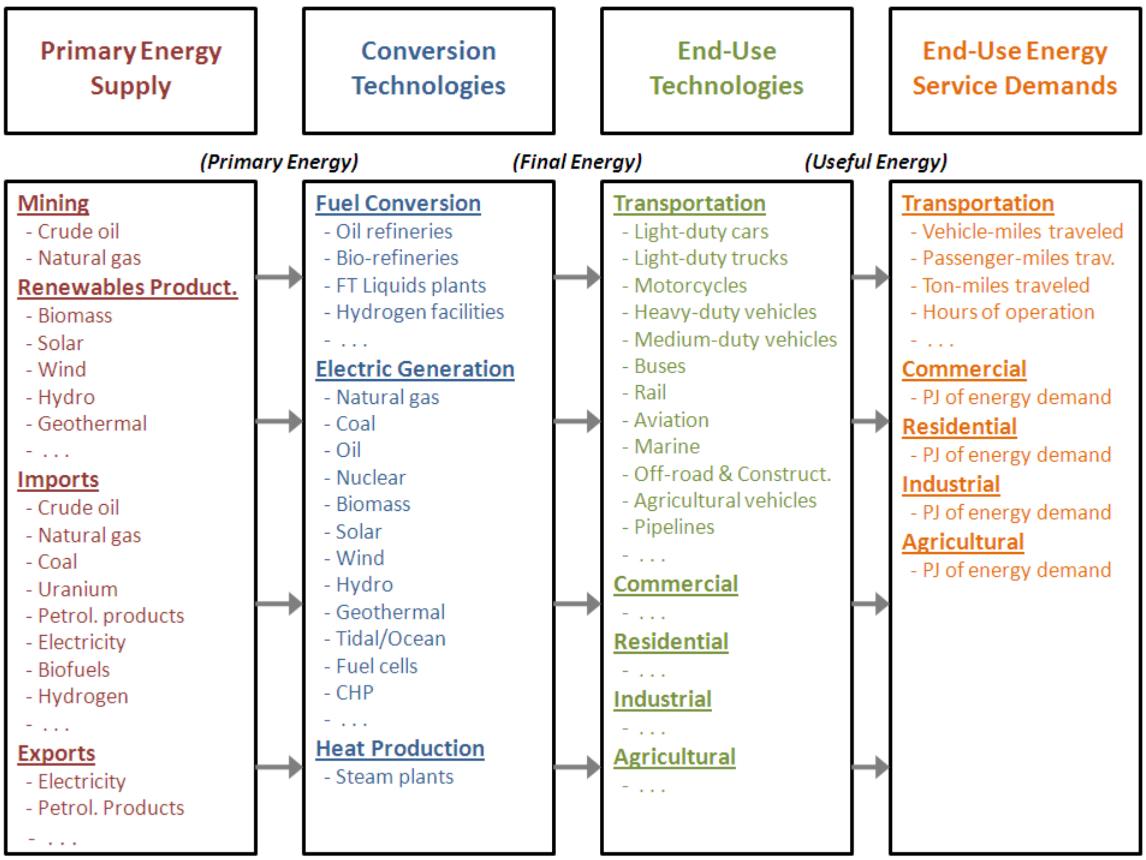

Figure 17 Simplified Schematic of the CA-TIMES Reference Energy System

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[11] A point of clarification: Note that in the diagram imports of refined petroleum products, electricity, biofuels, and hydrogen are shown to feed the fuel conversion sector when, in reality, these final energy commodities would bypass the fuel conversion sector and go directly to the end-use technologies.

Electric Generation Sector

The electric generation technologies in CA-TIMES are part of the larger fuel conversion sector. These technologies consume primary (and even some secondary) energy resources and convert them to a final energy commodity, electricity. (In certain cases, heat is also produced as a by-product.) Twenty-five (25) separate power plant technologies are used to represent California's entire generation system in the base-year 2005 (Table 2). A further thirty-seven (37) are available in future years as potential technologies in which CA-TIMES can choose to invest. The model aggregates the generation capacity of similar plant types (e.g., natural gas combined-cycle), as opposed to representing every single one of California's 690+ power plants as a separate entity (EPA, 2009). This distinction is important, as it should be recognized that CA-TIMES has been designed to be an energy *systems* model, not exclusively a power market model like PROSYM or ReEDS.[12] Such fine resolution would be beyond the scope of the current analysis.

[12] For further information on PROSYM, see the Ventyx webpage: http://www.ventyx.com/analytics/market-analytics.asp. For further information on ReEDS, see the NREL webpage: http://www.nrel.gov/analysis/reeds/.

Table 2 Electric Generation Technologies in CA-TIMES

Base-Year Technologies	Future Technologies
Oil Steam (Distillate, Jet Fuel, and RFO) Diesel Oil Combustion Turbine Diesel Oil Combined-Cycle Natural Gas Combustion (Gas) Turbine (NGGT) Natural Gas Steam Turbine (NGST) Natural Gas Combined-Cycle (NGCC) NGGT, Combined Heat & Power (CHP) Coal Steam Biomass Steam (Forest Residues) Biomass Steam (Municipal Solid Waste, Mixed) Biomass Steam (Municipal Solid Waste, Paper) Biomass Steam (Municipal Solid Waste, Wood) Biomass Steam (Municipal Solid Waste, Yard) Biomass Steam (Orchard and Vineyard Waste) Biomass Steam (Pulpwood) Biomass Steam (Agr. Residues, Stovers/Straws) Biomass Steam (Energy Crops) Biogas from Landfills and Animal Waste Digesters Geothermal Hydroelectric, Conventional Hydroelectric, Reversible (Pumped Storage) Wind Solar Thermal Solar Photovoltaic Nuclear, Conventional Light Water Reactors (LWR)	Natural Gas Combustion (Gas) Turbine (NGGT) Advanced Natural Gas Combustion (Gas) Turbine (NGGT) Natural Gas Combined-Cycle (NGCC) Advanced Natural Gas Combined-Cycle (NGCC) Advanced Natural Gas Combined-Cycle (NGCC), w/CCS Coal Steam Advanced Coal Int. Gasif. Combined-Cycle (IGCC) Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS Biomass IGCC (Forest Residues) Biomass IGCC (Municipal Solid Waste, Mixed) Biomass IGCC (Municipal Solid Waste, Paper) Biomass IGCC (Municipal Solid Waste, Wood) Biomass IGCC (Municipal Solid Waste, Yard) Biomass IGCC (Orchard and Vineyard Waste) Biomass IGCC (Pulpwood) Biomass IGCC (Agricultural Residues, Stovers/Straws) Biomass IGCC (Energy Crops) Biogas from Landfills and Animal Waste Digesters Geothermal, in California Geothermal, in Western U.S. Outside California Hydroelectric, Conventional Hydroelectric, Reversible (Pumped Storage) Wind, Lower Class Resources in CA Wind, Higher Class Resources in CA Wind, Lower Class Resources in Western U.S. Outside CA Wind, Higher Class Resources in Western U.S. Outside CA Wind, Offshore Solar Thermal, in CA Solar Thermal, in Western U.S. Outside CA Solar Photovoltaic Nuclear, Conventional Light Water Reactors (LWR) Nuclear, Pebble-Bed Modular Reactor (PBMR) Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR) Molten Carbonate Fuel Cell Tidal and Ocean Energy Generic Distributed Generation – Baseload Generic Distributed Generation – Peak

In order to paint a realistic picture of the current electricity landscape in California, the CA-TIMES electric generation sector is calibrated to the base-year 2005 based on data from a variety of sources, including most notably McCarthy (2009), CARB (2010b), CEC (2010b), and the California Biomass Collaborative (CBC, 2009). The types of data needed for calibration include plant efficiencies (i.e., heat rates), fuel input shares, fixed and variable O&M costs, generation capacities, scheduled capacity retirements, and plant-specific availabilities by timeslice. The model is then calibrated to the years 2006–2010 by carefully controlling the capacity investment in, and utilization of, future technologies (from the perspective of 2005), using the same sources listed above. (Note that while data for 2010 is not yet available in full, McCarthy (2009) has estimated what California's 2010 generation mix is likely to be in a baseline scenario.) After 2010, the model is free, more or less, to invest in any of the potential future power plant technologies shown in Table 2, subject to certain constraints on capacity growth and policies, such as the state's Renewable Portfolio Standard (RPS). The types of input assumptions that are needed for the future technologies are the same as those mentioned above, as well as a few others: start years (i.e., first year of plant availability), plant lifetimes (in years), investment costs, transmission costs, technology-specific discount rates (i.e., hurdle rates), and maximum annual limits to capacity growth.

Power plant investment, utilization, and fuel use decisions in CA-TIMES are made based on the principle of cost minimization (over the entire lifetimes and lifecycles of the technologies). In this sense, one might suppose that CA-TIMES in some way approximates an electricity dispatch model. While this may be true in a basic sense, it is not an entirely accurate depiction of the current version of the model. For instance, there are forty-eight (48) timeslices[13] in CA-TIMES, a number much less than typical power market models (which have hundreds or thousands of timeslices) but considerably more

[13] In the field of energy-economic systems modeling, a "timeslice" refers to the temporal disaggregation of the model. It represents a pre-defined length of time (typically on the order of hours, weeks, months, or years), for which the modeler provides data to the model. The model then treats each individual timeslice as homogenous throughout the year when carrying out its optimization. Generally speaking, the more timeslices available to the model, the more accurate the solution. However, that being said, there are important trade-offs with respect to model computation time and data availability.

than typical MARKAL-TIMES and other energy systems models (with only 6 to 12). This finer level of resolution offers certain advantages, paramount of which is a more realistic optimization/solution/scenario.

Each model year of CA-TIMES is divided up into six “seasons”, or rather, pairs of months:

- January/February
- March/April
- May/June
- July/August
- September/October
- November/December

These month-pairs are subsequently partitioned into eight three-hour time blocks:

- 0:00 – 3:00
- 3:00 – 6:00
- 6:00 – 9:00
- 9:00 – 12:00
- 12:00 – 15:00
- 15:00 – 18:00
- 18:00 – 21:00
- 21:00 – 24:00

The combination of the six month-pairs and eight time blocks leads to the 48 timeslices of the model (6 x 8 = 48). Every timeslice is unique; but within each, the representation is homogenous. For example, the time block between 6:00 to 9:00 during the January/February season is the same on January 4 as it is on January 23, February 12, or any other day during January or February. In addition, from the model’s perspective the timeslices are not chronological: in other words, what happens in the January/February 3:00-6:00 timeslice has little bearing on what happens in the 6:00-9:00 timeslice of the same season. The model treats each timeslice distinctly when making dispatch decisions. Other considerations that are not included in CA-TIMES but that would bear on dispatch decisions in reality include power plant air pollutant emissions rules, unexpected outages, and ramp rates.

Incorporating a fairly high degree of timeslice resolution into the model is important because electricity demand and supply fluctuates over the course of the day, week, month, and year. This is illustrated by the "heat maps" of Figure 18, where red colors indicate high values, yellow/orange indicates intermediate values, and green indicates low values. Clearly, California electricity demands peak during the afternoons and evenings of summer and early-autumn days. For the most part, this coincides with solar insolation (i.e., solar power potential), which is strong in California throughout the year and which peaks in the late-morning and early-afternoon. In contrast, wind speeds (i.e., wind power potential) tend to be strongest during the nighttime hours of spring and summer days, matching poorly the times of the day/year with the highest electricity demands. (This data is for 2003, and comes from McCarthy and Yang (2008a).)

Total Elec. Demand (share of year)

		T1 0:00 => 3:00	T2 3:00 => 6:00	T3 6:00 => 9:00	T4 9:00 => 12:00	T5 12:00 => 15:00	T6 15:00 => 18:00	T7 18:00 => 21:00	T8 21:00 => 24:00
1JF	January/February	1.4%	1.5%	1.9%	2.1%	2.0%	2.1%	2.2%	1.8%
2MA	March/April	1.5%	1.5%	1.9%	2.1%	2.1%	2.0%	2.2%	1.8%
3MJ	May/June	1.6%	1.6%	2.0%	2.3%	2.4%	2.4%	2.3%	2.0%
4JA	July/August	1.8%	1.8%	2.2%	2.7%	3.0%	3.1%	2.8%	2.3%
5SO	September/October	1.6%	1.7%	2.1%	2.4%	2.6%	2.7%	2.5%	2.0%
6ND	November/December	1.6%	1.6%	2.0%	2.2%	2.1%	2.2%	2.4%	2.0%

Wind Speeds (m/s)

		T1	T2	T3	T4	T5	T6	T7	T8
1JF	January/February	5.3	5.2	5.0	4.9	5.2	5.1	5.2	5.4
2MA	March/April	8.9	8.4	7.4	6.7	7.3	8.4	9.3	9.3
3MJ	May/June	10.5	9.7	8.5	7.7	8.2	9.6	10.7	10.7
4JA	July/August	9.9	8.6	7.1	5.9	6.9	8.9	10.9	11.0
5SO	September/October	6.9	6.3	5.6	4.9	5.5	6.1	6.6	7.2
6ND	November/December	5.9	5.7	5.1	4.9	5.5	5.6	6.1	6.1

Solar Insolation (W/m^2)

		T1	T2	T3	T4	T5	T6	T7	T8
1JF	January/February	0.0	0.0	315.9	668.6	609.8	246.7	0.0	0.0
2MA	March/April	0.0	23.7	536.8	723.5	693.5	422.8	0.0	0.0
3MJ	May/June	0.0	118.4	680.0	791.0	781.3	583.3	50.0	0.0
4JA	July/August	0.0	80.0	619.9	785.6	755.2	535.8	39.2	0.0
5SO	September/October	0.0	11.2	549.1	756.5	714.7	352.3	0.0	0.0
6ND	November/December	0.0	0.0	377.4	767.1	723.6	234.3	0.0	0.0

Figure 18 Electricity Demand, Wind Speeds, and Solar Insolation for Each of the 48 Timeslices in CA-TIMES

In the CA-TIMES model, the timing of electricity demands is specified for each of the end-use sectors, based on unpublished data from Ryan McCarthy that feeds into his EDGE-CA electricity dispatch model. The data represents the base-year 2005, and for the industrial, commercial, residential, and agricultural end-use sectors, the timing of electricity demands (across the 48 timeslices of the model) is assumed to follow the same temporal profile in all model years. Transportation demands for electricity are treated separately, however. In fact, in the current version of the model, these demands are only specified at the seasonal level, allowing the model to decide the optimal time to recharge plug-in electric vehicles. The only exception in the transport sector is the rail subsector, whose electricity demand profiles (for light- and heavy-rail) are currently known; hence, their demands are assumed to follow the same profile in all future years.

On the supply side the availability of all electric generation technologies are restricted to capacity factors within each timeslice that are consistent with historical averages (for thermal power plants, hydro, and nuclear) and resource availability (for wind, solar, and other renewables) for actual power plants and resources in California. These capacity factors depend on technological constraints to production (e.g., planned and unplanned outages due to maintenance), as well as on the timing of renewable resource potential (e.g., wind and hydro availability and solar insolation). In defining timeslice-specific capacity factors for the CA-TIMES model, information on power plant and renewable resource availability data is sourced from the EDGE-CA electricity dispatch model by McCarthy and Yang (2009), which compiles a large amount of data on historical outage periods for all thermal power plants in California, as well as actual wind speed and solar insolation profiles for several different sites in the state.

The CA-TIMES model also captures the cost of investing in new electrical transmission and distribution lines. This is especially important for “stranded” renewable resources that exist in remote regions of the western U.S. and Canada (e.g., solar, wind, and geothermal), for which transmission distances, and thus costs, would be rather significant if these resources were tapped for the California market. Transmission investment cost estimates for various renewable resource types are based on the California Public Utility

Commission's "33% RPS Implementation Analysis", which includes a spreadsheet model developed by the consulting firm E3 (CPUC, 2009).

Supply Sector

The supply sector is the largest and most complex sector of the CA-TIMES model, with respect to the sheer number of technologies and fuels that comprise it and the web of processes and commodity flows that link together to form its network. It is the most fundamental of all sectors in the model, since it is the source of all primary energy resources and is responsible for delivering all energy commodities (except for electricity) to both the fuel conversion and end-use sectors.

A number of primary energy resources are produced, or have the potential to be produced, in California or in surrounding states. CA-TIMES represents the production of these resources with supply curves of varying complexity. In the case of crude oil and natural gas, the "supply curves" are simply exogenous price projections for each future year, which are sourced from other studies (e.g., EIA (2010a) and IEA (2010)). Because oil and natural gas are globally-traded commodities and California only makes up a small share of global consumption/production, California is assumed to be a price-taker for these energy resources under the CA-TIMES framework – hence, the exogenous price projections, despite the fact that crude oil and natural gas are produced in California. In the case of biomass, CA-TIMES makes us of unique supply curves for each of twelve different feedstock types that have the potential to be produced "sustainably" (i.e., no water for irrigation, thus rain-fed, if water is needed for feedstock production) in

California and/or the Western United States outside of California. The supply curves are taken from Parker (2010), and the feedstocks include Forest Residues, Municipal Solid Waste (Mixed)[14], Municipal Solid Waste (Paper), Municipal Solid Waste (Wood), Municipal Solid Waste (Yard), Orchard and Vineyard Waste, Pulpwood, Agricultural Residues (Stovers and Straws), Energy Crops (Herbaceous), Yellow Grease, Animal Tallow, and Corn.

The CA-TIMES model also allows imports of primary energy resources and final energy commodities. For instance, because California does not have the capability to mine coal or uranium, these energy resources can be imported into the state from elsewhere in the U.S. or from abroad. And even for commodities that California can produce, the model still allows for a certain quantity to be imported from outside the state, as is the case for crude oil, natural gas (via pipeline or LNG), refined petroleum products (e.g., gasoline diesel, jet fuel, kerosene, residual fuel oil, etc.), biofuels (e.g., corn ethanol, cellulosic ethanol, sugarcane ethanol, bio-diesel, etc.), and hydrogen. Supply curves and/or exogenous price projections are specified for each of these imported commodities.

Dozens of fuel transport and delivery technologies are used in CA-TIMES to distribute the various primary and final energy commodities to the fuel conversion and end-use sectors. Along the way, production, transport, and delivery costs are assigned, and upstream emissions are allocated. The bulk of primary energy resources are delivered to the fuel conversion portion of the supply sector, which consists of crude oil refineries,

[14] Municipal Solid Waste (Mixed) includes the MSW (Dirty) and MSW (Food) categories from Nathan Parker's dissertation work.

bio-refineries, Fischer-Tropsch poly-generation plants, and hydrogen production facilities.

The refinery technology in CA-TIMES is able to flexibly produce a range of different petroleum products, taking crude oil, natural gas liquids, natural gas, and electricity as inputs (Figure 19). Crude oil and natural gas liquids are feedstock inputs (i.e., their carbon and energy content is converted into the fuel products), while the remaining energy carriers are combusted at the refinery in order to generate energy/heat for the various refining operations. In addition, a small fraction of the input crude oil is also combusted. Hydrogen is produced as an intermediary product/input at the refinery using natural gas steam methane reformation, though this process is not explicitly modeled. The outputs produced at the refinery include distillate heating oil #2, low-sulfur highway diesel (<500 ppm S), ultralow-sulfur highway diesel (<15 ppm S), conventional gasoline, reformulated gasoline, jet fuel, kerosene, high-sulfur residual fuel oil, low-sulfur residual fuel oil, liquefied petroleum gases (LPG), methanol, petrochemical feedstocks, asphalt, and petroleum coke. Reflective of a real-world refinery, the flexible technology in CA-TIMES is constrained from over-producing each fuel product by setting an upper limit on the share of total refinery output that can come from a particular fuel. These fuel product splits are relaxed slightly over time, and along with refinery efficiencies and resource inputs, they are calibrated to the base-year 2005, using data from the CEC's Energy Almanac (CEC, 2010a), the EIA Petroleum Navigator (EIA, 2010d), and the assumptions to the Petroleum Market Module of the EIA's NEMS model (EIA, 2010c). Through a process known as "capacity creep"[15], the existing stock of California refineries is allowed to expand over time. Estimates of future refinery creep for California refineries have been put at about 0.45% per year according to the CEC (CEC, 2010c). Thus, the state's refining capacity is able to grow, albeit with a much smaller capital outlay than would be expected if a "greenfield" refinery were to be built on a new site. Such greenfield expansions are also possible in the model through investments in a future refinery technology.

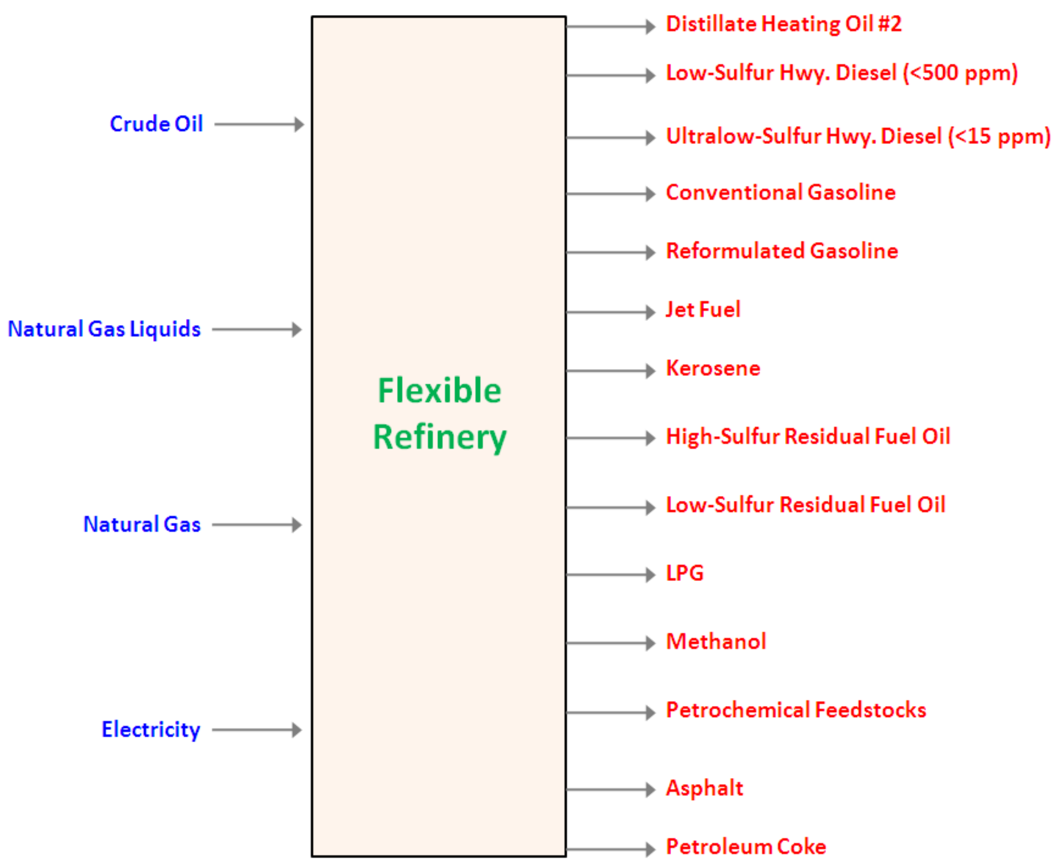

Figure 19 Simplified Schematic of Flexible Refinery Technology in CA-TIMES

[15] Refinery capacity creep is the term used to describe the cumulative result of many small projects and productivity enhancements that enable a refinery to increase crude oil input over time.

Several different types of bio-refinery technologies are modeled in CA-TIMES (Table 3), though only a couple of these are available in the base-year 2005: bio-diesel production facilities consuming yellow grease or animal tallow as feedstocks. Ethanol supply until 2010 is met by imports of corn ethanol from the Midwestern U.S. and sugarcane ethanol from Brazil. Soon after 2010, the model is able to invest in cellulosic ethanol plants (via either the biochemical or thermochemical pathway) and bio-derived residual fuel oil plants (via a pyrolysis bio-oil pathway). These future technologies consume one of nine types of cellulosic feedstock. In addition to producing their liquid fuel products, these bio-refineries also generate a small amount of electricity as a by-product. Feeding this low-carbon electricity to the grid can displace more carbon-intensive sources of electricity, such as natural gas plants. All future bio-refinery technologies are characterized by biomass input efficiencies, investment costs, fixed and variable O&M costs, annual capacity factors, technology-specific hurdle rates, year-to-year limits on capacity growth, and a variety of other information. These technology characterizations largely come from Bain (2007).

Table 3 Bio-Refineries and FT Poly-Generation Plants in CA-TIMES

Production Technology	Feedstock Types
Cellulosic Ethanol Plants	
Biochemical Pathway (50 or 100 million gal per year) Thermochemical Pathway (50 or 100 MGY)	Forest Residues Municipal Solid Waste, Paper Municipal Solid Waste, Wood Municipal Solid Waste, Yard Orchard and Vineyard Waste Pulpwood Agricultural Residues, Stovers/Straws Energy Crops
Bio-Residual Fuel Oil Plants	
Pyrolysis Bio-Oil Pathway (25 or 100 MGY)	Forest Residues Municipal Solid Waste, Mixed Municipal Solid Waste, Paper Municipal Solid Waste, Wood Municipal Solid Waste, Yard Orchard and Vineyard Waste Pulpwood Agricultural Residues, Stovers/Straws Energy Crops
Renewable Bio-Diesel Plants	
Hydro-treatment Pathway (50 or 100 MGY)	Yellow Grease Animal Tallow
Fischer-Tropsch Poly-Generation Plants	
Biomass Gasification (61 MGY) Biomass Gasification, w/ CCS (61 MGY)	Forest Residues Municipal Solid Waste, Mixed Municipal Solid Waste, Paper Municipal Solid Waste, Wood Municipal Solid Waste, Yard Orchard and Vineyard Waste Pulpwood Agricultural Residues, Stovers/Straws Energy Crops
Coal-Biomass Gasification, Syngas RC, w/ CCS (138 MGY) Coal-Biomass Gasification, Syngas OT, w/ CCS (112 MGY) Coal-Biomass Gasification, Syngas OT, w/ CCS (506 MGY)	Coal Forest Residues Municipal Solid Waste, Mixed Municipal Solid Waste, Paper Municipal Solid Waste, Wood Municipal Solid Waste, Yard Orchard and Vineyard Waste Pulpwood Agricultural Residues, Stovers/Straws Energy Crops

Fischer-Tropsch (FT) coal-biomass poly-generation plants represent yet another category of potential future fuel conversion technologies in CA-TIMES (Table 3). These plants consume one of nine types of cellulosic feedstock and then produce some combination of synthetic gasoline, diesel, jet fuel, and/or electricity. Co-firing with coal is an option with certain plant designs. In the current version of CA-TIMES, I have chosen to include five out of the sixteen biomass-to-liquid (BTL) and coal/biomass-to-liquid (CBTL) process configurations developed and analyzed by Kreutz et al. (2008). Using their naming convention, the following plant types are characterized in CA-TIMES: BTL-RC-V, BTL-RC-CCS, CBTL-RC-CCS, CBTL-OT-CCS, CBTL2-OT-CCS. According to the authors, all of these system designs are based on commercial or near-commercial technologies. The main differences between them have to do with their varying sizes, biomass-to-coal input ratios, and fuel/electricity product splits; whether or not CCS is utilized or CO_2 is vented to the atmosphere; and whether a once through (OT) or recycle (RC) approach is used for the initially unconverted synthetic gas ("syngas"). (Note that RC systems maximize FT liquids production, while OT systems allow for more electricity generation at the expense of reduced FT liquids production.) Two of the five plants made available to CA-TIMES consume only biomass (i.e., no coal co-firing); thus, they produce liquid fuel products with zero or significantly negative carbon intensities. For example, the BTL-RC-CCS plant design is an example of a negative emissions technology, since it takes carbon from biomass (which originally pulled CO_2 out of the atmosphere via photosynthesis) and permanently stores it underground. Further, because the three CBTL plants with coal-biomass co-firing each utilize CCS, they also produce liquid fuel products with relatively attractive carbon intensities, even though coal is used an input fuel. These carbon intensities are significantly better, or at least no worse, than petroleum-based gasoline. From a technological perspective, carbon capture and storage is particularly attractive with these FT liquids poly-generation plants because the CO_2 stream that is generated is naturally concentrated – in other words, a nearly pure stream of CO_2 is generated, by default, as a by-product of the FT process, thus the added costs of CO_2 capture are quite low. All future FT BTL/CBTL poly-generation plant technologies in CA-TIMES are characterized by coal and biomass input efficiencies, investment costs, fixed and variable O&M costs, annual capacity factors, technology-specific hurdle rates, year-to-year limits on capacity growth, and a variety of other information. The technology and cost assumptions come from Kreutz et al. (2008).

Hydrogen is supplied to the various end-use sectors in CA-TIMES via a number of different pathways. The following hydrogen production technologies are available to the model in future years: Coal Gasification (w/ and w/o CCS), Natural Gas Steam Methane Reformation (w/ and w/o CCS), Water Electrolysis, and Biomass Gasification (w/ and w/o CCS). Both coal gasification facilities in the model are intended for centralized production; the large-scale facility produces 1,200 metric tonnes of H_2 per day (t/d), while the mid-size facility produces 24 t/d.[16] The same situation is true of natural gas SMR facilities, except that a small-scale technology (0.48 t/d) is also available for distributed production at a refueling station. A mid-size water electrolysis technology (24 t/d) is available for centralized production, as well as a small-scale technology (0.48 t/d) for distributed production. All mid-size biomass gasification facilities (24 t/d), which consume one of the nine types of cellulosic feedstock, are intended for centralized production, and the biomass technologies that utilize CCS are potential negative emissions technologies. Hydrogen is the only commodity produced at each of the

[16] A 1,200 tonne/day H2 production facility is roughly equivalent to producing 438 million gasoline gallon equivalents (gge) per year on an energy basis. A 24 t/d facility is equivalent to 8.76 million gge/yr, while a 0.48 t/d facility is equivalent to 0.175 million gge/yr. A 2.74 t/d refueling station is equivalent to 1.00 million gge/yr.

production facilities, no matter the technology: no electricity co-generation takes place. All future hydrogen production technologies in CA-TIMES are characterized by coal, natural gas, biomass, electricity, and/or water input efficiencies, investment costs, fixed and variable O&M costs, annual capacity factors, technology-specific hurdle rates, year-to-year limits on capacity growth, and a variety of other information. The technology and cost assumptions draw heavily from the U.S. EPA's 9-region MARKAL model (EPA, 2008a), which is partially based on NRC (2004).

After it is produced, hydrogen is distributed to end-use sector technologies by either pipeline or truck transmission and delivery technologies, depending on the form in which the hydrogen is to be consumed, gas or liquid (Figure 20). (Of course, hydrogen produced with distributed technologies requires no transmission and delivery since the production occurs at the refueling station.) In the model, distinctions are made between three different levels of geographical aggregation: Urbanized Area (UA), Urban Cluster (UC), and Rural Region (RR). This has a bearing on the costs of hydrogen transmission and distribution. An urbanized area generally refers to a densely settled area of 50,000 or more people; an urban cluster refers to an area of at least 2,500 people but fewer than 50,000 people; and a rural region is any area that falls outside of the two urban designations. Pipeline delivery of gaseous hydrogen from a centralized production facility first occurs via long-distance transmission to a UA, UC, or RR city-gate. Then, trunk delivery via pipeline takes place within the UAs and UCs. Finally, service pipelines distribute hydrogen to refueling stations. (Note that in rural regions, the trunk delivery step is bypassed.) Truck delivery of liquid hydrogen is done in much the same way. First, long-distance transmission to UA, UCs, and RRs is carried out by large trucks; then, for UAs and UCs small trucks distribute hydrogen to refueling stations. An alternate pathway for UAs and UCs is for gaseous hydrogen to be transported to the city-gate by means of a pipeline; then, the hydrogen is liquefied and loaded onto a truck for distribution to the refueling station. Once at the refueling station, which is assumed to have a dispensing capacity of 2,740 kg/day, the model can choose to fuel hydrogen vehicles with either gaseous or liquefied hydrogen. This choice depends on the full lifecycle costs of the hydrogen fuel (production + delivery), as well as the investment costs of the hydrogen vehicles. Each step in the delivery process has some cost, efficiency, and emission flow associated with it. These technology characterizations are based on the EPAUS9r MARKAL model (EPA, 2008a), NRC (2004), and the U.S. DOE's Hydrogen Analysis (H2A) model (DOE, 2008).

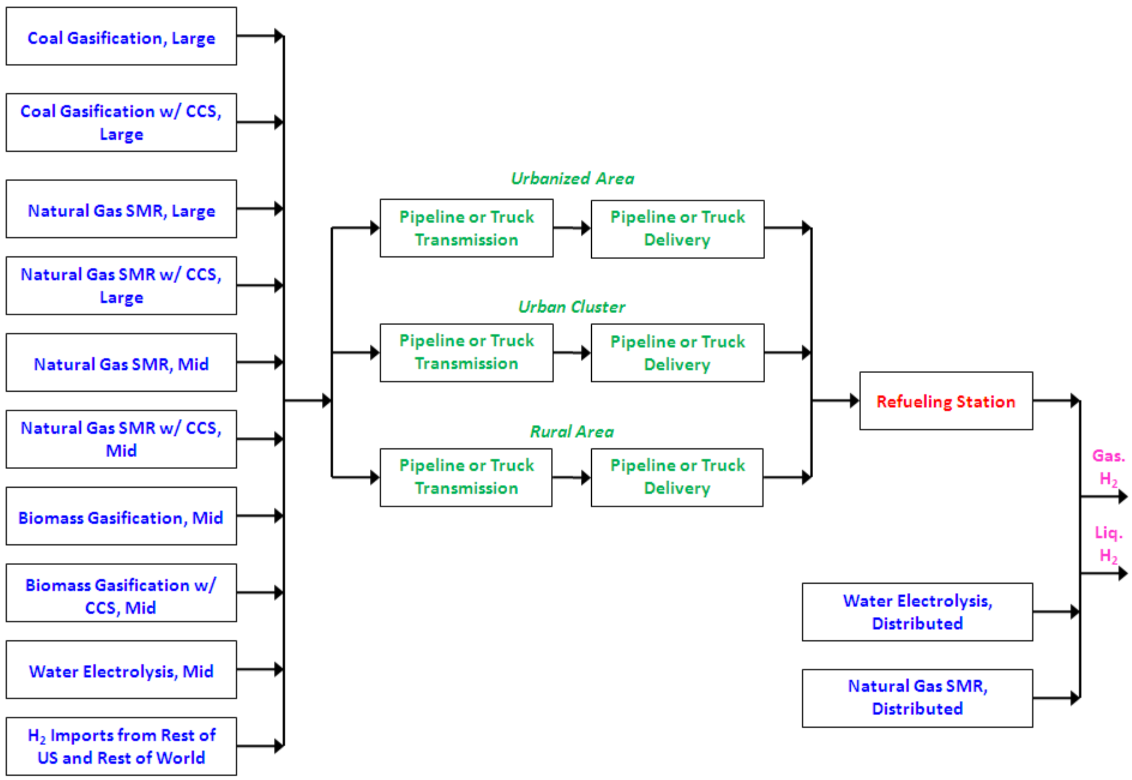

Figure 20 Simplified Schematic of Hydrogen Production and Supply Technologies in CA-TIMES

At this point, it should be noted, however, that despite the somewhat sophisticated treatment of hydrogen transmission and delivery in CA-TIMES that has been described in the above paragraphs, in the current version of the model, there are no constraints to specify demand splits between urbanized areas, urban clusters, and rural regions. In other words, there are no constraints to ensure a transition from distributed hydrogen production in the early years to centralized production later on, or from the large metropolitan areas of the state ("lighthouse cities") in the early stages to rural regions and smaller towns several years thereafter. The current version of CA-TIMES does not make these fine geographic distinctions since it treats California as a single region, although a more sophisticated spatial representation could certainly be added at a later date, as has already been discussed by other members of our research team. Such geographic detail is outside the scope of the present analysis. However, one of the goals of my dissertation work to this point has been to put in place most of the model structure needed for analyzing these issues, with a realization that there is considerable interest within ITS-Davis in analyzing spatial aspects of hydrogen (as well as biofuels) infrastructure development. I leave these interesting questions to others and to future research.

Transportation Sector

The transportation sector of CA-TIMES is the most detailed and disaggregated of the five end-use demand sectors. Indeed, the level of bottom-up technological detail is arguably greater than typical energy systems models, especially for the non-LDV transport subsectors. As shown in Table 4, the transport sector consists of eleven separate subsectors; a few of these subsectors are further disaggregated into segments (e.g., Transit Buses, School Buses, etc.). Each segment represents a unique service demand, which the model must satisfy. (The units of each service demand are shown in parentheses.) For instance, demand for light-duty cars is distinct from light-duty trucks. Both of these are exogenously specified by the modeler, and there is no possibility for endogenous segment-switching (i.e., from LDTs to LDCs) – at least in the current version of the model – unless the modeler decides to run a scenario with different demands for each segment. In general, demand projections are based on government forecasts and/or other research studies.

Within each subsector, a number of technologies exist for satisfying the specified end-use demands in each subsector/segment (Table 4). In the base-year 2005, and up through

2010, the model is calibrated to historical data. This effectively means that, aside from some Flex-Fuel E-85 vehicles in the light-duty subsector, the model is constrained to invest only in fossil fuel technologies between 2005 and 2010. (Note that in Table 4, a '*' represents technologies that were used in the base-year 2005.) After 2010, the model is free to invest in any technology, depending on its assumed first year of availability and subject to constraints on its growth. From a modeling perspective, every transport sector technology is represented in essentially the same way. The technologies consume fuel and energy carriers (gasoline, diesel, jet fuel, RFO, natural gas, biofuels, hydrogen, electricity, etc.) and produce end-use service demands. (These fuels/carriers come from the supply sector, as described previously.) Each technology has an assumed efficiency for turning energy into service demand, and each is given a fixed upper bound on its annual availability (e.g., the maximum number of miles that a single light-duty car can travel within a given year). For the base-year 2005, efficiencies and availabilities are calculated for each base-year technology in each transport subsector and segment. It is also necessary to specify average vehicle lifetimes and the stock of technologies in the base-year (i.e., how many vehicles of each type were available in each subsector and segment in 2005). Future technologies require much the same information, and in addition the technology's first year of market availability, investment and O&M costs (aside from fuel costs), and technology-specific hurdle rates. In some of these cases (e.g., for efficiencies and investment costs), the input assumptions are exogenously specified trajectories for all future model years. Other studies are used to inform these assumptions. With all of this information at its disposal, the model is free to make fuel use and investment decisions by trading off the costs of competing end-use technologies.

Of course, certain other considerations also come into play, such as vehicle efficiency standards and renewable fuel mandates. An expanded discussion of the CA-TIMES transportation sector is found in Section 3 below. Unfortunately, due to the inherent space limitations of this report, it is not possible to discuss the composition of each of the various transport subsectors in great detail, for example, the relative importance of freight versus passenger aviation (comparing intrastate, interstate, and international travel) or the breakdown between the various types of rail. That being said, a fair amount of research has previously been conducted on this topic for California, and the interested reader is encouraged to read through Yang, McCollum, McCarthy, and Leighty (2008) for a considerable amount of further information.

Table 4 Transportation Sector Technologies in CA-TIMES

Transport Subsectors and Service Demands	Technologies[†]
Light-Duty Vehicles	
Light-Duty Cars (vehicle-miles traveled) Light-Duty Trucks (vehicle-miles traveled)	Gasoline ICE * Gasoline HEV * Gasoline ICE (Moderate Eff.) Gasoline ICE (Advanced Eff.) Diesel ICE * Diesel HEV E-85 Flex Fuel ICE E-85 Flex Fuel ICE (Moderate Eff.) E-85 Flex Fuel ICE (Advanced Eff.) E-85 Flex Fuel HEV Dedicated Ethanol ICE Natural Gas ICE Natural Gas Bi-Fuel ICE LPG ICE LPG Bi-Fuel ICE Gasoline PHEV 10/30/40/60 E-85 Flex Fuel PHEV 10/30/40/60 Diesel PHEV 10/30/40/60 Battery-Electric Hydrogen Fuel Cell Methanol Fuel Cell Gasoline Fuel Cell
Motorcycles	
Motorcycles (vehicle-miles traveled)	Gasoline ICE * Dedicated Ethanol ICE
Heavy-Duty Trucks	
Heavy-Duty Trucks (vehicle-miles traveled)	Gasoline ICE * Diesel ICE * Diesel ICE (+10% Eff.) Diesel ICE (+20% Eff.) Diesel ICE (+40% Eff.) Natural Gas (CNG) ICE LPG ICE Dedicated Ethanol ICE Dedicated Methanol ICE
Medium-Duty Trucks	
Medium-Duty Trucks (vehicle-miles traveled)	Gasoline ICE * Gasoline HEV Diesel ICE * Diesel HEV Natural Gas (CNG) ICE Natural Gas (CNG) HEV LPG ICE Dedicated Ethanol ICE Gasoline PHEV30 Diesel PHEV30 Natural Gas (CNG) PHEV30 Hydrogen ICE–HEV Hydrogen Fuel Cell
Buses	
Transit Buses (vehicle-miles traveled) School Buses (vehicle-miles traveled) Intercity and Other Buses (vehicle-miles traveled)	Gasoline ICE * Gasoline ICE (+20% Eff.) Gasoline ICE (+40% Eff.) Diesel ICE * Diesel ICE (+20% Eff.) Diesel ICE (+40% Eff.) Diesel HEV

	Natural Gas (CNG) ICE * Natural Gas (CNG) HEV LPG ICE Dedicated Ethanol ICE Dedicated Methanol ICE Gasoline PHEV30 Diesel PHEV30 Natural Gas (CNG) PHEV30 Electric * Hydrogen ICE–HEV Hydrogen Fuel Cell
Rail	
Commuter Rail (passenger-miles traveled) Heavy Rail (passenger-miles traveled) Light Rail (passenger-miles traveled) Intercity Passenger Rail (passenger-miles traveled) Freight Rail (ton-miles traveled)	Diesel * Electric *
Marine	
Domestic - Intrastate/California - Large Shipping Vessel (ton-miles traveled) Domestic - Intrastate/California - Harbor Craft (hours of operation) Domestic - Intrastate/California - Personal Recreational Boat (hours of operation) Domestic - Interstate - Large Shipping Vessel (ton-miles traveled) Foreign/International - Large Marine Vessel (vessel-miles traveled)	Gasoline ICE * Diesel ICE * Residual Fuel Oil ICE * Dedicated Ethanol ICE Diesel Molten Carbonate Fuel Cell
Aviation	
Domestic - Intrastate/California - Passenger Aviation (passenger-miles traveled) Domestic - Intrastate/California - Freight Aviation (ton-miles traveled) Domestic - Intrastate/California - General Aviation (hours of operation) Domestic - Interstate - Passenger Aviation (passenger-miles traveled) Domestic - Intrastate/California - Freight Aviation (ton-miles traveled) Foreign/International - Passenger Aviation (passenger-miles traveled) Foreign/International - Freight Aviation (ton-miles traveled) Other Miscellaneous Aviation (PJ of activity)	Jet Fuel Turbofan Jet Engine * Aviation Gasoline Propeller * Gasoline * Hydrogen Turbofan Jet Engine
Off-Road & Construction	
Off-Road & Construction Devices (hours of operation)	Gasoline * Diesel * LPG/CNG * Dedicated Ethanol Hydrogen Electricity
Agriculture	
Agricultural Vehicles (hours of operation)	Gasoline * Diesel * Dedicated Ethanol Hydrogen Electricity
Pipelines	
Natural Gas Consumption for Pipelines (PJ of NG)	Natural Gas *

† *Notes: The '*' symbol is used to denote technologies that were used in the base-year 2005.*

Industrial, Commercial, Residential, and Agricultural Sectors

Because this dissertation research focuses on the transportation, electricity, and supply sectors (since they account for 85% of all GHG emissions related to fuel combustion in California), the current version of the CA-TIMES model has a fairly simple representation of end-use energy consumption in the industrial, commercial, residential, and agricultural (collectively "ICRA") sectors. Eventually, in later versions of the model and through contributions from other members of our research team, these other sectors will be modeled at a level of technological detail that is similar to that which currently exists for transportation, electricity, and supply (i.e., describing energy service demands for the different segments of each of these sectors and the technologies and fuels that can potentially be used to supply the end-use demands, such as light bulbs, air conditioner, refrigerators, etc.). In the meantime, however, in order to satisfactorily develop future energy scenarios where deep reductions in economy-wide greenhouse gas emissions are to be made, there must be at least some representation of the ICRA sectors (and the fuel they consume and emissions they generate), no matter how limited the detail. One cannot simply ignore these sectors entirely. My approach to solving this problem has been to represent final energy consumption in each of the four ICRA sectors with generic input-output technologies. Each sector possesses only one of these technologies, and each technology consumes exogenously specified quantities of various types of fuel in each year. In other words, both the supply of final energy and the demand for total useful energy are specified in energy units (e.g., PJ). The efficiency of each of the generic input-output technologies is set at 100%.

Total useful energy demand by sector and the breakdown of final energy by fuel type by sector are calibrated to published energy statistics for the base-year 2005, using the fuel use estimates of the CARB GHG Inventory (CARB, 2010b). For future years, demand trajectories and the fuel use mix are exogenously specified by the modeler; these input assumptions can be easily and quickly modified across different model runs (e.g., when running a reference case vs. a deep GHG reduction scenario). Obviously, given this rigid framework, the model is not free to make fuel use and investment decisions by trading off the costs of competing end-use technologies (e.g., boilers, furnaces, compact fluorescent light bulbs, solar hot water heating, etc.), as it is able to do in the transportation, electricity, and supply sectors. However, that being said, the framework does partially allow for feedback and interplay with the other sectors, since the fuel demands in the ICRA sectors send a price/quantity signal to these other sectors, which impacts the fuel use and investment decisions therein.

In my dissertation work, I have relied on other studies to develop future fuel use and demand scenarios for the ICRA sectors. For instance, in developing my Reference Case I draw heavily from the California Energy Commission and UC-Davis Advanced Energy Pathways (AEP) project (McCarthy et al., 2008a, b), while for my Deep GHG Reduction Scenario I base my projections on the well-known BLUE Map scenarios of the IEA's Energy Technology Perspectives (ETP) 2010 study (IEA, 2010). The projections by fuel type for these two sets of scenarios are shown for the four ICRA sectors starting from Figure 27 and Figure 57, respectively.

Figure 21 illustrates the modeling framework adopted for the industrial, commercial, residential, and agricultural end-use sectors. In each of the sectors, one or more of thirty different fuels is consumed by the generic input-output technology, and the combined intake of these fuels results in the total useful energy demand for the sector (IND/COM/RSD/AGR). Of course, not every fuel is consumed in each sector. For example, in the base-year 2005, only five different fuels were consumed in the agricultural sector, whereas more than a dozen fuels were consumed in the industrial sector.

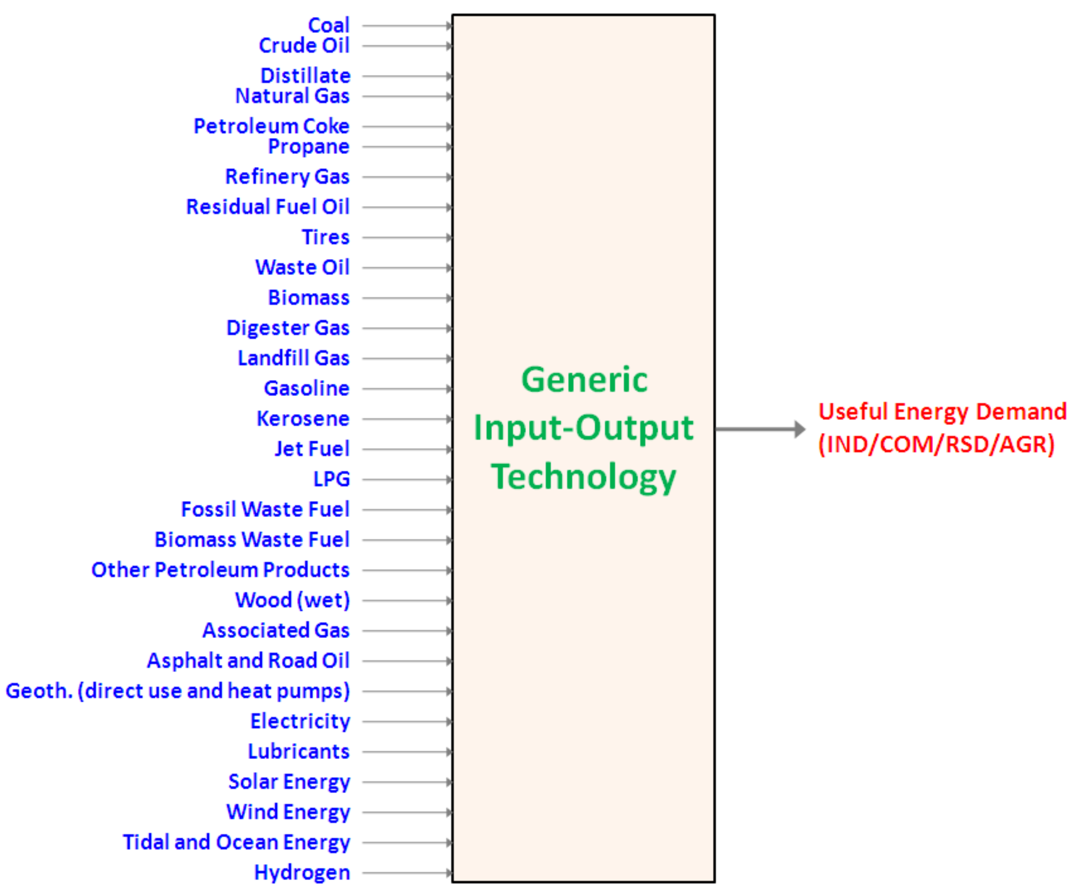

Figure 21 Simplified Schematic of Generic Input-Output Technology Used in the Industrial, Commercial, Residential, and Agricultural Sectors

3. Key Input Assumptions and Data Sources

The results generated using the CA-TIMES model are, like any other model, entirely a function of the data and assumptions that go into building them. It is, therefore, important to review some of the key input assumptions and data sources of the model, at least those that have not already been described. That being said, because CA-TIMES is such a large model (and will only grow larger in the future), it is rather infeasible to list all assumptions in this report, even in an appendix. (The best sources of documentation are the underlying VEDA-TIMES spreadsheets themselves.) For this reason, I concentrate here on only certain parts of the electricity, supply, and transportation sectors, given that these are of greatest relevance and interest for the purposes of my dissertation.

Electric Generation Sector

As mentioned previously, calibration of the electric generation sector between 2005 and 2010 is achieved by using input to and output from the EDGE-CA electricity dispatch model for California by McCarthy and Yang (2009), which is itself largely based on the U.S. EPA's eGRID power plant database (EPA, 2009). Then, in deciding how to supply electricity after 2010, the model is able to choose amongst a suite of more than three dozen power plant technologies. In this regard, two of the most important decision-making criteria are investment costs and plant efficiencies. The next two tables summarize the Reference Case cost and efficiency assumptions of the CA-TIMES model in the particular model years, for which data is provided to CA-TIMES; the model then interpolates for the costs in the in-between years.[17] In general, investment cost and efficiency assumptions are taken from the EIA's AEO2010 Reference Case. (Fixed and variable O&M costs are also generally taken from the same source, although they are not shown here.) Some notable exceptions include tidal/ocean energy plants, for which costs come from the IEA's ETP2008 report (IEA, 2008), and nuclear plants, for which costs and efficiencies are calculated based on a combination of data from several sources (Ansolabehere, 2003; DOE, 2001; EIA, 1998, 2010a; NEI, 2003; OECD, 2002). Note that the efficiencies of the three nuclear plants are not expressed in percentages, but rather in terms of metric tonnes of enriched uranium input per petajoule of produced electricity. The latter can be calculated with knowledge of both the burn-up (i.e., fuel utilization)[18] rate and thermal efficiency of each nuclear plant. Furthermore, the efficiency assumptions shown in the tables for non-geothermal and non-biomass renewables (e.g., solar, wind, hydro, and tidal) are simply those of an average fossil-thermal power plant. This is done so that, from a primary energy resource perspective, all power plant inputs can be represented in terms of fossil energy-equivalents. The investment cost numbers shown in the table below do not include the added costs of new transmission and distribution lines.

[17] Note that all costs in the CA-TIMES model are expressed in 2007 U.S. dollars.
[18] The burn-up rate is defined as amount of energy output (usually in terms of kWh or MW-days) divided by the unit mass of fuel input (usually expressed in terms of heavy metal, e.g., kg Uranium).

Table 5 Investment Cost Assumptions for New Power Plants in the Reference Case

Investment Costs for New Power Plants ($/kW) *(Notes: Costs are interpolated between the data years shown.)*	2005	2015	2035	2050
Natural Gas Combustion (Gas) Turbine (NGGT)	685	745	518	518
Advanced Natural Gas Combustion (Gas) Turbine (NGGT)	648	699	552	552
Natural Gas Combined-Cycle (NGCC)	984	1,070	744	744
Advanced Natural Gas Combined-Cycle (NGCC)	968	1,048	698	698
Advanced Natural Gas Combined-Cycle (NGCC), w/CCS	1,932	2,054	1,191	1,191
Coal Steam	2,223	2,418	1,681	1,681
Advanced Coal Int. Gasif. Combined-Cycle (IGCC)	2,569	2,769	1,829	1,829
Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS	3,776	4,022	2,410	2,410
Biomass IGCC (Forest Residues)	7,698	8,330	5,548	5,548
Biomass IGCC (Municipal Solid Waste, Mixed)	7,698	8,330	5,548	5,548
Biomass IGCC (Municipal Solid Waste, Paper)	7,698	8,330	5,548	5,548
Biomass IGCC (Municipal Solid Waste, Wood)	7,698	8,330	5,548	5,548
Biomass IGCC (Municipal Solid Waste, Yard)	7,698	8,330	5,548	5,548
Biomass IGCC (Orchard and Vineyard Waste)	7,698	8,330	5,548	5,548
Biomass IGCC (Pulpwood)	7,698	8,330	5,548	5,548
Biomass IGCC (Agricultural Residues, Stovers/Straws)	7,698	8,330	5,548	5,548
Biomass IGCC (Energy Crops)	7,698	8,330	5,548	5,548
Biogas from Landfills and Animal Waste Digesters	5,199	5,625	3,747	3,747
Geothermal, in California	3,498	3,785	2,521	2,521
Geothermal, in Western U.S. Outside California	3,498	3,785	2,521	2,521
Hydroelectric, Conventional	4,583	4,959	3,303	3,303
Hydroelectric, Reversible (Pumped Storage)	2,291	2,480	1,652	1,652
Wind, Lower Class Resources in CA	3,931	4,254	2,833	2,833
Wind, Higher Class Resources in CA	3,931	4,254	2,833	2,833
Wind, Lower Class Resources in Western U.S. Outside CA	3,931	4,254	2,833	2,833
Wind, Higher Class Resources in Western U.S. Outside CA	3,931	4,254	2,833	2,833
Wind, Offshore	7,874	8,520	5,675	5,675
Solar Thermal, in CA	8,725	9,441	7,398	7,398
Solar Thermal, in Western U.S. Outside CA	8,725	9,441	7,398	7,398
Solar Photovoltaic	10,491	11,352	8,895	8,895
Molten Carbonate Fuel Cell	9,313	10,078	7,896	7,896
Tidal and Ocean Energy	14,667	12,633	8,567	6,667
Generic Distributed Generation – Baseload	1,400	1,515	1,009	1,009
Generic Distributed Generation – Peak	1,681	1,819	1,212	1,212
Nuclear, Conventional Light Water Reactors (LWR)	3,820	4,089	2,496	2,496
Nuclear, Pebble-Bed Modular Reactor (PBMR)	3,316	3,549	2,167	2,167
Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR)	2,977	3,186	1,945	1,945

Table 6 Efficiency Assumptions for New Power Plants in the Reference Case

New Power Plant Efficiencies (%) *(Notes: For non-geothermal and non-biomass renewables, efficiencies are assumed to be similar to an average fossil-thermal plant. Efficiences are interpolated between the data years shown.)*			
	2005	2035	2055
Natural Gas Combustion (Gas) Turbine (NGGT)	31.6%	32.7%	32.7%
Advanced Natural Gas Combustion (Gas) Turbine (NGGT)	36.7%	39.9%	39.9%
Natural Gas Combined-Cycle (NGCC)	47.4%	50.2%	50.2%
Advanced Natural Gas Combined-Cycle (NGCC)	50.5%	53.9%	53.9%
Advanced Natural Gas Combined-Cycle (NGCC), w/CCS	39.6%	45.5%	45.5%
Coal Steam	37.1%	39.0%	39.0%
Advanced Coal Int. Gasif. Combined-Cycle (IGCC)	38.9%	45.8%	45.8%
Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS	31.6%	41.1%	41.1%
Biomass IGCC (Forest Residues)	36.1%	43.9%	43.9%
Biomass IGCC (Municipal Solid Waste, Mixed)	36.1%	43.9%	43.9%
Biomass IGCC (Municipal Solid Waste, Paper)	36.1%	43.9%	43.9%
Biomass IGCC (Municipal Solid Waste, Wood)	36.1%	43.9%	43.9%
Biomass IGCC (Municipal Solid Waste, Yard)	36.1%	43.9%	43.9%
Biomass IGCC (Orchard and Vineyard Waste)	36.1%	43.9%	43.9%
Biomass IGCC (Pulpwood)	36.1%	43.9%	43.9%
Biomass IGCC (Agricultural Residues, Stovers/Straws)	36.1%	43.9%	43.9%
Biomass IGCC (Energy Crops)	36.1%	43.9%	43.9%
Biogas from Landfills and Animal Waste Digesters	25.0%	25.0%	25.0%
Geothermal, in California	10.3%	11.3%	11.3%
Geothermal, in Western U.S. Outside California	10.3%	11.3%	11.3%
Hydroelectric, Conventional	34.5%	34.5%	34.5%
Hydroelectric, Reversible (Pumped Storage)	77.5%	77.5%	77.5%
Wind, Lower Class Resources in CA	34.5%	34.5%	34.5%
Wind, Higher Class Resources in CA	34.5%	34.5%	34.5%
Wind, Lower Class Resources in Western U.S. Outside CA	34.5%	34.5%	34.5%
Wind, Higher Class Resources in Western U.S. Outside CA	34.5%	34.5%	34.5%
Wind, Offshore	34.5%	34.5%	34.5%
Solar Thermal, in CA	34.5%	34.5%	34.5%
Solar Thermal, in Western U.S. Outside CA	34.5%	34.5%	34.5%
Solar Photovoltaic	34.5%	34.5%	34.5%
Molten Carbonate Fuel Cell	43.0%	49.0%	49.0%
Tidal and Ocean Energy	34.5%	34.5%	34.5%
Generic Distributed Generation – Baseload	37.7%	38.3%	38.3%
Generic Distributed Generation – Peak	33.9%	34.5%	34.5%

New Nuclear Plant Efficiencies (tonnes enriched uranium per PJ electricity) *(Notes: Efficiences are interpolated between the data years shown.)*			
	2005	2035	2055
Nuclear, Conventional Light Water Reactors (LWR)	0.65	0.65	0.65
Nuclear, Pebble-Bed Modular Reactor (PBMR)	0.36	0.36	0.36
Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR)	0.22	0.22	0.22

Supply Sector

Supply curves for crude oil, natural gas, and coal are modeled in CA-TIMES as exogenously specified price projections, since California is assumed to be a price-taker for these energy resources under the CA-TIMES framework. In the Reference Case scenario, these trajectories, which are shown in Figure 22, come from the EIA's AEO2010 Reference Case projections (and extended post-2035 using projections from the IEA's ETP 2010 Baseline Scenario), as discussed in Section 2. Interestingly, after having fallen steadily for several years, EIA forecasts oil and natural gas prices to rise significantly over the next two to three decades.

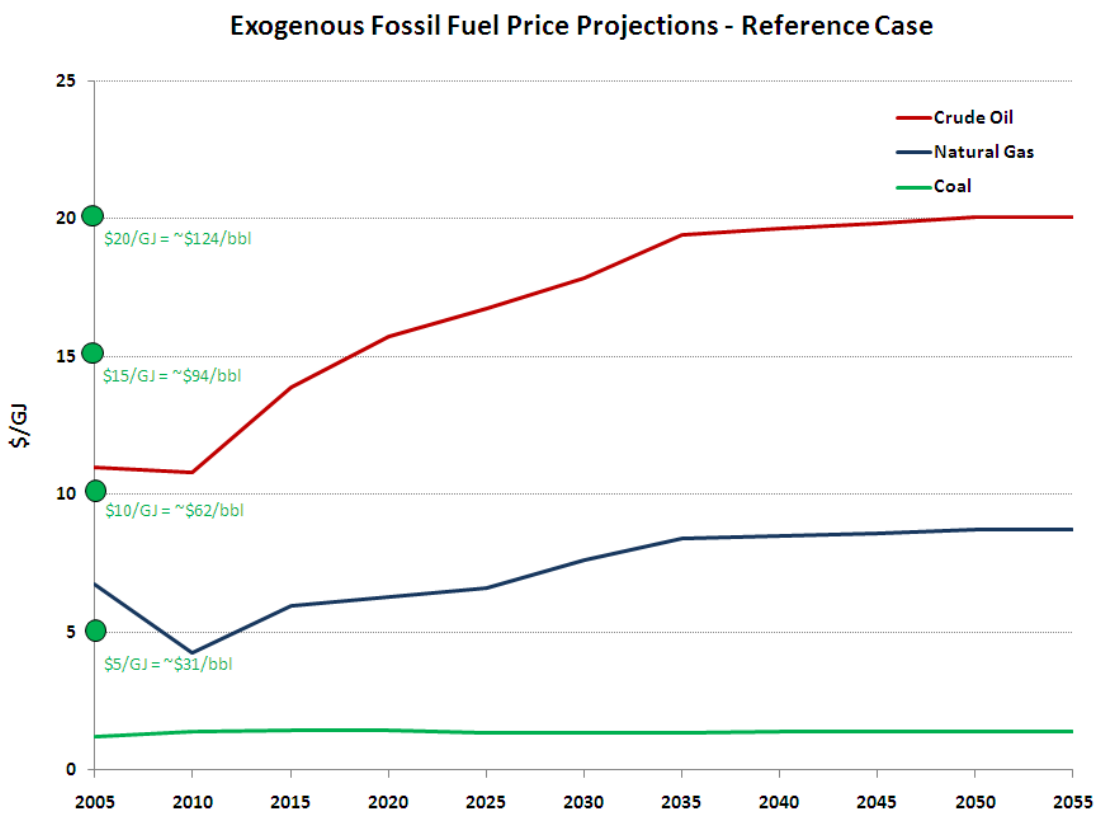

Figure 22 Exogenous Fossil Fuel Price Projections in the Reference Case

Biomass supply curves are based on work by Parker (2010). Two sets of his supply curves are used: one for biomass produced in California, and a second for biomass produced in the Western U.S. outside of California.[19] Unique supply curves exist for each of twelve different feedstock types. Presumably, all biomass produced in California will be available for consumption in the state. On the other hand, not all biomass in the Western U.S. will find its way to California in the form of raw biomass or, more likely, a liquid biofuel. In this latter case, an important assumption is made within CA-TIMES that only a fraction of Western U.S. biomass can be "captured" by the California market. This "fair share" assumption is varied in different scenarios, but in the Reference Case I assume a value of approximately 30%, which is roughly equivalent to California's current share (and projected future share) of Western U.S. population and liquid fuels consumption. As an illustration, Figure 23 sums up the availability of the various biomass feedstock types in 2050 in the Reference Case into an aggregate supply curve for both California and the Western U.S. Note that these costs only include biomass feedstock procurement; they do not include transport to a bio-refinery or power plant. In total, approximately 1,876 PJ of biomass are available for consumption in the California "energy system" in 2050. This is equivalent to roughly 117 million bone dry tons[20], or less than 10% of total sustainable biomass potential in the U.S., as estimated by the "Billion-Ton Study" (Perlack et al., 2005). For comparison, note that typical values for global sustainable biomass potential in 2050 are in the range of 50,000 to 150,000 PJ

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[19] The Western U.S. is defined as all states in the continental U.S. (lower 48) that are west of the Mississippi River.

[20] This simplified calculation assumes an average biomass energy content of 16 GJ per bone dry ton, which is representative of typical forest residues, energy crops, and certain types of municipal solid waste.

(van Vuuren et al., 2010) – between 27 and 80 times the level assumed to be available for California consumption in the same year.

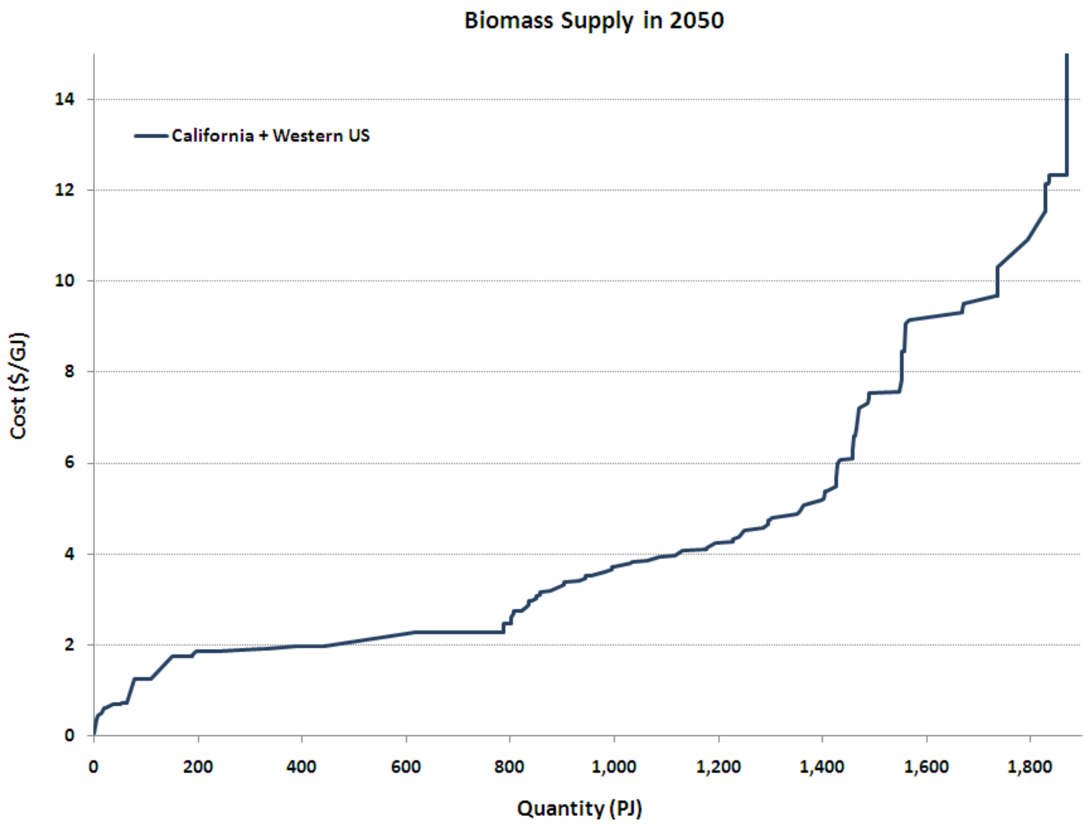

Figure 23 Aggregate Supply Curve for All Types of Biomass Available in California and the Western U.S. in the Reference Case in 2050

Investment cost and efficiency assumptions for refinery technologies are shown in Table 7 and Table 8, respectively.[21] As previously mentioned, California's existing refineries are able to expand production through a process known as "capacity creep". Such incremental growth is far less expensive than constructing a "greenfield" refinery on a brand new site. Refinery cost assumptions come from EIA (2006) and are consistent with those of EPA's US9r MARKAL model (EPA, 2008a). Efficiency assumptions for

[21] Investment costs are expressed in units of million dollars per annual input capacity ($/PJ-yr) because the refinery technologies are input-normalized in CA-TIMES.

existing refineries are calibrated to the base-year 2005, using data from the CEC's Energy Almanac (CEC, 2010a), the EIA Petroleum Navigator (EIA, 2010d), and the assumptions to the Petroleum Market Module of the EIA's NEMS model (EIA, 2010c). Efficiencies of future refineries are based on the latter. Note that refinery efficiencies are expressed in terms of the amount of energy consumed divided by crude oil feedstock consumption. In this sense, it is important to recognize that only a small portion of input crude oil is actually combusted at the refinery (~11%). The vast majority of the energy and carbon content of crude oil (i.e., the feedstock portion) is converted into fuel products, which are subsequently consumed/combusted in other sectors.

Table 7 Investment Cost Assumptions for New Refining Capacity

Investment Costs for New Refining Capacity (M$/PJ-yr) *(Notes: Values apply to all model years.)*	
Existing Refinery ("Creep")	4.61
New Refinery ("Greenfield")	18.43

Table 8 Efficiency Assumptions for Refineries

Refinery Energy Consumption (PJ_Input / PJ_Oil-Feedstock) *(Notes: Values apply to all model years.)*				
	Crude Oil	Natural Gas	Natural Gas Liquids	Electricity
Existing Refinery	1.110	0.019	0.019	0.003
New Refinery	1.110	0.014	0.019	0.004

The next several tables summarize the investment cost and efficiency assumptions for cellulosic ethanol, biodiesel, pyrolysis bio-oil, FT poly-generation, and hydrogen production plants and facilities.[22] Data sources and further information are discussed in Section 2, but in general the characterizations of these fuel conversion technologies are based on studies by Bain (2007) and Kreutz et al. (2008), EPA (2008a), and NRC (2004).

[22] Investment costs are expressed in units of million dollars per annual output capacity ($/PJ-yr) because these fuel conversion technologies are output-normalized in CA-TIMES.

Note that, in contrast to the flexible refineries, the efficiencies of these technologies are expressed in terms of the amount of energy consumed divided by total plant output. Furthermore, because of the particular studies that were consulted in building up the technological representation of the CA-TIMES model, many of the fuel conversion technologies are represented by investment cost and efficiency assumptions that do not change over time. The assumptions shown in the tables below are the learned-out values, which are assumed to be achieved once the technology has matured and is commercially available at large-scale. Such representation is a bit different than for the electric generation and, in general, transportation technologies, for which costs and efficiencies are assumed to change gradually over time due to learning and experience. A potentially important impact of this difference in technological representation is on the rate of adoption of specific technologies. For instance, CA-TIMES results could show initial growth of these constant cost/efficiency technologies to be faster than what might ultimately be seen in reality, if the assumptions in the model turned out to be a bit too optimistic. In the later years, however, the opposite effect could be seen: the assumptions could turn to be too pessimistic.

Table 9 Investment Cost Assumptions for New Cellulosic Ethanol Plants

Investment Costs for New Cellulosic Ethanol Plants (M$/PJ-yr) *(Notes: Values are interpolated between the data years shown.)*				
	2005	**2020**	**2035**	**2050**
Biochemical Production Pathway				
All Biomass Feedstock Types (50 MGY)	38.4	38.4	38.4	38.4
All Biomass Feedstock Types (100 MGY)	32.1	32.1	32.1	32.1
Thermochemical Production Pathway				
All Biomass Feedstock Types (50 MGY)	42.3	42.3	42.3	42.3
All Biomass Feedstock Types (100 MGY)	34.9	34.9	34.9	34.9

Table 10 Investment Cost Assumptions for New Biodiesel Plants

Investment Costs for New Biodiesel Plants (M$/PJ-yr) *(Notes: Values are interpolated between the data years shown.)*				
	2005	2020	2035	2050
All Biomass Feedstock Types (50 MGY)	1.8	1.8	1.8	1.8
All Biomass Feedstock Types (100 MGY)	1.5	1.5	1.5	1.5

Table 11 Investment Cost Assumptions for New Pyrolysis Bio-Oil Plants

Investment Costs for New Pyrolysis Bio-Oil Plants (M$/PJ-yr) *(Notes: Values are interpolated between the data years shown.)*				
	2005	2020	2035	2050
All Biomass Feedstock Types (25 MGY)	15.1	15.1	15.1	15.1
All Biomass Feedstock Types (100 MGY)	10.2	10.2	10.2	10.2

Table 12 Investment Cost Assumptions for New FT Poly-Generation Plants

Investment Costs for New FT Poly-Generation Plants (M$/PJ-yr) *(Notes: Values are interpolated between the data years shown. Costs are the same for all biomass feedstock types.)*				
	2005	2020	2035	2050
Biomass Gasification (61 MGY)	96.1	96.1	72.1	72.1
Biomass Gasification, w/ CCS (61 MGY)	106.0	106.0	75.7	75.7
Coal-Biomass Gasification, Syngas RC, w/ CCS (138 MGY)	93.8	93.8	66.9	66.9
Coal-Biomass Gasification, Syngas OT, w/ CCS (112 MGY)	88.3	88.3	63.1	63.1
Coal-Biomass Gasification, Syngas OT, w/ CCS (506 MGY)	67.9	67.9	48.4	48.4

Table 13 Investment Cost Assumptions for New Hydrogen Production Facilities

Investment Costs for New Hydrogen Production Facilities (M$/PJ-yr) *(Notes: Values apply to all model years.)*	
Centralized, Large-Size	
Coal Gasification	26.3
Coal Gasification, w/ CCS	26.9
Natural Gas SMR	11.0
Natural Gas SMR, w/ CCS	14.2
Centralized, Mid-Size	
Natural Gas SMR	24.5
Natural Gas SMR, w/ CCS	33.4
Biomass Gasification	138.0
Biomass Gasification, w/ CCS	141.2
Water Electrolysis	96.6
Distributed	
Natural Gas SMR	106.9
Water Electrolysis	144.8

Table 14 Efficiency Assumptions for New Cellulosic Ethanol Plants

Cellulosic Ethanol Plant Biomass Consumption (PJ_Input / PJ_Output) *(Notes: Values apply to all model years.)*		
Biochemical Production Pathway		
Forest Residues	**50 MGY**	1.74
	100 MGY	1.74
Municipal Solid Waste, Paper	**50 MGY**	1.54
	100 MGY	1.54
Municipal Solid Waste, Wood	**50 MGY**	1.72
	100 MGY	1.72
Municipal Solid Waste, Yard	**50 MGY**	1.59
	100 MGY	1.59
Orchard and Vineyard Waste	**50 MGY**	1.69
	100 MGY	1.69
Pulpwood	**50 MGY**	1.74
	100 MGY	1.74
Agricultural Residues, Stovers/Straws	**50 MGY**	1.53
	100 MGY	1.53
Energy Crops	**50 MGY**	1.76
	100 MGY	1.76
Thermochemical Production Pathway		
Forest Residues	**50 MGY**	2.12
	100 MGY	2.12
Municipal Solid Waste, Mixed	**50 MGY**	1.61
	100 MGY	1.61
Municipal Solid Waste, Paper	**50 MGY**	1.87
	100 MGY	1.87
Municipal Solid Waste, Wood	**50 MGY**	2.10
	100 MGY	2.10
Municipal Solid Waste, Yard	**50 MGY**	1.94
	100 MGY	1.94
Orchard and Vineyard Waste	**50 MGY**	2.05
	100 MGY	2.05
Pulpwood	**50 MGY**	2.12
	100 MGY	2.12
Agricultural Residues, Stovers/Straws	**50 MGY**	1.86
	100 MGY	1.86
Energy Crops	**50 MGY**	2.15
	100 MGY	2.15

Table 15 Efficiency Assumptions for New Biodiesel Plants

Biodiesel Plant Biomass Consumption (PJ_Input / PJ_Output) *(Notes: Values apply to all model years.)*		
Yellow Grease	**50 MGY**	0.98
	100 MGY	0.98
Animal Tallow	**50 MGY**	1.03
	100 MGY	1.03

Table 16 Efficiency Assumptions for New Pyrolysis Bio-Oil Plants

Pyrolysis Bio-Oil Plant Biomass Consumption (PJ_Input / PJ_Output)		
(Notes: Values apply to all model years.)		
Forest Residues	**25 MGY**	1.59
	100 MGY	1.59
Municipal Solid Waste, Mixed	**25 MGY**	1.20
	100 MGY	1.20
Municipal Solid Waste, Paper	**25 MGY**	1.40
	100 MGY	1.40
Municipal Solid Waste, Wood	**25 MGY**	1.57
	100 MGY	1.57
Municipal Solid Waste, Yard	**25 MGY**	1.45
	100 MGY	1.45
Orchard and Vineyard Waste	**25 MGY**	1.53
	100 MGY	1.53
Pulpwood	**25 MGY**	1.59
	100 MGY	1.59
Agricultural Residues, Stovers/Straws	**25 MGY**	1.39
	100 MGY	1.39
Energy Crops	**25 MGY**	1.61
	100 MGY	1.61

Table 17 Efficiency Assumptions for New FT Poly-Generation Plants

FT Poly-Generation Plant Energy Consumption (PJ_Input / PJ_Output) *(Notes: Values apply to all model years.)*			
		Biomass	Coal
Biomass Gasification (61 MGY)	Forest Residues	1.88	0.00
	Municipal Solid Waste, Mixed	1.43	0.00
	Municipal Solid Waste, Paper	1.66	0.00
	Municipal Solid Waste, Wood	1.86	0.00
	Municipal Solid Waste, Yard	1.72	0.00
	Orchard and Vineyard Waste	1.82	0.00
	Pulpwood	1.88	0.00
	Agricultural Residues, Stovers/Straws	1.65	0.00
	Energy Crops	1.91	0.00
Biomass Gasification, w/ CCS (61 MGY)	Forest Residues	1.94	0.00
	Municipal Solid Waste, Mixed	1.47	0.00
	Municipal Solid Waste, Paper	1.72	0.00
	Municipal Solid Waste, Wood	1.92	0.00
	Municipal Solid Waste, Yard	1.78	0.00
	Orchard and Vineyard Waste	1.88	0.00
	Pulpwood	1.94	0.00
	Agricultural Residues, Stovers/Straws	1.70	0.00
	Energy Crops	1.97	0.00
Coal-Biomass Gasification, Syngas RC, w/ CCS (138 MGY)	Forest Residues	0.83	1.14
	Municipal Solid Waste, Mixed	0.63	1.14
	Municipal Solid Waste, Paper	0.74	1.14
	Municipal Solid Waste, Wood	0.82	1.14
	Municipal Solid Waste, Yard	0.76	1.14
	Orchard and Vineyard Waste	0.81	1.14
	Pulpwood	0.83	1.14
	Agricultural Residues, Stovers/Straws	0.73	1.14
	Energy Crops	0.84	1.14
Coal-Biomass Gasification, Syngas OT, w/ CCS (112 MGY)	Forest Residues	0.76	1.30
	Municipal Solid Waste, Mixed	0.58	1.30
	Municipal Solid Waste, Paper	0.67	1.30
	Municipal Solid Waste, Wood	0.75	1.30
	Municipal Solid Waste, Yard	0.70	1.30
	Orchard and Vineyard Waste	0.73	1.30
	Pulpwood	0.76	1.30
	Agricultural Residues, Stovers/Straws	0.67	1.30
	Energy Crops	0.77	1.30
Coal-Biomass Gasification, Syngas OT, w/ CCS (506 MGY)	Forest Residues	0.17	1.95
	Municipal Solid Waste, Mixed	0.13	1.95
	Municipal Solid Waste, Paper	0.15	1.95
	Municipal Solid Waste, Wood	0.17	1.95
	Municipal Solid Waste, Yard	0.16	1.95
	Orchard and Vineyard Waste	0.17	1.95
	Pulpwood	0.17	1.95
	Agricultural Residues, Stovers/Straws	0.15	1.95
	Energy Crops	0.18	1.95

Table 18 Efficiency Assumptions for New Hydrogen Production Facilities

Hydrogen Production Facility Feedstock Consumption (PJ_Input / PJ_Output)		
(Notes: Units are in PJ_Input per PJ_Output, except for water electrolysis for which the primary feedstock is liquid H_2O, and consumption is in million liters per PJ_output. Energy consumption is the same for all biomass feedstock types. Values apply to all model years.)		
	Primary Feedstock	**Electricity**
Centralized, Large-Size		
Coal Gasification	1.39	0.07
Coal Gasification, w/ CCS	1.39	0.11
Natural Gas SMR	1.04	0.02
Natural Gas SMR, w/ CCS	1.10	0.05
Centralized, Mid-Size		
Natural Gas SMR	1.10	0.03
Natural Gas SMR, w/ CCS	1.15	0.07
Biomass Gasification	2.69	0.19
Biomass Gasification, w/ CCS	2.68	0.27
Water Electrolysis	156.77	1.63
Distributed		
Natural Gas SMR	1.32	0.07
Water Electrolysis	156.77	1.65

Transportation Sector

Base-Year 2005 Fuel Consumption

Base-year 2005 fuel consumption in each of the CA-TIMES transport subsectors and segments are estimated by a variety of means and sources – mostly by using the CARB GHG Inventory (CARB, 2010b), but in some cases other data sources are used to supplement, as described below. The historical figures are typically provided in their native units (e.g., gallons gasoline, gallons diesel, standard cubic feet of natural gas, etc.); these can then be converted to common units, such as petajoules (PJ).

For gasoline, diesel, and ethanol consumption by on-road transportation vehicles (i.e., light-duty passengers cars and trucks, heavy- and medium-duty trucks and buses, and motorcycles), historical fuel consumption estimates are based on a combination of data provided by the CARB GHG Inventory (CARB, 2010b), the California Energy

Commission (CEC, 2007) and the California Department of Transportation (Caltrans, 2006). Similarly, natural gas consumption for on-road passenger vehicles is taken from the CARB GHG Inventory.

Consumption of kerosene-type jet fuel for commercial passenger and freight aviation is calculated from data that was used to develop the CARB GHG Inventory estimates (CARB, 2008b). More specifically, I utilize air carrier data to estimate the number of flights within, into, and out of California (both domestic and international). Then, based on plane types and trip distances, fuel consumption is estimated. For general aviation[23], data on jet fuel and aviation gasoline consumption is obtained from the Federal Aviation Administration (FAA, 2007).

Diesel and residual fuel oil consumption for California marine transport is taken from the CARB GHG Inventory.

Diesel fuel consumption by California railways in 2005 is based on statistics from the U.S. DOT's National Transit Database for commuter, heavy, and light rail (DOT, 2006a). For intercity and freight rail, diesel fuel consumption is estimated based on California's share of intercity passenger-miles and freight ton-miles, respectively. California intercity passenger-miles are estimated by using Amtrak passenger boardings as a proxy, specifically the share of California passenger boardings in the U.S. total (DOT, 2007b). The share of freight rail ton-miles that originated in California compared to the entire U.S. is obtained from DOT data as well (DOT, 2006b).

[23] General aviation includes personal and corporate jets and other small propeller aircraft.

Electricity consumption for transportation is also taken from the National Transit Database (DOT, 2006a). First, the data are filtered for California transit agencies only, and then electricity consumption is estimated for each transit vehicle type. The data shows that in 2005, electricity was only consumed by the following vehicle types: cable car, heavy rail, light rail, bus, and trolleybus. Note that these figures do not include electricity consumption for Amtrak trains, which is understandable since no Amtrak trains use electricity in California – they are all diesel-powered. The data does not appear to include electricity consumption for recharging of personal electric vehicles (such as passenger cars, light-duty trucks, neighborhood electric vehicles, golf carts, etc.); though, in 2005 these demands were very small in comparison to other transportation electricity demands.

Gasoline, diesel, and natural gas consumption for off-road and construction, agricultural vehicles, and personal recreational boats are estimated by using data obtained by running CARB's OFFROAD2007 model for the year 2005 and then performing some subsequent calculations and data aggregation (CARB, 2007d). For consumption of liquefied petroleum gases (LPG), the CARB GHG Inventory is used.

California biodiesel consumption in 2005 is not listed in the GHG Inventory, so I estimate it independently by assuming that California's biodiesel consumption is approximately 10% of the national total, which was 75 million gallons biodiesel in 2005 (NBD, 2007). Thus, California consumed about 7.5 million gallons in 2005, a figure that is corroborated by the City and County of San Francisco Biodiesel Access Task Force, who estimate that California biodiesel consumption was about 7 million gallons in 2005 (SFBATF, 2006). Furthermore, it is assumed that in the base-year all biodiesel is consumed by heavy-duty vehicles (trucks and buses); obviously, this ignores the very small quantity of biodiesel consumed by passenger cars and light-duty trucks.

Base-Year 2005 Activity Demands and Vehicle Stocks

The calibration of base-year transport sector energy demands in CA-TIMES requires data on transport service demand, i.e., activity, (passenger-miles, vehicle-miles, ton-miles, etc.), vehicle stocks (cars, trucks, aircraft, ships, trains, etc.), and other data (e.g., passengers per vehicle, freight tons per train). In some cases these statistics are obtained specifically for California; however, in other cases the data are approximated for California based on aggregate U.S. data.

Light-duty Cars and Motorcycles

The unit of activity is vehicle-miles of travel (VMT). For cars, this data is obtained from CEC IEPR 2007 estimates (CEC, 2007). For motorcycles, it is taken from the Caltrans 2006 MVSTAFF report (Caltrans, 2006). Further, I was able to find data on the number of motorcycles in California and the annual average mileage of those vehicles by running CARB's EMission FACtors (EMFAC2007) model (CARB, 2007c). Note that EMFAC data on vehicle stocks originally come from California Department of Motor Vehicle (DMV) registration data. Stocks and annual mileages of conventional gasoline ICE vehicles and gasoline hybrid-electric vehicles are obtained from the CEC IEPR estimates.

The IEPR data shows that the number of diesel cars in California was zero in 2005; however, EMFAC shows otherwise. Therefore, the EMFAC data is used to estimate the number of diesel cars and their average annual mileage. Moreover, while EMFAC shows that there were a very small number of electric vehicles operating in California in 2005, I have ignored these vehicles here since their contribution to overall base-year energy demands is trivial, and little information exists about these vehicles. In contrast, I have not been able to find any consistent data on the stock and total mileage of all natural gas vehicles in California, so this category is also ignored in the base-year 2005.

Fuel economies for cars and motorcycles vary widely by vehicle type and model. Yet, for the purposes of calibrating base-year transport sector energy demands, only average fuel economy values are needed for gasoline ICE cars, gasoline HEV cars, diesel cars, and gasoline ICE motorcycles. These averages are obtained from the CEC IEPR and Caltrans MVSTAFF data.

All light-duty cars and motorcycles are assumed to have a lifetime of 15 years, consistent with assumptions used in the EPA 9-region MARKAL model for the U.S. The vehicle types, like all technologies in CA-TIMES are “vintaged”, meaning that the technological assumptions that apply to the technology in the year of its introduction continue to apply throughout the technology’s lifetime.

Light-Duty Trucks

Activity data (in VMT) for light-duty trucks is obtained from CEC IEPR 2007 estimates. The number of light-duty trucks in California and the annual average mileage of those vehicles are also taken from IEPR for conventional gasoline vehicles and gasoline HEVs. For diesel light-duty trucks, the data comes from running CARB's EMFAC model. In EMFAC, we consider the truck categories T1, T2, T3, and T4 to be light-duty trucks. These categories include trucks that are less than 10,000 pounds in weight, which is slightly different from the CAFE-defined 8,750 pound maximum weight for light-duty trucks but is consistent with definitions found elsewhere for "light-duty trucks". Note that because the number of electric and natural gas light-duty trucks was so small in the base-year (or data on them could not be found), these vehicle types are ignored. Average fuel economies for gasoline and gasoline HEV light-duty trucks are obtained from the CEC IEPR data. The average fuel economy of diesel light-duty trucks in California comes from the CalTrans MVSTAFF report.

All light-duty trucks are assumed to have a lifetime of 15 years, consistent with assumptions used in the EPA 9-region MARKAL model for the U.S.

Heavy-Duty and Medium-Duty Trucks

The EMFAC model is the source for total vehicle miles of travel, vehicle stock, and average annual mileage per vehicle for both medium- and heavy-duty trucks. Medium-duty trucks include EMFAC truck categories T5 and T6, corresponding to trucks with weights between 10,000 and 33,000 pounds. Heavy-duty trucks include category T7, with weights from 33,000 to 60,000 pounds. While there are a larger number of medium-duty trucks than heavy-duty trucks in California, they are typically used for shorter-distance travel, and they are more efficient. Hence, heavy-duty trucks account for greater quantities of total vehicle-miles and fuel consumption. Average fuel economies for the two vehicle categories are obtained from CalTrans MVSTAFF.

Heavy-duty trucks are assumed to have a lifetime of between 15 and 20 years, depending on technology, consistent with assumptions used in the IEA-ETP global MARKAL model. Medium-duty trucks have lifetimes of 10-20 years. In both cases, vehicles with compression-ignition (i.e., diesel) engines have longer lifetimes, while spark-ignition (i.e., gasoline) vehicles and other alternative-fuel vehicles have shorter lifetimes.

Buses

The bus subsector is comprised of three distinct segments: transit buses, school buses, and other buses, the latter of which includes intercity buses. The activity unit for all bus types is vehicle-miles traveled. All transit bus statistics come from either the National Transit Database or EMFAC. The number of school buses in operation in California is given by *School Transportation News* (STN, 2007). Data on school bus passenger-miles (PMT) for the entire U.S. comes from *The Public Purpose* (The Public Purpose, 2007). The share of school buses in California versus the entire U.S. (about 5.5%) is then used to estimate California's total school bus PMT. School bus VMT is given by EMFAC. All data on other types of buses, which include intercity (e.g., Greyhound) buses, are taken from EMFAC. Average fuel economies of the different bus types are calculated based on the fuel consumption and VMT estimates discussed above.

Transit, school, and other/intercity buses are all assumed to have a lifetime of between 15 and 20 years, depending on technology, consistent with assumptions used in the IEA-ETP global MARKAL model. As with trucks, vehicles with compression-ignition (i.e., diesel) engines have longer lifetimes, while spark-ignition (i.e., gasoline) vehicles and other alternative-fuel vehicles have shorter lifetimes.

Rail

There are five different types of rail transport in California. Passenger rail includes commuter, heavy, light, and intercity (e.g., Amtrak) rail. The activity unit for these passenger modes is PMT. The other type of rail transport is freight rail, the activity unit for which is ton-miles. The National Transit Database provides statistics on total PMT, VMT, train-miles traveled (TMT), and vehicle stocks for commuter, heavy, and light rail (where a 'train' refers to a collection of a number of individual rail 'vehicles', i.e., locomotives and/or rail cars). "Light rail" includes both traditional light rail street cars, as well as historic cable cars in San Francisco. In California all heavy rail (e.g., BART) and light rail systems are completed electrified. In contrast, commuter, intercity, and freight rail trains in California tend to use diesel-powered locomotives. For intercity rail, as mentioned above, California passenger-miles, vehicle-miles, and train-miles, as well as the stock of locomotives and rail cars in California, are estimated by using Amtrak statistics (DOT, 2007b). Similarly, freight rail ton-miles, vehicle-miles, train-miles, and vehicle stocks are estimated using the share of ton-miles originated in California compared to the entire U.S. (DOT, 2006b, 2007a). From these data I was able to calculate several useful metrics reflective of rail operations, including the number of passengers per rail vehicle, vehicles per train, passengers per train, and average train-miles per train per year, as well as energy intensities for each type of vehicle.

All types of rail equipment (i.e., locomotives and rolling stock for both passenger and freight trains) are assumed to have lifetimes of 20 years, consistent with assumptions used by the EPAUS9r and IEA-ETP.

Marine

The activity unit for domestic marine transport (both intrastate and interstate) via large shipping vessels is ton-miles. Yet, because I could only find data on marine ton-miles for the entire U.S., California's share of marine tons is used a proxy for ton-miles. The amount of tons shipped by large shipping vessels to intrastate, interstate, and foreign markets is obtained from the U.S. Army Corps of Engineers (USACE, 2007). California's share of intrastate tons shipped (i.e., originated) is about 4.9% of the U.S. total. When considering interstate shipments that either originate or terminate in California, the weighted average share is about 3.9%. I use this latter share to estimate the number of large shipping vessels in operation in the state and the amount of ton-miles shipped by these vessels. National level data are taken from the ORNL Transportation Energy Data Book (ORNL, 2010). The shares of marine tons shipped to intrastate and interstate markets (from USACE) are then used to estimate the number of large shipping vessels used for both intrastate and interstate marine transport. Interstate trade comprises about 70% of domestic marine tons (and thus vessels and ton-miles by our calculations) while the other 30% is intrastate. The energy intensity of California large shipping vessels is assumed to be the same as the national average value found in the ORNL Data Book.

Harbor craft[24] and personal recreational boats are two other types of domestic marine vehicles that operate within the state's boundaries. The unit of activity for both of these intrastate categories is hours of operation. Data on harbor craft activity, stock, and energy intensity are calculated from CARB's Statewide Commercial Harbor Craft Survey (CARB, 2004). Data on personal boats come from running CARB's OFFROAD2007 model for the year 2005, then aggregating the output and estimating vehicle stocks, activity (hours of operation per year), and energy intensities (gallons of fuel per hour).

The unit of activity for large marine vessels operating internationally is vessel-miles. The data for these vehicle types, including vessel stock, come from CARB's 2005 Oceangoing Ship Survey (see "Appendix C: Summary of Results" and "Appendix D: Emissions Estimation Methodology for Ocean-Going Vessels") (CARB, 2005). According to the survey, about 99% of today's large marine vessels use residual fuel oil as the main fuel for their propulsion systems, while the remaining 1% use diesel. Using data provided by the CARB survey report on emissions, average speed, and average propulsion system power by type of oceangoing vessel, I estimate the total number of

[24] Harbor craft are vessels used for commercial purposes or to support public services. There are several types of harbor craft including crew and supply boats, charter fishing vessels, commercial fishing vessels, ferry/excursion vessels, pilot vessels, towboat or push boats, tug boats and work boats.

vessel-miles traveled by these vessels in 2005, average annual mileage of the vessels, and fuel consumption per vessel-mile by.

Large shipping vessels, large marine vessels, and harbor craft are assumed to have lifetimes of 30 years, based on EPAUS9r values, while personal recreational boats are assumed to have lifetimes of 20 years.

Aviation

Information on commercial flights within, leaving from, and arriving to California are obtained from CARB staff in spreadsheet database format (CARB, 2008b). This data was originally obtained from DOT's Research and Innovative Technology Administration's (RITA) Form 41 Traffic database of air carrier statistics. CARB filtered this data for California and then organized it by type of flight – intrastate (CA to CA), interstate (CA to US, US to CA), and international (CA to World, World to CA). The database provides fairly detailed information for every single flight within these categories in 2005, for example, origin and destination airport, number of passengers, weight of freight, distance of flight, type of airplane, and so on. From this data, the total number of passenger-miles and freight ton-miles was estimated for California in 2005 for each of the different types of flights. Airplane stocks were determined by using as a proxy the share of California airplane-miles in the U.S. total (DOT, 2007c). In reality, airplanes cannot be said to "belong" to California or any other state. Yet, for the purposes of accounting and calibrating stock, passenger-mile, and ton-mile data to base-year fuel demands, it is necessary to roughly estimate the number of "airplane-equivalents" operating solely within California energy system in a given year – i.e., on intrastate, interstate, and international routes for both passenger and freight aviation.

The unit of activity for general aviation is hours of operation. I assume that general aviation operates completely within the state (i.e., only intrastate trips are possible), which is likely not true in all cases, for example, with personal and corporate jets. Nevertheless, because no specific data on general aviation flight movements could be found (all data is aggregated) the assumption of general aviation being in the intrastate aviation category is made. I recognize that this introduces a small amount of error into the model, though it is fairly trivial when considering that general aviation activity and fuel demands pale in comparison to commercial passenger and freight aviation. As with jet fuel and aviation gasoline consumption for general aviation aircraft, all transport activity and energy intensity data is obtained from the FAA (FAA, 2007). Some California-specific data is available in the survey, but most is for the entire U.S. Thus, the share of general aviation aircraft in operation in California and the share of hours of operation, both compared to U.S. totals, are used as proxies for estimating other values, such as the number of jet aircraft vs. propeller aircraft.

A third category of aviation includes other/miscellaneous aircraft flights and energy usage. This category is part of the CARB GHG Inventory, and according to earlier conversations with CARB staff, it is unclear what the category actually comprises (CARB, 2008c). Military flights are included, as is fuel used for ground operations at airports. Part of the category could also include activity and fuel use that should be a part of the passenger, freight, and general aviation categories but was not included because of errors in the calculations. In other words, the other/miscellaneous category probably includes some remainder values from other categories. Due to these data uncertainties, I make some simplifications in modeling this other/miscellaneous aviation category. First, the unit for activity is in fictional “activity units”, and the level of activity in the base-year 2005 is arbitrarily specified to be 100 activity units. Then, efficiency (in activity units per PJ) is estimated by dividing the fictional activity units by this category’s total fuel use in 2005, which is known from the CARB GHG Inventory.

Base-year aviation technologies of all types are assumed to have lifetimes of 20 years, consistent with EPAUS9r assumptions, whereas future aviation technologies have lifetimes of 30 years, consistent with IEA-ETP assumptions.

Off-Road & Construction Devices

The unit of activity for off-road and construction vehicles[25] is hours of operation, which is fitting given that some of these vehicles never actually move anywhere, so they are not “transport vehicles” in the strictest sense of the phrase. Data on total hours of vehicle operation, vehicle stocks by fuel type (gasoline, diesel, and LPG/CNG), and average annual hours of operation by fuel type all come from running CARB’s OFFROAD2007 model, then aggregating the output and performing some subsequent calculations

[25] The off-road & construction subsector is comprised of a diverse set of vehicles including (to name just a few) off-road motorcycles, snowmobiles, all-terrain vehicles (ATVs, 4-wheelers), golf carts, cranes, forklifts, loaders, tractors, backhoes, excavators, dumpers, dredgers, aerial lifts, sweepers and scrubbers, riding lawn mowers, lawn and garden tractors, cargo tractors, and various types of airport vehicles (A/C tugs, baggage tugs, cargo loaders, deicers, forklifts, fuel trucks, ground power units, maintenance trucks, catering trucks, lavatory trucks, water and hydrant trucks).

(CARB, 2007d). Energy intensity estimates are similarly obtained. Note that the overwhelming majority of off-road vehicles in California are gasoline-powered. Yet, because diesel vehicles consume so much fuel on a per hour basis, diesel fuel consumption is quite a bit higher than either gasoline or natural gas consumption. Because different fuels are used for different vehicle types, I divide this category up into three subcategories based on fuel type.

All off-road and construction technologies are assumed to have a lifetime of 25 years, consistent with EPAUS9r assumptions.

Agricultural Vehicles

The unit of activity for off-road and construction vehicles[26] is also hours of operation. As for off-road and construction vehicles, data on agricultural vehicles is obtained from running OFFROAD2007. Both gasoline and diesel are used in agricultural vehicles, and in terms of vehicle stocks, they are roughly equivalent. However, since fuel consumption per hour is much higher for diesel vehicles (presumably because they are larger), diesel fuel consumption is an order of magnitude larger than gasoline consumption. As with off-road and construction vehicles, I divide agricultural vehicles up into two categories based on fuel type.

All agricultural vehicle technologies are assumed to have a lifetime of 25 years, consistent with EPAUS9r assumptions.

[26] The agricultural vehicle subsector is comprised of a diverse set of vehicles including tractors, combines, balers, mowers, sprayers, tillers, and swathers.

Pipelines

Natural gas consumption for both natural gas and non-natural gas pipelines in California is taken from the EIA (EIA, 2010b). The unit of activity for pipeline natural gas consumption is assumed to be total California natural gas consumption in any given year, which is also obtained from the same source. In 2005, approximately 0.00479 scf of pipeline natural gas were consumed for every 1 scf of total natural gas transported (or alternatively, 0.00479 PJ per PJ). By this metric, the relative consumption of natural gas for pipeline compressors is extremely small. Note that this transport subsector is treated differently from the other subsectors since there is no stock or annual average activity *per se*.

Service Demand Projections

In CA-TIMES, future-year projections of demand (e.g., vehicle-miles, passenger-miles, ton-miles, vessel-miles, hours of operation, and so on) are exogenously specified. This section discusses the key input assumptions and data sources for developing reference case demand projections for the various transport subsectors.

Light-Duty Cars and Trucks

Total combined light-duty car and truck VMT in California is projected into the future by applying annual growth rates for U.S. VMT per capita, which come from the EIA's AEO2010 Reference Case projections (see Table 60 of AEO2010) (EIA, 2010a)[27], and

[27] Note that in order to extrapolate out to later years, I assume the average annual percentage growth rate in per-capita VMT declines from the mean 2025-2030 value down to 0.5% per year in 2050. Such a gradual

applying these rates to the base-year 2005 numbers from CEC. Similarly, car-truck share splits are projected into the future, using the EIA's projected changes for the U.S. light-duty stock (see Table 58 of AEO2010). With these two time series, the trajectories for both light-duty car and light-duty truck VMT can be calculated. These trajectories are shown in Figure 24.

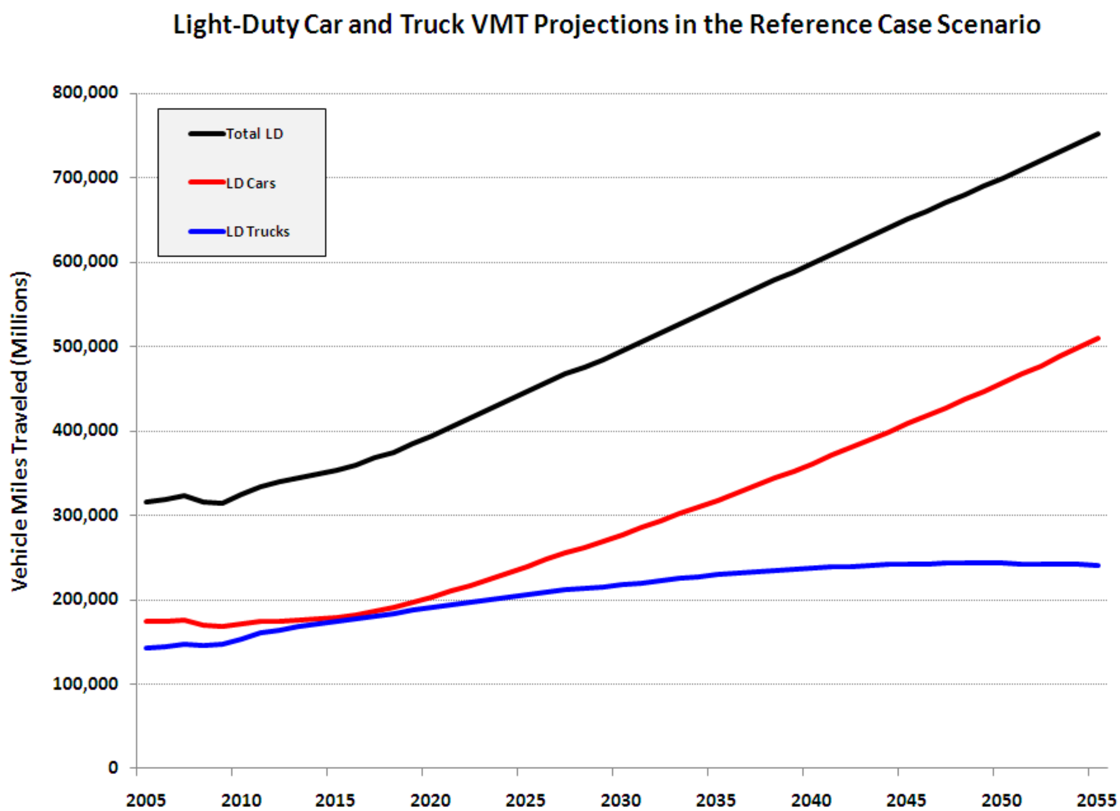

Figure 24 Light-Duty Car and Truck VMT Projections in the Reference Case Scenario

Motorcycles

Projections for on-road motorcycle demand between 2005 and 2030 are calculated based on growth rates from Caltrans (2009). Then, because base-year demands are derived

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decline is meant to represent an increasing saturation of private auto travel in California, as the population grows, densities increase, and congestion continues to get worse.

from EMFAC model results, the Caltrans growth rates are applied to the 2005 EMFAC numbers. For the post-2030 time period, extrapolation is done by using the average annual percentage growth rate between 2020 and 2030 and applying it to the later years as a constant growth rate.

Heavy-Duty and Medium-Duty Trucks

As is the case with motorcycles, base-year VMT demands are projected into the future, using growth rates from Caltrans (2009). Note that Caltrans' definition for medium-duty trucks ('Truck3' in the MVSTAFF report) is the same as the EMFAC truck categories T5 and T6 (vehicle weights of 10,000 – 33,000 pounds). Similarly, heavy-duty trucks ('Truck4' in Caltrans MVSTAFF) are equivalent to the EMFAC truck category T7 (greater than 33,000 pounds).

Buses

Because I was unable to find any reliable estimates of future California bus demands, I simply assume that the demands in the three bus segments each scale with population. California population projections are taken from the California Department of Finance (DOF, 2007).

Rail

Rail PMT and TMT in California is projected into the future by applying annual growth rates for energy use by rail segment for the entire U.S. These projections come from the EIA's AEO2010 Reference Case projections (see Supplemental Table 45 of AEO2010).

In doing this, I am effectively using rail energy growth as a proxy for demand growth, which is of course an approximation, though a necessary one given the absence of projections from any other sources.

Marine

For most of the marine segments (namely, domestic-intrastate and domestic-interstate large shipping vessels, harbor craft, and personal recreational boats), annual growth rates from AEO2010 are used to project ton-miles or hours of vehicle operation, whatever the case may be (see Supplemental Tables 7 and 67 of AEO2010). In some cases, energy use is taken as a proxy for demand. In contrast, for international large marine vessels, a different approach is utilized. In short, vessel population projections estimated by Dr. James Corbett (University of Delaware) are used as a proxy for future vessel-miles (see Appendix D of CARB's Oceangoing Ship Survey report, p. D-18) (CARB, 2005).

Aviation

For domestic and international freight and passenger aviation, national-level projections (in passenger-miles and ton-miles, respectively) are used to project California's future commercial aviation demands (see Supplemental Table 66 of AEO2010). Growth rates are estimated for each category of air travel and then applied to California's base-year demands. The domestic passenger and freight projections from AEO are assumed to be applicable to both domestic-intrastate and domestic-interstate aviation in California. General aviation demand is projected into the future using national-level projections of general aviation energy use as a proxy for hours of operation (see Supplemental Table 66 of AEO2010). It is important to note that this approximation masks any future shifts between jet-powered and propeller airplanes, as well as the changing efficiency and usage (in terms of hours per year) of those planes. The error this introduces to the model is relatively small, since general aviation demands are so minimal compared to the other aviation segments. For the other/miscellaneous aviation category, the growth rate in future activity is tied to growth in the U.S. population.

Off-Road & Construction Devices

Projections for off-road and construction activity in the three different demand segments are estimated using CARB's OFFROAD2007 model (CARB, 2007d). First, I run the model for the years 2005 and 2040, in order to obtain demand and fuel use. Then, I interpolate and extrapolate for all other years in the modeling horizon.

Agricultural Vehicles

Projections for agricultural vehicle activity are calculated in the same way as for off-road and construction devices by using CARB's OFFROAD2007 model.

Pipelines

Future consumption of pipeline natural gas depends on the total quantity of natural gas demanded/transported in California in the future. This, of course, depends on the particular scenario being run. Therefore, projections for pipeline natural gas demand must be continually updated so that the exogenously specified trajectories are in line with the endogenous demands for natural gas that are calculated by the model in a given model run.

Light-duty Vehicle Cost and Efficiency Assumptions

The following tables summarize the cost and efficiency assumptions for all light-duty vehicle technologies that are available to the CA-TIMES model in any future year. For the most part, the baseline assumptions come from the EIA's AEO2010 Reference Case assumptions and projections (EIA, 2010a, c). Investment costs refer to the average price that a consumer would expect to pay for a vehicle.

In certain cases, a handful of other sources are used to modify the EIA numbers data. For instance, Moderate and Advanced Gasoline Internal Combustion Engine (ICE) vehicles are not represented in the AEO2010. Instead, I have created these two technologies to capture the potential for efficiency improvements in the light-duty sector. These vehicles are simply conventional gasoline ICEs that achieve higher fuel economies (on the order of 15% to 30%) due to a suite of incremental efficiency enhancements, which necessitate small, but nontrivial, increases in the investment costs relative to the conventional Gasoline ICE. The technology characterizations for Moderate and Advanced Gasoline ICEs are based on unpublished data from the U.S. EPA Office of Transportation and Air Quality (OTAQ) by way of the EPA's US9r MARKAL model (EPA, 2008a). Similarly, I have also added several E-85 Flex Fuel vehicle technologies beyond those represented in AEO2010 (e.g., E-85 Moderate ICEs, Advanced ICEs, HEVs, and PHEVs). In all cases, the efficiencies of these technologies are the same as for their comparable gasoline counterparts, while investment costs are based on the incremental cost increase of AEO2010's standard E-85 Flex Fuel vehicle relative to the conventional Gasoline ICE (typically less than $1,000). Only Gasoline PHEVs with 10- and 40-mile all-electric ranges are represented in AEO2010; however, as the tables below indicate, I also make PHEV 30s and 60s available to the model, as well as E-85 Flex Fuel and Diesel PHEVs with 10-, 30-, 40-, and 60-mile all-electric ranges. In short, to make these technology characterizations, I use the AEO2010 cost estimates for PHEV 10s and 40s to approximate the cost of PHEV 30s and 60s, assuming the same per-kWh battery costs. (Note that in the AEO2010 Reference Case, the cost of lithium-ion batteries is assumed to level out at $500/kWh by 2030. Fuel cell costs are assumed to drop to $139/kW by 2030 and $55/kW by 2050.) Then, I take the incremental cost increases of the Gasoline PHEV 10/30/40/60s compared to a Gasoline HEV and apply these to the E-85 Flex Fuel HEV and Diesel HEV, in order to approximate the costs of the PHEV versions of these technologies. In general, Diesel ICEs, HEVs, and PHEVs are more expensive than the E-85 Flex Fuel versions, which are more expensive than the Gasoline versions. In calculating PHEV efficiencies, I assume that Gasoline, E-85 Flex Fuel, and Diesel PHEV 10/30/40/60 efficiencies in charge-sustaining (CS) mode are the same as for their HEV counterparts, while efficiencies in charge-depleting (CD) mode are much higher, due to the greater efficiency of an electric motor in all-electric operation.[28] CD-mode efficiencies are based on the technology characterizations of EPRI (2007) and Kromer and Heywood (2007a). Furthermore, PHEVs are restricted from over-consuming either

[28] Note that the assumption of all PHEVs having the same efficiency in charge-sustaining mode is a bit of an approximation because of the varying weights that these vehicles would achieve. However, for this same reason, I assume that PHEV efficiencies in charge-depleting mode are lower for vehicles with greater all-electric ranges (i.e., heavier battery packs).

electricity or liquid fuel for propulsion energy by applying fuel split shares based on published utility factor curves (EPRI, 2007; Kromer and Heywood, 2007a).

Table 19 Investment Cost Assumptions for New Light-Duty Cars in the Reference Case

Investment Costs for New Light-Duty Cars ($/vehicle)

(Note: Missing data value indicates that technology is not available in given year.)

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Gasoline ICE	25,775	25,924	26,421	26,875	26,951	27,092	27,291	27,291	27,291	27,291	27,291
Gasoline ICE (Moderate Eff.)	26,531	26,681	27,178	27,631	27,708	27,849	28,047	28,047	28,047	28,047	28,047
Gasoline ICE (Advanced Eff.)	27,288	27,437	27,934	28,388	28,464	28,605	28,804	28,804	28,804	28,804	28,804
Gasoline HEV	29,473	29,413	29,491	29,557	29,427	29,358	29,437	29,437	29,437	29,437	29,437
E85 Flex Fuel ICE	26,150	26,299	26,797	27,251	27,326	27,465	27,661	27,661	27,661	27,661	27,661
E85 Flex Fuel ICE (Moderate Eff.)	26,906	27,055	27,554	28,008	28,082	28,221	28,417	28,417	28,417	28,417	28,417
E85 Flex Fuel ICE (Advanced Eff.)	27,663	27,812	28,310	28,764	28,839	28,977	29,174	29,174	29,174	29,174	29,174
E85 Flex Fuel HEV	29,848	29,787	29,866	29,934	29,801	29,730	29,806	29,806	29,806	29,806	29,806
Diesel ICE	31,220	31,352	30,528	30,155	29,868	29,923	29,955	29,955	29,955	29,955	29,955
Diesel HEV	--	--	29,788	29,788	29,637	29,549	29,582	29,582	29,582	29,582	29,582
Gasoline PHEV10	31,967	31,967	31,967	31,456	30,962	30,745	30,824	30,824	30,824	30,824	30,824
Gasoline PHEV30	40,800	40,800	40,800	38,228	36,439	35,693	35,772	35,772	35,772	35,772	35,772
Gasoline PHEV40	45,216	45,216	45,216	41,614	39,178	38,167	38,246	38,246	38,246	38,246	38,246
Gasoline PHEV60	54,049	54,049	54,049	48,386	44,655	43,115	43,194	43,194	43,194	43,194	43,194
E85 Flex Fuel PHEV10	32,343	32,343	32,343	31,832	31,337	31,117	31,194	31,194	31,194	31,194	31,194
E85 Flex Fuel PHEV30	41,176	41,176	41,176	38,604	36,814	36,065	36,142	36,142	36,142	36,142	36,142
E85 Flex Fuel PHEV40	45,592	45,592	45,592	41,990	39,552	38,539	38,616	38,616	38,616	38,616	38,616
E85 Flex Fuel PHEV60	54,425	54,425	54,425	48,762	45,029	43,487	43,564	43,564	43,564	43,564	43,564
Diesel PHEV10	31,686	31,686	31,686	31,686	31,172	30,936	30,969	30,969	30,969	30,969	30,969
Diesel PHEV30	38,458	38,458	38,458	38,458	36,649	35,884	35,917	35,917	35,917	35,917	35,917
Diesel PHEV40	41,844	41,844	41,844	41,844	39,388	38,358	38,391	38,391	38,391	38,391	38,391
Diesel PHEV60	48,616	48,616	48,616	48,616	44,865	43,306	43,339	43,339	43,339	43,339	43,339
Battery-Electric	89,485	93,325	95,286	95,123	85,823	78,071	77,915	77,915	77,915	77,915	77,915
Hydrogen Fuel Cell	--	--	73,508	64,341	57,823	52,850	49,037	49,037	49,037	49,037	49,037
Gasoline Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Methanol Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Dedicated Ethanol ICE	--	--	--	--	--	--	--	--	--	--	--
Natural Gas ICE	33,400	33,541	33,971	34,413	34,485	34,607	34,790	34,790	34,790	34,790	34,790
Natural Gas Bi-Fuel ICE	32,065	32,211	32,634	33,077	33,159	33,300	33,515	33,515	33,515	33,515	33,515
LPG ICE	--	--	--	--	--	--	--	--	--	--	--
LPG Bi-Fuel ICE	31,104	31,253	31,750	32,204	32,280	32,421	32,620	32,620	32,620	32,620	32,620

Table 20 Investment Cost Assumptions for New Light-Duty Trucks in the Reference Case

Investment Costs for New Light-Duty Trucks ($/vehicle)											
(Note: Missing data value indicates that technology is not available in given year.)											
	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Gasoline ICE	34,084	34,207	34,658	35,174	35,353	35,561	35,818	35,818	35,818	35,818	35,818
Gasoline ICE (Moderate Eff.)	35,263	35,386	35,837	36,353	36,532	36,740	36,997	36,997	36,997	36,997	36,997
Gasoline ICE (Advanced Eff.)	36,442	36,565	37,016	37,532	37,711	37,919	38,176	38,176	38,176	38,176	38,176
Gasoline HEV	38,465	38,401	38,376	38,388	38,258	38,236	38,394	38,394	38,394	38,394	38,394
E85 Flex Fuel ICE	34,535	34,657	35,106	35,620	35,796	36,001	36,257	36,257	36,257	36,257	36,257
E85 Flex Fuel ICE (Moderate Eff.)	35,714	35,836	36,285	36,799	36,975	37,180	37,436	37,436	37,436	37,436	37,436
E85 Flex Fuel ICE (Advanced Eff.)	36,893	37,015	37,464	37,978	38,154	38,359	38,615	38,615	38,615	38,615	38,615
E85 Flex Fuel HEV	38,915	38,851	38,824	38,835	38,700	38,677	38,833	38,833	38,833	38,833	38,833
Diesel ICE	42,334	42,441	40,425	40,491	40,175	40,114	40,387	40,387	40,387	40,387	40,387
Diesel HEV	--	--	--	38,413	38,238	38,181	38,277	38,277	38,277	38,277	38,277
Gasoline PHEV10	39,793	39,793	39,793	39,793	39,793	39,623	39,781	39,781	39,781	39,781	39,781
Gasoline PHEV30	45,270	45,270	45,270	45,270	45,270	44,571	44,729	44,729	44,729	44,729	44,729
Gasoline PHEV40	48,008	48,008	48,008	48,008	48,008	47,045	47,203	47,203	47,203	47,203	47,203
Gasoline PHEV60	53,485	53,485	53,485	53,485	53,485	51,993	52,151	52,151	52,151	52,151	52,151
E85 Flex Fuel PHEV10	40,236	40,236	40,236	40,236	40,236	40,064	40,220	40,220	40,220	40,220	40,220
E85 Flex Fuel PHEV30	45,713	45,713	45,713	45,713	45,713	45,012	45,168	45,168	45,168	45,168	45,168
E85 Flex Fuel PHEV40	48,451	48,451	48,451	48,451	48,451	47,486	47,642	47,642	47,642	47,642	47,642
E85 Flex Fuel PHEV60	53,928	53,928	53,928	53,928	53,928	52,434	52,590	52,590	52,590	52,590	52,590
Diesel PHEV10	39,773	39,773	39,773	39,773	39,773	39,568	39,664	39,664	39,664	39,664	39,664
Diesel PHEV30	45,250	45,250	45,250	45,250	45,250	44,516	44,612	44,612	44,612	44,612	44,612
Diesel PHEV40	47,989	47,989	47,989	47,989	47,989	46,990	47,086	47,086	47,086	47,086	47,086
Diesel PHEV60	53,466	53,466	53,466	53,466	53,466	51,938	52,034	52,034	52,034	52,034	52,034
Battery-Electric	111,741	115,151	115,090	115,319	104,277	95,115	95,166	95,166	95,166	95,166	95,166
Hydrogen Fuel Cell	--	--	80,120	69,446	61,602	55,599	50,942	50,942	50,942	50,942	50,942
Gasoline Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Methanol Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Dedicated Ethanol ICE	--	--	--	--	--	--	--	--	--	--	--
Natural Gas ICE	33,503	33,584	34,026	34,630	34,749	34,898	35,064	35,064	35,064	35,064	35,064
Natural Gas Bi-Fuel ICE	32,604	32,687	33,123	33,716	33,837	33,991	34,173	34,173	34,173	34,173	34,173
LPG ICE	--	--	--	--	--	--	--	--	--	--	--
LPG Bi-Fuel ICE	31,269	31,361	31,839	32,532	32,676	32,834	33,013	33,013	33,013	33,013	33,013

Table 21 Fuel Economy Assumptions for New Light-Duty Cars, All Except PHEVs in the Reference Case

New Vehicle Fuel Economy (mpgge) - All Except PHEVs											
(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)											
	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Gasoline ICE	31.2	31.5	34.3	37.1	37.8	38.6	40.0	40.0	40.0	40.0	40.0
Gasoline ICE (Moderate Eff.)	35.3	35.7	38.8	42.0	42.7	43.6	45.2	45.2	45.2	45.2	45.2
Gasoline ICE (Advanced Eff.)	40.6	41.0	44.6	48.3	49.1	50.1	52.0	52.0	52.0	52.0	52.0
Gasoline HEV	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
E85 Flex Fuel ICE	31.5	31.9	34.6	37.5	38.1	38.9	40.3	40.3	40.3	40.3	40.3
E85 Flex Fuel ICE (Moderate Eff.)	35.3	35.7	38.8	42.0	42.7	43.6	45.2	45.2	45.2	45.2	45.2
E85 Flex Fuel ICE (Advanced Eff.)	40.6	41.0	44.6	48.3	49.1	50.1	52.0	52.0	52.0	52.0	52.0
E85 Flex Fuel HEV	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
Diesel ICE	39.2	39.5	42.4	45.6	46.2	46.7	47.0	47.0	47.0	47.0	47.0
Diesel HEV	--	--	59.5	59.1	59.8	60.3	60.6	60.6	60.6	60.6	60.6
Battery-Electric	91.1	86.8	100.9	126.0	149.3	148.4	146.5	146.5	146.5	146.5	146.5
Hydrogen Fuel Cell	74.9	75.7	82.3	89.1	90.6	92.5	96.0	96.0	96.0	96.0	96.0
Gasoline Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Methanol Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Dedicated Ethanol ICE	--	--	--	--	--	--	--	--	--	--	--
Natural Gas ICE	33.2	33.4	36.6	39.5	40.2	41.0	41.9	41.9	41.9	41.9	41.9
Natural Gas Bi-Fuel ICE	30.8	31.0	33.9	36.6	37.2	38.0	39.0	39.0	39.0	39.0	39.0
LPG ICE	--	--	--	--	--	--	--	--	--	--	--
LPG Bi-Fuel ICE	31.2	31.5	34.3	37.1	37.7	38.6	40.0	40.0	40.0	40.0	40.0

Table 22 Fuel Economy Assumptions for New Light-Duty PHEV Cars in the Reference Case

New Plug-in Hybrid Vehicle Fuel Economy (mpgge)

(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Charge-Sustaining Mode											
Gasoline PHEV10	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
Gasoline PHEV30	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
Gasoline PHEV40	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
Gasoline PHEV60	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
E85 Flex Fuel PHEV10	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
E85 Flex Fuel PHEV30	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
E85 Flex Fuel PHEV40	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
E85 Flex Fuel PHEV60	45.1	44.9	48.5	51.0	51.8	52.6	53.5	53.5	53.5	53.5	53.5
Diesel PHEV10	--	--	59.5	59.1	59.8	60.3	60.6	60.6	60.6	60.6	60.6
Diesel PHEV30	--	--	59.5	59.1	59.8	60.3	60.6	60.6	60.6	60.6	60.6
Diesel PHEV40	--	--	59.5	59.1	59.8	60.3	60.6	60.6	60.6	60.6	60.6
Diesel PHEV60	--	--	59.5	59.1	59.8	60.3	60.6	60.6	60.6	60.6	60.6
Charge-Depleting Mode											
Gasoline PHEV10	158.7	158.2	157.2	175.0	197.6	227.4	227.4	227.4	227.4	227.4	227.4
Gasoline PHEV30	156.9	156.3	155.4	170.5	189.2	212.7	212.7	212.7	212.7	212.7	212.7
Gasoline PHEV40	156.9	156.3	155.4	170.5	189.2	208.8	208.8	208.8	208.8	208.8	208.8
Gasoline PHEV60	155.3	154.8	153.8	166.8	182.4	201.4	201.4	201.4	201.4	201.4	201.4
E85 Flex Fuel PHEV10	158.7	158.2	157.2	175.0	197.6	227.4	227.4	227.4	227.4	227.4	227.4
E85 Flex Fuel PHEV30	156.9	156.3	155.4	170.5	189.2	212.7	212.7	212.7	212.7	212.7	212.7
E85 Flex Fuel PHEV40	156.9	156.3	155.4	170.5	189.2	208.8	208.8	208.8	208.8	208.8	208.8
E85 Flex Fuel PHEV60	155.3	154.8	153.8	166.8	182.4	201.4	201.4	201.4	201.4	201.4	201.4
Diesel PHEV10	--	--	157.2	175.0	197.6	227.4	227.4	227.4	227.4	227.4	227.4
Diesel PHEV30	--	--	155.4	170.5	189.2	212.7	212.7	212.7	212.7	212.7	212.7
Diesel PHEV40	--	--	155.4	170.5	189.2	208.8	208.8	208.8	208.8	208.8	208.8
Diesel PHEV60	--	--	153.8	166.8	182.4	201.4	201.4	201.4	201.4	201.4	201.4

Table 23 Fuel Economy Assumptions for New Light-Duty Trucks, All Except PHEVs in the Reference Case

New Vehicle Fuel Economy (mpgge) - All Except PHEVs

(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Gasoline ICE	22.5	22.5	24.4	26.9	28.0	28.9	30.0	30.0	30.0	30.0	30.0
Gasoline ICE (Moderate Eff.)	26.0	26.0	28.2	31.1	32.4	33.4	34.7	34.7	34.7	34.7	34.7
Gasoline ICE (Advanced Eff.)	30.8	30.7	33.3	36.8	38.3	39.5	41.0	41.0	41.0	41.0	41.0
Gasoline HEV	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
E85 Flex Fuel ICE	22.8	22.7	24.6	27.2	28.3	29.2	30.3	30.3	30.3	30.3	30.3
E85 Flex Fuel ICE (Moderate Eff.)	26.0	26.0	28.2	31.1	32.4	33.4	34.7	34.7	34.7	34.7	34.7
E85 Flex Fuel ICE (Advanced Eff.)	30.8	30.7	33.3	36.8	38.3	39.5	41.0	41.0	41.0	41.0	41.0
E85 Flex Fuel HEV	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
Diesel ICE	28.4	28.2	30.1	32.5	33.4	34.1	34.6	34.6	34.6	34.6	34.6
Diesel HEV	41.2	41.2	41.2	41.2	42.1	42.8	43.3	43.3	43.3	43.3	43.3
Battery-Electric	51.7	53.4	63.4	78.4	92.7	92.4	92.1	92.1	92.1	92.1	92.1
Hydrogen Fuel Cell	54.1	54.1	58.6	64.6	67.3	69.4	72.1	72.1	72.1	72.1	72.1
Gasoline Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Methanol Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Dedicated Ethanol ICE	--	--	--	--	--	--	--	--	--	--	--
Natural Gas ICE	25.7	25.6	27.8	30.9	31.8	32.6	33.5	33.5	33.5	33.5	33.5
Natural Gas Bi-Fuel ICE	23.9	23.7	25.7	28.6	29.4	30.2	31.1	31.1	31.1	31.1	31.1
LPG ICE	--	--	--	--	--	--	--	--	--	--	--
LPG Bi-Fuel ICE	23.9	23.8	26.0	29.5	30.6	31.4	32.4	32.4	32.4	32.4	32.4

Table 24 Fuel Economy Assumptions for New Light-Duty PHEV Trucks in the Reference Case

New Plug-in Hybrid Vehicle Fuel Economy (mpgge)

(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)

	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Charge-Sustaining Mode											
Gasoline PHEV10	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
Gasoline PHEV30	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
Gasoline PHEV40	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
Gasoline PHEV60	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
E85 Flex Fuel PHEV10	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
E85 Flex Fuel PHEV30	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
E85 Flex Fuel PHEV40	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
E85 Flex Fuel PHEV60	32.6	32.4	35.1	37.6	38.6	39.5	40.3	40.3	40.3	40.3	40.3
Diesel PHEV10	41.2	41.2	41.2	41.2	42.1	42.8	43.3	43.3	43.3	43.3	43.3
Diesel PHEV30	41.2	41.2	41.2	41.2	42.1	42.8	43.3	43.3	43.3	43.3	43.3
Diesel PHEV40	41.2	41.2	41.2	41.2	42.1	42.8	43.3	43.3	43.3	43.3	43.3
Diesel PHEV60	41.2	41.2	41.2	41.2	42.1	42.8	43.3	43.3	43.3	43.3	43.3
Charge-Depleting Mode											
Gasoline PHEV10	158.1	158.1	158.1	158.1	158.1	183.0	183.0	183.0	183.0	183.0	183.0
Gasoline PHEV30	151.3	151.3	151.3	151.3	151.3	171.2	171.2	171.2	171.2	171.2	171.2
Gasoline PHEV40	151.3	151.3	151.3	151.3	151.3	168.1	168.1	168.1	168.1	168.1	168.1
Gasoline PHEV60	145.9	145.9	145.9	145.9	145.9	162.1	162.1	162.1	162.1	162.1	162.1
E85 Flex Fuel PHEV10	158.1	158.1	158.1	158.1	158.1	183.0	183.0	183.0	183.0	183.0	183.0
E85 Flex Fuel PHEV30	151.3	151.3	151.3	151.3	151.3	171.2	171.2	171.2	171.2	171.2	171.2
E85 Flex Fuel PHEV40	151.3	151.3	151.3	151.3	151.3	168.1	168.1	168.1	168.1	168.1	168.1
E85 Flex Fuel PHEV60	145.9	145.9	145.9	145.9	145.9	162.1	162.1	162.1	162.1	162.1	162.1
Diesel PHEV10	158.1	158.1	158.1	158.1	158.1	183.0	183.0	183.0	183.0	183.0	183.0
Diesel PHEV30	151.3	151.3	151.3	151.3	151.3	171.2	171.2	171.2	171.2	171.2	171.2
Diesel PHEV40	151.3	151.3	151.3	151.3	151.3	168.1	168.1	168.1	168.1	168.1	168.1
Diesel PHEV60	145.9	145.9	145.9	145.9	145.9	162.1	162.1	162.1	162.1	162.1	162.1

IV. Scenario Results and Discussion

Now that the structure of the CA-TIMES model and many of its assumptions have been described, this section highlights the results of several analyses in which the model was used to understand how the California energy system could be significantly decarbonized in the long term, what the technological and resource implications might be in such a case, and how much the energy system transition could cost. To this end, a number of scenarios have been created using the model, first a Reference Case scenario and then a multi-strategy Deep GHG Reduction Scenario that looks specifically at an ambitious "80in50" emission reduction target for the entire energy system – not just the transport sector, as was the case in the original 80in50 studies (Yang, McCollum et al. 2009, and McCollum and Yang, 2009). Finally, several variants of the Deep GHG Reduction Scenario are analyzed, in order to understand how the transition to a low-carbon economy in California could be different if the potential of certain technologies and resources is substantially restricted or enhanced.

1. Reference Case Scenario

The CA-TIMES Reference Case is a scenario describing the potential development of California's energy system over the next several decades under business-as-usual (BAU) conditions. It is not a prediction of what will happen, but rather a single vision of what *could* happen, if the technological and policy assumptions in the model were to come to fruition and consumers and firms behaved optimally from a cost minimization standpoint. While, in theory, a number of Reference Case scenarios could be developed, it is really only practical to develop one. The Reference Case is the scenario to which all other scenarios, particularly the deep greenhouse gas reduction scenarios, are compared. The following sections illustrate the development of the energy system in the Reference Case, taking an in-depth view of it from a variety of different perspectives. These various "cuts" hopefully provide a sense for how the system could potentially develop in the absence of any substantial effort to transition California toward a low-carbon society.

Policy is an important driver of energy system development. And while the previous sections have discussed the most important resource, technology, and demand assumptions – and their respective data sources – that have been used to develop the CA-TIMES Reference Case, the Reference Case is also strongly dependent on current policies and how they are assumed to develop over time.

Table 25 summarizes the policies represented in the Reference Case, providing brief descriptions of each, how they are modeled in CA-TIMES, and when they are assumed to expire, if at all. Although it is not possible to represent every single policy that affects California's energy system, the list below attempts to capture those of greatest importance and with the largest impact. Notably excluded from explicit policy representation are, for example, the Low Carbon Fuel Standard (LCFS), Zero Emissions Vehicle (ZEV) mandates, California's "anti-sprawl" transportation and land use regulations (SB 375), and certain measures for appliance energy efficiency and goods movement. Future iterations will make it possible to represent these policies, especially with respect to the LCFS, for which the emissions accounting framework of CA-TIMES would first need to be significantly overhauled.

Table 25 Brief Descriptions of Policies Represented in the CA-TIMES Reference Case

Policies	Descriptions
Biofuel Subsidies	- Corn ethanol: Federal Volumetric Ethanol Excise Tax Credit (i.e., "blender's credit") of $0.45/gal. Assumed to expire in 2015. - Sugar cane ethanol: Same as corn ethanol. - Cellulosic ethanol: Federal tax credit of $1.01/gal. Based on the Food, Conservation and Energy Act of 2008 (i.e., the "farm bill"). Assumed to expire in 2020. - Biodiesel: Federal tax credit of $1.00/gal for biodiesel from soy and animal tallow, $0.50/gal for biodiesel from yellow grease. Based on American Jobs Creation Act of 2004. Assumed to expire in 2015.
Biofuel Import Tariffs	- Sugar cane and other types of imported ethanol: Import duty of $0.54/gal.
Transportation Fuel Taxes[29]	- Gasoline: California state tax of $0.49/gal (includes excise tax and state, county, and local sales taxes). Federal excise tax of $0.184/gal. Assumed to always be the same. - Diesel: California state tax of $0.49/gal (includes excise tax and state, county, and local sales taxes). Federal excise tax of $0.244/gal. Assumed to always be the same. - Ethanol and E-85: No additional taxes other than those for gasoline. - Jet Fuel (kerosene-type): Federal excise tax of $0.044/gal for commercial aviation. - Aviation gasoline: Federal excise tax of $0.194/gal. Assumed to always be the same. - Liquid Petroleum Gases (LPG): Federal excise tax of $0.183/gal. Assumed to always be the same. - Compressed Natural Gas (CNG): Federal excise tax of $0.044/gal. Assumed to be the same as jet fuel. Assumed to always be the same. - Liquefied Natural Gas (LNG): Federal excise tax of $0.243/gal. Assumed to always be the same. - Liquefied H_2: Federal excise tax of $0.184/gal. Assumed to be the same as conventional gasoline. Assumed to always be the same. - FT liquid fuels from coal: Federal excise tax of $0.244/gal. Assumed to be the same as conventional diesel. Assumed to always be the same. - FT liquid fuels from biomass: Federal excise tax of $0.244/gal. Assumed to be the same as conventional diesel. Assumed to always be the same.
Corporate Average Fuel Economy (CAFE) Standards	- Light-duty passenger cars: New model-year vehicle fleet must achieve 263 gCO_2/mile (33.8 mpg) in 2012, strengthening to 225 gCO_2/mile (39.5 mpg) in 2016, assumed to remain constant thereafter. - Light-duty passenger trucks: New model-year vehicle fleet must achieve 346 gCO_2/mile (25.7 mpg) in 2012, strengthening to 298 gCO_2/mile (29.8 mpg) in 2016, assumed to remain constant thereafter.
Electric Vehicle Subsidies	- Light-duty PHEVs and BEVs: Tax credit for new plug-in electric vehicles is worth $2,500 plus $417 for each kWh of battery capacity over 5 kWh. The portion of the credit determined by battery capacity cannot exceed $5,000; therefore, the total amount of the credit allowed for a new plug-in electric vehicle is $7,500. Based on the Energy Improvement and Extension Act of 2008, and later the American Clean Energy and Security Act of 2009. Credit is supposed to expire for each manufacturer soon after it has sold 200,000 cumulative PHEV/BEVs for use in the U.S. However, in CA-TIMES the credit is simply assumed to expire in 2012.
GHG Emission Performance Standard for New Power Plants	- Establishes a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation [California Senate Bill (SB) 1368]. This essentially equates to "no new coal plants in California". In CA-TIMES, the law is applied to coal steam, coal IGCC, and coal-to-H_2

[29] For current federal fuel tax information, see the following U.S. Internal Revenue Service (IRS) webpage: http://www.irs.gov/publications/p510/ch01.html#d0e2009. For current state gasoline and diesel tax information, see the following API webpage: http://www.api.org/statistics/fueltaxes/.

	plants.
Renewable Fuels Standard (RFS)	- Mandates the increased use of transportation biofuels, culminating in 15 billion gallons per year (BGY) of corn ethanol in 2022, 16 BGY cellulosic ethanol, 1 BGY biodiesel, and 4 BGY other advanced biofuels. "Other advanced biofuels" are assumed to be sugar cane ethanol and bio-gasoline in the CA-TIMES model. RFS mandates are assumed to end in 2022. California is assumed to only be "responsible" for 9% to 10.5% of the total U.S. biofuels mandates, consistent with its current and projected share of the U.S. population and liquid fuels consumption. Based on the Energy Independence and Security Act (EISA) of 2007.
Renewable Electricity Incentives	- <u>Renewable electricity production tax credit (PTC)</u>: Credit of 2.2 cents/kWh for Wind, Geothermal, and Closed-loop biomass; and 1.1 cents/kWh for all other renewables (Open-loop biomass, Landfill gas, Hydroelectric, Municipal Solid Waste, Hydrokinetic "Flowing Water" Power, Small Hydroelectric, Tidal Energy, Wave Energy, and Ocean Thermal). Duration of credit is 10 years for facilities placed in service by the end of 2012 (wind) or 2013 (all others). Thus, all credits assumed to expire by 2022/2023. Note that Solar is excluded from the production tax credit because it receives the investment tax credit. - <u>Business energy investment tax credit (ITC) for renewables</u>: Credit equal to 30% of capital expenditures for Solar and Fuel cells. No maximum credit for solar; a maximum of $3,000/kW for fuel cells. In general, credits are available for eligible systems placed in service before the end of 2016. In CA-TIMES, credits are assumed to expire in 2016. Note that as of 2009, other types of renewable generation are allowed to take the ITC; however, they would then have to forfeit the PTC. In CA-TIMES, it is assumed that only solar and fuel cells can take the ITC.

<u>Electricity Generation</u>

The electric generation sector is sure to play an instrumental role in the future development of California's energy system and its corresponding environmental impacts. Figure 25 illustrates the model's Reference Case projections for electricity generation by plant type over the entire time horizon. Several noteworthy observations can be made. First, electricity supply and demand is projected to grow significantly over the next several decades (by more than 50%). This will necessitate considerable future investment in the generation stock, especially in light of the multitude of older, existing plants, which are scheduled to retire over the next two decades. Second, natural gas generation grows considerably between 2020 and 2025. This is due to natural gas being the most attractive, least-cost generation source during these years and because a significant amount of generation is needed after 2020 to make up for the shortfall caused by the retirement of existing nuclear plants and termination of existing electricity import contracts, both of which are scheduled to occur around 2020 or soon thereafter. The growth in natural gas generation is accounted for by the increased utilization of existing NGCC plants, many of which are not at the moment used to their full capacities, as well as investment in new NGCC plants. In short, natural gas becomes increasingly used for baseload power generation in California. Later in the model time horizon, generation from wind, geothermal, and solar thermal plants becomes cost-competitive with natural gas plants, thanks to increasing natural gas prices and assumed declines in the investment costs of these renewable options. This causes the share of low- and zero-carbon electricity generation to rise in the later periods, after having been relatively low for several decades as a result of the retirement of the state's two nuclear plants around 2020 (Figure 26). Unless the lives of existing nuclear plants are extended, new nuclear plants are built, and/or a renewable portfolio standard is implemented, fossil generation could still be quite high in California for years to come.

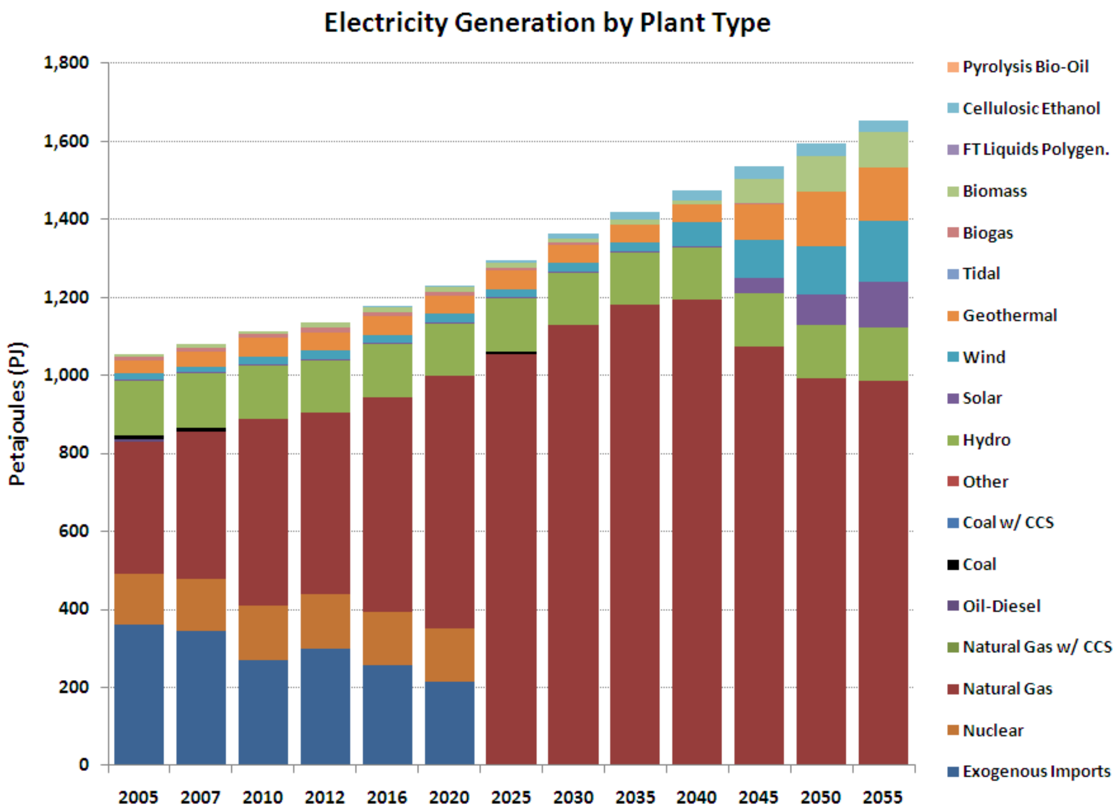

Figure 25 Electricity Generation by Plant Type in the Reference Case

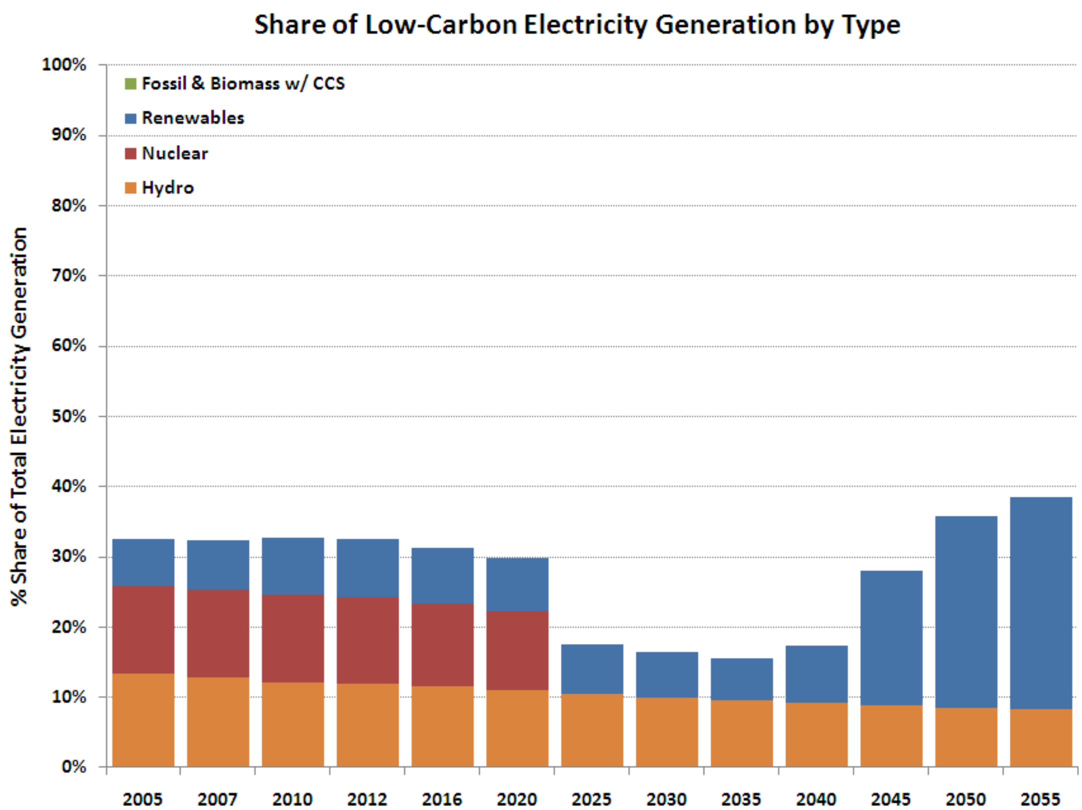

Figure 26 Share of Low-Carbon Electricity Generation by Type in the Reference Case

At this point, it is important to briefly note the way electricity imports are handled in CA-TIMES. There are two categories of imports, firm and system. Firm imports of coal, nuclear, hydro, and oil are dealt with in a relatively straightforward manner: they are phased out according to the scheduled expiration of known firm import contracts. System imports, on the other hand, are a bit less certain since they depend on the spot market for electricity, as well as electricity demand in other western states. In the CA-TIMES Reference Case, an important assumption is made that system imports from both the Pacific Northwest and Desert Southwest decline from 2010 to 2025, ultimately ceasing in this final year. This is not to say, however, that no electricity imports are allowed to enter California in the later years. They are just represented in a different way from the “Exogenous Imports” category shown in the figure (i.e., exogenous imports refers to current firm and system imports with a certain point-estimate cost signature, say in ¢/kWh, whose contracts are either set to retire within the next decade or whose use in California is difficult to predict going forward). From a modeling standpoint, it is preferable to represent all new electricity supply to California at the technology level (i.e., with investment cost, efficiency, availability data), rather than as commodity flows; hence, future supplies of imports are endogenously embedded in some of the power plant technologies listed in Table 2 and shown in Figure 25. For instance, although not shown, a portion of the wind generation expected in California in the Reference Case actually comes from out-of-state resources, since these resources are likely to be exploited by California electric utilities or their partners and are, thus, part of the California energy system within the framework of the CA-TIMES model. Similarly, due to siting issues, it may be reasonable to assume that a few of the natural gas plants that are brought into the state’s energy system over time will in fact be built outside of the its borders. The advantage of this approach to representing imports is that the electricity produced by these out-of-state power plants can be modeled with bottom-up technological detail. Note that electricity imports are also subject to the Renewable Portfolio Standard within the framework of CA-TIMES.

Industrial, Commercial, Residential, and Agricultural Sectors

Along with natural gas, electricity is one of the two most consumed energy commodities in the industrial, commercial, residential, and agricultural (ICRA) end-use sectors. Hence, it should not be surprising that the continuously growing energy demands of the

ICRA sectors are largely responsible for driving the increases in electricity generation witnessed above. Projections of useful energy demand by fuel type are shown for each of the ICRA sectors, starting in Figure 27. The industrial and commercial sectors appear poised for the most substantial growth over the next four decades, though growth is strong in the residential and agricultural sectors as well. In terms of the fuel mix, there is a small, but noticeable, shift from natural gas to electricity; yet, for the most part the mix remains unchanged. It is important to remember that, as discussed previously, both demand trajectories and the fuel use mix for each of the ICRA sectors are exogenously specified by the modeler for all future years. Therefore, the assumptions input to the model entirely govern the solution that is obtained. In developing the CA-TIMES Reference Case, I have decided to ground these exogenous assumptions in a publicly available scenario that has already undergone review, namely the *Baseline demand* scenario developed for the California Energy Commission as part of the UC-Davis Advanced Energy Pathways (AEP) project (McCarthy et al., 2008a, b). The energy demand projections created in the AEP study are based on growth trajectories for various other things, such as shipments of industrial and agricultural products, commercial floor space, number of residential households, gross state product, and population, to name just a few. Incremental energy efficiency improvements are taken into account in these projections, in the sense that the *Baseline demand* scenario assumes a continuation of historical and projected near-term trends – in other words, business-as-usual.

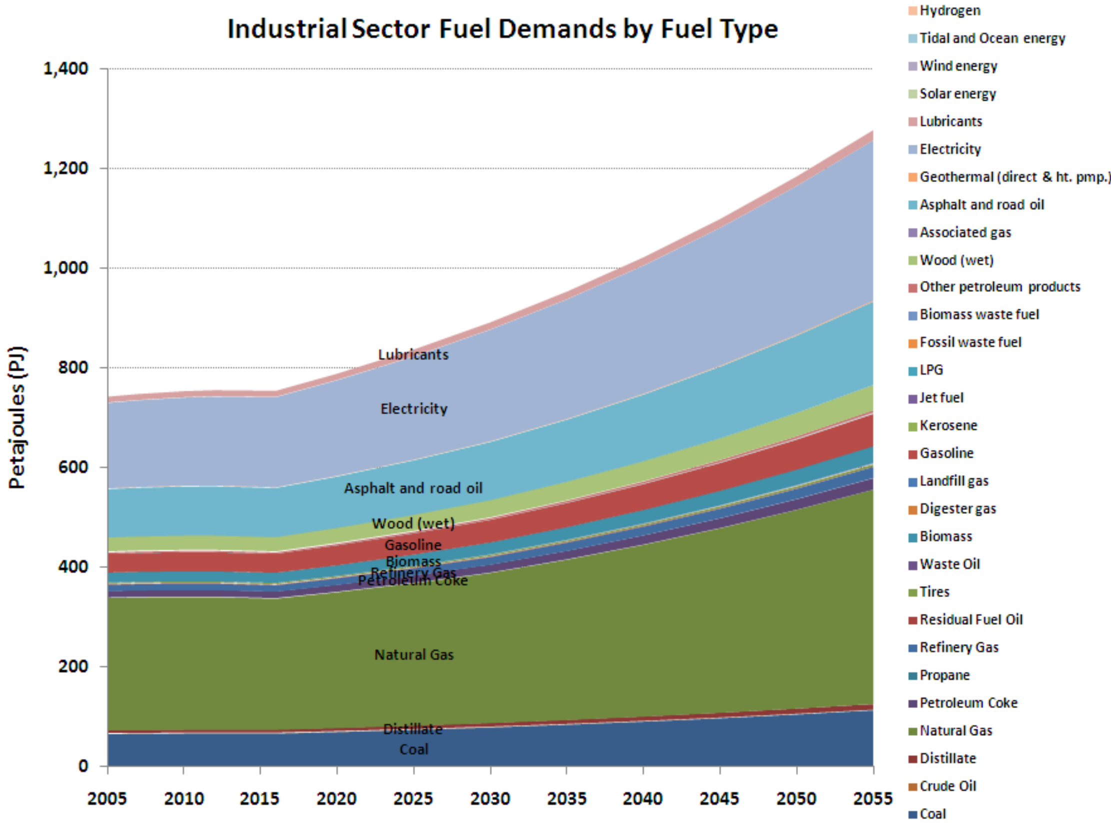

Figure 27 Useful Energy Demand by Fuel Type in the Industrial Sector in the Reference Case

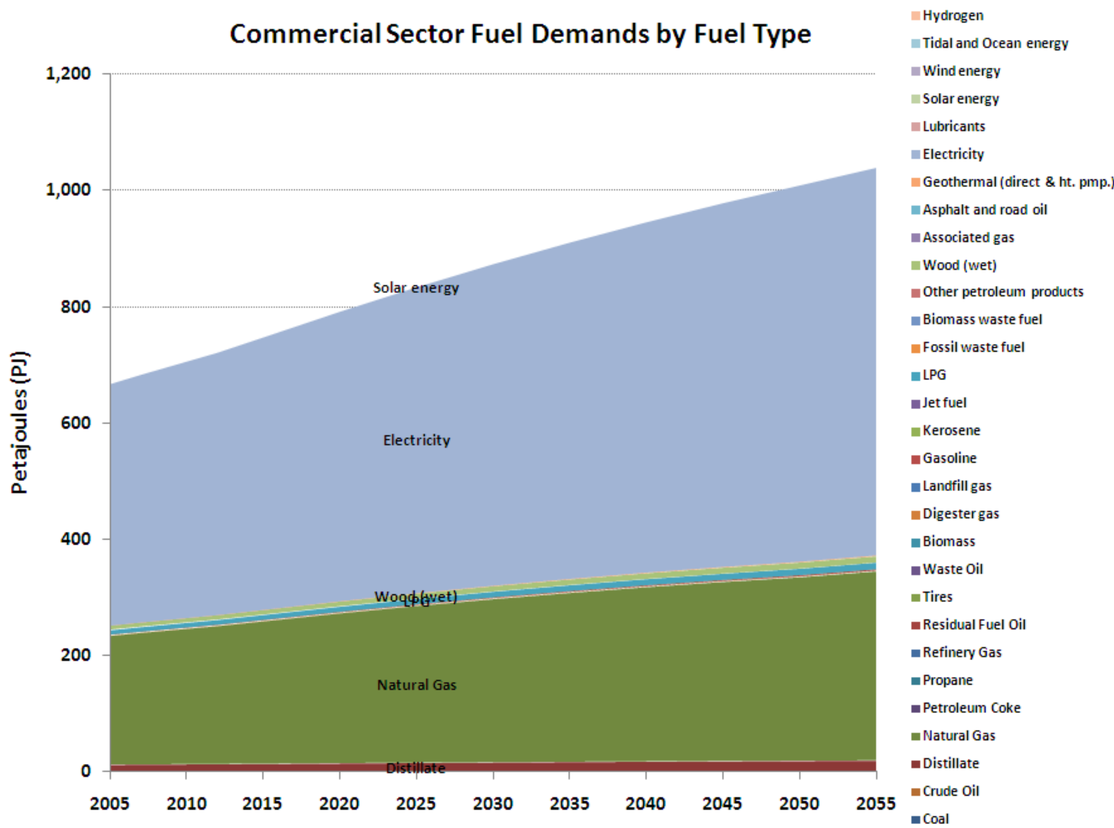

Figure 28 Useful Energy Demand by Fuel Type in the Commercial Sector in the Reference Case

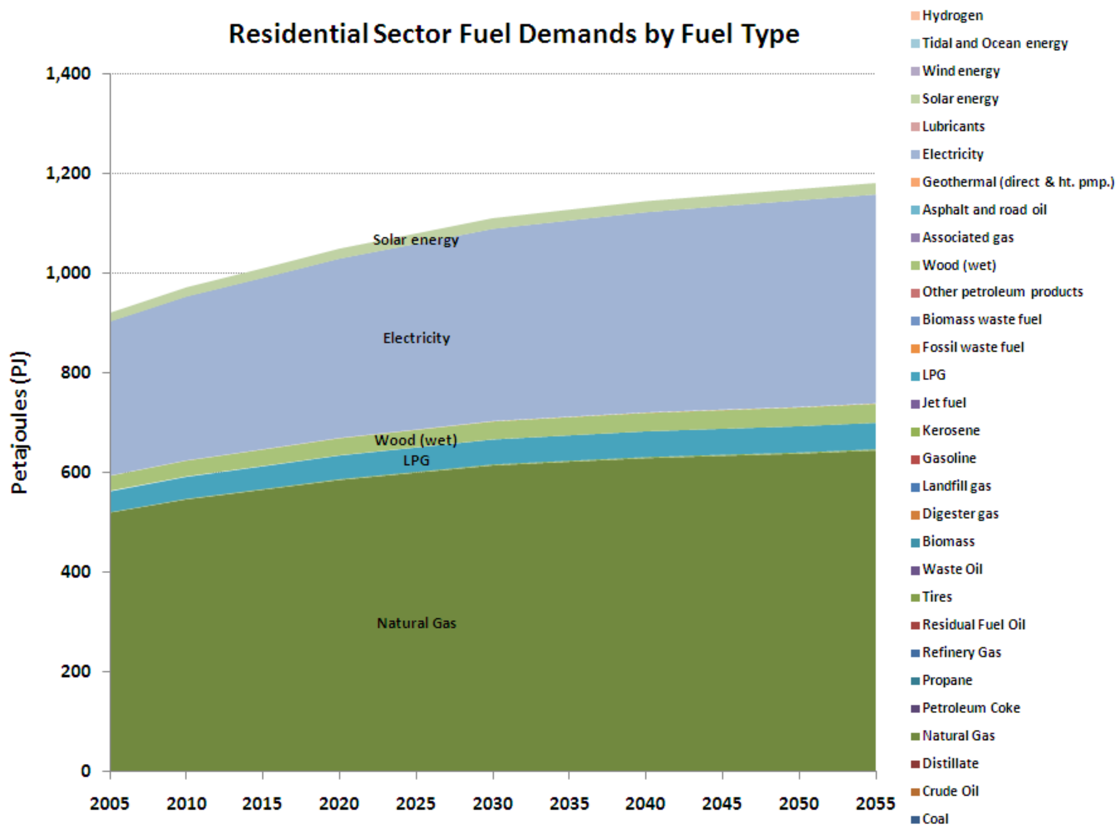

Figure 29 Useful Energy Demand by Fuel Type in the Residential Sector in the Reference Case

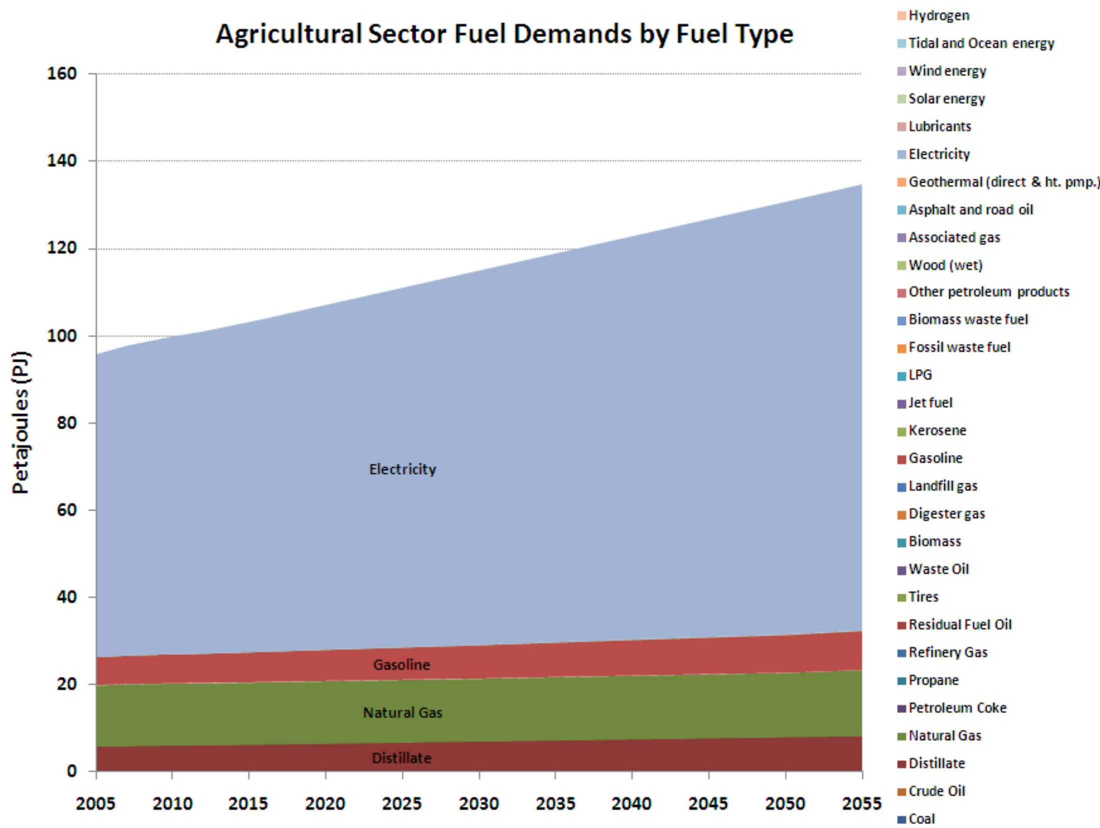

Figure 30 Useful Energy Demand by Fuel Type in the Agricultural Sector in the Reference Case

Transportation Fuels Consumption and Technology Trends

Final energy demand in the transportation sector is projected to grow strongly in the Reference Case (more than 50% between 2005 and 2050), as shown in Figure 31. (Note that unlike for the ICRA sectors, fuel choice and investment decisions in the transport sector – as in the electric generation and energy supply and conversion sectors – are calculated endogenously by the model. In other words, they are model outputs, not input assumptions.) Increased consumption of diesel, jet fuel, natural gas, and residual fuel oil in the non-LDV subsectors is responsible for much of this growth, while increased ethanol demand (primarily cellulosic ethanol) in the light-duty subsector, particularly in the later years, contributes to a slowing of gasoline demand. A considerable quantity of ethanol is consumed in the form of E-85 fuel (85% ethanol, 15% gasoline, by volume), as opposed to oxygenated gasoline, for which the ethanol blend limit after 2010 is, by assumption, relaxed from 5.7% to 10% (by vol.) – so-called E-10 fuel. After initially being spurred by the biofuels mandates of the RFS, cellulosic ethanol consumption grows on its own, thanks to favorable production economics compared to gasoline, which only becomes more expensive over time due to the ever-increasing cost of crude oil (Figure 22).

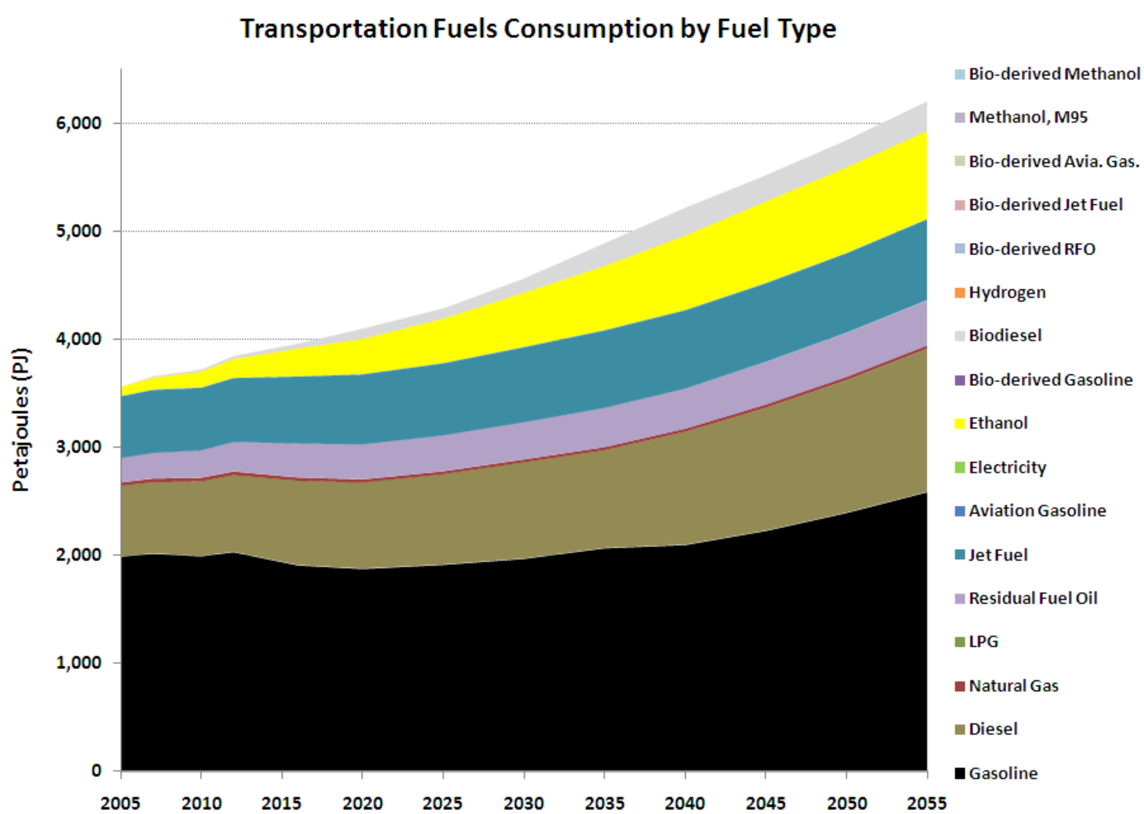

Figure 31 Final Energy Demand by Fuel Type in the Transportation Sector in the Reference Case

In fact, biofuels consumption in general takes off in the Reference Case, experiencing a more than 10-fold increase between 2005 and 2050, reaching a combined level of almost

1,050 PJ (~8.0 billion gge) by 2050 (Figure 32). Continued use of imported corn- and sugarcane-based ethanol, combined with an expanding market for biodiesel and cellulosic ethanol, contribute to this strong growth. For the biofuels whose production is explicitly modeled in CA-TIMES (i.e., all except for corn and sugar cane ethanol imports), Figure 33 shows the breakdown of the various biomass feedstock types used for production. Some feedstocks grow more quickly than others and/or are consumed in greater quantities in the near to medium term, i.e., pre-2030 (e.g., Orchard and Vineyard Wastes and the various types of Municipal Solid Waste). Of course, the particular biomass feedstocks the model chooses to use are simply a function of the production economics, specifically the assumed supply curves for each feedstock type, which come from Parker (2010). Site-specific issues and geo-spatial concerns are not explicitly taken into account within the single-region framework of the CA-TIMES model. That being said, the biomass supply curves from Parker (2010) *are* derived from a spatially-explicit geographic information system (GIS) optimization model for biomass production, transport, and conversion to liquid fuel products. Hence, spatial considerations are, at the very least, *not* completely overlooked in the current analysis.

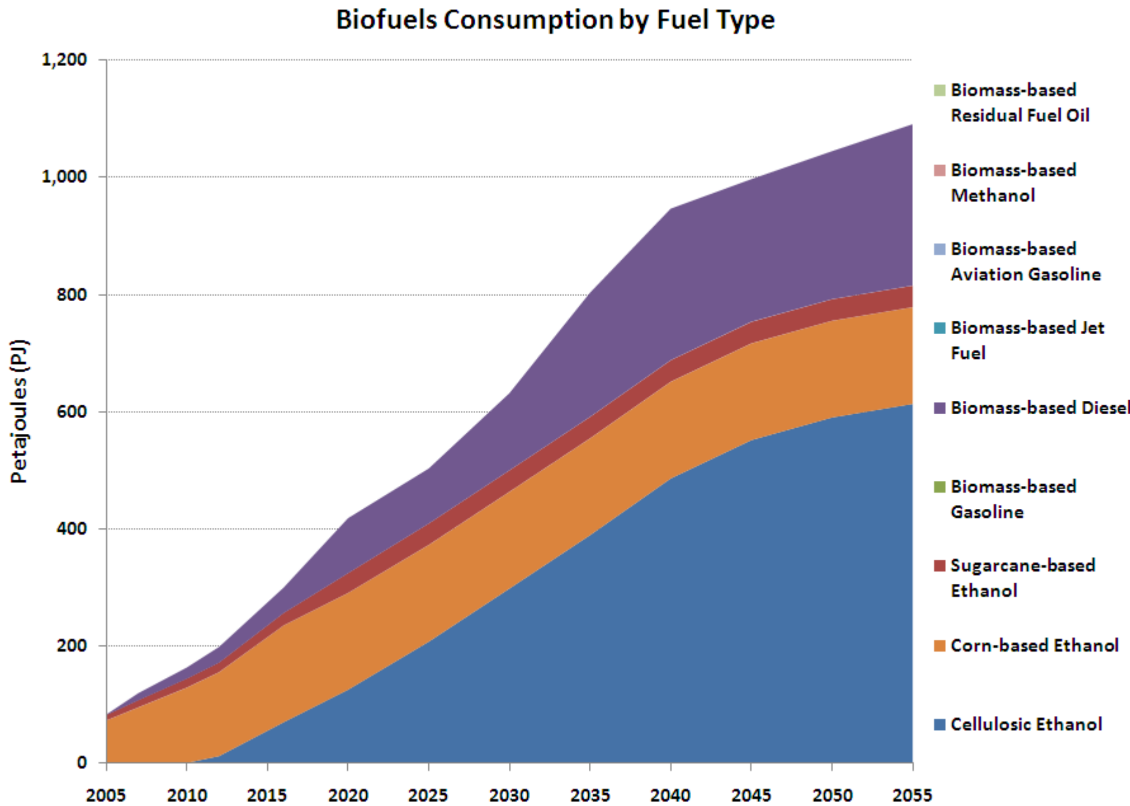

Figure 32 Biofuels Consumption by Fuel Type in the Reference Case

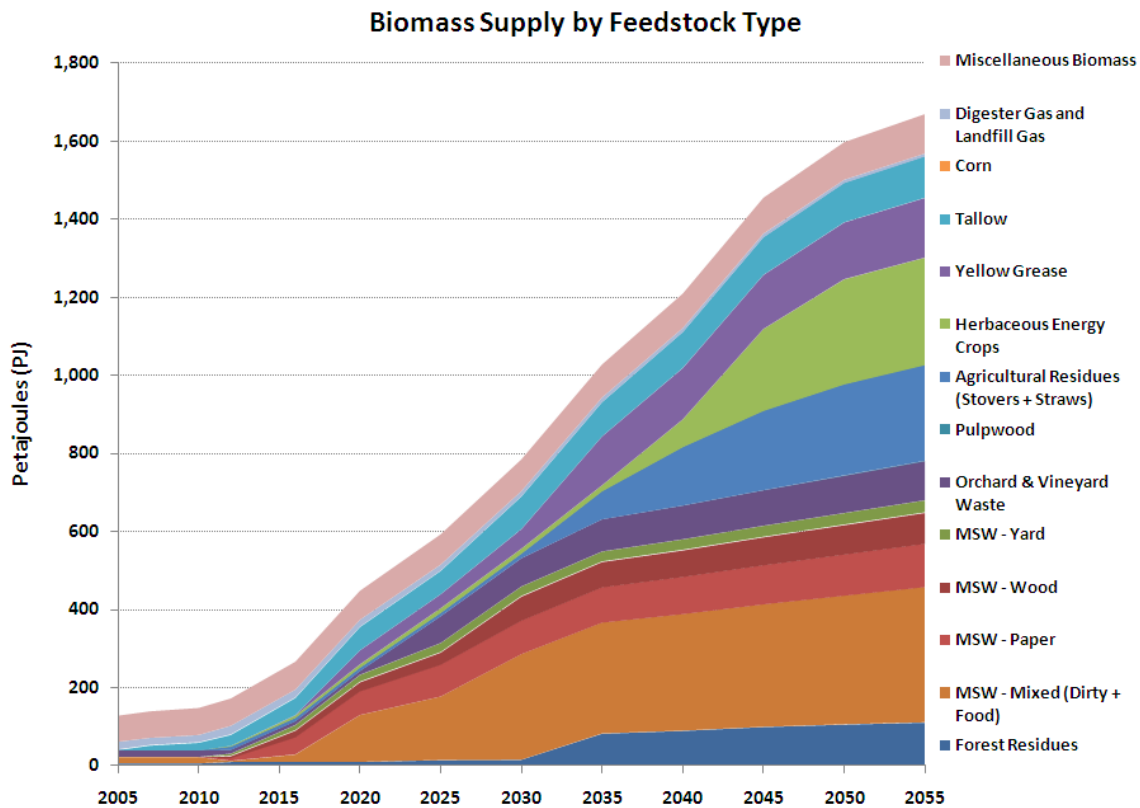

Figure 33 Biomass Supply by Feedstock Type in the Reference Case

The previous figures have shown essentially no increased penetration of electricity or hydrogen as transportation fuels in the Reference Case, save for electricity use in the light- and heavy-rail segments. This result is a function of the economics of these vehicle pathways, including vehicle investment, O&M, and fuel costs, the latter of which depends on the cost of building new fuel conversion facilities and refueling/recharging infrastructure to supply electricity and hydrogen to these vehicles. The costs of these alternative pathways are further compounded by the higher technology-specific discount rates that are assumed for them in order to better represent consumer behavior (i.e., perceived risk and unfamiliarity with alternative fuel vehicles). Higher hurdle rates have the impact of increasing annualized investment costs, in effect shortening required payback periods. Hence, the more efficient, though more capital-intensive, vehicle technologies – HEVs, PHEVs, BEVs, and FCVs – become less attractive from the point-of-view of the model, since their fuel savings are not valued quite as much. The hurdle rates assumed in the CA-TIMES model are pulled from different sources – namely, Schäfer and Jacoby (2006) and the U.S. EPA's 9-region MARKAL model (EPA, 2008a). As an example, conventional gasoline and ethanol ICE vehicles are assumed to have a hurdle rate of 18%, gasoline and ethanol HEVs 25%, and BEVs and FCVs 45%.[30]

Over the next several decades, Reference Case energy consumption by light-duty cars and trucks is projected to grow quite significantly (Figure 34) and in addition is expected to maintain its high share of total transportation fuels demand (~50%), even in spite of considerable demand growth expected in the non-LDV subsectors. Unlike today, however, LDV energy demand will be met by more than just oxygenated gasoline. E-85 could also see much more widespread use, due to the biofuels mandates and increasing cost-competitiveness of ethanol relative to gasoline. Such significant market penetration would necessitate a fairly rapid uptake of E-85 Flex Fuel vehicles, especially over the next 10-15 years (Figure 35). Aside from flex fuel technologies, gasoline vehicles continue to remain the dominant technology in the LDV subsector, though not all of these will be of the conventional ICE variety. As Figure 35 shows, both Advanced Gasoline ICEs and Gasoline HEVs achieve significant market share over the next two decades. At first, these more efficient technologies are needed to meet the increasingly stringent CAFE standards of the 2012-2016 time period. But then, the model simply chooses them

[30] A 25% hurdle rate corresponds to a payback period of approximately 4 years, while a 45% payback period is a little more than 2 years.

because, with rising oil prices ($98/barrel in 2020, $111/barrel in 2030, and $125/barrel in 2050), they are more attractive from an economic standpoint (weighing the lifecycle costs of fuel, capital, variable and fixed O&M, and taking into account higher hurdle rates). Due to the rising average fuel economy of the light-duty vehicle fleet (Figure 36), total fuel consumption plateaus over the next decade or so, before re-attaining its historically steep upward trajectory once annual demand growth again overtakes annual efficiency gains. The obvious take-home message from this model result is that increased fuel economy standards can indeed by quite effective at slowing the growth of light-duty vehicle fuel consumption. Though, achieving absolute reductions in fuel use, in the face of continuously increasing demand for light-duty VMT, could be a substantially more difficult challenge altogether.

Note that in Figure 35, the reason conventional Gasoline ICEs re-take their portion of the gasoline vehicle market in the later years is simply because of the exogenously specified inputs for vehicle efficiency, which assume (at the technology level) a slow but sustained rise in conventional ICE vehicle fuel economy over time, even in the absence of more stringent CAFE standards after 2016. This also explains why one observes a "kink" after 2030 in the new model-year vehicle fuel economies shown in Figure 36. Of course, it is entirely possible that, in a BAU baseline future, new vehicle fuel economies never again rise above the 2016 CAFE standard requirement, with automakers choosing to put all propulsion system efficiency gains into increased vehicle weight, higher horsepower, and vehicle acceleration times. After all, this is what we have seen over the past 25 years, and barring increasingly stringent vehicle efficiency and emissions standards and/or high, sustained fuel prices, there is probably no reason to think that the situation going forward will be any different.

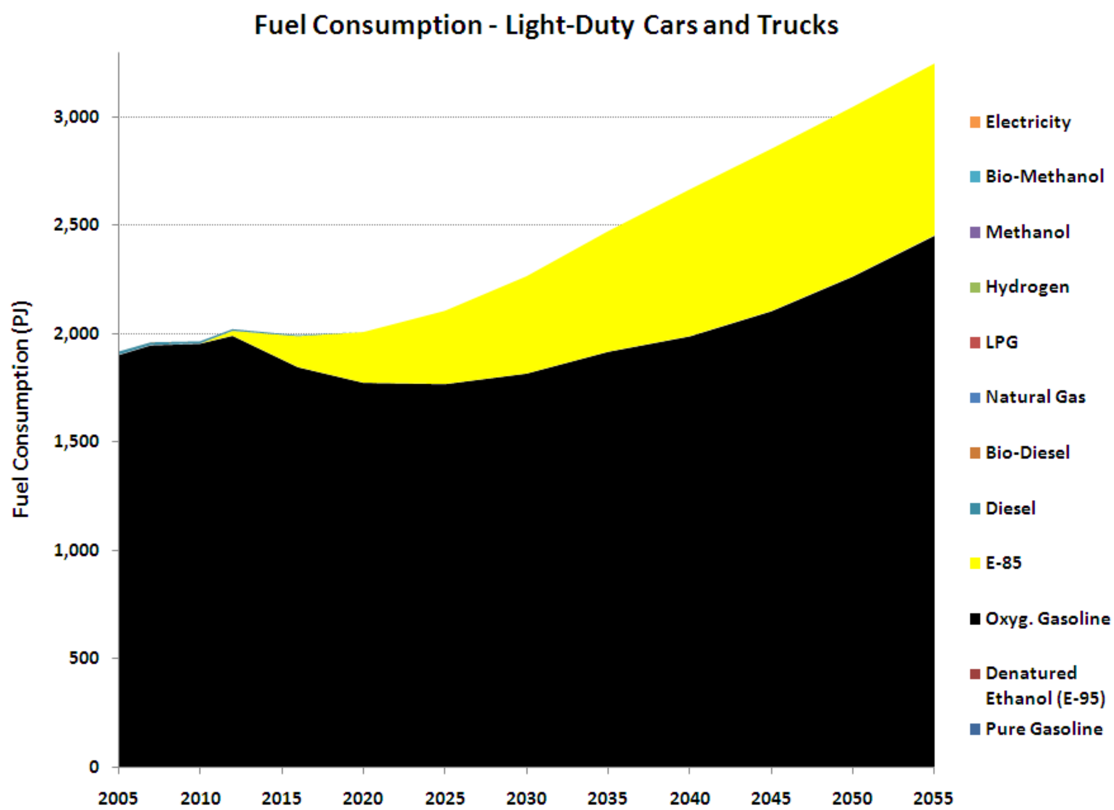

Figure 34 Fuel Consumption for Light-Duty Vehicles in the Reference Case

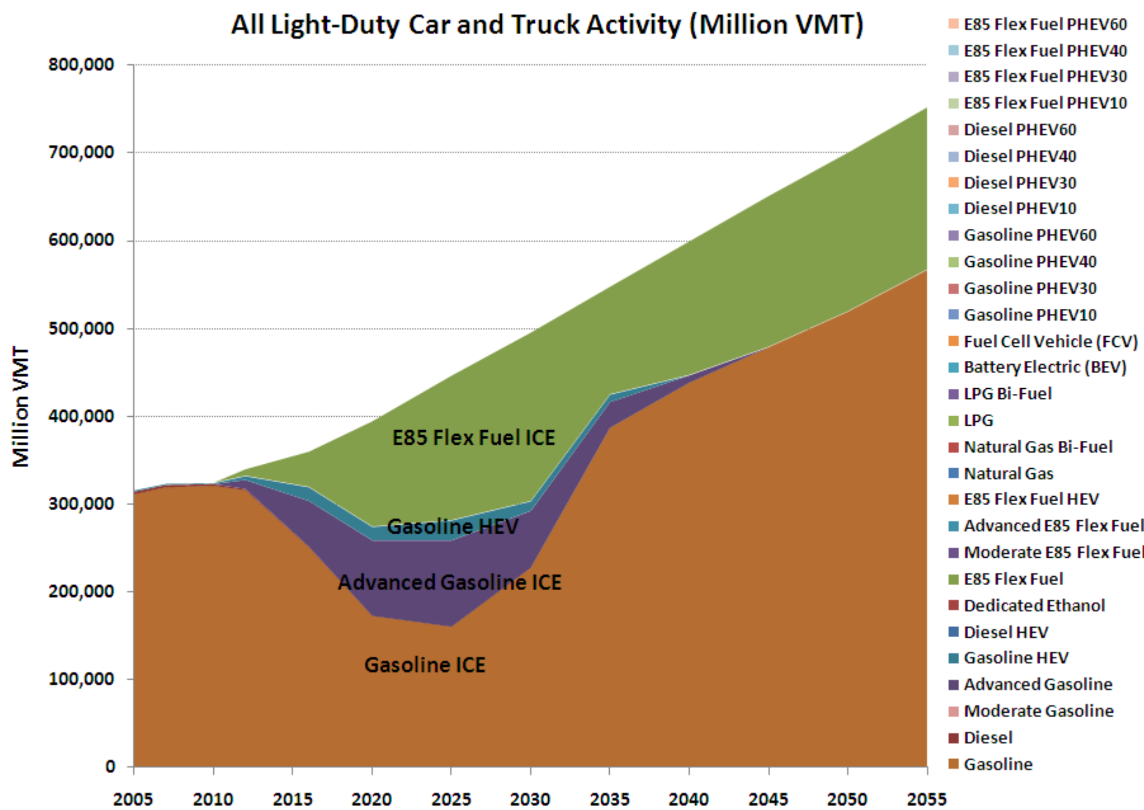

Figure 35 Technology Penetration in the Light-Duty Vehicle Subsector in the Reference Case

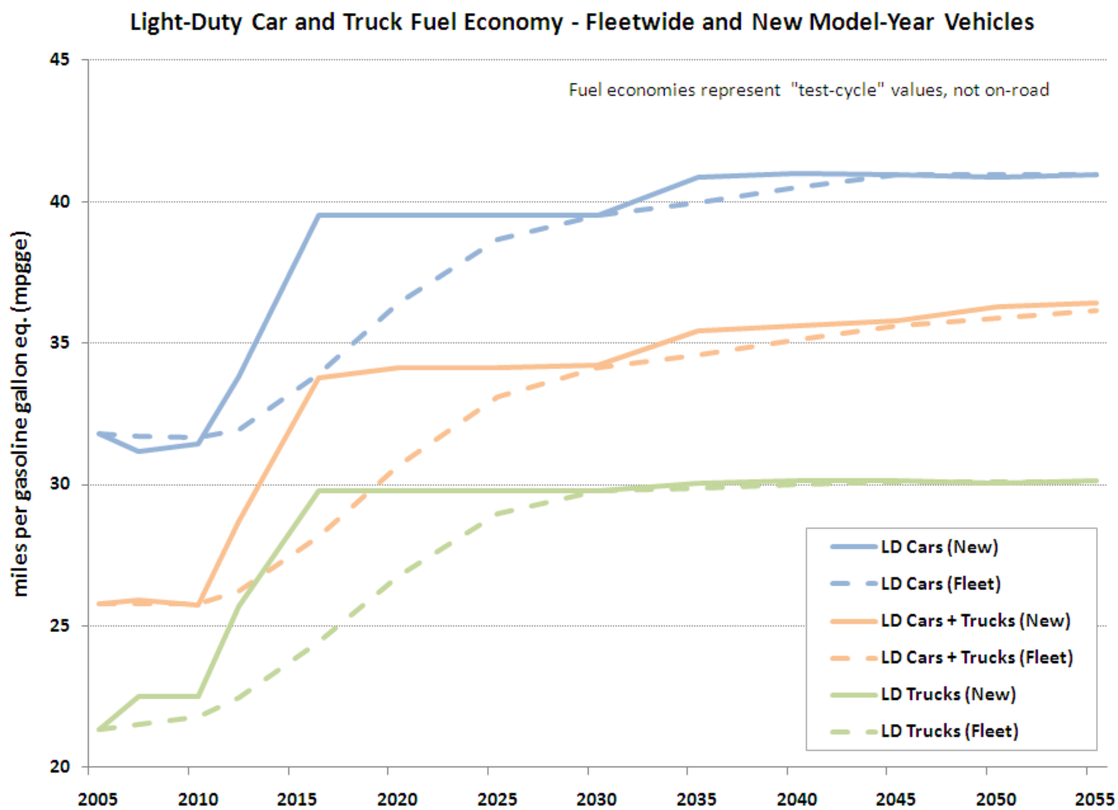

Figure 36 Average Light-Duty Vehicle Fuel Economy in the Reference Case

Fuel consumption trends in the non-LDV transport subsectors are, for the most part, in line with what one would typically expect of a Reference Case: the various subsectors continue to look very much like they do today, save for some increased biodiesel consumption as a result of the RFS mandates and, in later years, due to favorable production economics compared to conventional fossil diesel. The only means of producing biodiesel in the Reference Case is via hydrotreatment of yellow grease and animal tallow feedstocks, which are in relatively short supply in comparison to the various types of cellulosic biomass. Moreover, biodiesel production via FT synthesis of these feedstocks remains uncompetitive from a cost perspective in all years, even at high, sustained crude oil prices later in the modeling horizon. If biomass supplies were not so limited, biodiesel consumption would likely capture even greater market share than what we see in the Reference Case. However, as it stands, cellulosic ethanol is the preferred pathway for supplying biofuels. In particular, utilization of a biochemical (hydrolysis) process is the most attractive pathway.

The technology and fuel development trends in the medium-duty truck and bus subsectors are particularly interesting. More specifically, diesel replaces oxygenated gasoline within a specific segment of the medium-duty subsector (Figure 38), a decision made by the model because of the increasing cost competitiveness of diesel vehicles in this segment (namely, fleet delivery trucks). Similarly, natural gas loses market share to diesel in the bus subsector for essentially the same reason (Figure 39): the capital costs of natural gas buses are simply too high, and their efficiencies too low, to make up for the lower cost of natural gas fuel compared to petroleum-based diesel. In considering the likelihood of these findings, it is important to note that in these cases the model does not explicitly take air quality and noise concerns into account during its decision-making process, both of which represent two important motivating factors for why we see natural gas vehicles in cities around the world today.

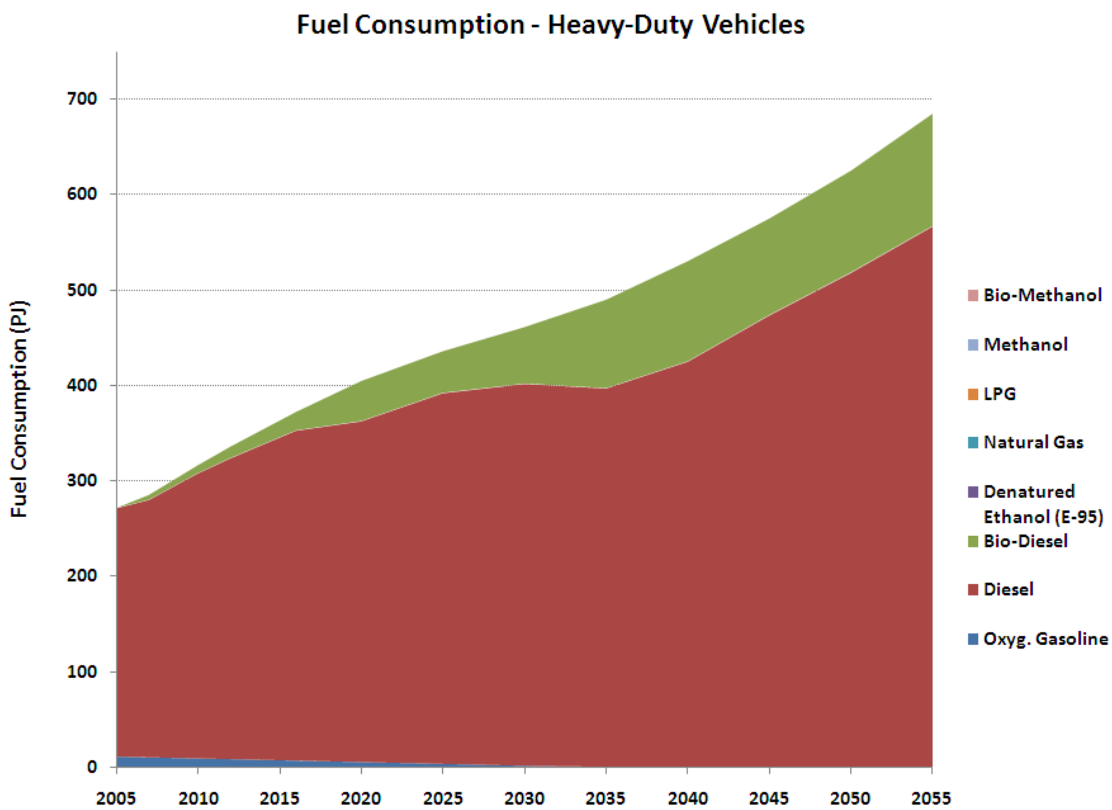

Figure 37 Fuel Consumption for Heavy-Duty Trucks in the Reference Case

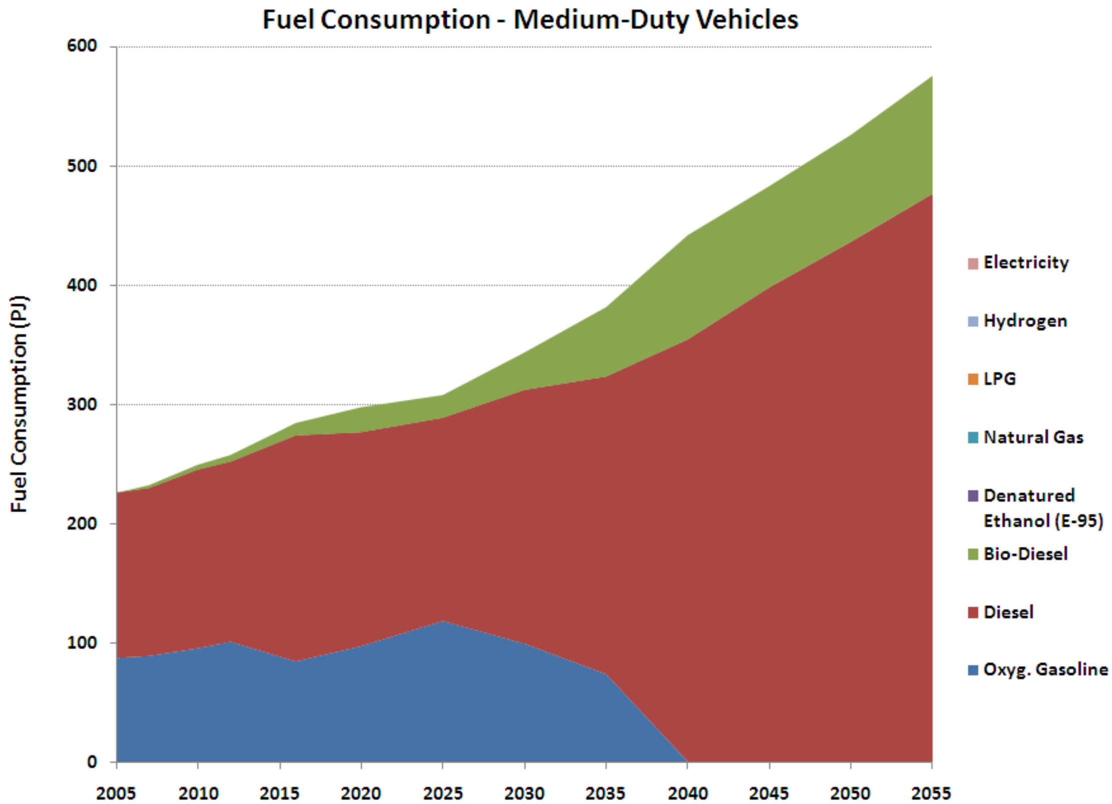

Figure 38 Fuel Consumption for Medium-Duty Trucks in the Reference Case

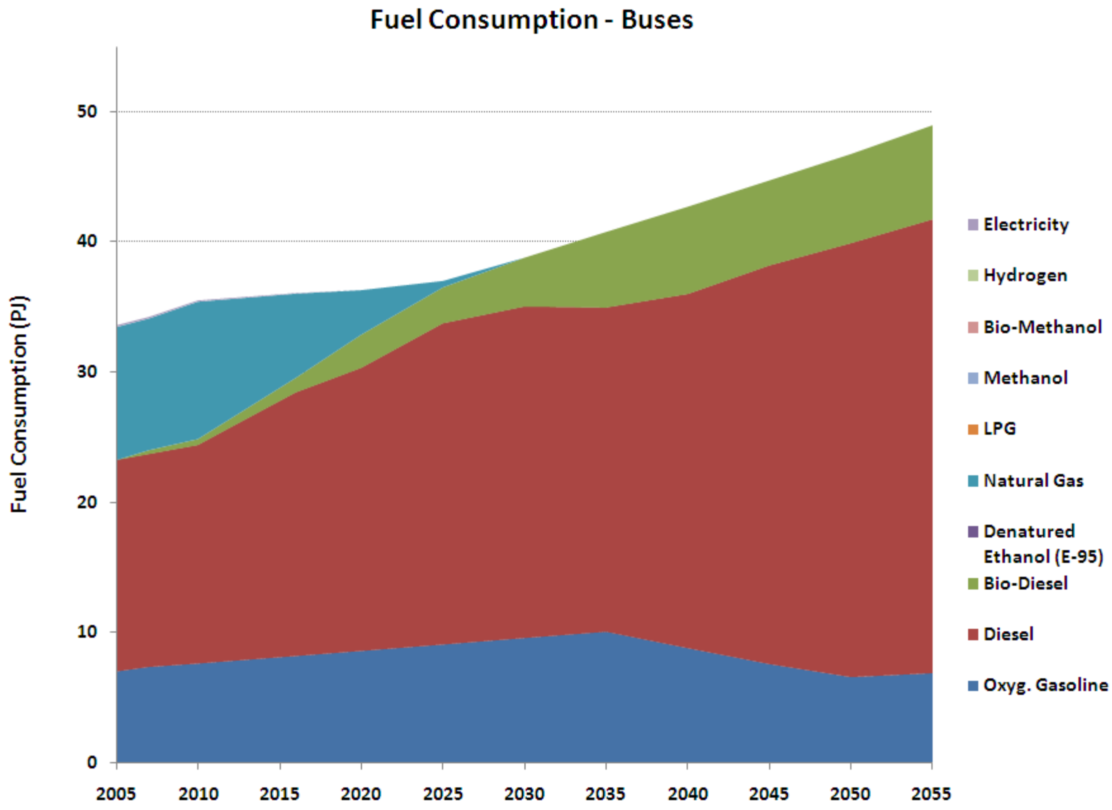

Figure 39 Fuel Consumption for Buses in the Reference Case

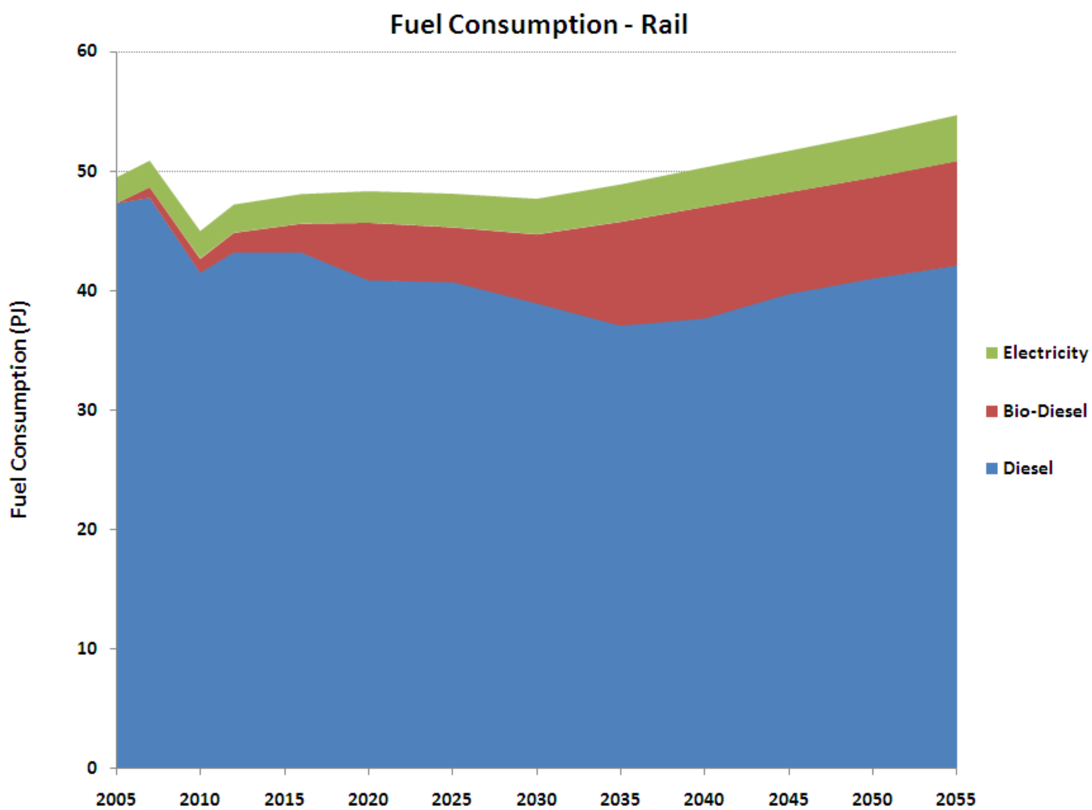

Figure 40 Fuel Consumption for Rail in the Reference Case

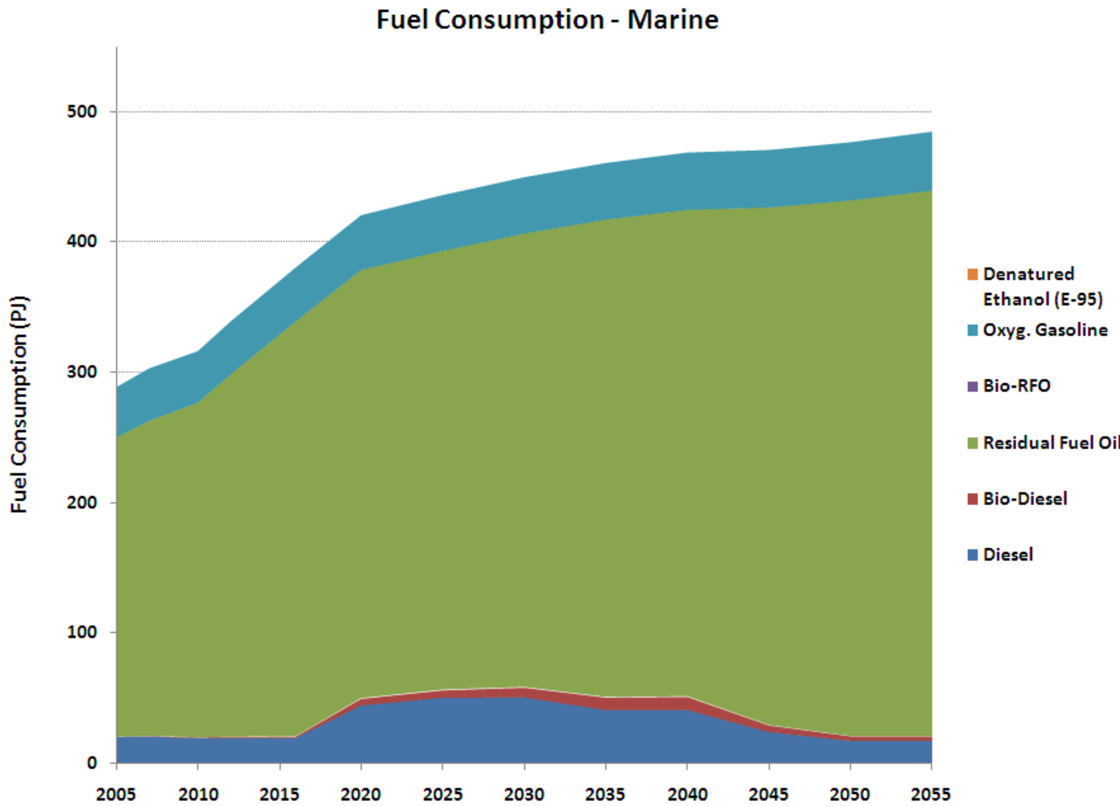

Figure 41 Fuel Consumption for Marine Vessels in the Reference Case

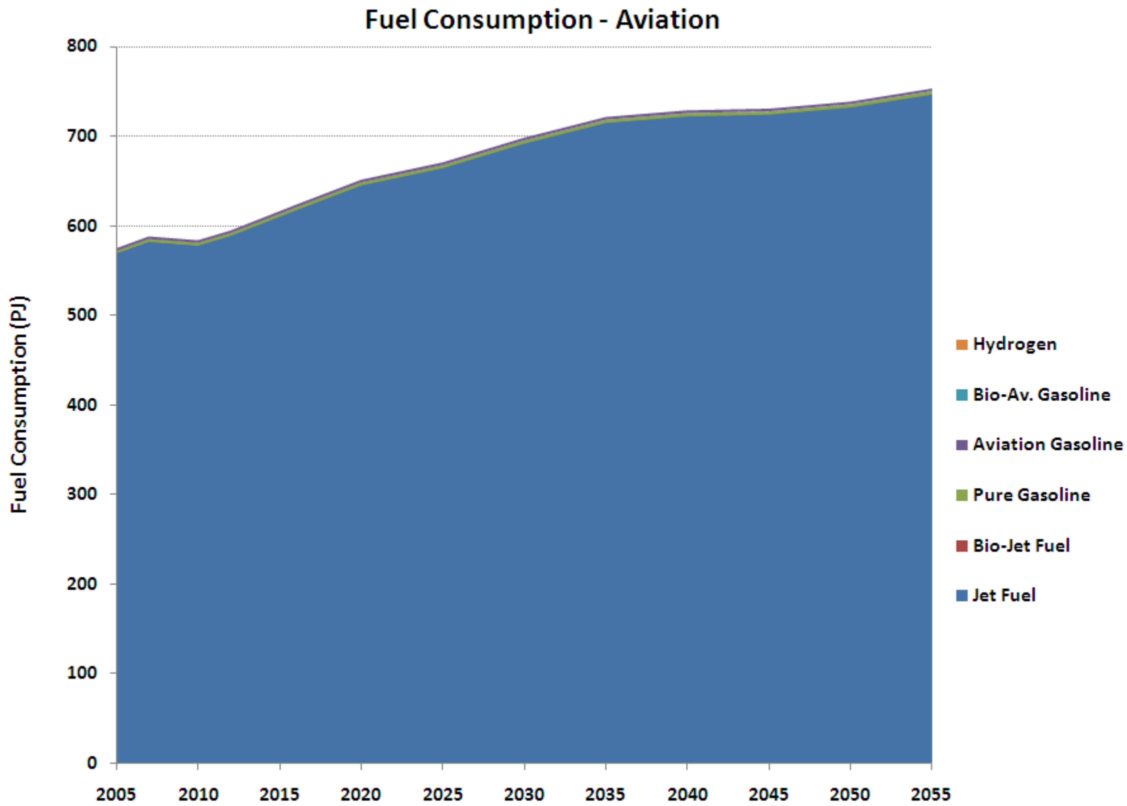

Figure 42 Fuel Consumption for Aviation in the Reference Case

Greenhouse Gas Emissions

Given the projected increases in service demands and energy consumption in the business-as-usual Reference Case scenario, it is perhaps not surprising that California greenhouse gas emissions are expected to continue to rise over the next several decades. Figure 43 shows CA-TIMES model estimates of *CA-Combustion* GHG emissions[31] produced via fuel combustion activities in each of the various energy producing and consuming sectors. (As discussed in Section 3, the model covers intrastate, interstate,

[31] *CA-Combustion* GHGs include all emissions produced from fuel combustion activities within California's borders, from interstate and international aviation and marine trips whose origin is California, and from production of electricity that is consumed in California, even if the plants producing the electricity are located out-of-state. *+Out-of-state Supply* GHGs also include upstream emissions of imported energy commodities, which therefore captures well-to-tank emissions that are generated outside of California.

and international aviation and marine activities, whereas non-energy GHGs are not estimated at the present time.) The transportation sector remains the single largest emissions category for many years to come, growing its share of total fuel combustion emissions to well over half (~56%) by 2050. The combined industrial/supply sector eventually takes over the second position from the electric sector, whose emissions are about the same in 2050 as they are today. Allocation of electric sector emissions to end-uses (Figure 44) better illustrates the contribution of the industrial, commercial, residential, and agricultural sectors to total GHG emissions. Yet, even under this accounting scheme, it is clear that the transportation sector is poised to drive emissions growth in California in the long term. What is potentially more interesting is the near term, specifically the coming decade up to 2020. Results of the CA-TIMES model show that the currently planned policies of the Reference Case (i.e., those summarized in

Table 25) are not likely to be enough to bring emissions back down to 1990 (or even 2005) levels by 2020. That being said, the new CAFE standards (from 2012 to 2016) and the RFS biofuels mandates (to 2022) do help to slow California's rapid emissions growth quite considerably.

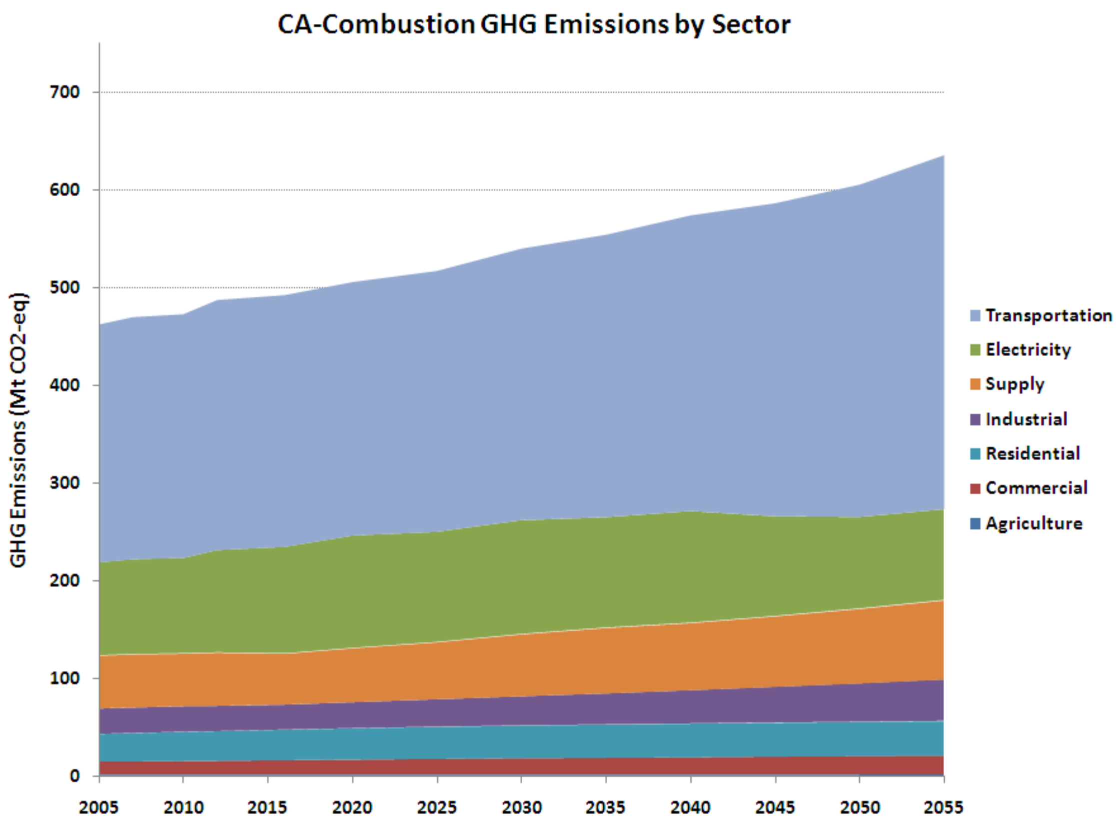

Figure 43 ***CA-Combustion*** **GHG Emissions by Sector in the Reference Case**

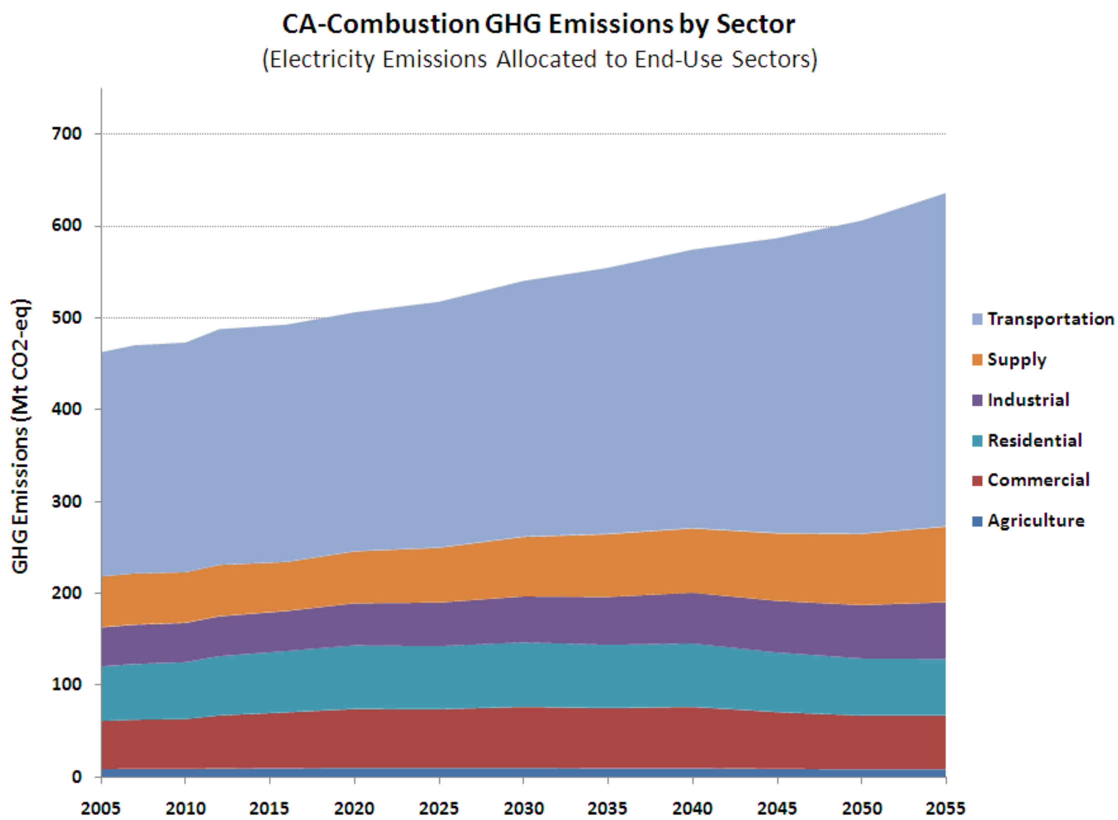

Figure 44 ***CA-Combustion*** **GHG Emissions by Sector in the Reference Case with Electricity Emissions Allocated to the Various End-Use Sectors**

If one also considers upstream emissions of imported energy commodities (i.e., *+Out-of-state Supply* emissions), the projected future increases in California's GHG emissions become even greater (Figure 45 and Figure 46). The significantly higher growth of supply sector emissions, especially in the long term, is entirely responsible for this result, since emissions from all other sectors are, by definition, the same in both the CA-Combustion and +Out-of-state Supply cases. Allocation of supply sector emissions to each of the end-use sectors, in a way similar to electric sector emissions, is also possible in theory. While not shown here, the likely result of such an allocation would be a further increase in emissions for each of the end-use sectors. The bulk of supply sector emissions in the Reference Case actually occur as a result of crude oil and natural gas extraction and petroleum refining. Therefore, the end-use sectors that consume the most crude-oil- and natural-based fuels (transportation, industrial, and residential) would see particularly large gains in GHG emissions.

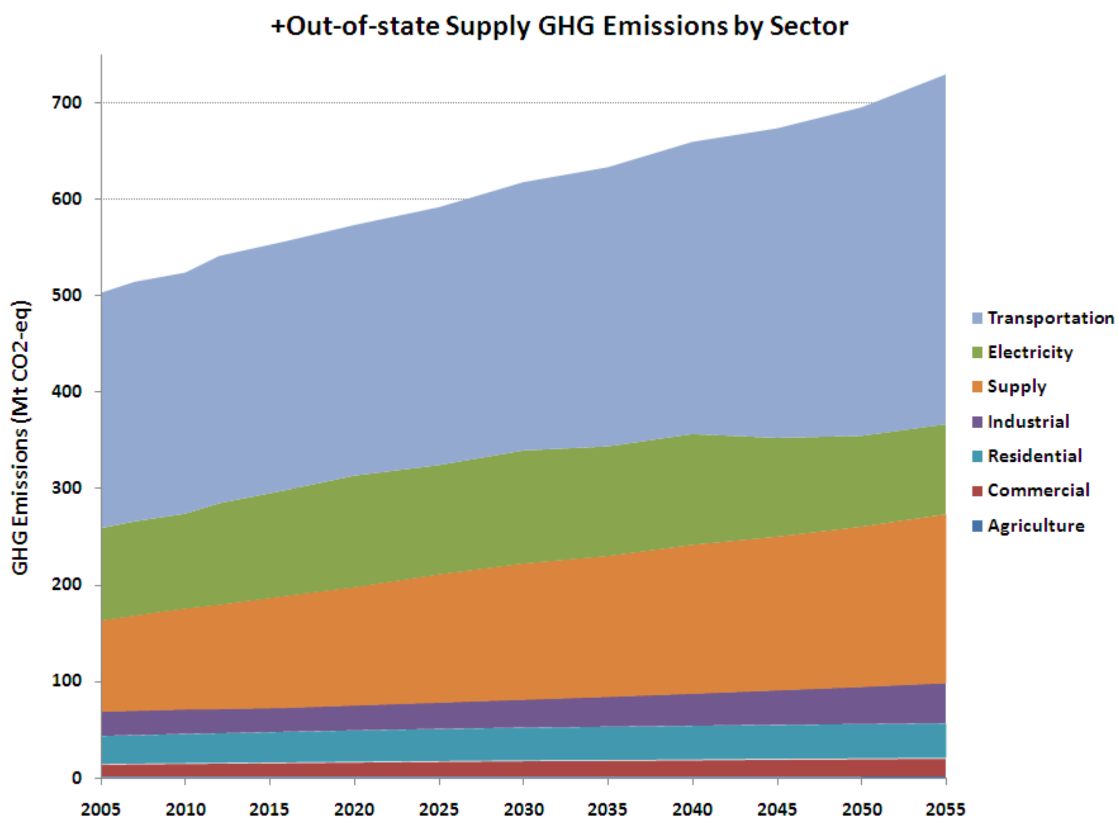

Figure 45 +*Out-of-state Supply* GHG Emissions by Sector in the Reference Case

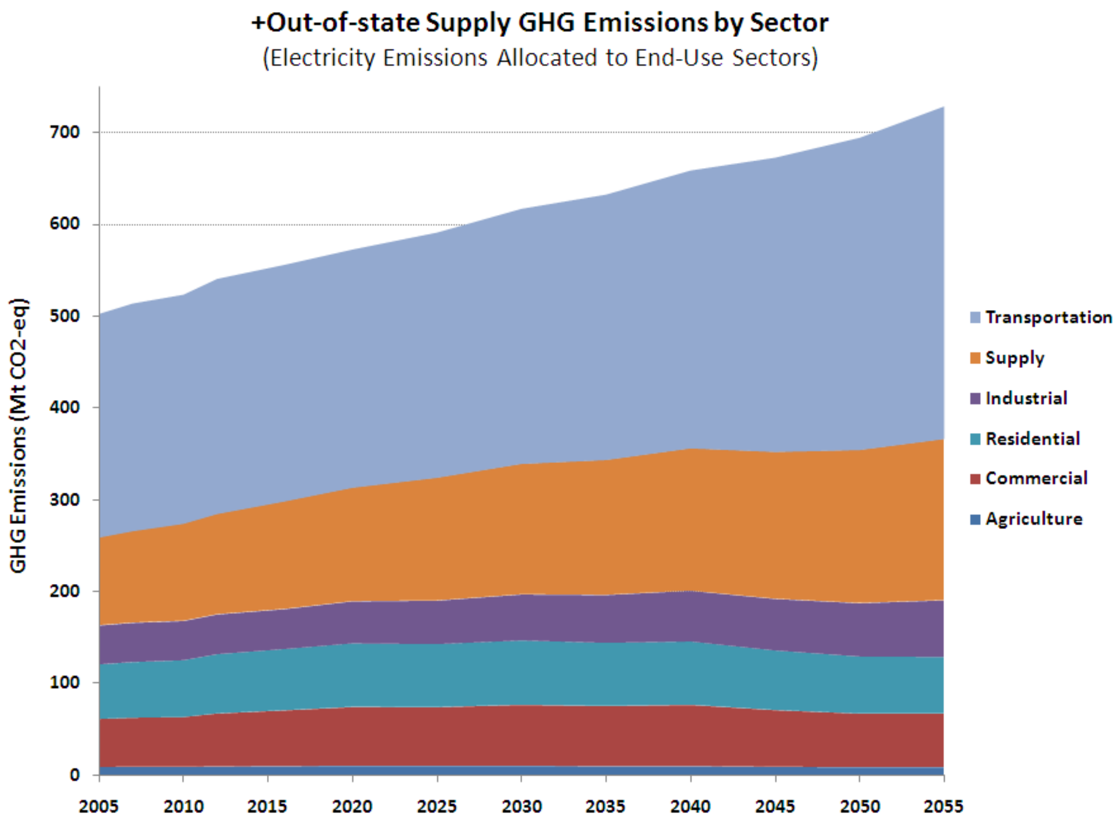

Figure 46 ***+Out-of-state Supply*** **GHG Emissions by Sector in the Reference Case with Electricity Emissions Allocated to the Various End-Use Sectors**

The implications of allowing California GHG emissions to rise to such high levels in the long term are not entirely certain, principally because the situation depends entirely on how the energy system develops in the rest of the United States and in other countries over the next several decades. If the adoption of advanced technologies and alternative fuels also remains weak throughout the rest of the world, then emissions will continue to rise at a rapid pace, with growth being strongest in developing countries. According to the Intergovernmental Panel on Climate Change (IPCC) 4th Assessment Report, such unrestrained emissions growth could ultimately lead to severe climate change, with global mean surface air temperatures rising by 1.1 to 6.4 ºC ("likely range", depending on scenario and assumptions) over the course of the century (IPCC, 2007). Based on the various computer models used to support the IPCC 4AR, warming of the planet is likely to lead to an increase in the frequency of warm spells, heat waves, and events of heavy rainfall, as well as sea level rise of 18 to 59 cm. These *global* changes will most probably have a pronounced *local* impact here in California, affecting the state's economy, natural and managed ecosystems, and human health and mortality in ways that are hard to predict (California Department of Environmental Protection, 2006).

While transportation-related GHG emissions (including both upstream/ "well-to-tank" and downstream/"tank-to-wheel" stages) rise considerably in the Reference Case, their growth is actually slower than total transport sector energy consumption (see Figure 31). Hence, the average lifecycle carbon intensity of all fuels consumed in the transportation sector decreases, from 82.8 gCO_2-eq/MJ_{HHV} in 2005 to 75.1 gCO_2-eq/MJ_{HHV} in 2050, a difference of about 10% (Figure 47). Figure 48 shows similar trends for fuels consumed in the light-duty vehicle subsector. (Remember that because these carbon intensities are calculated on a HHV basis, they are about 7 to 11% lower than if calculated on a LHV basis.) Increased consumption of natural gas and biofuels is primarily responsible for lowering average lifecycle carbon intensities. In particular, greater utilization of biofuels raises the relative contribution from upstream fuel production processes and consequently lowers the contribution from downstream fuel combustion activities. Interestingly, in the near term ethanol consumption actually increases the average carbon intensity of LDV fuels, at least according to the results of CA-TIMES, which are based on input assumptions for imported corn and sugar cane ethanol that include significant indirect land use change (iLUC) impacts in their carbon intensity values. For example, the total lifecycle carbon intensity, including iLUC, of corn ethanol is 121.4 gCO_2-eq/MJ_{HHV}, while for sugar cane ethanol it is 66.3 gCO_2-eq/MJ_{HHV}, assumptions that are based on CARB (2009b) and Plevin et al. (2010).[32] In addition, the total carbon intensity (including iLUC) of energy crop-derived cellulosic ethanol is assumed to be a much smaller 18.4 gCO_2-eq/MJ_{HHV}. Of course, in reality, with the LCFS regulations in place, it is unlikely that biofuels with such high iLUC impacts would ever be used in California, and in the Deep GHG Reduction Scenario described later, these two types of ethanol are actually phased out over time.

[32] A median estimate for iLUC of 58.7 gCO_2-eq/MJ_{HHV} is assumed for corn ethanol based on Plevin et al. CARB's mean iLUC estimate of 41.5 gCO_2-eq/MJ_{HHV} is assumed for sugar cane ethanol from Brazil.

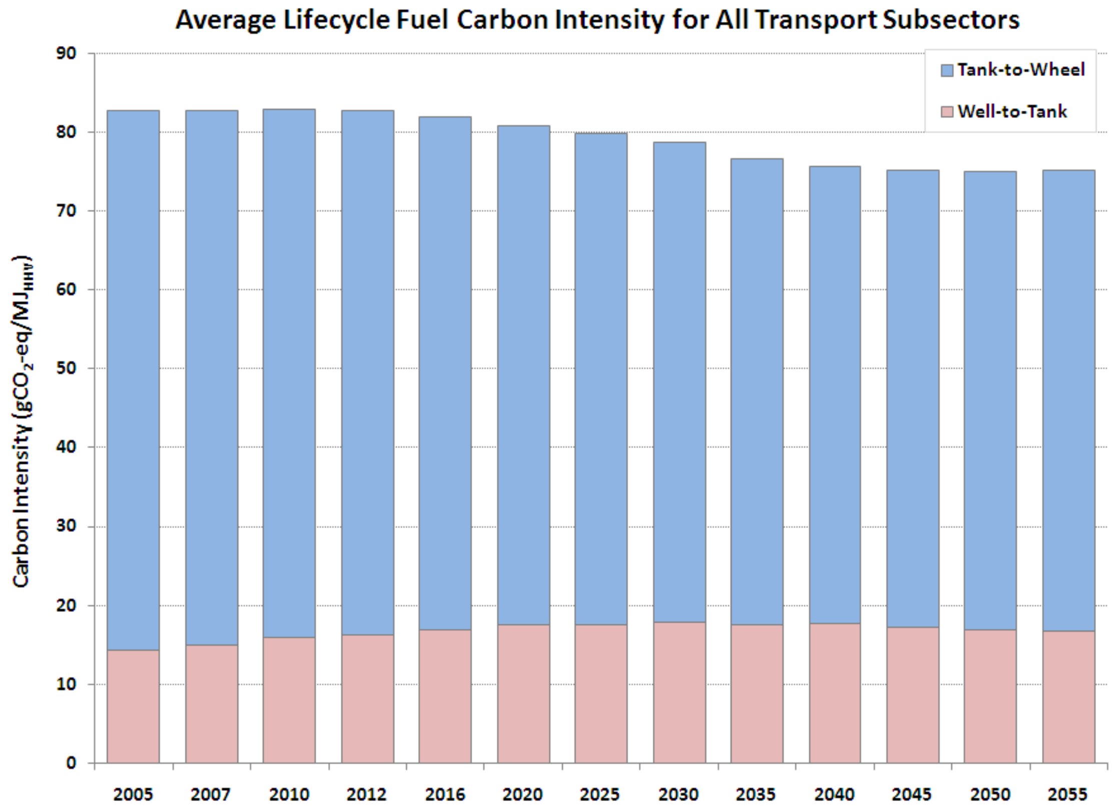

Figure 47 Average Lifecycle Carbon Intensity of All Fuels Consumed in the Transportation Sector in the Reference Case

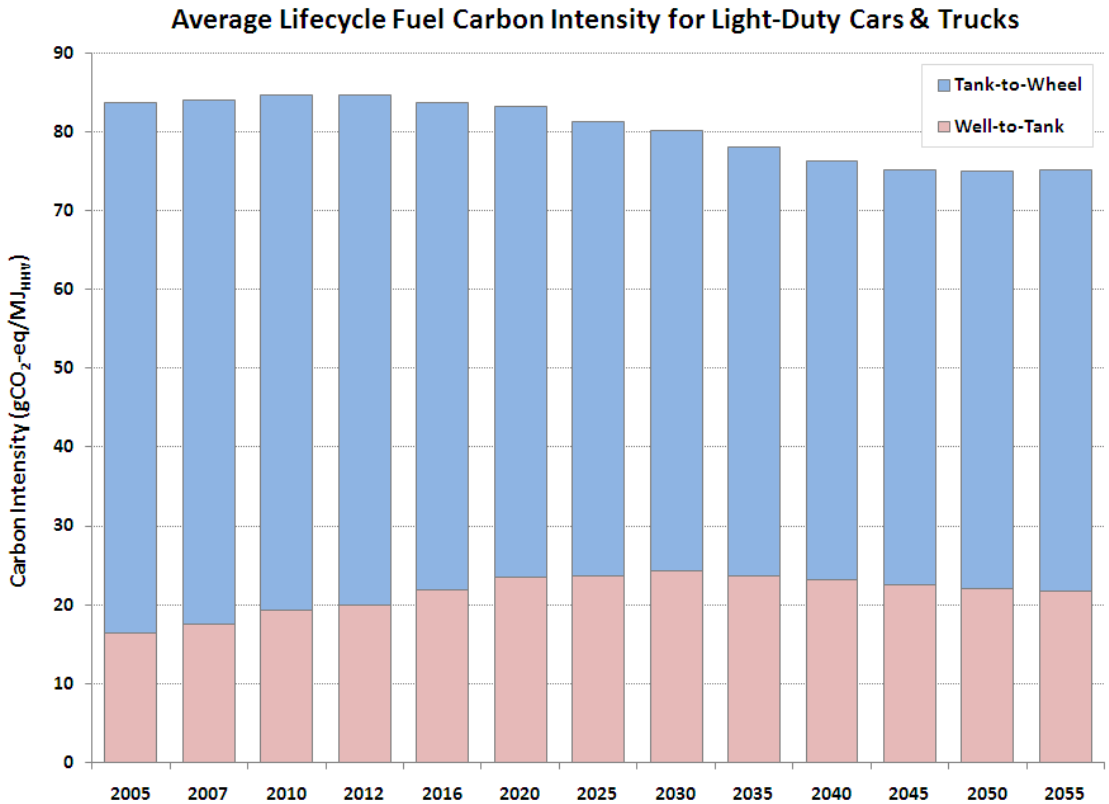

Figure 48 Average Lifecycle Carbon Intensity of All Fuels Consumed in the Light-Duty Vehicle Subsector in the Reference Case

2. Deep GHG Reduction Scenario

The CA-TIMES Deep GHG Reduction Scenario describes the potential development of California's energy system over the next several decades in the context of a social, political, and economic framework that highly values the threat of climate change, both within California and in the rest of the U.S. and the world. Hence, individuals, firms, and governments all make substantial efforts to transition California toward a low-carbon society. As with the Reference Case, one should not misconstrue this scenario as a prediction of what will happen as a result of strong climate policy, but rather as a single vision of what *could* feasibly happen, under the large set of technological and policy assumptions input to the model. In theory, an infinite number of GHG reduction scenarios could potentially be developed; however, in order to keep the current analysis manageable and digestible, only a limited number will be discussed here. In particular, I first develop and discuss a Deep GHG Reduction Scenario that achieves an 80% reduction in greenhouse gas emissions below 1990 levels by 2050, with most major advanced technology and alternative fuel options available to the model (at least in the sectors that are represented with bottom-up detail). Then, I develop several interesting variants of this core scenario, most of which do not actually meet the 80% reduction target because the availability of key resources and technologies is limited. The following sections take an in-depth look at the Deep GHG Reduction Scenario and its variants.

Notable Modifications of the Reference Case Input Assumptions in Developing the Deep GHG Reduction Scenario

Policy is undoubtedly the most important driver of the dramatic energy system transition that plays itself out in the Deep GHG Reduction Scenario.[33] The scenario includes all the same policies that are present in the Reference Case, as well as additional policies that would likely also need to be enacted, if the goal were to drive the energy system toward a low-carbon future (Table 26). A few of these policies are already being discussed, the most important of which is the so-called "80in50" target, which calls for an 80% reduction in GHG emissions below 1990 levels by 2050. In reality, this would probably be achieved by a market mechanism such as a cap-and-trade (i.e., emissions trading)

[33] Some might argue that evolving social values, like increased environmental consciousness, will be the most important driver of global change in the future. While this is very much true, I would contend that policy is simply the embodiment of society's collective willingness to enact change.

program or a carbon tax. For simplicity and transparency within the CA-TIMES model, a declining carbon cap constraint is utilized – specifically, a straight line trajectory from 2020 to 2050 is assumed. Other policies included in the Deep GHG Reduction Scenario are renewable portfolio standard on electricity generation and energy efficiency and emissions standards for end-use sector demand technologies (e.g., cars, trucks, heaters, light bulbs, air conditioners, consumer and household electronic appliances, etc.).

Table 26 Additional Policies Represented in the CA-TIMES Deep GHG Reduction Scenario

Policies	Descriptions
80% GHG Reduction Goal by 2050	- Reduce GHG emissions to 1990 levels by 2020, and 80% below 1990 levels by 2050. Based on a California Executive Order S-3-05. Only applies to fuel combustion emissions in CA-TIMES. Interim emission targets between 2020 and 2050 are linearly interpolated.
Renewable Portfolio Standard (RPS)	- By 2020, 33% of California electricity generation must come from renewable sources (excluding hydro). Assumed to remain constant thereafter. Based on Executive Order S-14-08 and Executive Order S-21-09.
Light-Duty Vehicle GHG Emission Standards (CAFE for 2017-2025)	- GHG emissions rate of new model-year light-duty cars and trucks declines 4.5% per annum (on a gCO_2-eq per mile basis) between 2017 and 2025. Based on notices of intent and an interim technical assessment by DOT-NHTSA, EPA-OTAQ, and CARB, which analyzes the feasibility of an annual rate of improvement of 3 to 6% (EPA-DOT-CARB, 2010). - <u>Light-duty passenger cars</u>: New model-year vehicle fleet must achieve 215 gCO_2/mile (41.4 mpg) in 2017, strengthening to 149 gCO_2/mile (59.8 mpg) in 2025, assumed to remain constant thereafter. - <u>Light-duty passenger trucks</u>: New model-year vehicle fleet must achieve 285 gCO_2/mile (31.2 mpg) in 2017, strengthening to 197 gCO_2/mile (45.1 mpg) in 2025, assumed to remain constant thereafter.
Energy Efficiency Standards for ICRA Sector Technologies	- Average annual efficiency improvement of generic end-use sector technologies in the Industrial, Commercial, Residential, and Agricultural sectors. Efficiency gains are over and above those assumed in the Reference Case, and are technically feasible with today's technologies. Industrial (0.41% per year); Commercial (0.50% per year); Residential (0.68% per year); Agricultural (0% per year). Based on the *Baseline – high efficiency* scenario of McCarthy et al. (2008b) compared to the *Baseline demand* scenario.

In addition to policy, the development of the energy system in the Deep GHG Reduction Scenario depends on the multitude of resource, technology, and demand assumptions that are input to the CA-TIMES model. These assumptions are for the most part the same in both the Reference Case and Deep GHG Reduction Scenario. However, in some important instances, they are quite different. The following discussion attempts to summarize the key areas where the inputs diverge.

Electric Generation Sector

The following two tables summarize the cost and efficiency assumptions of the CA-TIMES model in the Deep GHG Reduction Scenario. The values, which are notably more optimistic than in the Reference Case, are drawn from the EIA's Electricity Module Assumptions to the AEO2010 (EIA, 2010a). More specifically, I utilize a combination of the assumptions used for the EIA's *Low Fossil Technology Cost Case*, *Low Nuclear Cost Case*, and *Low Renewable Technology Cost Case*. Underlying these cases is a storyline where strong policy and R&D efforts lead to significant technological advances and progress along the cost curves for various energy technologies. In other words, the Deep GHG Reduction Scenario exogenously assumes greater technological learning than in the Reference Case, namely because energy R&D (for both fossil and low-carbon technologies) is given much higher priority in a future world where energy and climate become much higher priorities than they are today. These cost reductions and efficiency improvements are achieved for free within the context of the simplified CA-TIMES model (since endogenous technological learning and a top-down macro-economic model are not utilized); though to be sure, these gains would not be achieved for free in reality, give that there are very real costs to R&D spending on the part of public and private entities.

Combined with caps on greenhouse gas emissions, and thus a strong carbon price, and various other energy and environmental policies, the advanced power plant technologies naturally become increasingly attractive. Specifically, the investment costs for coal, natural gas, nuclear, and renewable power plants are 10% lower than in the Reference Case in 2010, and they fall to 25% below Reference Case levels in 2035 and beyond. The cost distribution among the various power plant technologies does not change markedly in the Deep GHG Reduction Scenario compared to the Reference Case: renewables and other advanced technologies (e.g., coal and natural gas with CCS) continue to be more expensive than conventional fossil thermal technologies. Therefore, the main effect is increasing the attractiveness of electricity as an end-use fuel and reducing the cost of electricity produced by renewables and other advanced types of power plants. Lastly, all fixed and variable O&M costs and power plant efficiencies in the Deep GHG Reduction Scenario are assumed to be the same as in the Reference Case.

Table 27 Investment Cost Assumptions for New Power Plants in the Deep GHG Reduction Scenario

Investment Costs for New Power Plants ($/kW) *(Notes: Costs are interpolated between the data years shown.)*				
	2005	**2015**	**2035**	**2050**
Natural Gas Combustion (Gas) Turbine (NGGT)	685	648	388	388
Advanced Natural Gas Combustion (Gas) Turbine (NGGT)	648	608	339	339
Natural Gas Combined-Cycle (NGCC)	984	931	559	559
Advanced Natural Gas Combined-Cycle (NGCC)	968	913	524	524
Advanced Natural Gas Combined-Cycle (NGCC), w/CCS	1,932	1,787	893	893
Coal Steam	2,223	2,104	1,261	1,261
Advanced Coal Int. Gasif. Combined-Cycle (IGCC)	2,569	2,408	1,372	1,372
Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS	3,776	3,499	1,807	1,807
Biomass IGCC (Forest Residues)	7,698	7,257	4,165	4,165
Biomass IGCC (Municipal Solid Waste, Mixed)	7,698	7,257	4,165	4,165
Biomass IGCC (Municipal Solid Waste, Paper)	7,698	7,257	4,165	4,165
Biomass IGCC (Municipal Solid Waste, Wood)	7,698	7,257	4,165	4,165
Biomass IGCC (Municipal Solid Waste, Yard)	7,698	7,257	4,165	4,165
Biomass IGCC (Orchard and Vineyard Waste)	7,698	7,257	4,165	4,165
Biomass IGCC (Pulpwood)	7,698	7,257	4,165	4,165
Biomass IGCC (Agricultural Residues, Stovers/Straws)	7,698	7,257	4,165	4,165
Biomass IGCC (Energy Crops)	7,698	7,257	4,165	4,165
Biogas from Landfills and Animal Waste Digesters	5,199	4,901	2,813	2,813
Geothermal, in California	3,498	3,298	1,893	1,893
Geothermal, in Western U.S. Outside California	3,498	3,298	1,893	1,893
Hydroelectric, Conventional	4,583	4,959	3,303	3,303
Hydroelectric, Reversible (Pumped Storage)	2,291	2,480	1,652	1,652
Wind, Lower Class Resources in CA	3,931	3,706	2,127	2,127
Wind, Higher Class Resources in CA	3,931	3,706	2,127	2,127
Wind, Lower Class Resources in Western U.S. Outside CA	3,931	3,706	2,127	2,127
Wind, Higher Class Resources in Western U.S. Outside CA	3,931	3,706	2,127	2,127
Wind, Offshore	7,874	7,423	4,260	4,260
Solar Thermal, in CA	8,725	8,225	5,554	5,554
Solar Thermal, in Western U.S. Outside CA	8,725	8,225	5,554	5,554
Solar Photovoltaic	10,491	9,890	6,678	6,678
Molten Carbonate Fuel Cell	9,313	8,779	5,928	5,928
Tidal and Ocean Energy	14,667	12,633	8,567	6,667
Generic Distributed Generation – Baseload	1,400	1,320	758	758
Generic Distributed Generation – Peak	1,681	1,585	910	910
Nuclear, Conventional Light Water Reactors (LWR)	3,820	3,470	1,872	1,872
Nuclear, Pebble-Bed Modular Reactor (PBMR)	3,316	3,012	1,625	1,625
Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR)	2,977	2,704	1,459	1,459

Table 28 Efficiency Assumptions for New Power Plants in the Deep GHG Reduction Scenario

New Power Plant Efficiencies (%)

(Notes: For non-geothermal and non-biomass renewables, efficiencies are assumed to be similar to an average fossil-thermal plant. Efficiences are interpolated between the data years shown.)

	2005	2035	2055
Natural Gas Combustion (Gas) Turbine (NGGT)	31.6%	32.7%	32.7%
Advanced Natural Gas Combustion (Gas) Turbine (NGGT)	36.7%	39.9%	39.9%
Natural Gas Combined-Cycle (NGCC)	47.4%	50.2%	50.2%
Advanced Natural Gas Combined-Cycle (NGCC)	50.5%	53.9%	53.9%
Advanced Natural Gas Combined-Cycle (NGCC), w/CCS	39.6%	45.5%	45.5%
Coal Steam	37.1%	39.0%	39.0%
Advanced Coal Int. Gasif. Combined-Cycle (IGCC)	38.9%	45.8%	45.8%
Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS	31.6%	41.1%	41.1%
Biomass IGCC (Forest Residues)	36.1%	43.9%	43.9%
Biomass IGCC (Municipal Solid Waste, Mixed)	36.1%	43.9%	43.9%
Biomass IGCC (Municipal Solid Waste, Paper)	36.1%	43.9%	43.9%
Biomass IGCC (Municipal Solid Waste, Wood)	36.1%	43.9%	43.9%
Biomass IGCC (Municipal Solid Waste, Yard)	36.1%	43.9%	43.9%
Biomass IGCC (Orchard and Vineyard Waste)	36.1%	43.9%	43.9%
Biomass IGCC (Pulpwood)	36.1%	43.9%	43.9%
Biomass IGCC (Agricultural Residues, Stovers/Straws)	36.1%	43.9%	43.9%
Biomass IGCC (Energy Crops)	36.1%	43.9%	43.9%
Biogas from Landfills and Animal Waste Digesters	25.0%	25.0%	25.0%
Geothermal, in California	10.3%	11.3%	11.3%
Geothermal, in Western U.S. Outside California	10.3%	11.3%	11.3%
Hydroelectric, Conventional	34.5%	34.5%	34.5%
Hydroelectric, Reversible (Pumped Storage)	77.5%	77.5%	77.5%
Wind, Lower Class Resources in CA	34.5%	34.5%	34.5%
Wind, Higher Class Resources in CA	34.5%	34.5%	34.5%
Wind, Lower Class Resources in Western U.S. Outside CA	34.5%	34.5%	34.5%
Wind, Higher Class Resources in Western U.S. Outside CA	34.5%	34.5%	34.5%
Wind, Offshore	34.5%	34.5%	34.5%
Solar Thermal, in CA	34.5%	34.5%	34.5%
Solar Thermal, in Western U.S. Outside CA	34.5%	34.5%	34.5%
Solar Photovoltaic	34.5%	34.5%	34.5%
Molten Carbonate Fuel Cell	43.0%	49.0%	49.0%
Tidal and Ocean Energy	34.5%	34.5%	34.5%
Generic Distributed Generation – Baseload	37.7%	38.3%	38.3%
Generic Distributed Generation – Peak	33.9%	34.5%	34.5%

New Nuclear Plant Efficiencies (tonnes enriched uranium per PJ electricity)

(Notes: Efficiences are interpolated between the data years shown.)

	2005	2035	2055
Nuclear, Conventional Light Water Reactors (LWR)	0.65	0.65	0.65
Nuclear, Pebble-Bed Modular Reactor (PBMR)	0.36	0.36	0.36
Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR)	0.22	0.22	0.22

Supply Sector

Exogenously specified resource price trajectories for crude oil, natural gas, and coal are lower in the Deep GHG Reduction Scenario than in the Reference Case. Up until 2015, the price paths are the same, but eventually there is a divergence in the two, which actually becomes quite pronounced in the later time periods, especially for crude oil (compare Figure 49 with Reference Case Figure 22). The reason for lower fossil fuel prices is that, in a less carbon-intensive world (where other U.S. states and countries are also trying to significantly reduce their GHG emissions), the demand for crude oil, natural gas, and coal will likely be lower than in a BAU future; therefore, fossil prices are likely to fall. At least, this is the storyline underlying the *BLUE Map* scenario of the IEA's Energy Technology Perspective (ETP) 2010 study, which envisions a 50% reduction in global energy-related CO_2 emissions below 2005 levels by 2050. In support of this worldwide effort, the IEA estimates that energy-related CO_2 emissions in the U.S. and other industrialized nations would have to be reduced by about 80% over this timeframe, implying concomitant reductions in fossil energy consumption of almost the same magnitude.[34] The fossil fuel price projections that I have assumed in the CA-TIMES Deep GHG Reduction Scenario are largely based on the IEA's BLUE Map scenario.[35] As shown in Figure 49, crude oil and natural gas prices increase over the next few years before leveling out at roughly constant values until 2035. Prices then drop

[34] See Chapter 9 of the IEA's 2010 Energy Technology Perspectives report for a U.S.-focused analysis in both BAU and deep GHG reduction scenarios.

[35] Technically, the fossil fuel price projections of the Deep GHG Reduction Scenario are developed by first calculating the price reductions assumed in the IEA's BLUE Map scenario versus their BAU Reference Case, and then second by applying the reduction ratios in each year to the Reference Case fossil fuel price projections of the EIA's AEO2010. The reason for using the EIA projections as a basis is because their numbers are more specific, and arguably more applicable, to the U.S. context.

considerably until 2050 as the world shifts away from fossil fuels to lower-carbon options.

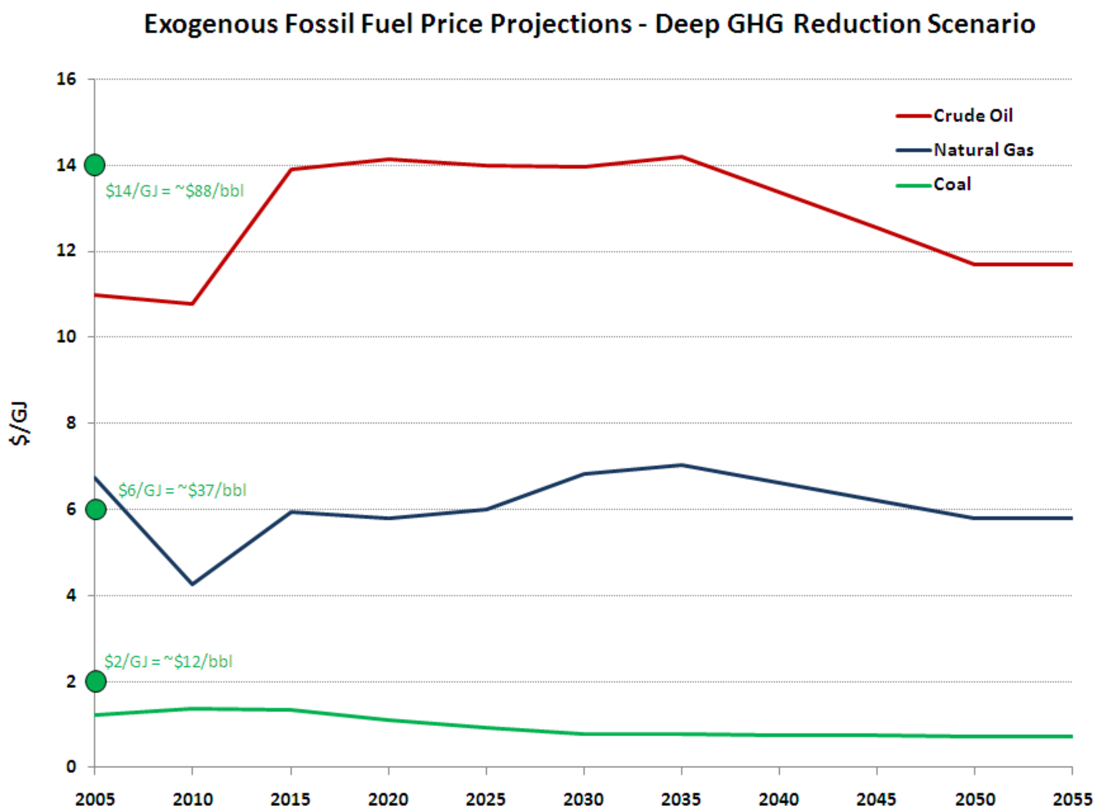

Figure 49 Exogenous Fossil Fuel Price Projections in the Deep GHG Reduction Scenario

All other supply sector assumptions and data sources are the same as in the Reference Case. This includes the biomass supply curves and investment cost and efficiency assumptions for petroleum refineries and cellulosic ethanol, biodiesel, pyrolysis bio-oil, FT poly-generation, and hydrogen production plants (see Section 3 above).

Transportation Sector

Projections of transportation demand (e.g., in vehicle-miles, passenger-miles, ton-miles, vessel-miles, hours of operation, and so on) in the Deep GHG Reduction Scenario are exogenously specified modifications of the demands in the Reference Case. For certain transport subsectors and segments, these demands are assumed to be higher, while for others they are lower. In the light-duty sector, for instance, lower demands are consistent with a low-carbon scenario storyline. Specifically, I assume that a suite of strong travel demand management (TDM) policies dealing with transit, land use, and auto pricing (e.g., road, cordon, and parking pricing; fuel taxes; and pay-as-you-go insurance) could feasibly reduce VMT 7% (18/21/24%) below Reference Case levels by 2020 (2030/2040/2050). Such VMT reduction potential has been estimated by both Cowart (2008b) and Rodier (2009). In addition, the Deep GHG Reduction Scenario assumes a gradual shift in consumer preferences away from light-duty trucks and toward light-duty cars.[36] Starting from their approximate share of total light-duty vehicle VMT of 53% in 2005, cars are assumed to obtain 55% market share in 2020, 65% in 2030, 70% in 2040, and 75% in 2050. (Compare this to the Reference Case, for which the light-duty car market share is projected to be 51% in 2020, 56% in 2030, 60% in 2040, and 65% in 2050.) Contingent upon these assumptions, the light-duty VMT projections of the Deep GHG Reduction Scenario are shown in Figure 50 (compare to Reference Case Figure 24).

[36] One could imagine this shift occurring for a number of reasons, e.g., high and sustained energy prices: greater environmental consciousness among society; the coming of age of a new generation of drivers for whom “bigger is *not* always better”; and/or a preference for smaller vehicles as urban and suburban spaces become denser and more crowded. Of course, the shift could also happen the other way (toward light-duty trucks), but this outcome would not be entirely consistent with the low-carbon scenario storyline envisioned here.

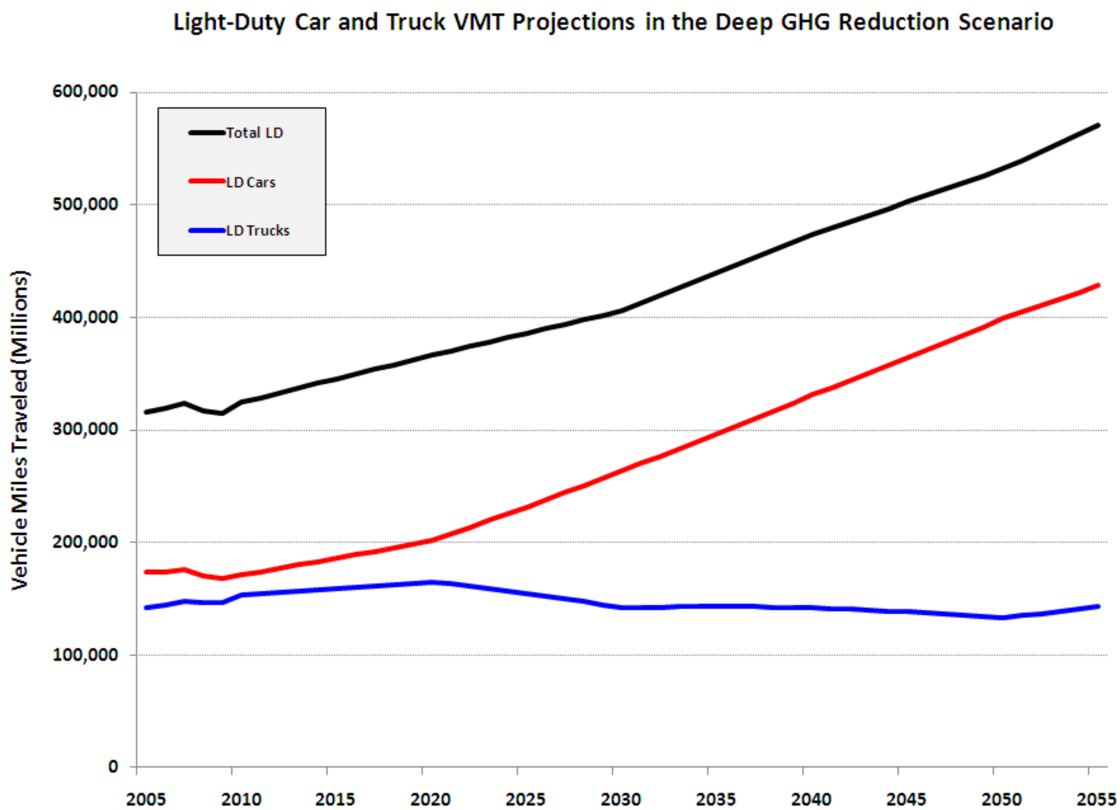

Figure 50 Light-Duty Car and Truck VMT Projections in the Deep GHG Reduction Scenario

If transit, land use, and auto pricing policies are the driving force behind the light-duty VMT reductions assumed above, then one would naturally expect the projected future demands for bus and rail transit to rise gradually over time, as they substitute for trips not taken by private motor vehicles. For this reason, the Deep GHG Reduction Scenario assumes greater demand for urban transit bus VMT and commuter, heavy, and light rail PMT in the future. More specifically, I assume that one out of every ten vehicle-miles lost by LDVs is shifted to either bus or rail transit. This is not to say that one out of every ten people, who decide not to drive, end up shifting their mode of travel to bus or rail, but rather the $1/10^{th}$ factor accounts for the greater occupancy levels that transit vehicles can accommodate (at reasonably high transit ridership levels). Therefore, not every vehicle-mile of travel that is lost by LDVs is actually gained by bus or rail transit. In fact, some of the VMT would, in effect, disappear, as improved land use patterns and more densely populated cities would allow for shorter trip distances and/or the avoidance of motorized trips in general (i.e., greater number of bike and walk trips).

For all other transport subsectors/segments, the future-year demands assumed in the Deep GHG Reduction Scenario are the same as in the Reference Case (see Section 3).

The cost and efficiency assumptions for certain transportation technologies are also modified in the Deep GHG Reduction Scenario, most notably for light-duty cars and trucks. As in the Reference Case, the LDV input values are largely based on the EIA's AEO2010 assumptions and projections; however, in this instance I use the EIA's *High Technology Case* assumptions for light-duty vehicles as a basis for the CA-TIMES technology characterizations (EIA, 2010a, c). This generally has the effect of reducing the costs of ICEs and HEVs by a small amount, while for BEVs, PHEVs, and FCVs, the differences are much larger. For example, whereas in the Reference Case the cost of lithium-ion batteries is assumed to level out at $500/kWh by 2030, the Deep GHG Reduction Scenario assumes a drop to a much lower $196/kWh by the same year. Similarly, in the Deep GHG Reduction Scenario I assume that fuel cell costs drop to $55/kW by 2030 and are held constant thereafter, well ahead of the Reference Case cost trajectory, which assumes that fuel cell costs are still $139/kW in 2030 and do not reach $55/kW until 2050. Efficiency assumptions are also slightly more optimistic in the EIA's High Technology Case and, thus, in the Deep GHG Reduction Scenario. The following few tables summarize the investment cost and efficiency assumptions for light-duty cars and trucks in the Deep GHG Reduction Scenario. (These can be compared to Reference Case Table 19 and the several tables that come after it.)

Table 29 Investment Cost Assumptions for New Light-Duty Cars in the Deep GHG Reduction Scenario

Investment Costs for New Light-Duty Cars ($/vehicle) *(Note: Missing data value indicates that technology is not available in given year.)*	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Gasoline ICE	25,775	25,924	26,141	26,544	26,648	26,809	26,990	26,990	26,990	26,990	26,990
Gasoline ICE (Moderate Eff.)	26,531	26,681	26,898	27,300	27,404	27,565	27,746	27,746	27,746	27,746	27,746
Gasoline ICE (Advanced Eff.)	27,288	27,437	27,654	28,057	28,160	28,322	28,502	28,502	28,502	28,502	28,502
Gasoline HEV	29,352	29,239	28,586	28,726	28,568	28,575	28,650	28,650	28,650	28,650	28,650
E85 Flex Fuel ICE	26,150	26,299	26,513	26,918	27,019	27,178	27,357	27,357	27,357	27,357	27,357
E85 Flex Fuel ICE (Moderate Eff.)	26,906	27,055	27,269	27,674	27,776	27,934	28,114	28,114	28,114	28,114	28,114
E85 Flex Fuel ICE (Advanced Eff.)	27,663	27,812	28,026	28,430	28,532	28,691	28,870	28,870	28,870	28,870	28,870
E85 Flex Fuel HEV	29,727	29,613	28,958	29,099	28,940	28,944	29,017	29,017	29,017	29,017	29,017
Diesel ICE	31,220	31,352	30,252	29,906	29,522	29,671	29,953	29,953	29,953	29,953	29,953
Diesel HEV	--	--	28,856	28,856	28,664	28,652	28,685	28,685	28,685	28,685	28,685
Gasoline PHEV10	32,218	32,218	32,218	30,658	29,143	29,150	29,225	29,225	29,225	29,225	29,225
Gasoline PHEV30	44,233	44,233	44,233	37,876	32,896	32,902	32,977	32,977	32,977	32,977	32,977
Gasoline PHEV40	50,179	50,179	50,179	41,388	34,620	34,626	34,702	34,702	34,702	34,702	34,702
Gasoline PHEV60	62,082	62,082	62,082	48,432	38,099	38,105	38,180	38,180	38,180	38,180	38,180
E85 Flex Fuel PHEV10	32,590	32,590	32,590	31,031	29,515	29,519	29,593	29,593	29,593	29,593	29,593
E85 Flex Fuel PHEV30	44,605	44,605	44,605	38,249	33,267	33,271	33,345	33,345	33,345	33,345	33,345
E85 Flex Fuel PHEV40	50,550	50,550	50,550	41,762	34,992	34,996	35,069	35,069	35,069	35,069	35,069
E85 Flex Fuel PHEV60	62,454	62,454	62,454	48,806	38,470	38,474	38,548	38,548	38,548	38,548	38,548
Diesel PHEV10	30,788	30,788	30,788	30,788	29,239	29,227	29,260	29,260	29,260	29,260	29,260
Diesel PHEV30	38,006	38,006	38,006	38,006	32,991	32,979	33,013	33,013	33,013	33,013	33,013
Diesel PHEV40	41,518	41,518	41,518	41,518	34,715	34,703	34,737	34,737	34,737	34,737	34,737
Diesel PHEV60	48,562	48,562	48,562	48,562	38,194	38,182	38,216	38,216	38,216	38,216	38,216
Battery-Electric	77,838	72,673	67,548	69,711	61,111	54,625	54,409	54,409	54,409	54,409	54,409
Hydrogen Fuel Cell	--	--	68,962	58,725	50,359	43,112	39,171	39,171	39,171	39,171	39,171
Gasoline Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Methanol Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Dedicated Ethanol ICE	--	--	--	--	--	--	--	--	--	--	--
Natural Gas ICE	33,400	33,541	33,693	34,093	34,195	34,387	34,629	34,629	34,629	34,629	34,629
Natural Gas Bi-Fuel ICE	32,065	32,211	32,384	32,766	32,880	33,075	33,320	33,320	33,320	33,320	33,320
LPG ICE	--	--	--	--	--	--	--	--	--	--	--
LPG Bi-Fuel ICE	31,104	31,253	31,470	31,873	31,976	32,138	32,318	32,318	32,318	32,318	32,318

Table 30 Investment Cost Assumptions for New Light-Duty Trucks in the Deep GHG Reduction Scenario

Investment Costs for New Light-Duty Trucks ($/vehicle) (Note: Missing data value indicates that technology is not available in given year.)	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Gasoline ICE	34,084	34,207	34,609	34,927	35,074	35,276	35,521	35,521	35,521	35,521	35,521
Gasoline ICE (Moderate Eff.)	35,263	35,386	35,788	36,106	36,253	36,455	36,700	36,700	36,700	36,700	36,700
Gasoline ICE (Advanced Eff.)	36,442	36,565	36,967	37,285	37,432	37,634	37,879	37,879	37,879	37,879	37,879
Gasoline HEV	38,276	38,123	37,576	37,398	37,194	37,267	37,401	37,401	37,401	37,401	37,401
E85 Flex Fuel ICE	34,535	34,657	35,057	35,372	35,517	35,716	35,958	35,958	35,958	35,958	35,958
E85 Flex Fuel ICE (Moderate Eff.)	35,714	35,836	36,236	36,551	36,696	36,895	37,137	37,137	37,137	37,137	37,137
E85 Flex Fuel ICE (Advanced Eff.)	36,893	37,015	37,415	37,730	37,875	38,074	38,316	38,316	38,316	38,316	38,316
E85 Flex Fuel HEV	38,726	38,573	38,024	37,843	37,636	37,707	37,838	37,838	37,838	37,838	37,838
Diesel ICE	42,334	42,441	40,408	40,442	40,221	40,185	40,457	40,457	40,457	40,457	40,457
Diesel HEV	--	--	--	37,499	37,259	37,306	37,379	37,379	37,379	37,379	37,379
Gasoline PHEV10	37,769	37,769	37,769	37,769	37,769	37,842	37,976	37,976	37,976	37,976	37,976
Gasoline PHEV30	41,521	41,521	41,521	41,521	41,521	41,595	41,729	41,729	41,729	41,729	41,729
Gasoline PHEV40	43,245	43,245	43,245	43,245	43,245	43,319	43,453	43,453	43,453	43,453	43,453
Gasoline PHEV60	46,724	46,724	46,724	46,724	46,724	46,798	46,932	46,932	46,932	46,932	46,932
E85 Flex Fuel PHEV10	38,211	38,211	38,211	38,211	38,211	38,283	38,413	38,413	38,413	38,413	38,413
E85 Flex Fuel PHEV30	41,964	41,964	41,964	41,964	41,964	42,035	42,166	42,166	42,166	42,166	42,166
E85 Flex Fuel PHEV40	43,688	43,688	43,688	43,688	43,688	43,759	43,890	43,890	43,890	43,890	43,890
E85 Flex Fuel PHEV60	47,167	47,167	47,167	47,167	47,167	47,238	47,369	47,369	47,369	47,369	47,369
Diesel PHEV10	37,834	37,834	37,834	37,834	37,834	37,881	37,954	37,954	37,954	37,954	37,954
Diesel PHEV30	41,587	41,587	41,587	41,587	41,587	41,634	41,707	41,707	41,707	41,707	41,707
Diesel PHEV40	43,311	43,311	43,311	43,311	43,311	43,358	43,431	43,431	43,431	43,431	43,431
Diesel PHEV60	46,790	46,790	46,790	46,790	46,790	46,837	46,910	46,910	46,910	46,910	46,910
Battery-Electric	98,179	90,892	82,851	87,325	79,138	71,814	71,888	71,888	71,888	71,888	71,888
Hydrogen Fuel Cell	--	--	74,505	63,214	53,687	45,526	40,813	40,813	40,813	40,813	40,813
Gasoline Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Methanol Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Dedicated Ethanol ICE	--	--	--	--	--	--	--	--	--	--	--
Natural Gas ICE	33,503	33,584	34,022	34,421	34,513	34,640	34,807	34,807	34,807	34,807	34,807
Natural Gas Bi-Fuel ICE	32,604	32,687	33,114	33,491	33,580	33,709	33,894	33,894	33,894	33,894	33,894
LPG ICE	--	--	--	--	--	--	--	--	--	--	--
LPG Bi-Fuel ICE	31,269	31,361	31,814	32,254	32,359	32,490	32,656	32,656	32,656	32,656	32,656

Table 31 Fuel Economy Assumptions for New Light-Duty Cars, All Except PHEVs in the Deep GHG Reduction Scenario

New Vehicle Fuel Economy (mpgge) - All Except PHEVs (Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Gasoline ICE	31.2	31.5	34.6	37.4	38.5	39.5	41.1	41.1	41.1	41.1	41.1
Gasoline ICE (Moderate Eff.)	35.3	35.7	39.1	42.3	43.5	44.7	46.4	46.4	46.4	46.4	46.4
Gasoline ICE (Advanced Eff.)	40.6	41.0	45.0	48.6	50.1	51.4	53.4	53.4	53.4	53.4	53.4
Gasoline HEV	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
E85 Flex Fuel ICE	31.5	31.9	34.9	37.8	38.9	39.9	41.5	41.5	41.5	41.5	41.5
E85 Flex Fuel ICE (Moderate Eff.)	35.3	35.7	39.1	42.3	43.5	44.7	46.4	46.4	46.4	46.4	46.4
E85 Flex Fuel ICE (Advanced Eff.)	40.6	41.0	45.0	48.6	50.1	51.4	53.4	53.4	53.4	53.4	53.4
E85 Flex Fuel HEV	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
Diesel ICE	39.2	39.5	42.2	45.0	46.0	46.2	45.4	45.4	45.4	45.4	45.4
Diesel HEV	--	--	59.6	59.3	60.5	61.2	61.5	61.5	61.5	61.5	61.5
Battery-Electric	91.1	86.8	100.0	121.2	142.5	142.2	141.3	141.3	141.3	141.3	141.3
Hydrogen Fuel Cell	74.9	75.7	83.1	89.7	92.4	94.8	98.6	98.6	98.6	98.6	98.6
Gasoline Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Methanol Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Dedicated Ethanol ICE	--	--	--	--	--	--	--	--	--	--	--
Natural Gas ICE	33.2	33.4	37.0	40.4	42.1	43.0	43.9	43.9	43.9	43.9	43.9
Natural Gas Bi-Fuel ICE	30.8	31.0	34.3	37.4	39.0	40.0	41.0	41.0	41.0	41.0	41.0
LPG ICE	--	--	--	--	--	--	--	--	--	--	--
LPG Bi-Fuel ICE	31.2	31.5	34.6	37.4	38.5	39.5	41.1	41.1	41.1	41.1	41.1

Table 32 Fuel Economy Assumptions for New Light-Duty PHEV Cars in the Deep GHG Reduction Scenario

New Plug-in Hybrid Vehicle Fuel Economy (mpgge)											
(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)											
	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Charge-Sustaining Mode											
Gasoline PHEV10	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
Gasoline PHEV30	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
Gasoline PHEV40	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
Gasoline PHEV60	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
E85 Flex Fuel PHEV10	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
E85 Flex Fuel PHEV30	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
E85 Flex Fuel PHEV40	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
E85 Flex Fuel PHEV60	45.1	44.9	48.4	51.6	53.2	54.3	55.5	55.5	55.5	55.5	55.5
Diesel PHEV10	--	--	59.6	59.3	60.5	61.2	61.5	61.5	61.5	61.5	61.5
Diesel PHEV30	--	--	59.6	59.3	60.5	61.2	61.5	61.5	61.5	61.5	61.5
Diesel PHEV40	--	--	59.6	59.3	60.5	61.2	61.5	61.5	61.5	61.5	61.5
Diesel PHEV60	--	--	59.6	59.3	60.5	61.2	61.5	61.5	61.5	61.5	61.5
Charge-Depleting Mode											
Gasoline PHEV10	158.7	158.2	157.2	175.0	197.6	227.4	227.4	227.4	227.4	227.4	227.4
Gasoline PHEV30	156.9	156.3	155.4	170.5	189.2	212.7	212.7	212.7	212.7	212.7	212.7
Gasoline PHEV40	156.9	156.3	155.4	170.5	189.2	208.8	208.8	208.8	208.8	208.8	208.8
Gasoline PHEV60	155.3	154.8	153.8	166.8	182.4	201.4	201.4	201.4	201.4	201.4	201.4
E85 Flex Fuel PHEV10	158.7	158.2	157.2	175.0	197.6	227.4	227.4	227.4	227.4	227.4	227.4
E85 Flex Fuel PHEV30	156.9	156.3	155.4	170.5	189.2	212.7	212.7	212.7	212.7	212.7	212.7
E85 Flex Fuel PHEV40	156.9	156.3	155.4	170.5	189.2	208.8	208.8	208.8	208.8	208.8	208.8
E85 Flex Fuel PHEV60	155.3	154.8	153.8	166.8	182.4	201.4	201.4	201.4	201.4	201.4	201.4
Diesel PHEV10	--	--	157.2	175.0	197.6	227.4	227.4	227.4	227.4	227.4	227.4
Diesel PHEV30	--	--	155.4	170.5	189.2	212.7	212.7	212.7	212.7	212.7	212.7
Diesel PHEV40	--	--	155.4	170.5	189.2	208.8	208.8	208.8	208.8	208.8	208.8
Diesel PHEV60	--	--	153.8	166.8	182.4	201.4	201.4	201.4	201.4	201.4	201.4

Table 33 Fuel Economy Assumptions for New Light-Duty Trucks, All Except PHEVs in the Deep GHG Reduction Scenario

New Vehicle Fuel Economy (mpgge) - All Except PHEVs											
(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)											
	2005	2010	2015	2020	2025	2030	2035	2040	2045	2050	2055
Gasoline ICE	22.5	22.5	24.6	27.2	29.0	30.2	31.5	31.5	31.5	31.5	31.5
Gasoline ICE (Moderate Eff.)	26.0	26.0	28.4	31.4	33.5	34.9	36.4	36.4	36.4	36.4	36.4
Gasoline ICE (Advanced Eff.)	30.8	30.7	33.6	37.1	39.6	41.3	43.1	43.1	43.1	43.1	43.1
Gasoline HEV	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
E85 Flex Fuel ICE	22.8	22.7	24.9	27.4	29.3	30.5	31.8	31.8	31.8	31.8	31.8
E85 Flex Fuel ICE (Moderate Eff.)	26.0	26.0	28.4	31.4	33.5	34.9	36.4	36.4	36.4	36.4	36.4
E85 Flex Fuel ICE (Advanced Eff.)	30.8	30.7	33.6	37.1	39.6	41.3	43.1	43.1	43.1	43.1	43.1
E85 Flex Fuel HEV	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
Diesel ICE	28.4	28.2	30.0	32.0	33.2	34.0	34.5	34.5	34.5	34.5	34.5
Diesel HEV	41.2	41.2	41.2	41.2	42.2	43.2	43.7	43.7	43.7	43.7	43.7
Battery-Electric	51.7	53.4	63.3	77.4	91.4	91.1	90.7	90.7	90.7	90.7	90.7
Hydrogen Fuel Cell	54.1	54.1	59.1	65.2	69.6	72.5	75.7	75.7	75.7	75.7	75.7
Gasoline Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Methanol Fuel Cell	--	--	--	--	--	--	--	--	--	--	--
Dedicated Ethanol ICE	--	--	--	--	--	--	--	--	--	--	--
Natural Gas ICE	25.7	25.6	27.8	30.4	31.8	32.9	34.1	34.1	34.1	34.1	34.1
Natural Gas Bi-Fuel ICE	23.9	23.7	25.7	28.1	29.4	30.4	31.6	31.6	31.6	31.6	31.6
LPG ICE	--	--	--	--	--	--	--	--	--	--	--
LPG Bi-Fuel ICE	23.9	23.8	26.2	29.6	31.6	32.9	34.1	34.1	34.1	34.1	34.1

Table 34 Fuel Economy Assumptions for New Light-Duty PHEV Trucks in the Deep GHG Reduction Scenario

New Plug-in Hybrid Vehicle Fuel Economy (mpgge)											
(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)											
	2005	**2010**	**2015**	**2020**	**2025**	**2030**	**2035**	**2040**	**2045**	**2050**	**2055**
Charge-Sustaining Mode											
Gasoline PHEV10	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
Gasoline PHEV30	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
Gasoline PHEV40	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
Gasoline PHEV60	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
E85 Flex Fuel PHEV10	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
E85 Flex Fuel PHEV30	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
E85 Flex Fuel PHEV40	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
E85 Flex Fuel PHEV60	32.6	32.4	35.3	38.1	40.2	41.6	42.6	42.6	42.6	42.6	42.6
Diesel PHEV10	41.2	41.2	41.2	41.2	42.2	43.2	43.7	43.7	43.7	43.7	43.7
Diesel PHEV30	41.2	41.2	41.2	41.2	42.2	43.2	43.7	43.7	43.7	43.7	43.7
Diesel PHEV40	41.2	41.2	41.2	41.2	42.2	43.2	43.7	43.7	43.7	43.7	43.7
Diesel PHEV60	41.2	41.2	41.2	41.2	42.2	43.2	43.7	43.7	43.7	43.7	43.7
Charge-Depleting Mode											
Gasoline PHEV10	158.1	158.1	158.1	158.1	158.1	183.0	183.0	183.0	183.0	183.0	183.0
Gasoline PHEV30	151.3	151.3	151.3	151.3	151.3	171.2	171.2	171.2	171.2	171.2	171.2
Gasoline PHEV40	151.3	151.3	151.3	151.3	151.3	168.1	168.1	168.1	168.1	168.1	168.1
Gasoline PHEV60	145.9	145.9	145.9	145.9	145.9	162.1	162.1	162.1	162.1	162.1	162.1
E85 Flex Fuel PHEV10	158.1	158.1	158.1	158.1	158.1	183.0	183.0	183.0	183.0	183.0	183.0
E85 Flex Fuel PHEV30	151.3	151.3	151.3	151.3	151.3	171.2	171.2	171.2	171.2	171.2	171.2
E85 Flex Fuel PHEV40	151.3	151.3	151.3	151.3	151.3	168.1	168.1	168.1	168.1	168.1	168.1
E85 Flex Fuel PHEV60	145.9	145.9	145.9	145.9	145.9	162.1	162.1	162.1	162.1	162.1	162.1
Diesel PHEV10	158.1	158.1	158.1	158.1	158.1	183.0	183.0	183.0	183.0	183.0	183.0
Diesel PHEV30	151.3	151.3	151.3	151.3	151.3	171.2	171.2	171.2	171.2	171.2	171.2
Diesel PHEV40	151.3	151.3	151.3	151.3	151.3	168.1	168.1	168.1	168.1	168.1	168.1
Diesel PHEV60	145.9	145.9	145.9	145.9	145.9	162.1	162.1	162.1	162.1	162.1	162.1

The cost and efficiency assumptions for technologies in most of the other transport subsectors are the same in the Deep GHG Reduction Scenario as they are in the Reference Case. (Of course, just because an advanced technology, say an electrified railway or hydrogen fuel cell bus, is available to the model in the Reference Case does not necessarily mean that the model will choose it.[37]) An important exception is the aviation subsector, for which cost and efficiency trajectories from the BLUE Map scenario of the IEA's 2008 ETP report are used as a basis for CA-TIMES inputs (IEA, 2008). These assumptions represent a *maximum technology* case in which aircraft energy intensity reductions are 10% below the Reference Case by 2050. (Note that the Reference Case itself already assumes reasonable increases in energy efficiency and

[37] The decision depends on the full lifecycle costs of the technology compared to all other technologies; and since advanced technologies tend to have higher costs, at least when external/social costs are ignored, they are not typically chosen in a BAU Reference Case scenario.

airplane load factors, amounting to a 28% total reduction in aircraft energy intensity between 2005 and 2050.) This should not be confused with an extreme technology case, however. For example, conventional swept-wing body aircraft designs remain the norm in the Deep GHG Reduction Scenario, and new designs (e.g., flying wing and blended wing body aircraft) are not introduced. On the other hand, Deep GHG Reduction Scenario sees an increased utilization of winglets and increased wingspans; light-weighting via advanced materials becomes an important design feature; and more advanced technologies, such as laminar flow control and highly efficient unducted fan open-rotor engines, become more common. In addition, the Deep GHG Reduction Scenario assumes that aircraft energy intensity is reduced by an additional 5% due to air traffic control and operational improvements, such as (1) greater use of continuous descent approaches, (2) improvements in communications, navigation, and surveillance (CNS) and air traffic management (ATM) systems, and/or (3) utilization of multiple stages for long-distance travel (i.e., limiting trip lengths to shorter-distances). (Such operational improvements are the goal of the NextGen project in the U.S. and SESAR in Europe.) In order to make all of these efficiency gains possible, investment costs for aircraft would likely be higher. Therefore, this scenario assumes that the cost difference between conventional aircraft in the Reference Case and advanced aircraft in the Deep GHG Reduction Scenario gradually climbs to 25% by 2050.

Industrial, Commercial, Residential, and Agricultural Sectors

In the “ICRA” sectors, future energy demand trajectories and fuel use mixes are exogenously specified by the modeler. Hence, the greenhouse gas reductions that are achieved are entirely a function of the input assumptions. For this reason, it is important that the fuel demands of the Deep GHG Reduction Scenario are consistent with an overall storyline where GHGs are reduced 80% below 1990 levels by 2050, and to this end the IEA's well-known BLUE Map scenario – published in the 2010 ETP study (IEA, 2010) – greatly informs the CA-TIMES Deep GHG Reduction Scenario. In BLUE Map, global energy-related CO_2 emissions are reduced 50% below 2005 levels by 2050, with the U.S. and other industrialized countries reducing their emissions by about 80%. In developing this scenario, the IEA partly utilized its global MARKAL energy systems model, which simulates energy investment and fuel use decisions across all regions of the world and in all sectors. These decisions are made based on the least-cost principle, just as in CA-TIMES, in an effort to reflect reality as much as possible. The U.S. is one of many regions in the IEA's global MARKAL model, and I use the results of ETP analysis for the U.S. as a basis for defining the fuel use mixes in the industrial, commercial, residential, and agricultural sectors in 2030 and 2050 in the CA-TIMES Deep GHG Reduction Scenario. Fuel demand shares in the in-between years are automatically calculated by the model via linear interpolation. For a summary of energy use, emissions, and technology development in the industrial and buildings sectors in the IEA's Baseline and BLUE Map scenarios, see Figures 9.10 and 9.14 of the IEA's most recent ETP report (IEA, 2010).

Utilization of U.S.-specific results from another scenario study has some limitations, however. Most notably, the current energy landscape in California is a bit different than it is in the rest of the U.S., and this is likely to remain the case for some time into the future. For instance, because the state is not home to certain heavy industries (e.g., steel-making), only a small amount of coal is consumed in the industrial sector. Also, due to California's relatively temperate climate, heating demands are not as high as in other parts of the country, and for historical reasons heating oil is not a commonly used fuel in the commercial and residential sectors. Previous sections have shown that California currently relies heavily on natural gas and electricity in each of the ICRA sectors; as a result, the carbon intensity of state's end-use sectors, aside from transport, is lower in than in other parts of the country. Assuming these trends continue in the long term (i.e., assuming that California remains ahead of other states on the "carbon intensity curve" and continues on its path toward being a post-industrial, service-oriented, information-based economy), and drawing on the results of the IEA BLUE Map scenario, it is perhaps reasonable to assume that a dramatic transition to a low-carbon economy in California could potentially lead to much greater use of electricity as an end-use fuel, even moreso than today. In the cases where electricity is not a satisfactory alternative, such as steam generation and other high-temperature processes, natural gas or biomass could become attractive low-carbon options. Such a storyline forms the basis of the fuel use mix assumptions of the ICRA sectors in the Deep GHG Reduction Scenario.

Furthermore, the projected demands for each of the ICRA sectors (except for Agriculture) are lower in the Deep GHG Reduction Scenario than in the Reference Case. In particular, the projections are based on the *Baseline – high efficiency* scenario developed for the California Energy Commission as part of the UC-Davis Advanced Energy Pathways (AEP) project (McCarthy et al., 2008a, b). Motivating these demand reductions are energy efficiency and conservation efforts, spurred by a strong carbon price and efficiency standards on end-use technologies (as described in Table 26). The annual efficiency improvements assumed in the Deep GHG Reduction Scenario (0% to 0.7% depending on the end-use sector), which are over and above those already embedded in the Reference Case, are technically feasible with today's technologies (McCarthy et al., 2008a, b).

The Deep GHG Reduction Scenario also assumes that carbon capture and storage technologies are increasingly utilized for a certain portion of fuel combustion in the industrial sector. Specifically, CCS is applied to ten percent (10%) of CO_2 emissions from natural gas, biomass, and coal (where utilized) combustion processes in 2030, a share that rises to 75% in 2050. Values in the in-between years are calculated by linear interpolation. The assumed capture rate for all of these generic CCS processes is 90%.

Results of the Deep GHG Reduction Scenario

Electricity Generation

The development of the electric sector in the Deep GHG Reduction Scenario is markedly different than in the Reference Case (Figure 51). For starters, the sheer magnitude of electricity generation is substantially greater in this scenario, as a result of the increased electrification of the end-use sectors. In 2050, electricity supply is 36% greater than in the Reference Case, and compared to 2005, it is 105% greater. Second, over time natural gas ceases to be the preferred method of generation; instead, the generation mix becomes much more diverse. Of the natural gas generation that still lingers in 2050, most is equipped with carbon capture and storage. Coal IGCC plants with CCS also achieve significant market share in the later time periods. In order to achieve deep reductions in GHG emissions, however, zero-carbon electricity must grow significantly in the years ahead. For this reason the scenario sees a large uptake of new nuclear plants (particularly of the advanced light water reactor variety) and of renewables (solar, wind, geothermal, biomass). In addition, a small but non-trivial amount of electric generation comes from bio-refineries and FT poly-generation plants. The primary purpose of these facilities is to produce liquid fuels, but they also happen to produce low-carbon electricity as a co-product; thus, they are especially attractive to the model.

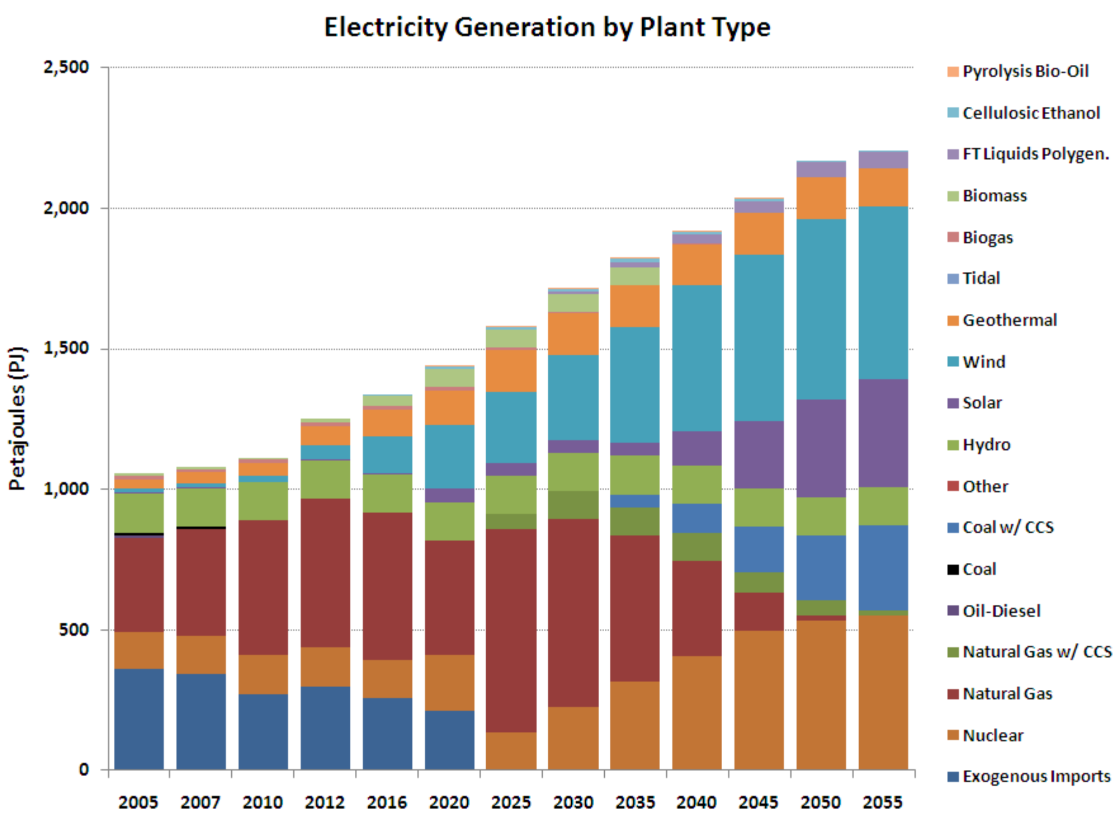

Figure 51 Electricity Generation by Plant Type in the Deep GHG Reduction Scenario

Figure 52 shows the dramatic growth of low- and zero-carbon electric generation over time in the Deep GHG Reduction Scenario. By 2050, more than 80% of all California's electricity is produced by zero-carbon sources (nuclear, hydro, and other renewables), with the remainder coming from biomass and fossil power plants equipped with CCS. In particular, the share of non-hydro renewables in the generation mix grows to approximately 50% in 2050, a fairly high level in light of intermittency concerns with solar and wind power. Whether or not the vast array of renewable resources (not all of which are intermittent) could reliably supply such a large share of California's electricity demand is still an open question, and one this analysis only begins to address. To some extent, both geothermal and solar thermal technologies have the potential to act as baseload generators; however, the intermittency of wind power could become a major challenge without adequate electrical storage capacity. On these points, it is important to note that the Deep GHG Reduction Scenario assumes no additional storage capacity than what already exists in California's power system today (i.e., a small amount of pumped storage). Moreover, while the CA-TIMES model is not able to represent the timing of electricity supply and demand in the way that a full-blown electricity dispatch model is able to do, its high timeslice resolution nevertheless allows it to do a fairly reasonable job. Even though no constraints have been introduced to the model to limit the share of generation from particular renewable technologies in a given year (as is common practice in other energy systems models), CA-TIMES has full knowledge of end-use electricity demands and the availability of renewable resource supplies in all timeslices. Therefore, in some sense the model is capable of acting as a judge for how much electricity could be feasibly supplied from renewables in any future time period. Lastly, it is important to note that the total generation potential from each of the various renewable resource types is constrained based on total renewable resource estimates for California and the western United States, which are found in the California Public Utility Commission's "33% RPS Implementation Analysis" (CPUC, 2009). Only a share of these total resources are made available to the California market.

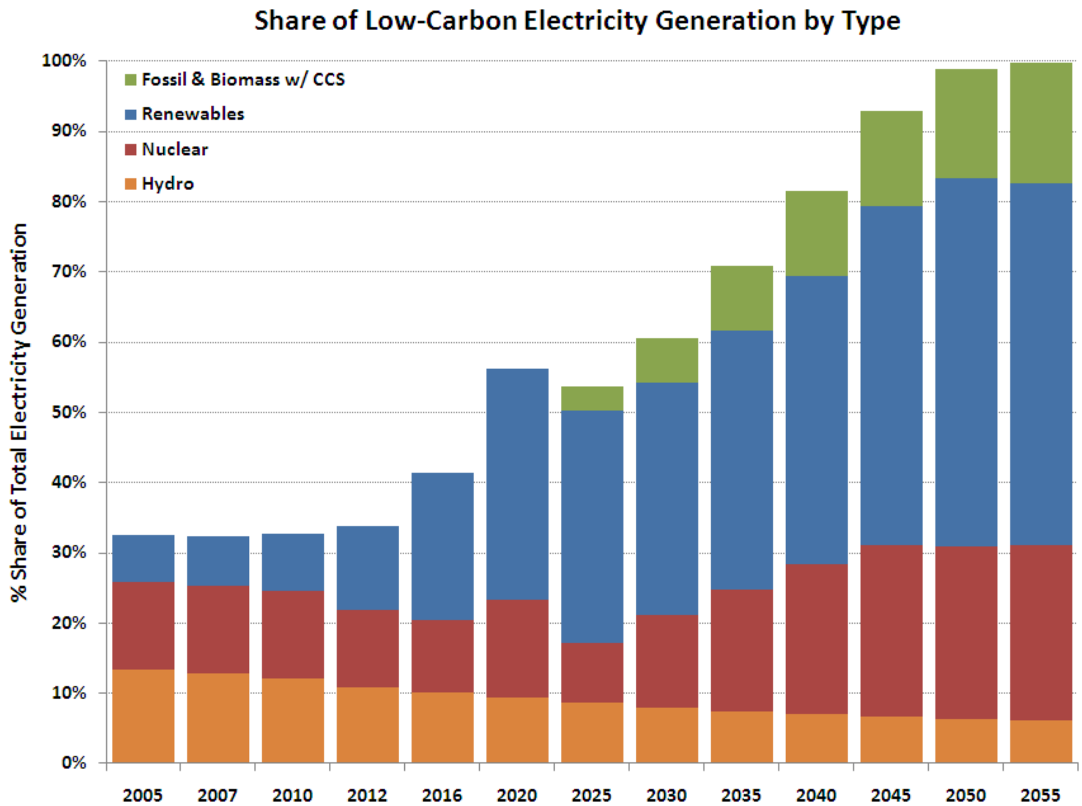

Figure 52 Share of Low-Carbon Electricity Generation by Type in the Deep GHG Reduction Scenario

Energy Supply and Conversion

The mix of fuels supplied by the resource and energy conversion sectors also looks quite different in the Deep GHG Reduction Scenario than in the Reference Case. Most notably, a substantial quantity of liquid fossil fuels is replaced by low-carbon substitutes, such as biofuels, synthetic fuels, electricity, and hydrogen. The types of biofuels consumed are not the same as in the Reference Case, however; for instance, the importance of ethanol declines significantly in the Deep GHG Reduction Scenario (compare Figure 53 with Reference Case Figure 32). Instead, the model chooses to direct biomass to the production of bio-derived gasoline, diesel, jet fuel, and residual fuel oil. The reason for this is fairly intuitive: there are fewer technological/fuel options to reduce GHG emissions in the non-LDV transport subsectors, hence the value of a tonne of biomass is higher when producing a liquid fuel for these other uses. Especially attractive are FT poly-generation plants equipped with CCS and consuming only biomass. In the process of producing zero-carbon bio-based gasoline, diesel, and jet fuel, as well as clean electricity, these technologies function as negative emissions technologies, essentially removing CO_2 from the atmosphere and permanently sequestering it underground.

Interestingly, total consumption of biofuels in the Deep GHG Reduction Scenario is at roughly the same level in 2050 (975 PJ or 7.5 billion gge) as it is in the Reference Case. In the latter scenario, the high price of crude oil in a BAU future is enough to motivate substantial biofuels production, while in the former the incentive for biofuels has more to do with the stringent climate targets that are imposed. Total biomass supply (roughly 1,740 PJ, or 108 million bone dry tons) is a bit higher in the Deep GHG Reduction Scenario than in the Reference Case (Figure 54 vs. Reference Case Figure 33), due to the marginally less efficient production methods for producing the non-ethanol biofuels and the attractiveness of generating zero-carbon outputs while at the same time storing CO_2 permanently underground. One important difference, however, is just how much more quickly biomass supply grows in the Deep GHG Reduction Scenario, especially between 2025 and 2035, in order to meet the increasingly stringent cap on GHG emissions. Specifically, Herbaceous Energy Crops see greater utilization in the Deep GHG Scenario, despite their higher prices relative to other types of biomass. On the other hand, the model opts for a slower uptake of Mixed Municipal Solid Waste (e.g., foodstuffs and other dirty MSW), which is presumably related to the non-zero carbon intensity of the latter.

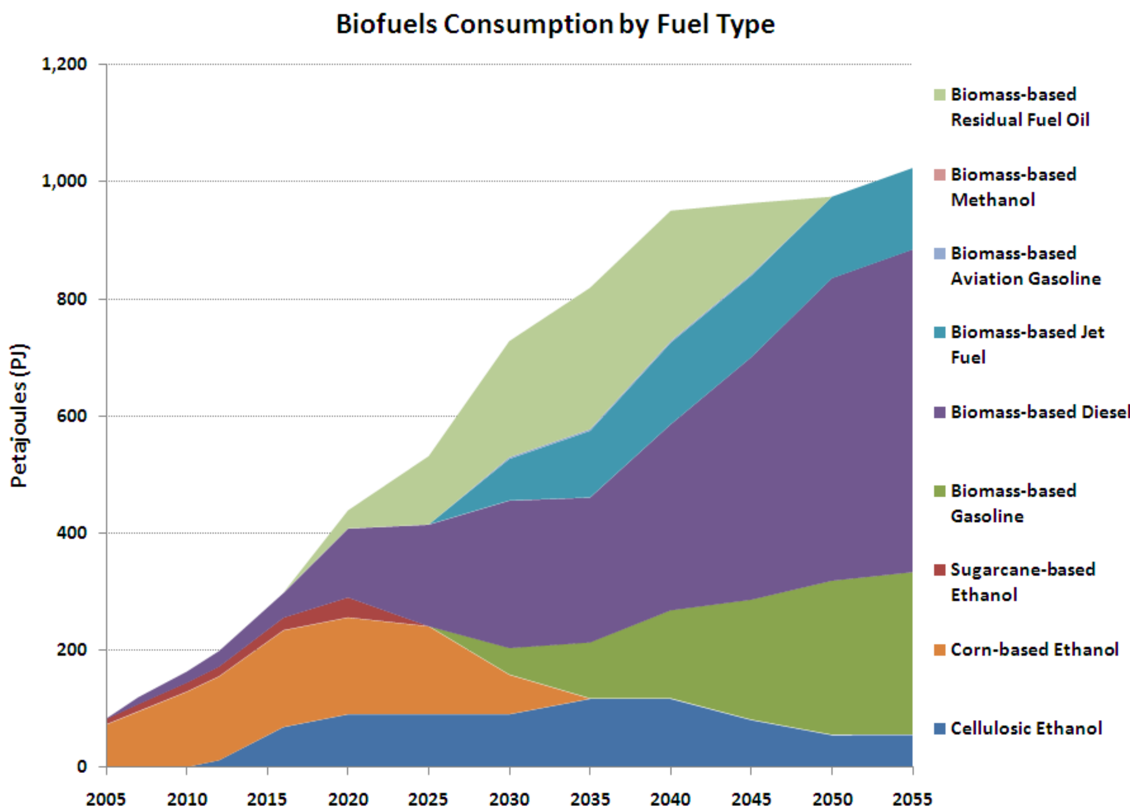

Figure 53 Biofuels Consumption by Fuel Type in the Deep GHG Reduction Scenario

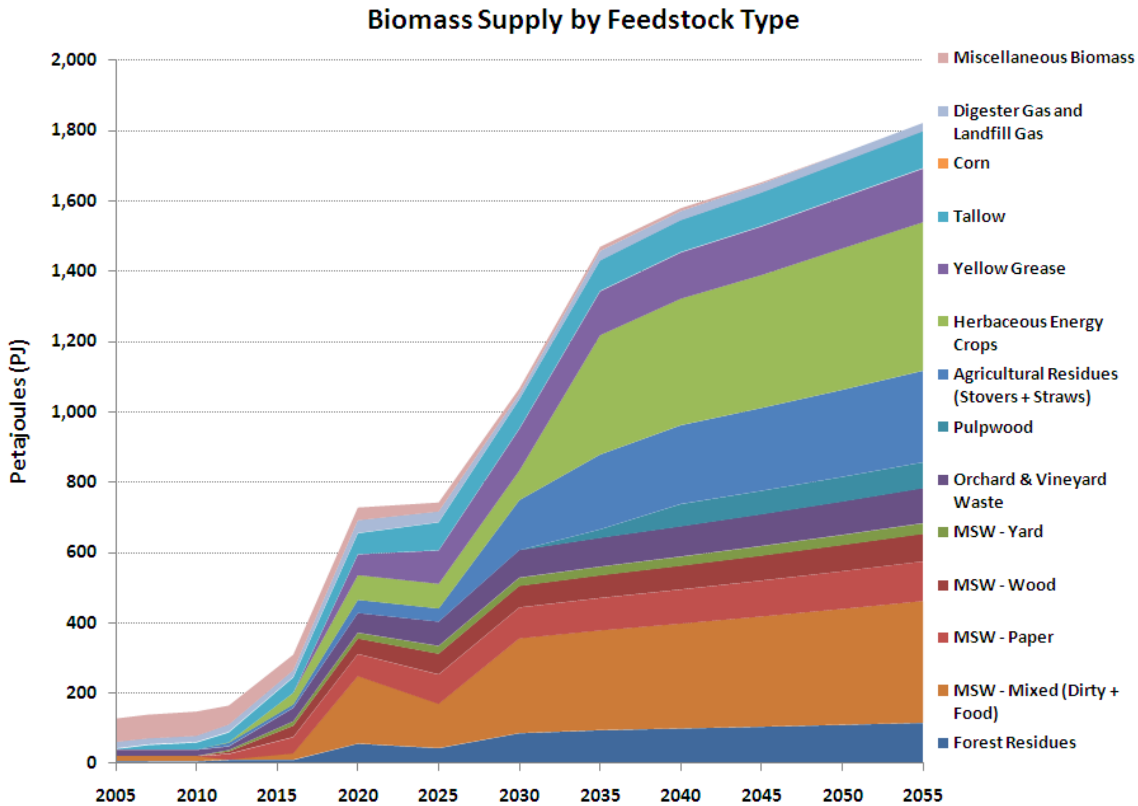

Figure 54 Biomass Supply by Feedstock Type in the Deep GHG Reduction Scenario

Hydrogen also becomes an extremely important fuel in the Deep GHG Reduction Scenario, and as Figure 55 illustrates the hydrogen production industry grows quickly after 2030. The preferred method of generation is natural gas steam methane reforming (SMR) with CCS. Water electrolysis and biomass gasification are, in contrast, not cost-competitive under the set of assumptions supplied to the model; hence, they are not used. Moreover, the fact that the model does not opt for biomass-to-H_2 plants with CCS – even though this pathway is also a negative emissions option – is particularly noteworthy since it shows the relative attractiveness of converting biomass into liquid fuels via a FT process equipped with CCS, rather than biomass-to-H_2. Of course, adding to this attractiveness is the fact that biofuels are in such high demand in certain transport subsectors for which there is no substitute.

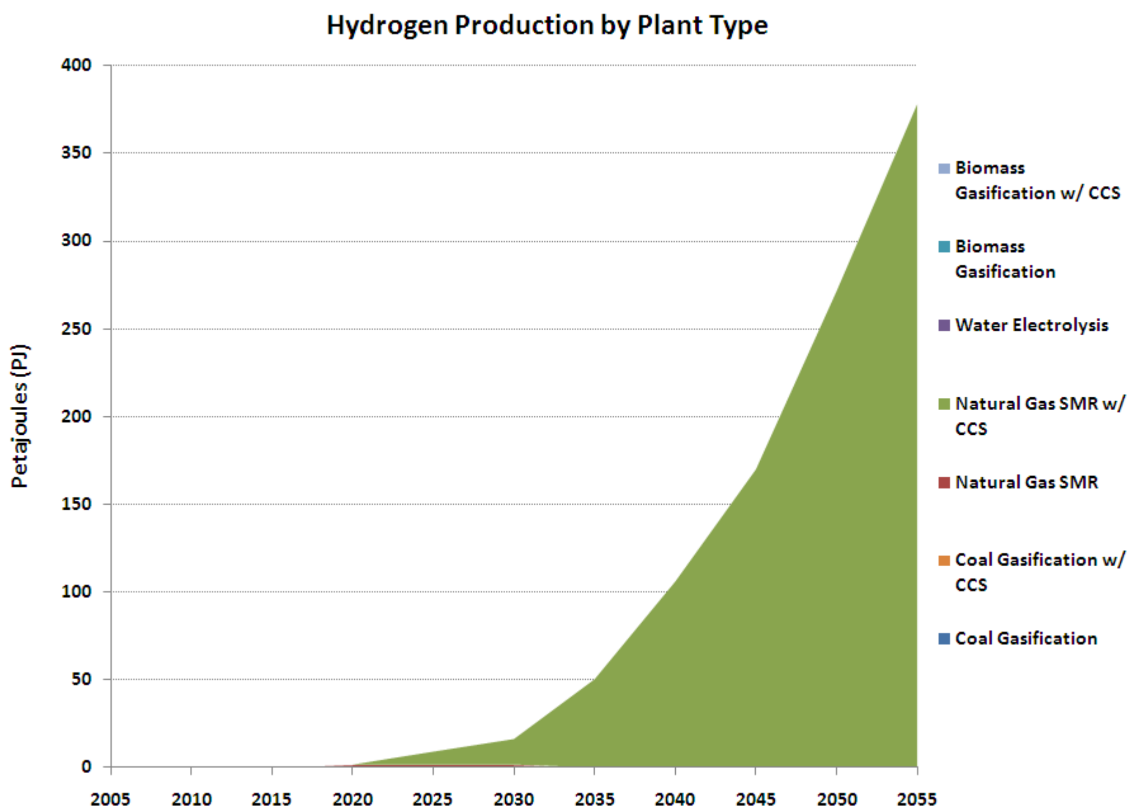

Figure 55 Hydrogen Production by Plant Type in the Deep GHG Reduction Scenario

The CCS industry grows quickly after 2025 in the Deep GHG Reduction Scenario (Figure 56), and by 2050 the total quantity of carbon dioxide being stored underground every year is almost twice as much as that being emitted to the atmosphere. Such high CO_2 flows may seem high at first glance, but actually the cumulative quantity of emissions stored until 2055 (~2,930 Mton CO_2) is fairly small relative to the overall storage potential that exists in California (~1.5% of total estimated capacity) and the potential in the western U.S. that California energy facilities could possibly have access to (~0.3%), according to mid-range geologic storage estimates from the U.S. DOE National Energy Technology Laboratory's (NETL) *Carbon Sequestration Atlas of the United States and Canada* (NETL, 2008). In other words, CCS is not likely to be limited by storage capacity going forward. The bulk of CO_2 capture and storage takes place at natural gas combined-cycle and coal IGCC power plants and FT poly-generation and hydrogen production facilities.

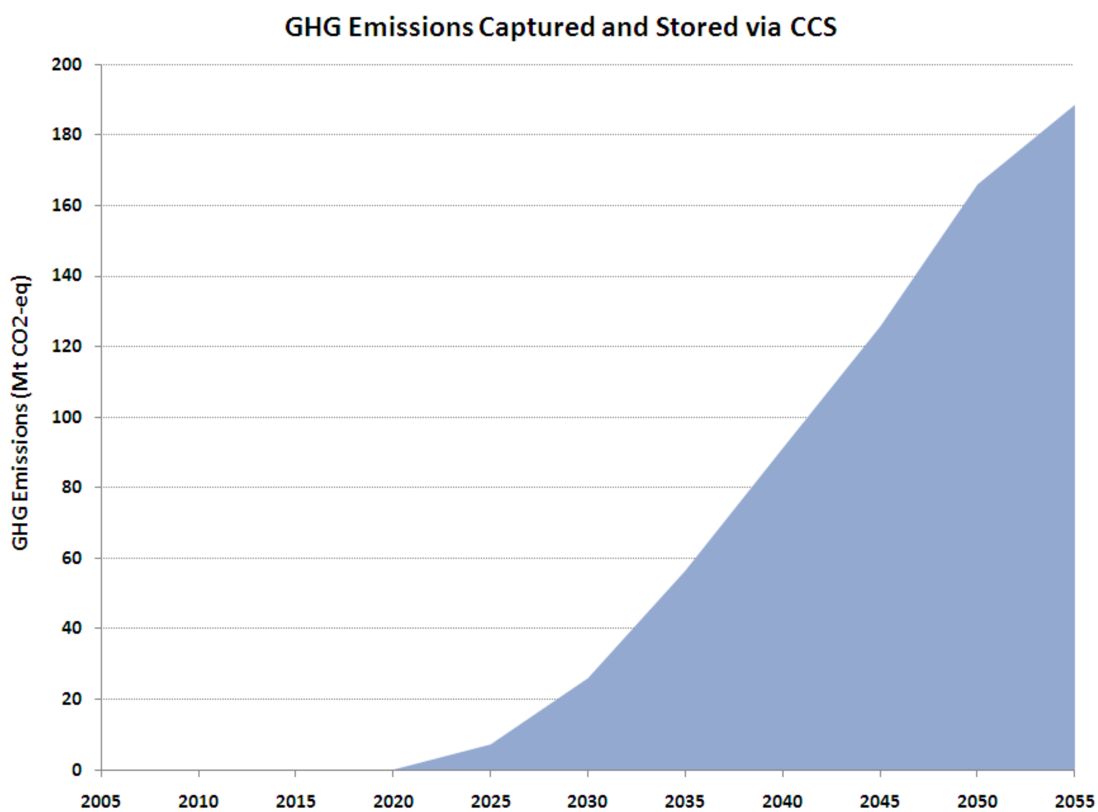

Figure 56 CO_2 Emissions Captured and Stored via CCS in the Deep GHG Reduction Scenario

Industrial, Commercial, Residential, and Agricultural Sectors

Treatment of the ICRA sectors – and their exogenously specified trajectories for energy demands and fuel mixes – has already been described earlier in this section. The key points to make note of are two-fold. First, the fuel use mixes of the Deep GHG Reduction Scenario are largely based on the BLUE Map scenario of the IEA. Hence, they are consistent with an overall storyline where California greenhouse gas emissions are reduced 80% below 1990 levels by 2050. Second, the carbon intensities of these sectors are substantially reduced due to a pronounced shift towards what essentially becomes a dual fuel system: electricity is the energy carrier of choice in applications where its use is feasible, and natural gas is utilized for high temperature processes. In addition, a small but non-trivial amount of both biomass (e.g., for industrial boilers) and solar energy (e.g., passive rooftop water heating on buildings) also contributes to the energy supply. The following four figures illustrate the evolution of the ICRA sectors over time in the Deep GHG Reduction Scenario.

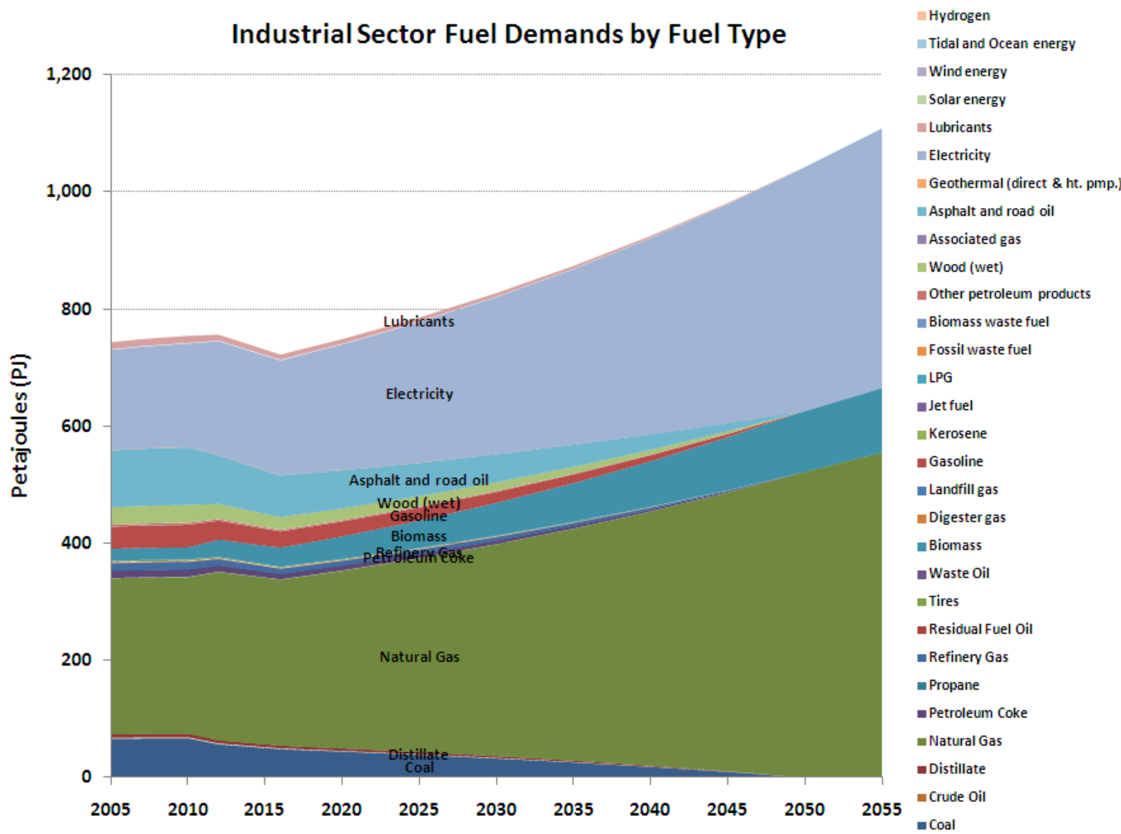

Figure 57 Useful Energy Demand by Fuel Type in the Industrial Sector in the Deep GHG Reduction Scenario

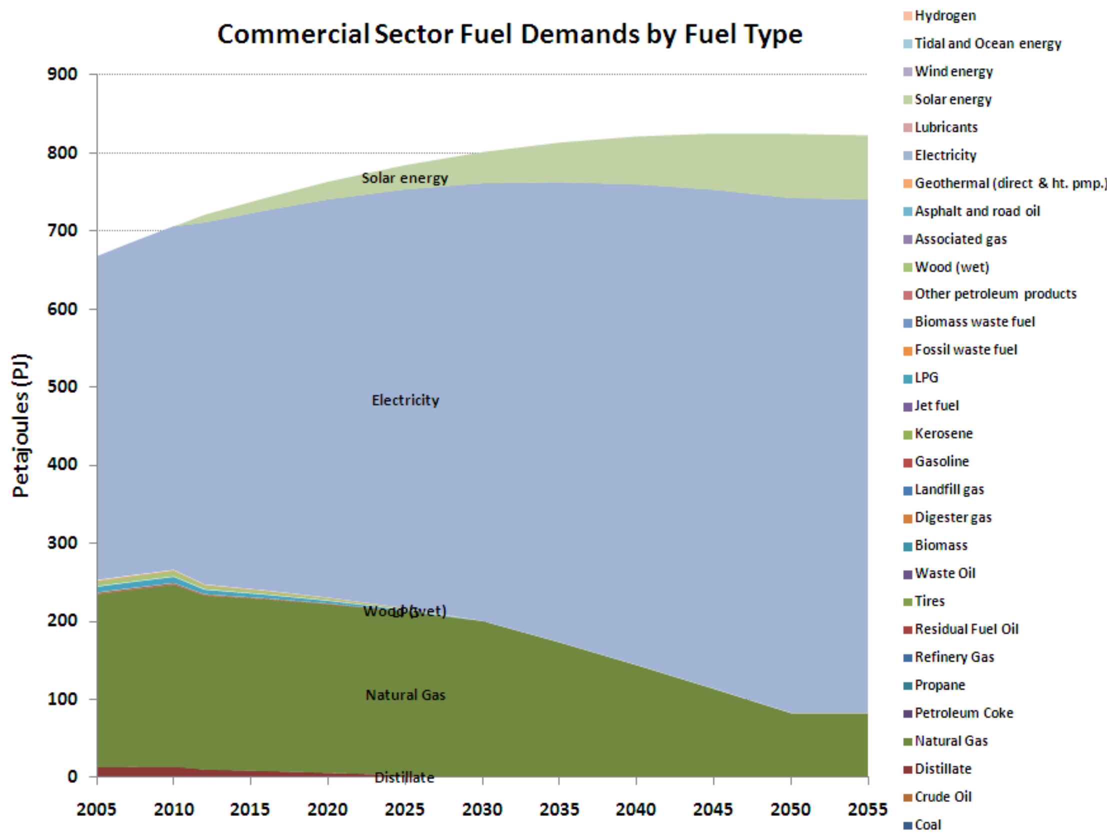

Figure 58 Useful Energy Demand by Fuel Type in the Commercial Sector in the Deep GHG Reduction Scenario

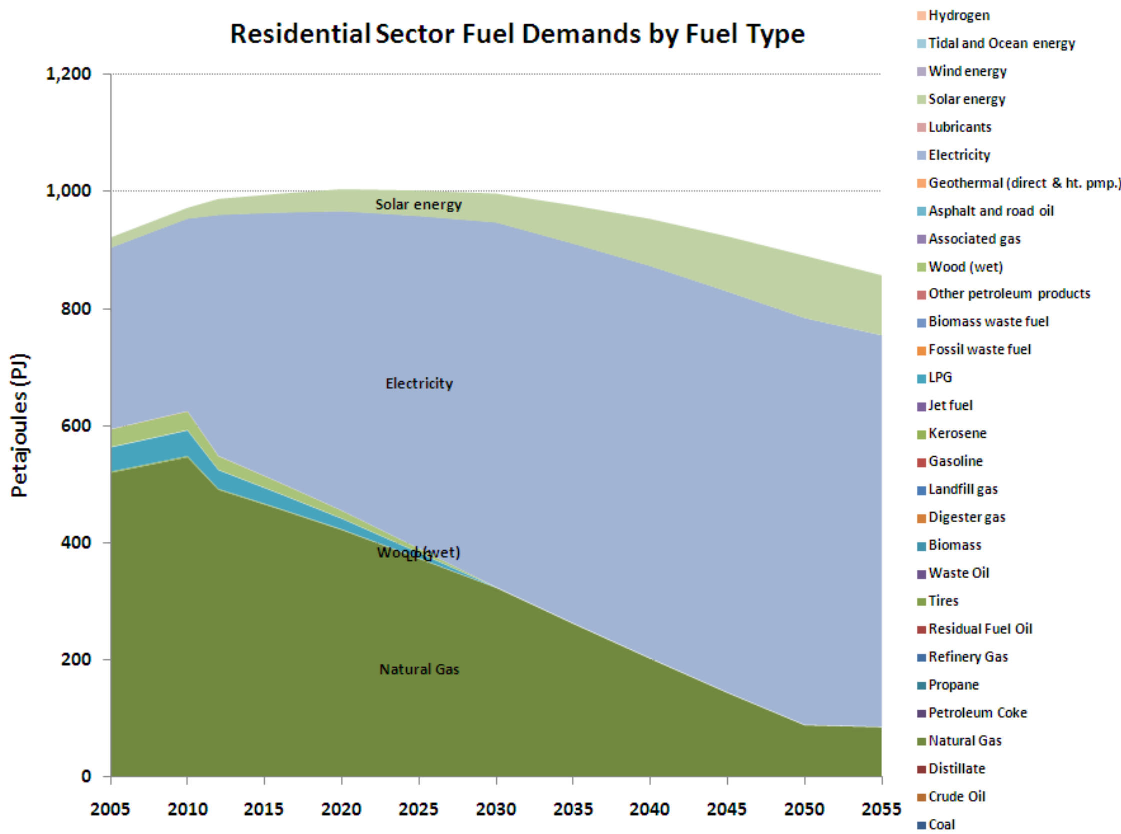

Figure 59 Useful Energy Demand by Fuel Type in the Residential Sector in the Deep GHG Reduction Scenario

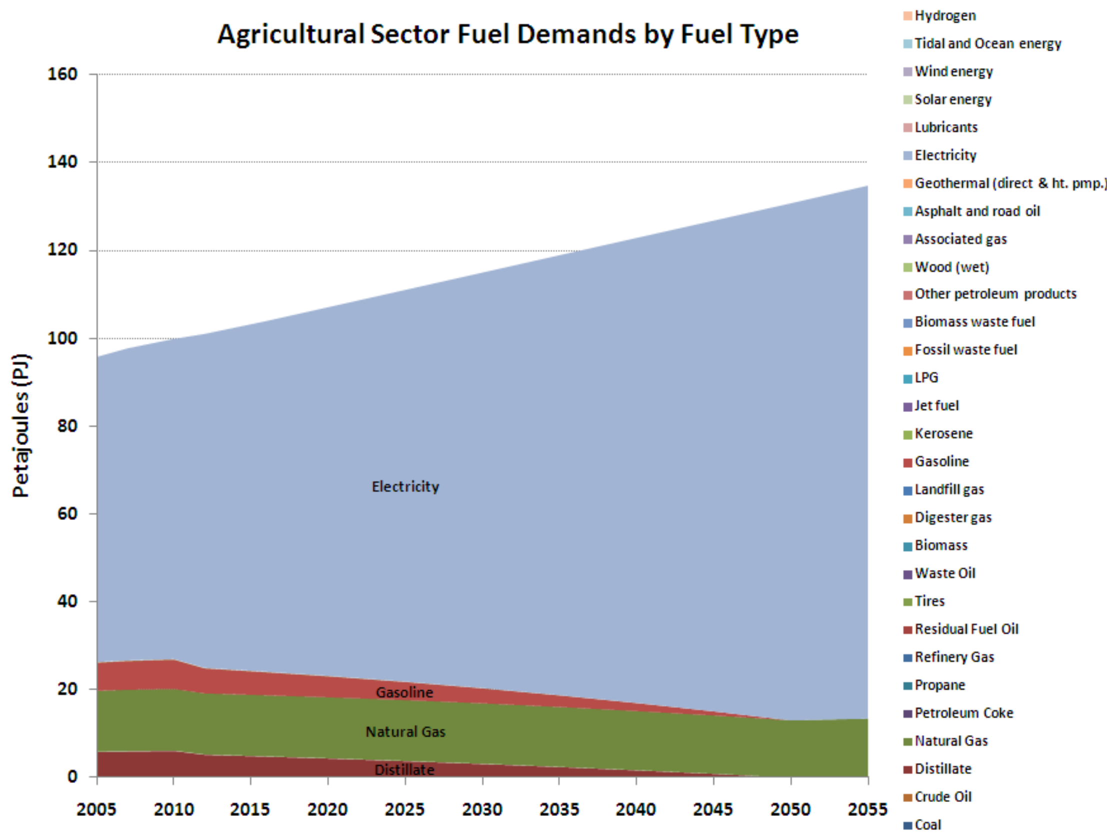

Figure 60 Useful Energy Demand by Fuel Type in the Agricultural Sector in the Deep GHG Reduction Scenario

Transportation Fuels Consumption and Technology Trends

A major transformation also occurs in the transportation sector in the Deep GHG Reduction Scenario. This is illustrated in Figure 61, which shows the mix of fuels consumed sector-wide. The main fossil fuels of today (gasoline, diesel, jet fuel, and residual fuel oil) decline in importance over time: they are still widely used, but their continued upward growth slows down significantly. In contrast ethanol, biodiesel, bio-gasoline, bio-RFO, bio-jet fuel, hydrogen, and electricity all gain market share in the future. Particularly interesting is the small contribution from ethanol in this scenario. In the Reference Case, ethanol (in the form of both E-10 and E-85) grows substantially over the coming decades, once its cost of production becomes competitive with petroleum-based gasoline at high and sustained crude oil prices. In the Deep GHG Reduction Scenario, however, ethanol consumption initially increases (due to the RFS biofuels mandates), but then in the long-run its importance diminishes. The reason for this, as has been discussed previously, is the absence of suitable alternatives for liquid fuels in some of the other transport subsectors and, hence, the higher value of converting biomass to other forms of biofuel (e.g., namely biodiesel, bio-RFO, and bio-jet fuel). An important lesson for policy that derives from these results is the following: while low-carbon ethanol may be an attractive alternative to gasoline over the next 10-20 years, its production may not be the best use of biomass in the long term, assuming deep reductions in GHG emissions need to be made across the all transport subsectors and indeed the entire economy.

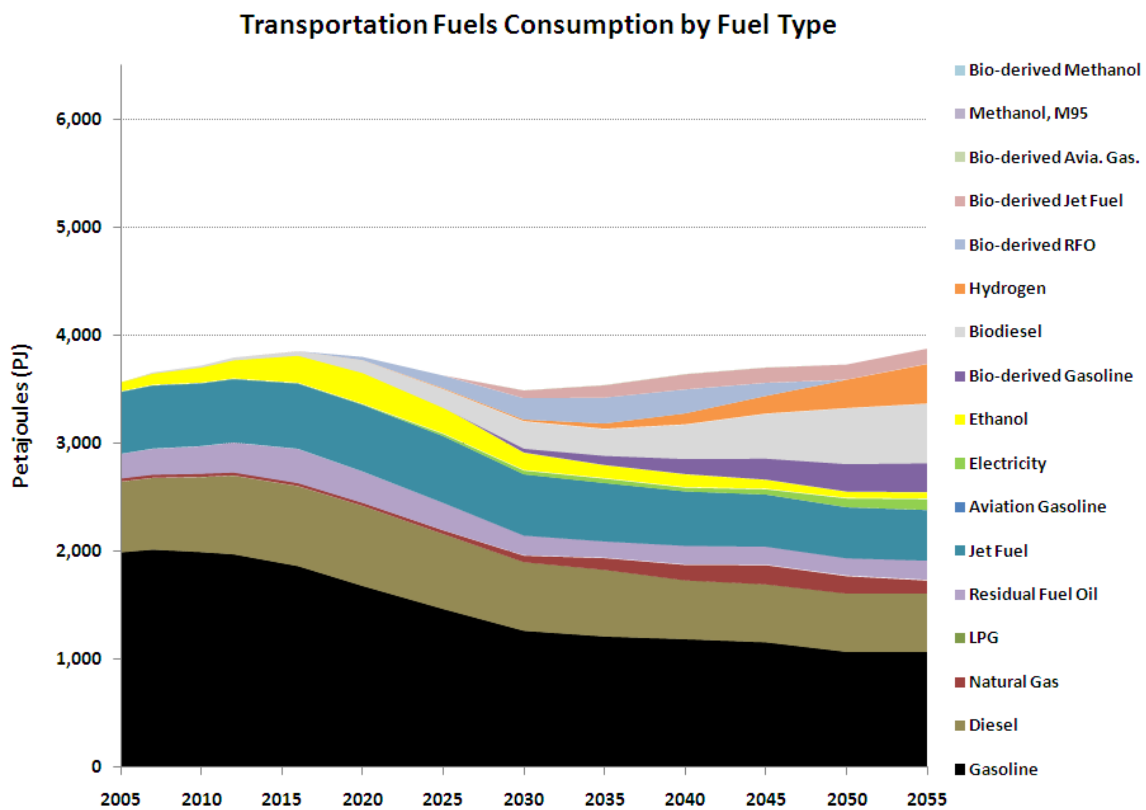

Figure 61 Final Energy Demand by Fuel Type in the Transportation Sector in the Deep GHG Reduction Scenario

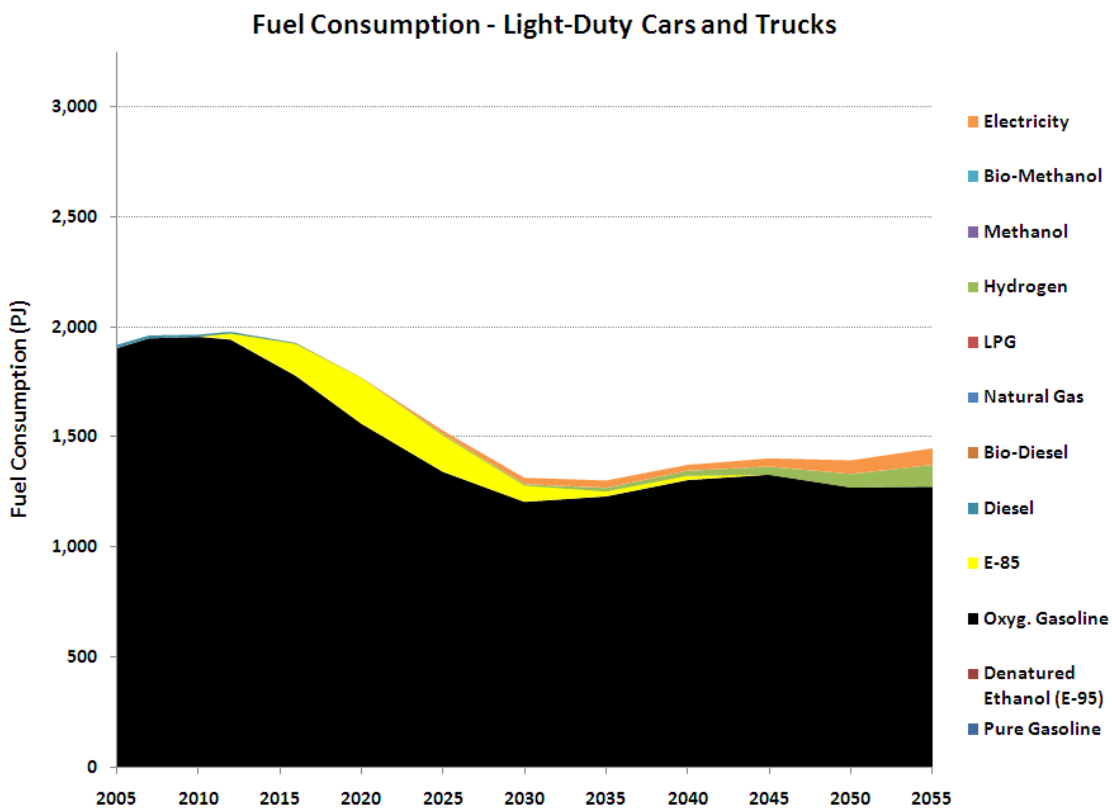

Figure 62 Fuel Consumption for Light-Duty Vehicles in the Deep GHG Reduction Scenario

Total transportation fuel consumption in 2050 is cut by about one-third in the Deep GHG Reduction Scenario compared to the same year in the Reference Case, while for light-duty vehicles the reduction is even greater, about one-half (Figure 62). A portion of this reduction can be attributed to the lower LDV VMT demands assumed in this scenario, which are motivated by strong transit, land use, and auto pricing policies. The bulk of the reductions, however, are due to greatly increased vehicle efficiencies, made possible by advanced technologies.

The Deep GHG Reduction Scenario sees extensive penetration of advanced vehicle technologies, particularly in the light-duty sector (Figure 63).[38] These actions are motivated by the declining cap on economy-wide GHG emissions, as well as the new, more stringent LDV GHG emissions standards, which are enacted between 2017 and 2025 and gradually raise the minimum fuel economies of new light-duty cars and trucks to 60 mpg and 45 mpgge, respectively, assuming all the GHG reductions are achieved by vehicle efficiency improvements (Figure 64). Standards of such stringency are in line with recent announcements of the U.S. EPA, U.S. DOT, and CARB, who are currently in the process of setting new federal fuel economy and tailpipe emissions standards for model-year 2017-2025 vehicles. In support of this plan, the organizations recently undertook a joint technical assessment to gauge the feasibility of raising vehicle efficiency standards from 3% to 6% per year between 2017 and 2025 (EPA-DOT-CARB, 2010). (The current CAFE standards are set to expire in 2016.) Several scenarios are developed in their analysis, but the main conclusion is that between now and 2025 automakers will need to significantly increase their supply of advanced technology vehicles (namely HEVs, PHEVs, BEVs, and Diesel ICEs) if they hope to meet the more stringent standards. My analysis essentially reaches this same conclusion, as evidenced by the vehicle market share curves shown in Figure 63. The primary difference is that the CA-TIMES Deep GHG Reduction Scenarios also foresees a limited introduction of Hydrogen FCVs by 2025, since the model (with its perfect foresight) recognizes that this low-carbon option must be introduced to the market in the near to medium term, in order for FCVs to have adequate time to build up their capacity by the 2040-2050 timeframe.

[38] Note that while the main purpose of CA-TIMES is to serve as an energy systems model, it also acts implicitly as a vehicle stock turnover model as well.

Actually, this is true of all advanced vehicle types: subject to constraints on growth, if these technologies are to have enough time to gain significant market share by the middle part of the century, their introduction needs to occur in earnest over the next 10-20 years.

By 2050, the LDV market is dominated by Gasoline HEVs, with Gasoline PHEVs, Hydrogen FCVs, Gasoline ICEs, and E-85 Flex Fuel ICEs and HEVs also playing important roles (Figure 63). Much of the gasoline still consumed by the ICE and PHEV vehicles is petroleum-based, whereas a significant portion (~20%) is either bio-gasoline or synthetic gasoline, both of which are low in carbon and produced by one of the various FT coal-biomass poly-generation plants. Interestingly, battery-electric vehicles do not experience any growth in the Deep GHG Reduction Scenario, an outcome due entirely to the relatively high lifecycle costs of supplying VMT using BEVs, considering both the capital costs of vehicles and their requisite recharging infrastructure (the capital costs for Level I, II, and III charging are all represented in the model). Such a result is indeed questionable given the activity we see around electric vehicles today. However, from the perspective of the CA-TIMES model, one can understand this result by noting that in the model no distinction is made between vehicle classes – i.e., all LDV technologies are represented as mid-size cars. Because mid-size cars weigh significantly more than the types of compact BEVs currently being introduced by automakers around the world, and in order to satisfy consumer demands for vehicle range (200+ miles on a single charge), the battery packs for the light-duty BEVs represented in the CA-TIMES model are actually quite large (~80 kWh). Therefore, total BEV costs are rather expensive relative to other advanced LDV technologies, and partly for this reason we do not see any significant penetration of these vehicles in this very low-carbon future. It is planned that future versions of the CA-TIMES model will allow for greater disaggregation of the various LDV class segments, from compact to mid-size to large cars, and from small to large trucks, minivans, and SUVs. Such market segmentation could potentially lead to greater penetration of BEVs.

The fact that ICE-based drivetrains (including HEVs and PHEVs) continue to make up the bulk of the light-duty vehicle market in 2050 is an interesting result, as it shows the relatively higher abatement costs in this particular transport subsector, not to mention the others. As discussed later, the lack of a dramatic transformation in transport has much to do with the huge emissions reductions that are achieved in the other energy sectors over the next few decades, particularly in the electricity and supply sectors, where zero and even negative emissions are possible, thanks to bio-CCS technologies.

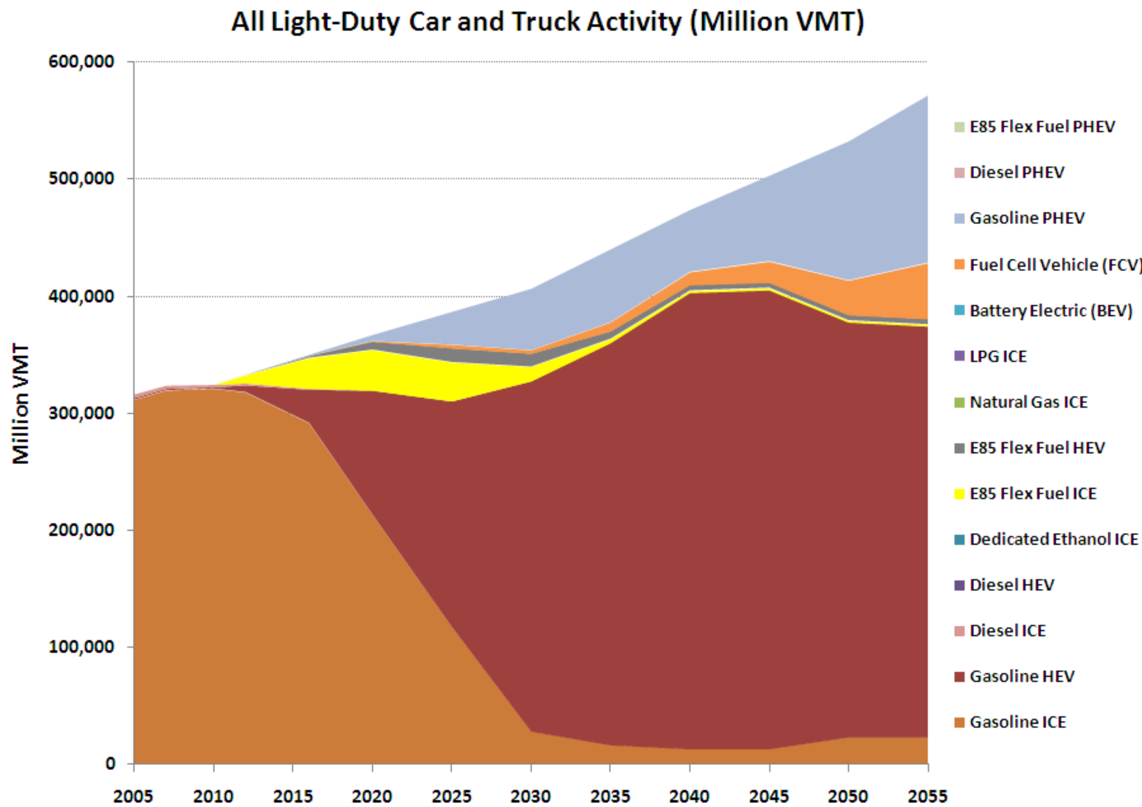

Figure 63 Technology Penetration in the Light-Duty Vehicle Subsector in the Deep GHG Reduction Scenario

The average new model-year vehicle fuel economy for light-duty cars and trucks is approximately 66 mpgge in 2050, almost twice the level in the Reference Case and 2.5 times that of today (Figure 64). Fleet fuel economy (averaging both on-road and new cars and trucks) climbs to 60 mpgge by 2050. Such high efficiencies lead to the large reductions in LDV fuel demand that are shown in Figure 62. (Note that the peak in new vehicle fuel economy in 2050 is caused by the so-called "end-year effect", an artifact of energy-economic systems optimization models that is actually quite common. In this case, because the required GHG reductions between 2050 and 2055 are quite small, in comparison to the reductions required in the previous five-year intervals, the model –

with its perfect foresight – chooses to invest in cheaper, less efficient vehicles in 2055 than in 2050.)

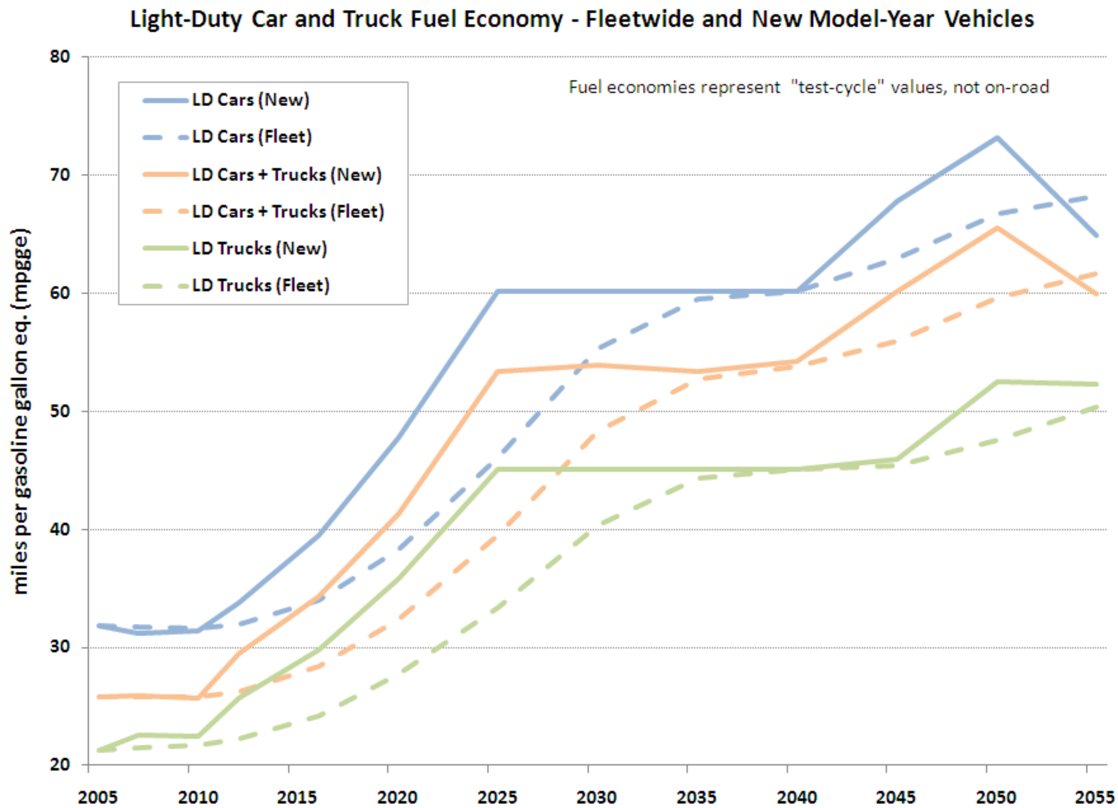

Figure 64 Average Light-Duty Vehicle Fuel Economy in the Deep GHG Reduction Scenario

In the non-LDV subsectors, the Deep GHG Reduction Scenario also sees a pronounced shift toward alternative fuels and advanced technologies. Heavy-duty trucks provide a good example: total fuel demands are cut significantly as a result of the introduction of high-efficiency Diesel ICE technologies. (Other advanced technologies, such as PHEVs, BEVs, and FCVs, are not available to the HDT subsector in CA-TIMES, due to range limitations and excessively long refueling times.) Moreover, the diesel consumed by these vehicles is only partly sourced from conventional petroleum; a large portion comes from low-carbon biodiesel and synthetic diesel. The Medium-duty Truck and Bus subsectors do not face some of the range and refueling issues associated with long-haul trucks (in fact, a large share of MDTs and Buses are fleet vehicles), hence a greater number of alternative fuel and technology options are available. Accordingly, we see a shift in these subsectors from high-carbon fossil fuels, such as gasoline and diesel, to lower-carbon biodiesel, hydrogen, and natural gas. The model invests in both Hydrogen FCVs and Hydrogen hybrid-electric ICEs in these cases, since both technologies allow for higher efficiencies than Diesel ICEs and both make possible the use of low-carbon hydrogen fuel. In the rail subsector, a portion of Freight Rail operations are electrified by 2050, despite the relatively high capital costs assumed in the model for rail track electrification. Because electrically-powered locomotives are more efficient than conventional diesel or diesel-electric propulsion systems, this technological shift helps to lower total energy demand in the subsector. Emissions reductions in the Marine and Aviation subsectors, on the other hand, are primarily limited to fuel switching, as the options for alternative propulsion systems are more limited. Therefore, the model chooses to direct substantial quantities of bio-derived RFO and bio-jet fuel to these subsectors. Interestingly, Figure 69 shows bio-RFO consumption by marine vessels growing quickly from 2020 to 2035 and then shrinking just as quickly toward 2050. The reason for this seemingly odd behavior has to do with the lack of CCS-capability (and thus negative emissions potential) with the pyrolysis bio-oil production pathway used for making bio-RFO. The model prefers instead to direct limited biomass supplies to the FT poly-generation plants, which produce bio-based gasoline, diesel, and jet fuel, as well as electricity, while at the same time sequestering a significant portion of the biomass carbon permanently underground.

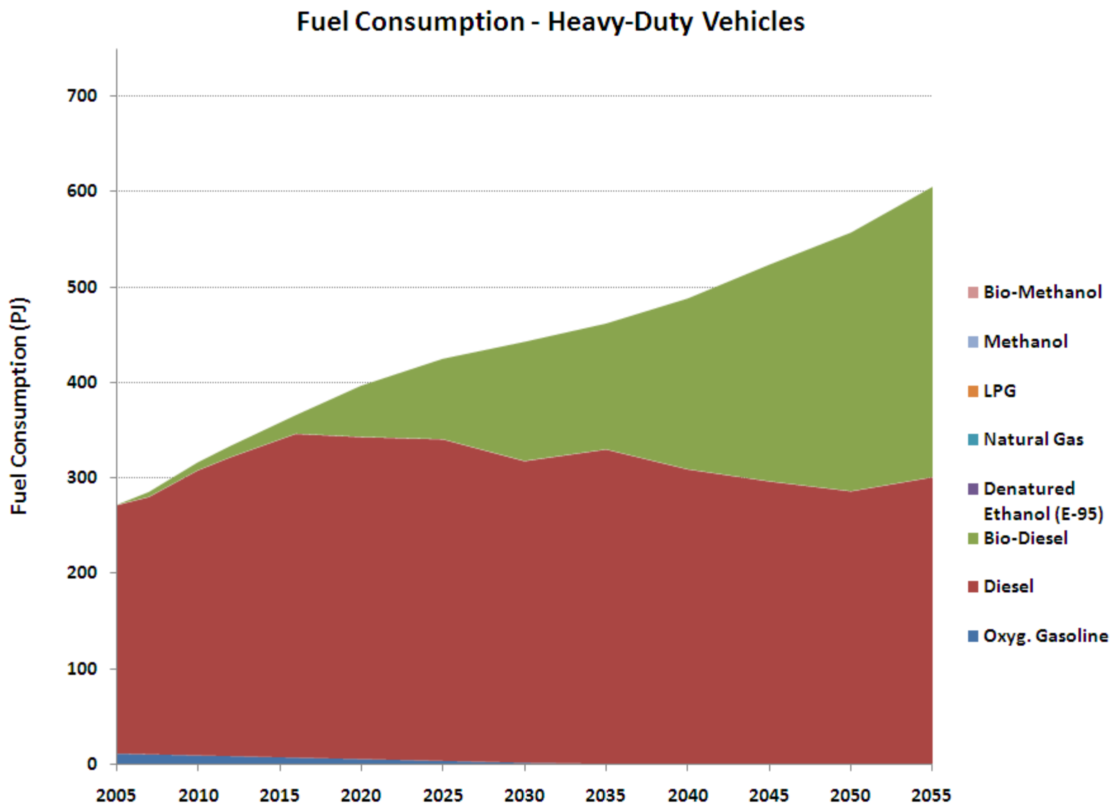

Figure 65 Fuel Consumption for Heavy-Duty Trucks in the Deep GHG Reduction Scenario

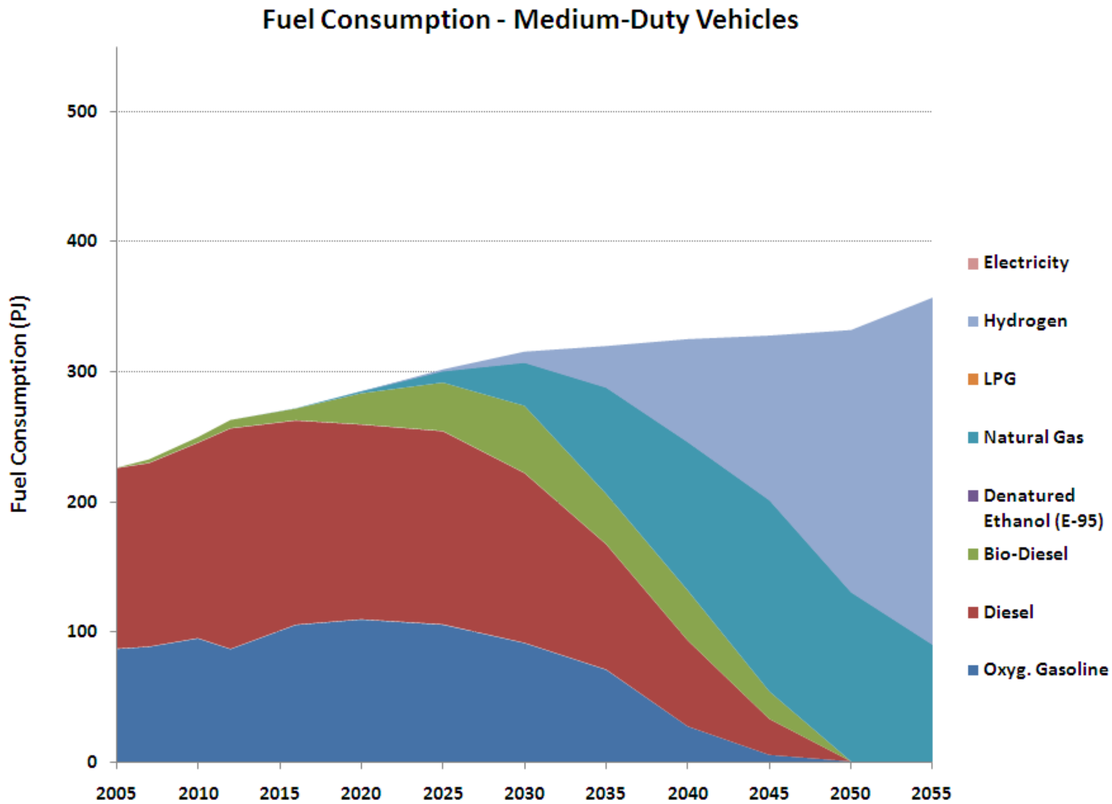

Figure 66 Fuel Consumption for Medium-Duty Trucks in the Deep GHG Reduction Scenario

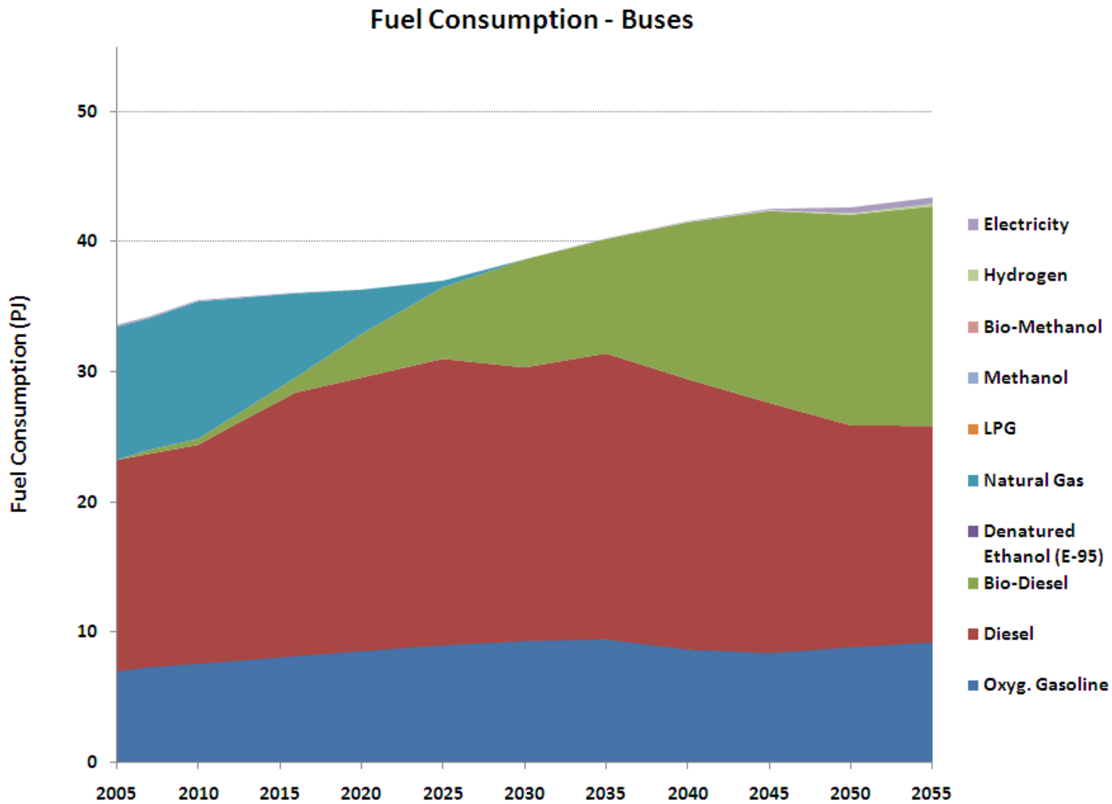

Figure 67 Fuel Consumption for Buses in the Deep GHG Reduction Scenario

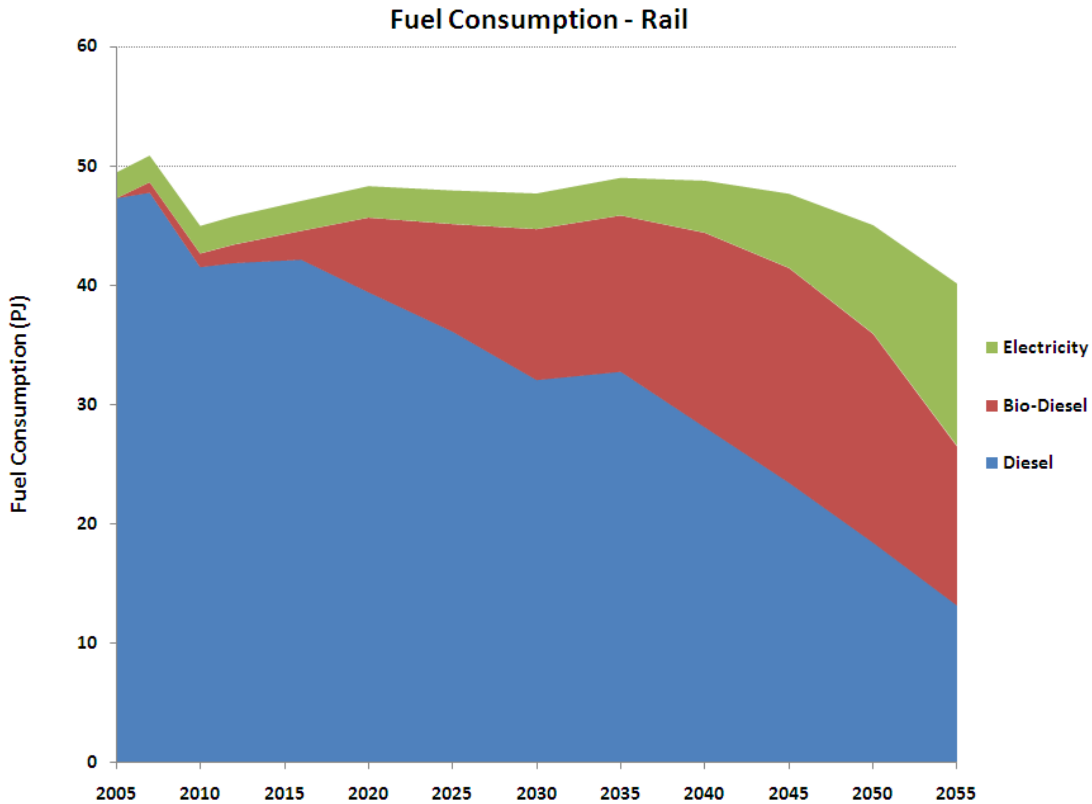

Figure 68 Fuel Consumption for Rail in the Deep GHG Reduction Scenario

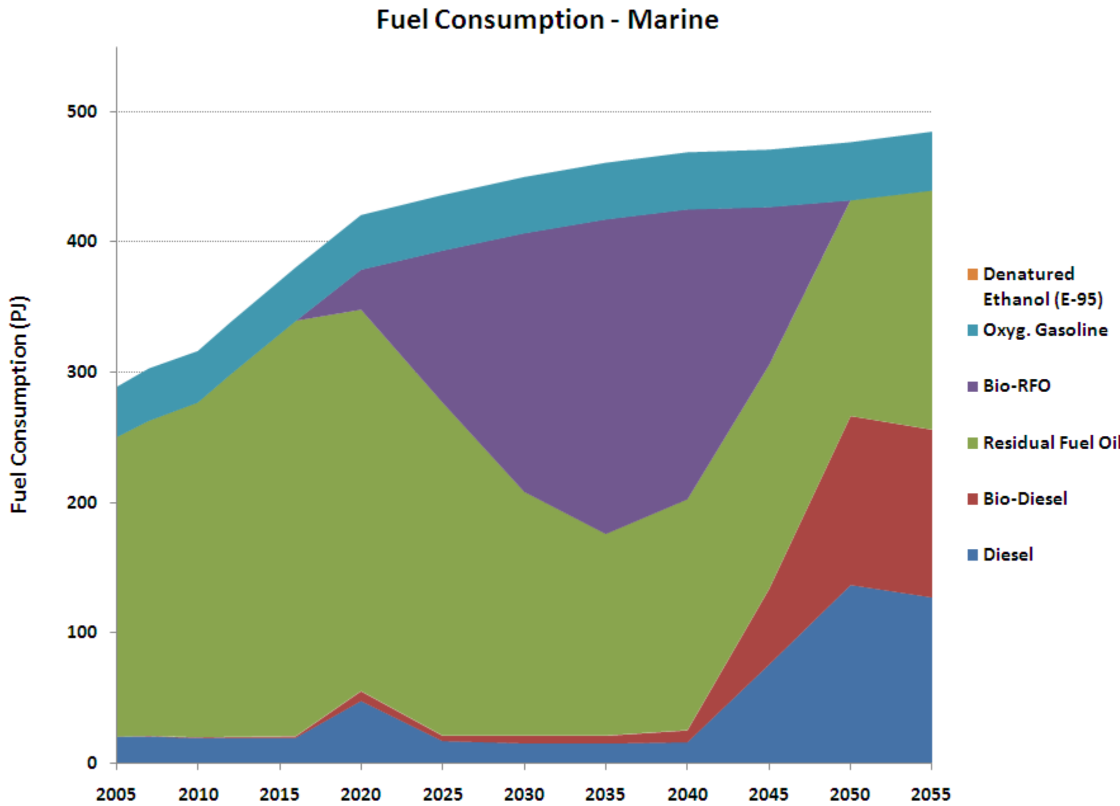

Figure 69 Fuel Consumption for Marine Vessels in the Deep GHG Reduction Scenario

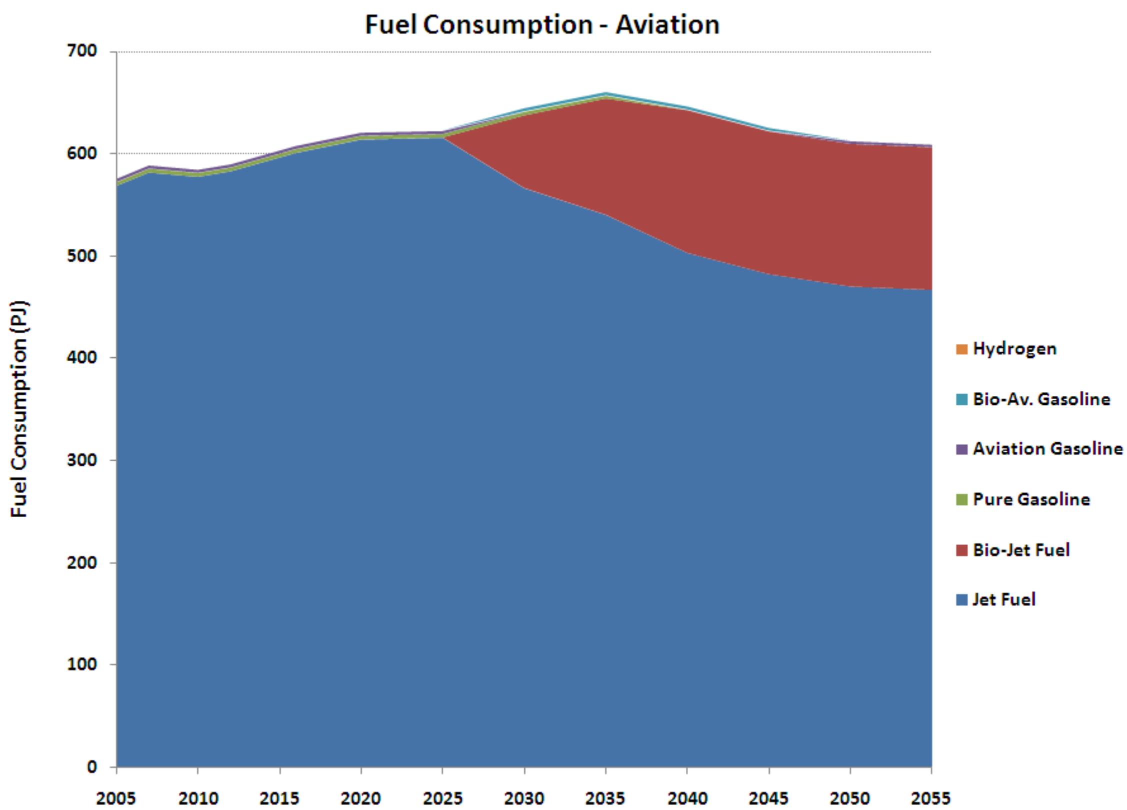

Figure 70 Fuel Consumption for Aviation in the Deep GHG Reduction Scenario

Greenhouse Gas Emissions

By transitioning to an energy system that relies more heavily on advanced technologies and alternative fuels, the potential exists for substantial reductions in greenhouse gas emissions in California in the long term. Figure 71 shows CA-TIMES model estimates of annual GHG emissions produced via fuel combustion activities in each of the state's various energy sectors. Figure 72 is similar except that emissions from electric generation are allocated to end-uses. Note that a straight line declining cap on emissions is assumed in the scenario, which helps to explain the shape of the emissions trajectory shown here.[39] Otherwise, if the model were free to set its own schedule for emission reductions (as estimated in a side analysis, the results for which are not shown here), it would choose to push the deepest cuts to the later time periods (i.e., after 2040), in response to the non-zero global discount rates used in the model, which essentially make long-term costs less important than near- to medium-term costs in the calculation of total discounted system costs on a net present value basis.[40] While postponing mitigation actions may make sense from the point of view of the model, it is probably not reflective of the real world, in which policymakers of the future are likely set interim emission targets between 2020 and 2050, in order to ensure that the system is on track to meet the long-term deep reduction goals (as well as to further the achievement of various other political objectives, such as job creation).

A particularly noteworthy finding relates to the GHG emissions target for 2020 (i.e., the AB32 goal of returning to 1990 levels by this year). Even though a cap is set for 2020, the model actually opts to undershoot the limit (i.e., the constraint is non-binding), in order to prepare for the following time period just five years later, when the emissions cap is lower still. What this says is that, according to the multitude of assumptions made in this particular scenario, for the California energy system to put itself on track to reach the deep reduction targets of the long term (80% by 2050), while following a linearly declining emissions trajectory, GHG emissions in 2020 will likely need to be lower than

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[39] Other modeling groups in the U.S. and abroad tend to represent declining emission caps by the same straight line trajectory approach that I have used, as noted through my interactions with the North American MARKAL-TIMES users group and the Stanford-based Energy Modeling Forum.
[40] In such a case, the primary limiting factors that would militate against such an outcome (i.e., pushing GHG emissions reductions to the very last period) are the growth constraints assumed in the model, which force the investment in and utilization of advanced technologies and alternative fuels in the near- and medium-term, so that there is enough time for them to gain significant market share by 2050.

the cap currently specified by AB32. In other words, while returning to 1990 emission levels by 2020 will certainly represent a big achievement for California, from a long-term perspective such a target may not be stringent enough.

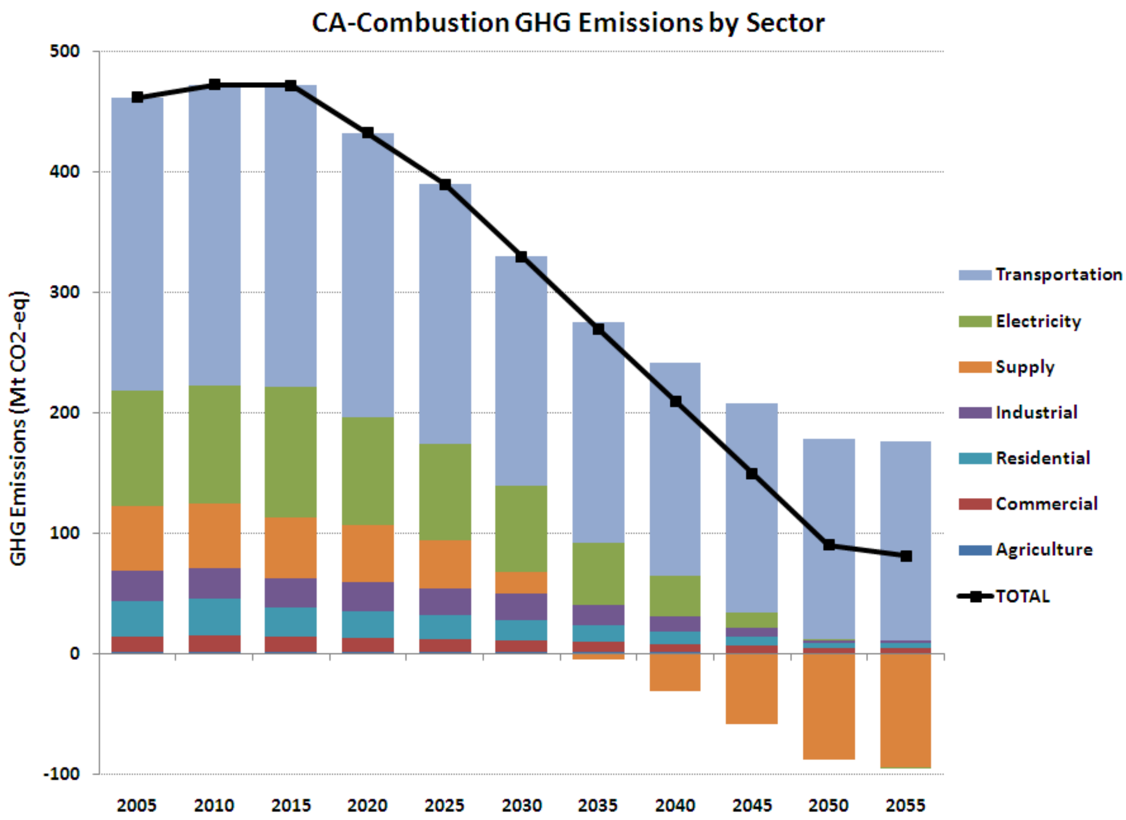

Figure 71 ***CA-Combustion* GHG Emissions by Sector in the Deep GHG Reduction Scenario**

Two other striking observations from the GHG emissions figures shown here relate to the dominance of transport sector emissions in the long term and the huge potential for negative emissions in the supply sector. Both of these findings are intimately related to each other, since the types of technologies that are able to permanently sequester biomass carbon underground (i.e., FT poly-generation plants) are the same ones that supply the transport sector with biomass-based gasoline, diesel, and jet fuel. Because of the considerable potential for bio-CCS, the other sectors are allowed to emit more than they otherwise would be able to, if negative emissions technologies were not available. In other words, these other sectors are not forced to reduce their emissions so stringently. The transportation sector is the primary benefactor in such a circumstance, given that marginal CO_2 abatement costs are generally higher in transport than in other sectors. (Another reason is the exogenously specified scenario storyline assumed for the industrial, commercial, residential, and agricultural sectors.) For instance, while supply sector emissions are reduced 262% between 2005 and 2050 (and in the electric sector by 99%), emissions in transport decrease by only 32%. Such findings are in line with other modeling studies (e.g., IEA (2010)), which show that from a cost-perspective and in the absence of any transport-specific GHG policies, certain segments of the transport sector are likely to be the last to decarbonize. The unique contribution of this study, at least within the California context, is that it highlights the enormous potential for bio-CCS negative emissions technologies and the critical role they may be able to play in controlling GHG emissions in the state, as well as taking the load off some of the other sectors, especially transport. Of course, this line of reasoning is contingent upon the eventual success and public acceptance of these technologies, as well as the ultimate size of the sustainable biomass feedstock base available to California. If bio-CCS technologies are constrained for any of these reasons in the future, then the potential for negative emissions in California would be significantly hindered, and the transportation sector would indeed be required to reduce its emissions by a considerably larger amount. These kind of sensitivities are explored in later sections of this report, wherein a handful of interesting variants of the Deep GHG Reduction Scenario are analyzed.

At first glance, the results discussed here might seem to contradict those of the original *80in50* studies, which looked at the potential for making 80% cuts in (well-to-wheel) greenhouse gas emissions in the U.S. transport sector by 2050 (McCollum and Yang, 2009; also Yang, McCollum et al. (2009), who studied similar scenarios for California). That analysis highlighted the critical role that advanced vehicle technologies and alternative fuels would perhaps need to play in the long term. The question raised by the analysis was whether or not the transport sector would ever actually need to achieve an 80% reduction on its own, or could emissions reductions be made more cost-effectively in other sectors. The CA-TIMES work discussed here was developed for the express purpose of addressing these kinds of questions, and the findings that derive from the analysis are very interesting. Namely, emissions reductions in the transport sector may not actually need to be as large as those assumed in the previous 80in50 studies (Yang, McCollum et al. 2009, and McCollum and Yang, 2009); in fact, they may not need to be anywhere near as great, so long as the potential for negative emissions technologies exists on the supply side.

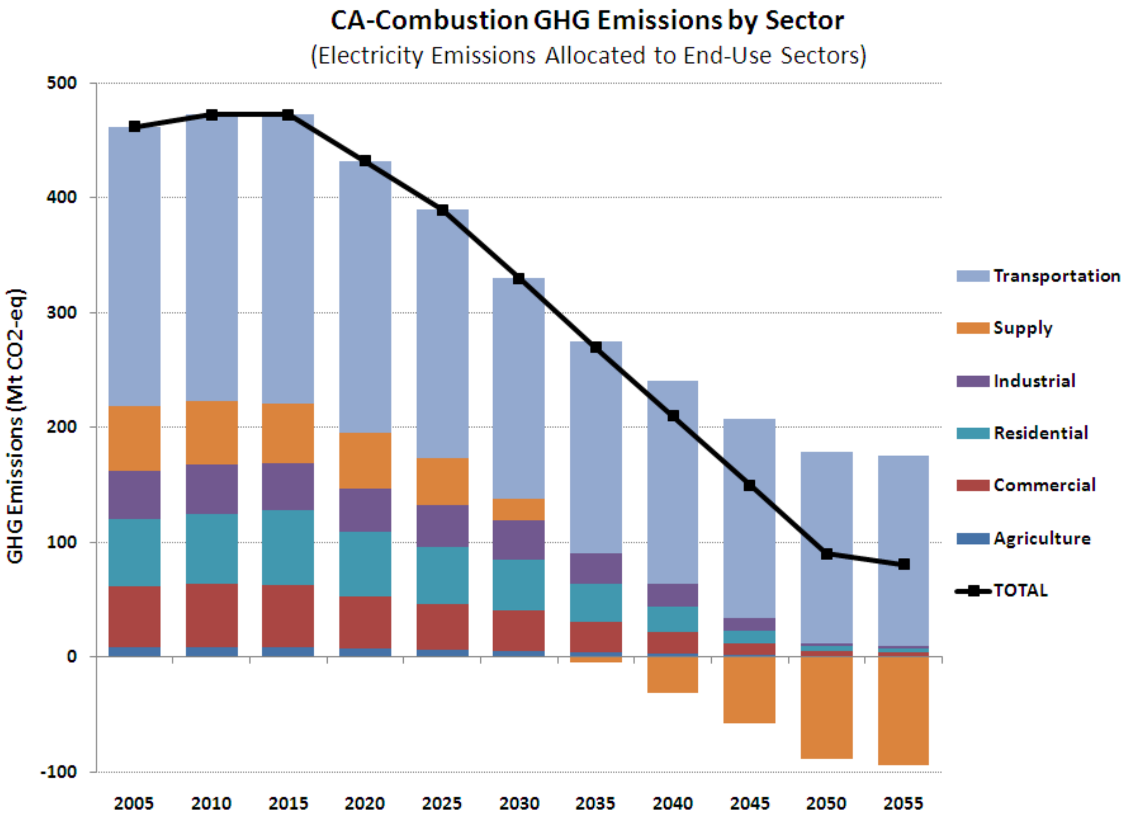

Figure 72 ***CA-Combustion*** **GHG Emissions by Sector in the Deep GHG Reduction Scenario with Electricity Emissions Allocated to the Various End-Use Sectors**

The cumulative quantity of GHGs emitted between 2005 and 2055 (i.e., the area under the total emissions curve in Figure 71) is approximately 15,762 Mton CO_2-eq in the Deep GHG Reduction Scenario. Over the more limited period of 2012 to 2050, cumulative emissions are just 12,048 Mton CO_2-eq. By comparison, cumulative emissions in the Reference Case are a much higher 27,552 and 21,140 Mton CO_2-eq, respectively, over these two timeframes. The period between 2012 and 2050 is particularly relevant because of the U.S. National Research Council's recent recommendation that total domestic U.S. greenhouse gases from all sources (both fuel combustion and non-energy GHGs) stay within a cumulative emissions "budget" of 170,000 to 200,000 Mton CO_2-eq during this timeframe (NRC, 2010). Such a budget corresponds to reductions in annual

GHG emissions by 2050 that are between 80% and 50% below 1990 levels, respectively, at the national level. In the Deep GHG Reduction Scenario developed here (an 80% reduction scenario), California's cumulative emissions, which one should be reminded only include fuel combustion, represent about 7.1% of this national emissions budget, which is only slightly less than the state's current contribution to total domestic U.S. GHGs. (The small discrepancy is understandable when considering that only fuel combustion emissions are captured by CA-TIMES.) For illustrative purposes, if we assume that this 7.1% figure is roughly representative of California's "fair share" of U.S. GHGs, then California's emissions budget over the 2012 to 2050 time period is estimated at 12,100 and 14,200 Mton CO_2-eq, respectively, depending on the stringency of the 2050 emissions target (80% or 50%). While the Deep GHG Reduction Scenario remains within these budgets, the Reference Case far exceeds it. In fact, if California continues to follow a business-as-usual Reference Case scenario for energy system development, then its emissions budget is likely to be exceeded well before 2050. Instead, the budget would probably be exceeded around 2035.

The average "well-to-wheel" lifecycle carbon intensity (including both upstream/ "well-to-tank" and downstream/"tank-to-wheel" stages) of all fuels consumed in the transportation sector decreases from 82.8 gCO_2-eq/MJ_{HHV} in 2005 to 31.1 gCO_2-eq/MJ_{HHV} in 2050, a difference of about 62% (Figure 73). (Remember that because these carbon intensities are calculated on a HHV basis, they are about 7 to 11% lower than if calculated on a LHV basis.) In the LDV subsector, the drop is not quite as large, with average carbon intensity declining to just 44.8 gCO_2-eq/MJ_{HHV} in 2050 (Figure 74). In other words, fuel carbon intensities are lower, on average, in the non-LDV subsectors, thanks to a larger amount of fuel switching. Emissions reductions made during the well-to-tank stages of fuel production are the primary driver of lower total lifecycle carbon intensities. In particular, the fact that well-to-tank emissions eventually become negative has everything to do with the increased utilization of biomass-based gasoline, diesel, and jet fuel, which are produced by bio-CCS negative emissions technologies, as previous discussions in this section have made all too clear. During the tank-to-wheel stage (i.e., fuel combustion), greater consumption of low- and zero-carbon biofuels and electricity, as well as hydrogen in certain transport subsectors, is responsible for the declines that result.

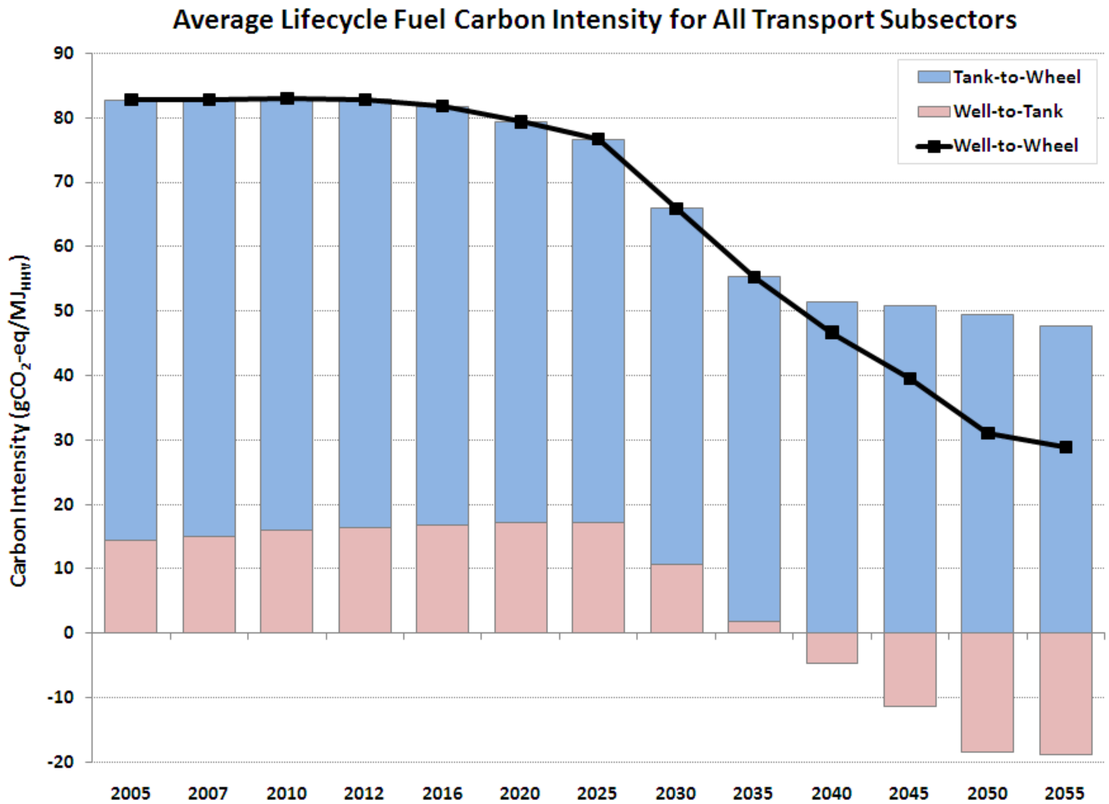

Figure 73 Average Lifecycle Carbon Intensity of All Fuels Consumed in the Transportation Sector in the Deep GHG Reduction Scenario

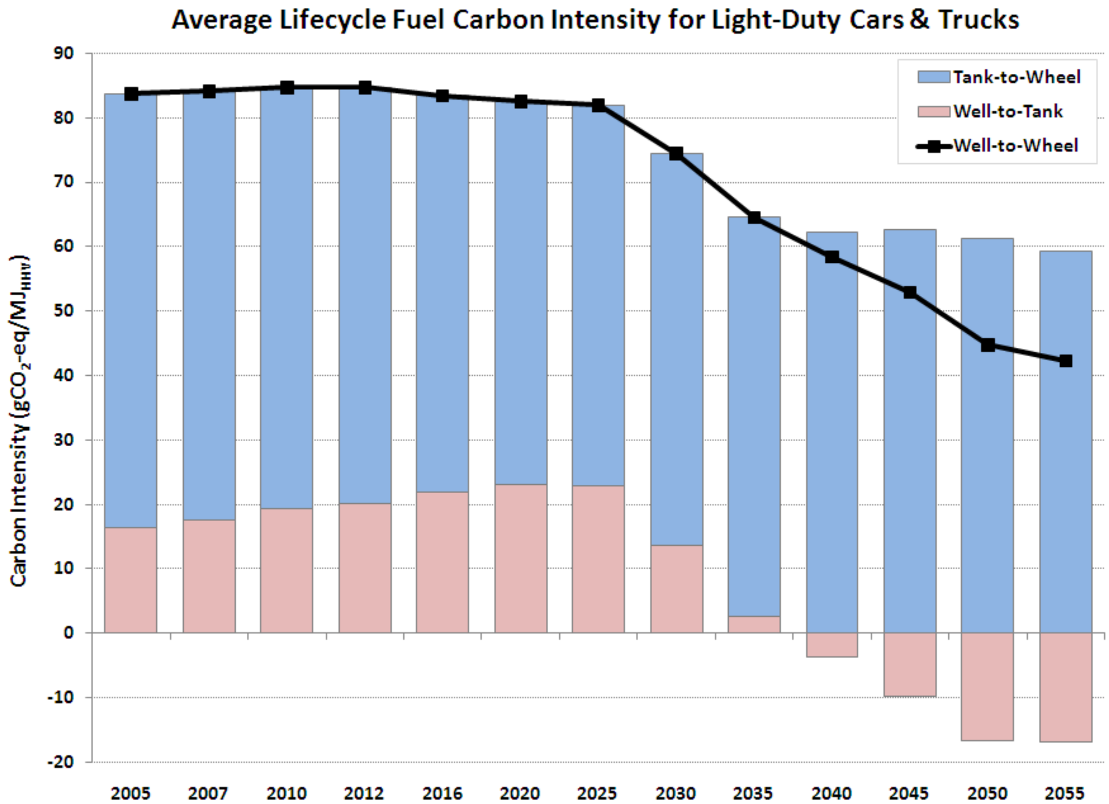

Figure 74 Average Lifecycle Carbon Intensity of All Fuels Consumed in the Light-Duty Vehicle Subsector in the Deep GHG Reduction Scenario

3. Deep GHG Reduction Scenario Variants

Up to this point in the report, two core scenarios have been thoroughly discussed – the Reference Case and Deep GHG Reduction Scenario. Each represents a potential path for the development of California's energy system over the coming decades. A considerable amount of time and effort has gone into creating these scenarios, but at the end of the day they are just two out of an infinite number of possible eventualities. And while both paths are thought to be feasible from a technological perspective, in the sense that both were developed based on reasonable assumptions from the literature, neither should be taken as a definitive prediction of how events will unfold in the coming years. Herein lies one of the most delicate elements of “what-if”-type scenario analyses: because no single scenario offers an absolutely certain picture of the future, it is up to the modeler to develop alternate scenarios and to undertake sensitivity analyses around key assumptions. The challenge, of course, centers around where to focus one’s attention, given that scenarios of the type developed using energy systems models, such as CA-TIMES, are built on thousands, or even tens of thousands, of assumptions.

In this section, several variants of the Deep GHG Reduction Scenario are developed. In the first exercise, I maintain all previous assumptions, while changing the most important policy driver: the stringency of the cap on GHG emissions. Then, in a second exercise the Deep GHG Reduction Scenario is modified much more extensively: specifically, assumptions concerning the potential of certain key low-carbon technologies and resources are significantly altered (generally resulting in less technological optimism). The scenario variants are compared across a range of energy, environmental, and cost metrics.

Scenario Variants #1: Modification of the GHG Emissions Cap

The most important driver of energy system development in the core Deep GHG Reduction Scenario is the declining cap on GHG emissions, which ultimately reaches 80% below 1990 emissions levels by 2050. A climate target of such stringency leads to dramatic shifts in the types of technologies and fuels utilized in California in the future, as shown in previous sections. Due to its importance, an obvious question thus becomes, “How might the situation change if the emissions cap were less stringent?” Perhaps policymakers decide next year, or in ten years from now, to scale back their aspirations for achieving the 80% reduction target, opting instead for something less stringent. Or perhaps the science surrounding climate change evolves in such a way that suggests an 80% cut in California (as well as U.S. and other industrialized country) emissions is not actually necessary. (Of course, the alternate outcome is equally as likely, that even deeper cuts in emissions are needed.) In an effort to address this question, I develop three additional scenarios, in which the cap on GHG emissions is set at 50%, 60%, and 70% below 1990 levels by 2050. For each scenario, the trajectory of the cap is assumed to decline linearly from the same 2020 starting point as in the original Deep GHG Reduction Scenario (i.e., the 1990 level).

Other than the modified emission targets, all other assumptions in these scenario variants are the same as in the core Deep GHG Reduction Scenario. This includes the exogenous fossil fuel price projections and the exogenously specified fuel demands in the ICRA sectors, both of which, it should be reminded, were developed with an 80% reduction scenario in mind. With respect to the ICRA sectors in particular, by keeping their fuel mixes the same, the introduction of climate caps with reduced stringencies effectively means that the transport, electricity, and supply sectors do not have to reduce their emissions quite as much. This potentially injects some error into these scenarios, since it is unlikely that exactly the same technologies and fuels would be used in the ICRA sectors in an 80% reduction scenario as would be in a 50% scenario. However, in any event I have decided not to explicitly address the issue for now, given that my analysis focuses on the transport, electricity, and supply sectors and the advanced technologies and alternative fuels utilized therein.

In addition to the three scenario variants with alternative caps on GHG emissions, I also develop a scenario that is a variant of the Reference Case. The only differences between the original Reference Case and its variant are the demands exogenously assumed in the end-use sectors. More specifically, the lower demands of the Deep GHG Reduction Scenario are used; hence, this scenario variant is named “Reference Case (w/ Lower Demands)”. Otherwise, all technological assumptions are the same as in the original Reference Case – fossil fuel price projections, the exogenously specified fuel demands of the ICRA end-use sectors, and so on. The reason for developing this scenario variant is that, as evidenced in the discussions that follow, demand reduction apparently has a fairly substantial impact on energy use, greenhouse gas emissions, and costs. Therefore, in analyzing the Deep GHG Reduction Scenario variants across the range of energy, environmental, and cost metrics, it seems only fair to compare them to the Reference Case (w/ Lower Demands), since the policies leading to the assumed demand reductions in these scenarios (e.g., strong transit, land use, and auto pricing policies in the transport sector, and energy efficiency standards in the industrial, commercial, residential, and agricultural sectors) are not adequately captured by the CA-TIMES model.

Figure 75 compares the GHG emissions trajectories of the Reference Case, Reference Case (w/ Lower Demands), Deep GHG Reduction Scenario, and the three Deep GHG variants. As a result of demand reduction, GHG emissions in 2050 are 125 Mton lower in the Reference Case (w/ Lower Demands) than in the original Reference Case. All other emissions cuts can be classified as technological reductions, in the sense that they result from switching to lower-carbon fuels and the introduction of advanced, more efficient technologies. Increasing the stringency of the emissions cap plays an important role in driving technological change, as is clearly evident in Figure 75, and by 2050 the emissions spread between the Deep GHG Reduction Scenario and its variants is quite large. In fact, annual GHG emissions in 2050 in the five scenario variants are lower than in the original Reference Case by 21%, 63%, 70%, 78%, and 85%, respectively. Particularly in the Deep GHG scenario variants, the reductions stem from energy system development paths that actually quite different from each other. Nevertheless, it is interesting to note that up until about 2020–2025, these landscapes are still quite similar, and the GHG emissions trajectories of each do not diverge until about this time. Such a result essentially says that whether California ultimately decides to follow a 50% or 80% GHG reduction path, or any path in between, technological investment decisions and fuel choices made over the coming decade (2010-2020) will, for the most part, need to be the same.

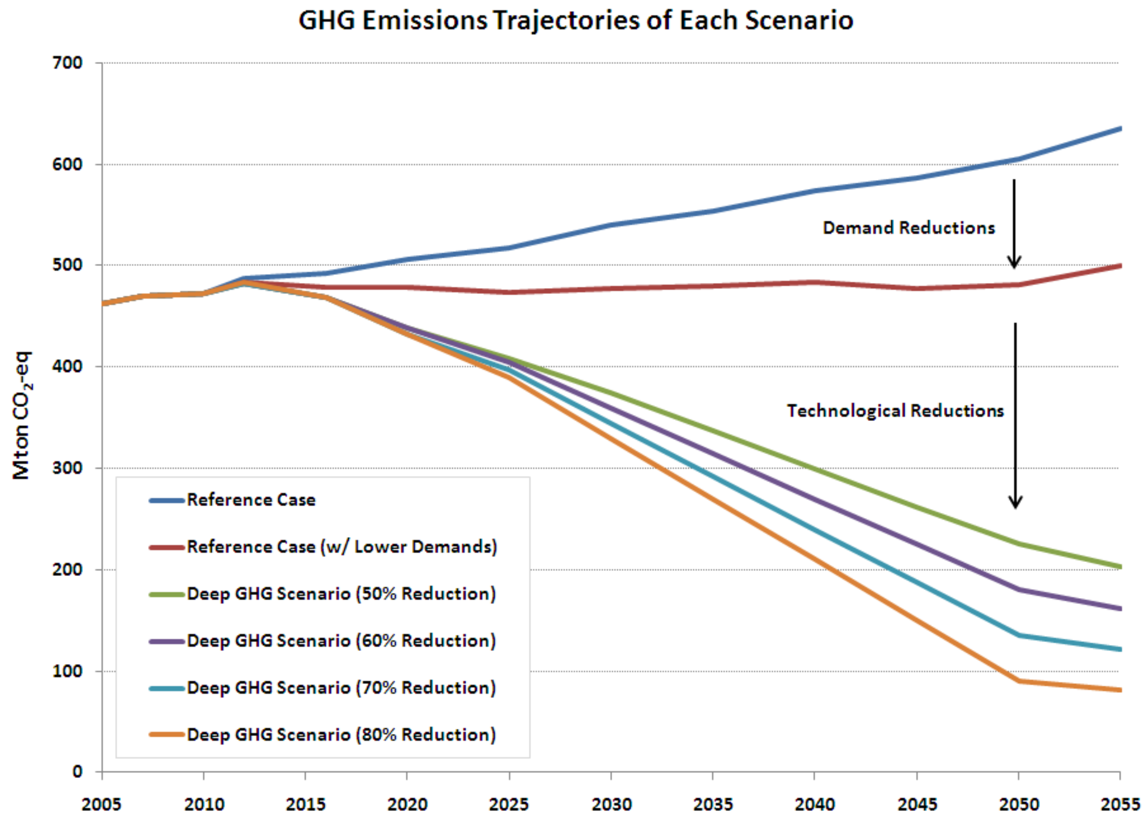

Figure 75 GHG Trajectories of the Scenario Variants with Modified Emissions Caps

The following series of tables shows a number of indicators comparing the Reference Case, Deep GHG Reduction Scenario, and their variants across several different dimensions. Particular attention is paid to the transportation sector, electricity generation, biofuels and biomass supply, and emissions. A fairly small number of indicators are shown (out of the hundreds or thousands possible), but the point here is to give the reader a quick sense of what these scenarios look like and how the stringency of the emissions cap impacts the development of the energy system in a different way. For instance, targeting deeper reductions in GHG emissions necessitates greater electrification of the light-duty vehicle fleet, namely PHEVs and Hydrogen FCVs (

Table 35). In the Deep GHG 50% scenario, the total share of light-duty VMT supplied by PHEVs, BEVs, and FCVs is just 11% in 2050, whereas it rises to 28% in the Deep GHG 80% scenario. Electrification of vehicles has the effect of raising the average fuel economy of the entire 2050 LDV fleet (both on-road and new cars and trucks) from 55 mpgge to 60 mpgge in these two scenarios, respectively. Simultaneously, because of the much greater use of low-carbon biofuels, electricity, and hydrogen, the average lifecycle carbon intensity of all fuels consumed in the California transportation sector in 2050 declines from 53.2 gCO_2-eq/MJ_{HHV} in the Deep GHG 50% scenario to 31.1 gCO_2-eq/MJ_{HHV} in the Deep GHG 80% scenario. Furthermore, while the light-duty vehicle fleet becomes increasingly electrified, in no scenarios do we see a penetration of battery-electric vehicles, which as described previously has everything to do with the relatively high lifecycle costs of supplying VMT using mid-sized BEVs with relatively large batteries, considering both the capital costs of vehicles and their requisite recharging infrastructure.

Table 35 Comparison of Key Transportation Indicators for Scenario Variants with Modified Emissions Caps

Transportation Indicators		2010	2020	2030	2040	2050
Share of LDV VMT Supplied by PHEVs	Reference Case	0.0%	0.0%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (50% Reduction)	0.0%	1.4%	12.5%	12.4%	10.9%
	Deep GHG Scenario (60% Reduction)	0.0%	1.4%	12.5%	12.4%	10.9%
	Deep GHG Scenario (70% Reduction)	0.0%	1.4%	12.5%	12.4%	10.8%
	Deep GHG Scenario (80% Reduction)	0.0%	1.4%	12.9%	11.1%	22.3%
Share of LDV VMT Supplied by BEVs	Reference Case	0.0%	0.0%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (50% Reduction)	0.0%	0.0%	0.1%	0.0%	0.0%
	Deep GHG Scenario (60% Reduction)	0.0%	0.0%	0.1%	0.0%	0.0%
	Deep GHG Scenario (70% Reduction)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (80% Reduction)	0.0%	0.0%	0.0%	0.0%	0.0%
Share of LDV VMT Supplied by FCVs	Reference Case	0.0%	0.0%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (50% Reduction)	0.0%	0.1%	0.6%	0.0%	0.0%
	Deep GHG Scenario (60% Reduction)	0.0%	0.1%	0.6%	0.0%	0.0%
	Deep GHG Scenario (70% Reduction)	0.0%	0.2%	0.7%	0.0%	0.1%
	Deep GHG Scenario (80% Reduction)	0.0%	0.2%	0.7%	2.4%	5.6%
Average LDV Fleet Fuel Economy (mpgge, test-cycle)	Reference Case	25.8	30.7	34.2	35.1	35.9
	Reference Case (w/ Lower Demands)	25.8	30.8	35.0	36.1	37.0
	Deep GHG Scenario (50% Reduction)	25.8	32.3	48.3	53.8	54.6
	Deep GHG Scenario (60% Reduction)	25.8	32.3	48.3	53.8	54.6
	Deep GHG Scenario (70% Reduction)	25.8	32.3	48.3	53.8	54.6
	Deep GHG Scenario (80% Reduction)	25.8	32.3	48.3	53.8	59.6
Average New Model-Year LDV Fuel Economy (mpgge, test-cycle)	Reference Case	25.8	34.1	34.2	35.6	36.3
	Reference Case (w/ Lower Demands)	25.8	34.3	35.5	36.7	36.9
	Deep GHG Scenario (50% Reduction)	25.8	41.3	53.9	54.2	54.7
	Deep GHG Scenario (60% Reduction)	25.8	41.3	53.9	54.2	54.7
	Deep GHG Scenario (70% Reduction)	25.8	41.3	53.9	54.2	54.7
	Deep GHG Scenario (80% Reduction)	25.8	41.3	53.9	54.2	65.6
Average Carbon Intensity of All Transportation Fuels ($gCO2\text{-}eq/MJ_{HHV}$)	Reference Case	83.0	80.8	78.8	75.6	75.1
	Reference Case (w/ Lower Demands)	83.0	80.0	77.7	74.2	73.3
	Deep GHG Scenario (50% Reduction)	83.0	79.4	71.5	60.3	53.2
	Deep GHG Scenario (60% Reduction)	83.0	79.4	69.6	54.3	45.6
	Deep GHG Scenario (70% Reduction)	83.0	79.4	67.8	49.8	38.1
	Deep GHG Scenario (80% Reduction)	83.0	79.4	65.9	46.7	31.1

Climate policies of greater stringency also have the effect decarbonizing the electric generation mix to increasingly lower levels (Table 36). The contribution from nuclear power is roughly the same in each of the Deep GHG scenarios; however, generation from renewable sources and from fossil and biomass plants equipped with CCS grows higher. These differences lead to average carbon intensities for electricity in 2050 that range from 35 gCO_2-eq/kWh in the Deep GHG 50% scenario to -11 gCO_2-eq/kWh in the Deep GHG 80% scenario (9.7 and -3.1 gCO_2-eq/MJ_{HHV}, respectively).

Table 36 Comparison of Key Electricity Generation Indicators for Scenario Variants with Modified Emissions Caps

Electricity Generation Indicators		2010	2020	2030	2040	2050
Share of Renewable & Hydro Electricity in Total Generation	Reference Case	20.2%	18.6%	16.4%	17.4%	35.7%
	Reference Case (w/ Lower Demands)	20.3%	19.4%	17.9%	20.2%	42.5%
	Deep GHG Scenario (50% Reduction)	20.3%	42.4%	40.9%	40.1%	47.3%
	Deep GHG Scenario (60% Reduction)	20.3%	42.4%	40.9%	40.1%	50.2%
	Deep GHG Scenario (70% Reduction)	20.3%	42.4%	41.0%	41.7%	51.1%
	Deep GHG Scenario (80% Reduction)	20.2%	42.4%	41.1%	48.3%	58.7%
Share of Nuclear Electricity in Total Generation	Reference Case	12.4%	11.2%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	12.4%	11.7%	0.0%	0.0%	0.0%
	Deep GHG Scenario (50% Reduction)	12.4%	9.6%	9.7%	18.1%	25.2%
	Deep GHG Scenario (60% Reduction)	12.4%	9.6%	9.7%	18.1%	25.2%
	Deep GHG Scenario (70% Reduction)	12.4%	13.6%	13.0%	21.1%	27.8%
	Deep GHG Scenario (80% Reduction)	12.4%	13.8%	13.2%	21.2%	24.6%
Share of Fossil & Biomass w/ CCS Electricity in Total Generation	Reference Case	0.0%	0.0%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (50% Reduction)	0.0%	0.0%	2.2%	8.2%	14.1%
	Deep GHG Scenario (60% Reduction)	0.0%	0.0%	2.7%	8.9%	15.0%
	Deep GHG Scenario (70% Reduction)	0.0%	0.0%	3.0%	9.2%	14.9%
	Deep GHG Scenario (80% Reduction)	0.0%	0.0%	6.3%	12.1%	15.7%
Average Carbon Intensity of Electricity (gCO2-eq/kWh)	Reference Case	317	337	308	277	210
	Reference Case (w/ Lower Demands)	317	334	306	272	186
	Deep GHG Scenario (50% Reduction)	317	239	169	110	35
	Deep GHG Scenario (60% Reduction)	317	239	165	104	19
	Deep GHG Scenario (70% Reduction)	317	223	159	85	5
	Deep GHG Scenario (80% Reduction)	317	222	146	53	-11

Biomass supply and biofuels consumption are strong in each of the Deep GHG scenario variants (Table 37). In fact, because of the attractive of achieving emissions reductions through utilization of negative emissions bio-CCS technologies, the scenarios with 50%, 60%, and 70% reduction targets have biomass/biofuels demands that are about the same in 2050 as in the Deep GHG 80% scenario – biomass consumption of 1,669 to 1,737 PJ, or 104 to 108 million bone dry tons; biofuels consumption of 972 to 1,019 PJ, or 7.41 to 7.77 billion gge. Actually, these levels are approximately the same as in the Reference

Case, though the types of biofuels being produced are markedly different (more cellulosic ethanol and less bio-based gasoline, diesel, and jet fuel in the Reference Case).

Table 37 Comparison of Key Biofuels and Biomass Indicators for Scenario Variants with Modified Emissions Caps

Biofuels & Biomass Indicators		2010	2020	2030	2040	2050
Biofuels Consumption (PJ)	Reference Case	164	419	632	946	1044
	Reference Case (w/ Lower Demands)	164	447	647	937	1039
	Deep GHG Scenario (50% Reduction)	164	441	513	795	972
	Deep GHG Scenario (60% Reduction)	164	441	614	877	1019
	Deep GHG Scenario (70% Reduction)	164	439	690	937	976
	Deep GHG Scenario (80% Reduction)	164	439	728	951	975
Biomass Supply (PJ)	Reference Case	148	448	785	1210	1598
	Reference Case (w/ Lower Demands)	148	471	751	1159	1555
	Deep GHG Scenario (50% Reduction)	148	744	914	1407	1669
	Deep GHG Scenario (60% Reduction)	148	744	974	1534	1732
	Deep GHG Scenario (70% Reduction)	148	742	1026	1580	1732
	Deep GHG Scenario (80% Reduction)	148	729	1067	1581	1737

Table 38 highlights some key GHG emissions indicators of the scenarios, for example, total energy sector GHG emissions in California relative to projected sizes of the state's population and economy. Also shown are total cumulative GHG emissions over the entire model time horizon and the annual quantity of emissions that are captured and stored underground via CCS. In all instances, the trends appear sensible: GHG emissions per capita and per GSP decline to increasingly lower levels as the climate policy becomes more stringent, and utilization of CCS grows as the GHG reduction targets become stricter.

Table 38 Comparison of Key GHG Emissions Indicators for Scenario Variants with Modified Emissions Caps

GHG Emissions Indicators		2010	2020	2030	2040	2050
GHG Emissions Relative to Gross State Product (tCO_2e per M$ GSP)	Reference Case	256	211	174	143	117
	Reference Case (w/ Lower Demands)	256	200	154	121	93
	Deep GHG Scenario (50% Reduction)	256	183	121	75	43
	Deep GHG Scenario (60% Reduction)	256	183	116	67	35
	Deep GHG Scenario (70% Reduction)	256	181	111	60	26
	Deep GHG Scenario (80% Reduction)	256	181	106	52	17
GHG Emissions per Capita (tCO_2e per person)	Reference Case	12.1	11.5	11.0	10.6	10.2
	Reference Case (w/ Lower Demands)	12.1	10.9	9.7	8.9	8.1
	Deep GHG Scenario (50% Reduction)	12.1	9.9	7.6	5.5	3.8
	Deep GHG Scenario (60% Reduction)	12.1	9.9	7.3	5.0	3.0
	Deep GHG Scenario (70% Reduction)	12.1	9.8	7.0	4.4	2.3
	Deep GHG Scenario (80% Reduction)	12.1	9.8	6.7	3.9	1.5
GHG Emissions Captured and Stored via CCS (Mton CO_2e)	Reference Case	0	0	0	0	0
	Reference Case (w/ Lower Demands)	0	0	0	0	0
	Deep GHG Scenario (50% Reduction)	0	0	7	59	115
	Deep GHG Scenario (60% Reduction)	0	0	11	71	135
	Deep GHG Scenario (70% Reduction)	0	0	18	79	152
	Deep GHG Scenario (80% Reduction)	0	0	26	91	166
Cumulative GHG Emissions, 2005-2055 (Mton CO_2e)	Reference Case			27,552		
	Reference Case (w/ Lower Demands)			24,433		
	Deep GHG Scenario (50% Reduction)			18,498		
	Deep GHG Scenario (60% Reduction)			17,609		
	Deep GHG Scenario (70% Reduction)			16,670		
	Deep GHG Scenario (80% Reduction)			15,762		

Costs are another important metric by which to compare the Deep GHG Reduction Scenario and its variants with the Reference Case. Figure 76 shows cumulative total discounted energy system costs for each of these scenarios. Energy system costs include all investment, fixed and variable O&M, and resource/fuel costs accounted for in the CA-TIMES model. (Note that investments and O&M costs in the industrial, commercial, residential, and agricultural end-use sectors are not captured, but at least fuel costs are accounted for.) The first observation one makes is that costs in the Reference Case (w/ Lower Demands) are lower than in the original Reference Case by a fair amount. This result illustrates the importance of controlling the future growth of end-use demands, which can lead to significantly reduced capital investment requirements and substantial O&M and fuel savings. (Of course, the steps taken to reduce demand are themselves likely to incur costs that are non-trivial, and so long as they are made outside of the energy system, they are not captured by the CA-TIMES model.) Second, total costs appear to increase with the stringency of the emission reduction target. Compared to the Reference Case (w/ Lower Demands), for example, costs are between 7.3% and 9.7% higher in the Deep GHG scenarios. Interestingly, the jump from a 70% to 80% target necessitates a greater incremental cost increase than for the other scenario variants (i.e., from 50% to 60%, and 60% to 70%). Moreover, while investment costs continue to rise under increasingly stringent climate policy, variable costs (namely fuel costs) remain roughly constant, and compared to the Reference Case (w/ Lower Demands), variable costs are actually smaller. For instance, while cumulative investment costs are estimated to be $1.34 trillion greater in the Deep GHG 80% scenario than in the Reference Case (w/ Lower Demands), variable and O&M costs are actually $0.41 trillion lower. These are important results because they show that the although the per-unit cost of fuels may be higher in the Deep GHG scenarios, total aggregate fuel costs across the entire energy system are lower, as a result of greatly increased technological efficiencies in all sectors.

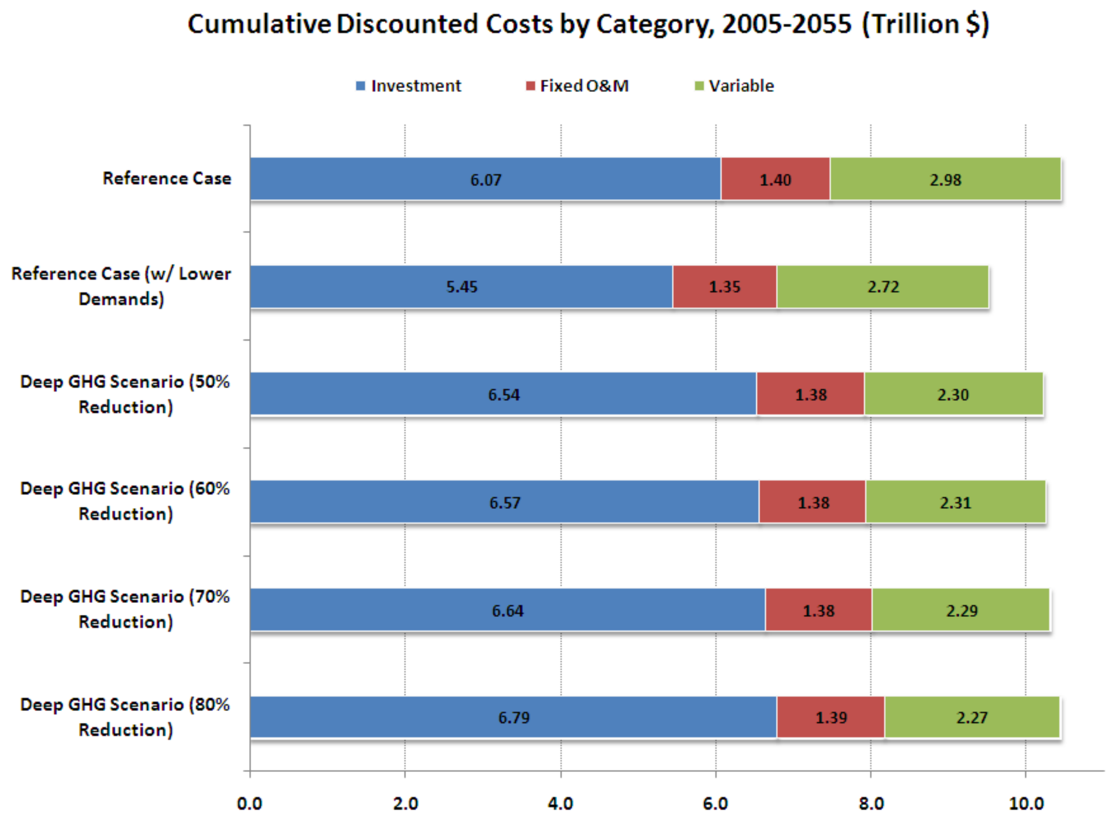

Figure 76 Comparison of Cumulative Total Discounted Energy System Costs for Scenario Variants with Modified Emissions Caps

While the costs of the scenarios may seem high at first glance (in the trillions of dollars), they actually only make up a fraction of California's projected cumulative discounted GSP over the same time period.

Table 39 shows that the climate policies of the Deep GHG scenarios (50% to 80% reductions) add about 1.1 to 1.5 percentage points to total energy system costs (as a share of cumulative discounted GSP). In fact, in none of the Deep GHG scenarios are the costs incurred any greater than in the original Reference Case, again highlighting the important effect of demand reduction.

Table 39 Comparison of Key Cost Indicators for Scenario Variants with Modified Emissions Caps

Cost Indicators			Notes
Cumulative Discounted System Costs, 2005-2055	Reference Case	9.8%	Costs are relative to Reference Case (w/ Lower Demands)
	Reference Case (w/ Lower Demands)	--	
	Deep GHG Scenario (50% Reduction)	7.3%	
	Deep GHG Scenario (60% Reduction)	7.7%	
	Deep GHG Scenario (70% Reduction)	8.3%	
	Deep GHG Scenario (80% Reduction)	9.7%	
Cumulative Discounted System Costs as a Share of Cumulative Discounted GSP, 2005-2055	Reference Case	1.5%	Costs are relative to Reference Case (w/ Lower Demands)
	Reference Case (w/ Lower Demands)	--	
	Deep GHG Scenario (50% Reduction)	1.1%	
	Deep GHG Scenario (60% Reduction)	1.2%	
	Deep GHG Scenario (70% Reduction)	1.3%	
	Deep GHG Scenario (80% Reduction)	1.5%	
Average Cost of GHG Abatement ($ per tCO_2e)	Reference Case	--	Costs and GHGs are relative to Reference Case (w/ Lower Demands)
	Reference Case (w/ Lower Demands)	--	
	Deep GHG Scenario (50% Reduction)	118	
	Deep GHG Scenario (60% Reduction)	107	
	Deep GHG Scenario (70% Reduction)	102	
	Deep GHG Scenario (80% Reduction)	107	

It should be noted that in estimating costs relative to GSP, the results presented here do not account for investment and O&M costs in the industrial, commercial, residential, commercial, and agricultural end-use sectors. And while not the focus of the current study, this undoubtedly leaves a gaping hole in the analysis. That being said, it is not entirely clear that the results shown here on a relative change basis would differ markedly if these other sectors were added to the model in bottom-up technological detail. After all, absolute costs would rise in all scenarios, including the Reference Case, and thus relative changes could theoretically remain the same. The exact change would, of course, depend on the relative costs of deploying advanced technologies to reduce GHG emissions in the ICRA sectors. If the marginal costs of doing so were less than for the sectors explicitly modeled in the current version of CA-TIMES (transport, electricity, supply), one might even expect the relative increases for total energy system costs to be lower than those discussed here.

Another potentially useful metric for comparing the relative costs of the Deep GHG scenario variants is the average cost of GHG abatement over the entire model time horizon. For a given scenario, this is calculated as the difference in cumulative total discounted energy system costs relative to the Reference Case (w/ Lower Demands) divided by the cumulative emissions of the same scenario relative to the Reference Case (w/ Lower Demands).

Table 39 summarizes these values for each of the Deep GHG scenarios. Average costs are in the range of $102 to $118 per tonne of CO_2-equivalent, which means that marginal costs of emissions abatement range from well below this average (i.e., near zero) all the way up to several hundred dollars per tonne. Of particular note is the fact that the average cost of abatement is actually lower for the more stringent climate scenarios. Generally, one would expect average abatement costs to exhibit an upward trend with increasingly stringent climate policy, as shown previously for total system costs. Presumably, this has to do with the specific timing of energy investments and the fact that on a net present value basis utilization of a non-zero discount rate makes costs incurred in later time periods less significant in the calculation of total energy system costs.

The transportation sector is responsible for an overwhelming share of the total capital investment costs shown in Figure 76, with electric sector investments coming a distant second (see Figure 77). In particular, capital costs of light-duty vehicles account for about 50-55% of all transport sector investments (which interestingly is roughly the same level as the subsector's share of energy use and GHG emissions in the overall transport total). One of the reasons why transport sector investments – especially for LDVs – are so disproportionately high is that cars, trucks, buses, ships, airplanes, and trains are relatively expensive energy production devices, when viewed on a $/MJ basis, compared to power plants, refineries, and other fuel conversion facilities.[41] In addition to the

[41] Firstly, the efficiency of converting a MJ of fuel to a MJ of useful work is substantially lower for transportation vehicles, due to the range of parasitic, dissipative, aerodynamic and hydrodynamic drag, and other losses that come into play. Secondly, the capacity factors of transportation vehicles, particularly private motor vehicles, are extremely low compared to energy supply facilities, some of which operate almost continuously. For example, a typical light-duty car or truck is used for perhaps a handful of trips a day, and for just an hour in total time. The remainder of the day, the vehicle, and all the capital investment that went into producing it, sits idle. Heavy- and medium-duty trucks, ships, airplanes, and trains are much

transport and electric sectors, imposition of increasingly stringent climate policies leads to larger investments in the hydrogen and syn-fuels industries (Figure 77). At the same time, investments in the fossil fuels and biofuels industries decline. (Note that by this definition, production of bio-based gasoline, diesel, and jet fuel at FT poly-generation plants is accounted for in the syn-fuels industry.) The diminishing importance of the fossil fuels industry is an intuitive result, but that of the biofuels industry requires a bit of explanation. As the model attempts to meet the lower emissions targets of the Deep GHG scenarios, it relies less heavily on certain biofuels production technologies – namely cellulosic ethanol (via biochemical and thermochemical pathways) and biodiesel (via hydrotreatment) – and instead it shifts limited biomass resources to FT poly-generation plants equipped with CCS.

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better in this respect, since they are treated more like business investments; however, they are still relatively expensive means by which to produce useful work.

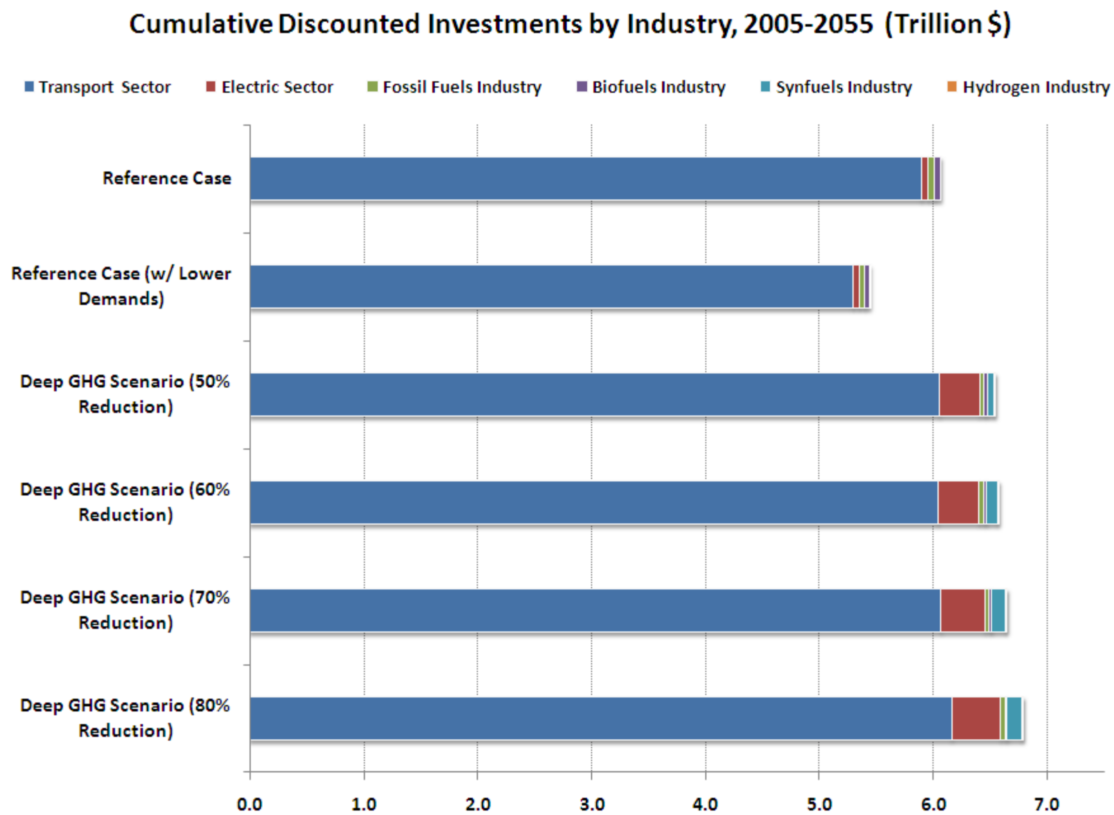

Figure 77 Comparison of Cumulative Discounted Energy Investments for Scenario Variants with Modified Emissions Caps

On a final note, even though the fossil industry is seen to shrink in the low-carbon futures described here, it may very well be the case that the same players continue to be involved, as today's large fuel producers and energy companies are likely to be the only ones capable of making the necessary, but huge, capital investments in syn-fuels and hydrogen production/distribution capacity over the coming decades. In other words, the industry may look different, but the names may be the same.

<u>Scenario Variants #2: Modification of Key Resource and Technology Potentials</u>

To be sure, the stringency of future climate policy is by no means the only uncertainty going forward. The potential of certain key resources and technologies to mitigate greenhouse gas emissions on a large scale is also not yet fully understood at the present time. For instance, many questions still remain regarding the availability of sustainable biomass in large quantities; the risks associated with and social acceptance of nuclear power and carbon capture and storage; the ability of batteries to meet the stringent demands of transport vehicles; and the well-known "chicken and egg" dilemma for initiating hydrogen infrastructure. In an effort to partially address these questions, I develop several additional variants of the original Deep GHG Reduction Scenario in this section. As with the first set of scenario variants dealing with the stringency of the emissions cap, all assumptions are the same in these scenarios as they are in the core Deep GHG Reduction Scenario. Importantly, fuel demands in the ICRA sectors remain the same as before.

- ***Deep GHG Reduction Scenario (Low Biomass)***

  Assumes the potential supply of sustainable biomass in California and the Western U.S. is 50% lower than in the original Deep GHG Reduction Scenario. The supply curves for each type of biomass feedstock retain their same shapes (i.e., same price levels), but the quantities available at each step and for each type of biomass are reduced.

- ***Deep GHG Reduction Scenario (High Biomass)***

  Assumes the potential supply of sustainable biomass in California and the Western U.S. is 50% greater than in the original Deep GHG Reduction Scenario. The supply curves for each type of biomass feedstock retain their same shapes (i.e., same price levels), but the quantities available at each step and for each type of biomass are increased.

- ***<u>Deep GHG Reduction Scenario (No Nuclear or CCS)</u>***

  Assumes that due to basic NIMBY ("Not In My Backyard") issues and societal concerns over, for example, nuclear waste and security and CO_2 leakage and groundwater contamination, neither new nuclear power nor CCS ever become viable technological options within the California energy system. No new nuclear plants are allowed to be built, and no carbon capture and storage ever takes place. The GHG mitigation potential of these technologies is, therefore, zero in all future years.

- ***<u>Deep GHG Reduction Scenario (Limited EV-FCV Success)</u>***

  Assumes that on the one hand battery technology never matures to the point where consumer demands for vehicle size, power, and range are met at reasonable cost (or alternately, that consumers never become willing to sacrifice these attributes by adopting smaller, less powerful vehicles), and that at the same time the chicken and egg problem for centralized hydrogen production and distribution proves to be impossible to overcome at large scale. Thus, BEVs and PHEVs are substantially more limited in the share of LDV, MDT, and Bus VMT they are able to supply. (For example, in the light-duty subsector, the original Deep GHG Reduction Scenario assumed that no more than 50% of VMT could be supplied jointly by BEVs and PHEVs due to real limits on the number of people who would be able to recharge at home or work (O'Connor, 2007b). However, in this scenario variant the share is reduced to just 25%.) In the case of FCVs, only distributed production of hydrogen is possible at refueling stations and fleet vehicle depots, and the availability of this infrastructure is fairly limited in scope (maximum 200 PJ, or 1.41 million metric tonnes, of hydrogen production in any year).

Figure 78 compares the GHG emissions trajectories of the Reference Case, Reference Case (w/ Lower Demands), and these new variants of the Deep GHG Reduction Scenario. The first thing one notices is that not all scenarios are able to meet the 80% reduction target. In fact, only the High Biomass and Limited EV-FCV Success scenarios are able to make such deep reductions, whereas imposing such a stringent target in the other scenarios leads to model infeasibilities. This is not to say that it is absolutely impossible to make an 80% cut in GHGs without a large supply of biomass and without widespread success of nuclear or CCS. Rather, the scenarios show that, based on the current assumptions input to the model, it becomes extremely difficult to meet such a target if the potential of any of these key resources and technologies is significantly limited. In other words, meeting California's long-term goal of an 80% reduction in GHG emissions essentially requires that every major technological and fuel option remains on the table (i.e., a multi-strategy, portfolio approach is needed). If some of these options are unavailable, then demand reduction through even more aggressive energy and conservation efforts would have to play a much greater role in helping to bring emissions down to lower levels. Nevertheless, while deep cuts in GHGs depend strongly on the availability of technologies, it is quite interesting to note that large reductions still appear to be possible by 2050 in these other scenario variants: Low Biomass (70% reduction) and No Nuclear or CCS (65%).

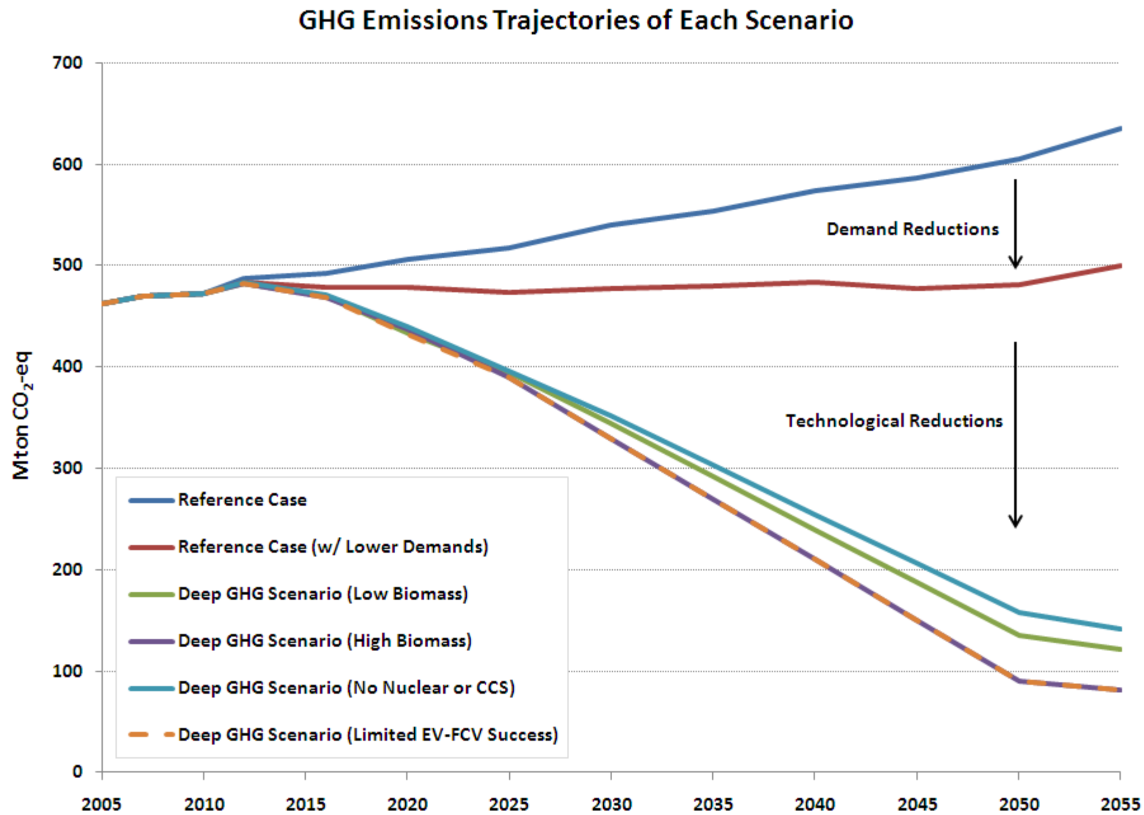

Figure 78 GHG Trajectories of the Scenario Variants with Modified Resource and Technology Potentials

Because these scenario variants do not meet the 80% reduction target in all cases, it is a little difficult to compare them with the original Deep GHG Reduction Scenario. Perhaps a more useful exercise is to compare them with the first set of scenario variants, which, as discussed in the previous section, look at emissions caps of varying stringencies. For example, the Low Biomass scenario reduces GHGs 70% below 1990 levels by 2050, but the way these reductions are made is a bit different than in the Deep GHG 70% scenario variant from above. Notably, because supplies of biomass, and thus biofuels, are so limited in the Low Biomass scenario, the model relies more heavily on electricity and hydrogen in the transport sector, especially for light-duty vehicles (Table 40). Whereas the share of LDV VMT supplied by PHEVs, BEVs, and FCVs was about 11% in the

Deep GHG 70% scenario, it is a much greater 70% in the Deep GHG Low Biomass scenario. For this reason, average fleet fuel economy is higher in 2050 in the latter case: 75.1 vs. 54.6 mpgge. In contrast, when assuming much more optimistic levels of biomass availability, as in the High Biomass scenario, there is less of a need for hydrogen, and the penetration of FCVs in the LDV subsector is a bit lower: 11% in the Deep GHG High Biomass scenario compared to 28% in the original Deep GHG Reduction Scenario (both of these scenarios meet the 80% reduction target in 2050).

Table 40 Comparison of Key Transportation Indicators for Scenario Variants with Modified Resource and Technology Potentials

Transportation Indicators		2010	2020	2030	2040	2050
Share of LDV VMT Supplied by PHEVs	Reference Case	0.0%	0.0%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (Low Biomass)	0.0%	1.4%	11.8%	19.0%	42.1%
	Deep GHG Scenario (High Biomass)	0.0%	1.4%	12.5%	12.4%	10.9%
	Deep GHG Scenario (No Nuclear or CCS)	0.0%	1.4%	16.1%	22.1%	50.0%
	Deep GHG Scenario (Limited EV-FCV Success)	0.0%	1.4%	12.8%	11.7%	24.3%
Share of LDV VMT Supplied by BEVs	Reference Case	0.0%	0.0%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (Low Biomass)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (High Biomass)	0.0%	0.0%	0.1%	0.0%	0.0%
	Deep GHG Scenario (No Nuclear or CCS)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (Limited EV-FCV Success)	0.0%	0.0%	0.0%	0.0%	0.0%
Share of LDV VMT Supplied by FCVs	Reference Case	0.0%	0.0%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (Low Biomass)	0.0%	0.2%	2.5%	8.7%	18.7%
	Deep GHG Scenario (High Biomass)	0.0%	0.1%	0.6%	0.0%	0.0%
	Deep GHG Scenario (No Nuclear or CCS)	0.0%	0.3%	3.2%	11.3%	26.4%
	Deep GHG Scenario (Limited EV-FCV Success)	0.0%	0.2%	0.7%	1.8%	4.2%
Average LDV Fleet Fuel Economy (mpgge, test-cycle)	Reference Case	25.8	30.7	34.2	35.1	35.9
	Reference Case (w/ Lower Demands)	25.8	30.8	35.0	36.1	37.0
	Deep GHG Scenario (Low Biomass)	25.8	32.3	48.3	55.2	75.1
	Deep GHG Scenario (High Biomass)	25.8	32.3	48.3	53.8	54.6
	Deep GHG Scenario (No Nuclear or CCS)	25.8	32.3	48.3	57.9	83.7
	Deep GHG Scenario (Limited EV-FCV Success)	25.8	32.3	48.3	53.8	60.7
Average New Model-Year LDV Fuel Economy (mpgge, test-cycle)	Reference Case	25.8	34.1	34.2	35.6	36.3
	Reference Case (w/ Lower Demands)	25.8	34.3	35.5	36.7	36.9
	Deep GHG Scenario (Low Biomass)	25.8	41.3	53.9	58.2	107.3
	Deep GHG Scenario (High Biomass)	25.8	41.3	53.9	54.2	54.7
	Deep GHG Scenario (No Nuclear or CCS)	25.8	41.3	53.9	67.0	104.3
	Deep GHG Scenario (Limited EV-FCV Success)	25.8	41.3	53.9	54.2	68.3
Average Carbon Intensity of All Transportation Fuels ($gCO2\text{-}eq/MJ_{HHV}$)	Reference Case	83.0	80.8	78.8	75.6	75.1
	Reference Case (w/ Lower Demands)	83.0	80.0	77.7	74.2	73.3
	Deep GHG Scenario (Low Biomass)	83.0	80.0	72.4	58.0	43.8
	Deep GHG Scenario (High Biomass)	83.0	79.4	63.1	42.9	28.0
	Deep GHG Scenario (No Nuclear or CCS)	83.0	79.6	68.7	57.8	43.4
	Deep GHG Scenario (Limited EV-FCV Success)	83.0	79.4	65.8	47.5	31.5

The results of this study illustrate that bio-CCS negative emissions technologies can be a cost-effective means by which to significantly reduce California energy system emissions. When these technologies are available, the model fully maximizes their utilization (subject to constraints on biomass supply) and at the same time chooses not to decarbonize the transport sector to a significant degree. However, when CCS is eliminated from the potential technology mix, the situation changes drastically. For instance, Table 40 shows that in the Deep GHG No Nuclear or CCS scenario, the contribution of PHEVs, BEVs, and FCVs to total LDV VMT rises to 76%, thus raising the fleet-average fuel economy of all on-road light-duty cars and trucks to 83.7 mpgge by 2050. In sum, when bio-CCS is on the table, the more advanced vehicle technologies (especially BEVs and FCVs) may not actually be needed to reach the deep GHG reduction targets; instead, HEVs and PHEVs fueled by a mixture of conventional and bio-based gasoline and E-85 ethanol may be able to suffice.

The impact of removing both nuclear power and CCS from the technology portfolio is also evident in the electric sector. For the most part, the electric generation mix is consistent between the scenario variants shown here and the previous set with modified emission caps. However, in the No Nuclear or CCS scenario the model is forced to supply electricity using a far greater share of renewable resources: 86% in the No Nuclear or CCS scenario (Table 41) compared to between 47% and 59% in the scenario variants with modified emission caps. Although not shown, the bulk of the renewable generation in the No Nuclear or CCS scenario is from solar and wind, though geothermal and hydro make important contributions as well. Due to the inherent mismatch between nighttime wind generation and daytime electricity loads (assuming no significant storage), the model estimates the upper limit on wind power, as a share of total generation, to be about 40%, a level that is somewhat higher than the 20-30% limits estimated by recent wind integration and transmission studies, albeit for the 2030 time horizon (NREL, 2010a, b). A reason for this discrepancy is the inability of CA-TIMES to analyze timing and intermittency issues on the level of seconds to minutes, but rather on the level of hours. In the real world, it could very well be the case that such high levels of renewable penetration are simply unrealistic from an operational standpoint, barring significant investments in storage capacity. Hence, by extension, it may be unrealistic to expect GHG reductions on the order of 50-80% if low-carbon options such as nuclear and CCS are altogether absent from the available technology portfolio. Future research with the CA-TIMES model will attempt to shed some more light on these issues.

Table 41 Comparison of Key Electricity Generation Indicators for Scenario Variants with Modified Resource and Technology Potentials

Electricity Generation Indicators		2010	2020	2030	2040	2050
Share of Renewable & Hydro Electricity in Total Generation	Reference Case	20.2%	18.6%	16.4%	17.4%	35.7%
	Reference Case (w/ Lower Demands)	20.3%	19.4%	17.9%	20.2%	42.5%
	Deep GHG Scenario (Low Biomass)	20.3%	42.4%	45.6%	55.8%	65.4%
	Deep GHG Scenario (High Biomass)	20.3%	42.4%	41.0%	43.7%	53.8%
	Deep GHG Scenario (No Nuclear or CCS)	20.3%	42.4%	60.4%	78.3%	86.2%
	Deep GHG Scenario (Limited EV-FCV Success)	20.3%	42.4%	41.2%	49.6%	60.9%
Share of Nuclear Electricity in Total Generation	Reference Case	12.4%	11.2%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	12.4%	11.7%	0.0%	0.0%	0.0%
	Deep GHG Scenario (Low Biomass)	12.4%	13.8%	13.2%	20.8%	20.7%
	Deep GHG Scenario (High Biomass)	12.4%	11.1%	10.9%	19.3%	26.3%
	Deep GHG Scenario (No Nuclear or CCS)	12.4%	9.6%	0.0%	0.0%	0.0%
	Deep GHG Scenario (Limited EV-FCV Success)	12.4%	13.8%	13.2%	21.3%	23.2%
Share of Fossil & Biomass w/ CCS Electricity in Total Generation	Reference Case	0.0%	0.0%	0.0%	0.0%	0.0%
	Reference Case (w/ Lower Demands)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (Low Biomass)	0.0%	0.0%	6.9%	12.1%	13.8%
	Deep GHG Scenario (High Biomass)	0.0%	0.0%	3.2%	9.4%	14.3%
	Deep GHG Scenario (No Nuclear or CCS)	0.0%	0.0%	0.0%	0.0%	0.0%
	Deep GHG Scenario (Limited EV-FCV Success)	0.0%	0.0%	6.4%	12.3%	15.4%
Average Carbon Intensity of Electricity (gCO2-eq/kWh)	Reference Case	317	337	308	277	210
	Reference Case (w/ Lower Demands)	317	334	306	272	186
	Deep GHG Scenario (Low Biomass)	317	223	124	34	-6
	Deep GHG Scenario (High Biomass)	317	233	163	81	0
	Deep GHG Scenario (No Nuclear or CCS)	317	238	146	60	27
	Deep GHG Scenario (Limited EV-FCV Success)	317	222	145	47	-13

The Deep GHG Low Biomass scenario sees the use of only 489 PJ (3.7 billion gge) of biofuels in 2050 (Table 42), half that of the original Deep GHG Reduction Scenario. Most of this biofuel is in the form of bio-based residual fuel oil, diesel, jet fuel, and gasoline, with only a fraction coming from cellulosic ethanol. As has been previously discussed, when supplies of biomass/biofuels are limited, the results of this analysis indicate that biofuels are most optimally used in the non-LDV subsectors, due to inherent technological limitations on fuel switching to hydrogen and electricity in these other segments. Results of the Deep GHG High Biomass scenario appear to lead to the same conclusion, except in this case the supply of biofuels is large enough (1,669 PJ in 2050, or 12.7 billion gge) that a GHG reduction target of 80% is able to be reached. (In the Low Biomass scenario, only a 70% reduction is possible.) Another interesting, even counter-intuitive, finding from the High Biomass scenario is that when the availability of biomass is extremely large, the model actually chooses to utilize less carbon capture and storage than in the original Deep GHG Reduction Scenario, where mid-range estimates for biomass supply are used (Table 43). One might expect to see greater utilization of CCS when biomass supplies are large, because of the potential for negative emissions using bio-CCS technologies. However, it seems that the high cost of CCS as a mitigation option is an impediment to its use, especially when the potential for "conventional" zero-emissions biomass conversion technologies is larger (e.g., bio-refineries and FT poly-generation plants *without* CCS).

Table 42 Comparison of Key Biofuels and Biomass Indicators for Scenario Variants with Modified Resource and Technology Potentials

Biofuels & Biomass Indicators		2010	2020	2030	2040	2050
Biofuels Consumption (PJ)	Reference Case	164	419	632	946	1044
	Reference Case (w/ Lower Demands)	164	447	647	937	1039
	Deep GHG Scenario (Low Biomass)	164	450	445	466	489
	Deep GHG Scenario (High Biomass)	164	440	843	1257	1669
	Deep GHG Scenario (No Nuclear or CCS)	164	430	652	920	973
	Deep GHG Scenario (Limited EV-FCV Success)	164	438	720	951	975
Biomass Supply (PJ)	Reference Case	148	448	785	1210	1598
	Reference Case (w/ Lower Demands)	148	471	751	1159	1555
	Deep GHG Scenario (Low Biomass)	148	583	726	846	924
	Deep GHG Scenario (High Biomass)	148	755	1252	2187	2757
	Deep GHG Scenario (No Nuclear or CCS)	148	448	947	1536	1737
	Deep GHG Scenario (Limited EV-FCV Success)	148	733	1069	1580	1737

Table 43 Comparison of Key GHG Emissions Indicators for Scenario Variants with Modified Resource and Technology Potentials

GHG Emissions Indicators		2010	2020	2030	2040	2050
GHG Emissions Relative to Gross State Product (tCO_2e per M$ GSP)	Reference Case	256	211	174	143	117
	Reference Case (w/ Lower Demands)	256	200	154	121	93
	Deep GHG Scenario (Low Biomass)	256	181	111	60	26
	Deep GHG Scenario (High Biomass)	256	183	106	52	17
	Deep GHG Scenario (No Nuclear or CCS)	256	184	114	64	30
	Deep GHG Scenario (Limited EV-FCV Success)	256	181	106	52	17
GHG Emissions per Capita (tCO_2e per person)	Reference Case	12.1	11.5	11.0	10.6	10.2
	Reference Case (w/ Lower Demands)	12.1	10.9	9.7	8.9	8.1
	Deep GHG Scenario (Low Biomass)	12.1	9.8	7.0	4.4	2.3
	Deep GHG Scenario (High Biomass)	12.1	9.9	6.7	3.9	1.5
	Deep GHG Scenario (No Nuclear or CCS)	12.1	10.0	7.2	4.7	2.6
	Deep GHG Scenario (Limited EV-FCV Success)	12.1	9.8	6.7	3.9	1.5
GHG Emissions Captured and Stored via CCS (Mton CO_2e)	Reference Case	0	0	0	0	0
	Reference Case (w/ Lower Demands)	0	0	0	0	0
	Deep GHG Scenario (Low Biomass)	0	0	21	82	139
	Deep GHG Scenario (High Biomass)	0	0	22	83	145
	Deep GHG Scenario (No Nuclear or CCS)	0	0	0	0	0
	Deep GHG Scenario (Limited EV-FCV Success)	0	0	26	86	153
Cumulative GHG Emissions, 2005-2055 (Mton CO_2e)	Reference Case			27,552		
	Reference Case (w/ Lower Demands)			24,433		
	Deep GHG Scenario (Low Biomass)			16,671		
	Deep GHG Scenario (High Biomass)			15,779		
	Deep GHG Scenario (No Nuclear or CCS)			17,144		
	Deep GHG Scenario (Limited EV-FCV Success)			15,761		

Figure 79 and Table 44 both illustrate that total policy costs are lower in the Deep GHG High Biomass scenario than in the original Deep GHG Reduction Scenario (1.3% vs. 1.5% as a share of GSP, relative to the baseline), even though both scenarios achieve the same GHG reduction target of 80%. The average cost of carbon abatement is lower in the High Biomass scenario as well. The explanation for this finding is relatively straightforward: since, based on the assumptions for biomass used in this study, biofuels are a relatively inexpensive way to mitigate emissions in the transport sector – compared to electric and hydrogen vehicles and their requisite recharging/refueling infrastructure – greater biomass potential leads to reduced mitigation costs. Of course, it is none too clear that upwards of 13 billion gge of biofuels will be available to the California transportation fuels market in the future, especially if all other U.S. states and countries are also pushing for deep emission cuts (though it should noted that this analysis already builds this supposition into all the scenario storylines). The availability of biofuels may ultimately turn out to be lower than 13 billion gge, or even less than 8 billion gge as is the case in the Reference Case and the original Deep GHG Reduction Scenario. On the other hand, there is still a chance, albeit small, that total biofuels potential could be larger than this already high estimate. At this point in the time, the situation is none too clear. Biomass supply continues to be one of the greatest uncertainties in modeling low-carbon futures at all levels, whether for California, the U.S., or globally – hence the importance of conducting a sensitivity analysis on this critical issue.

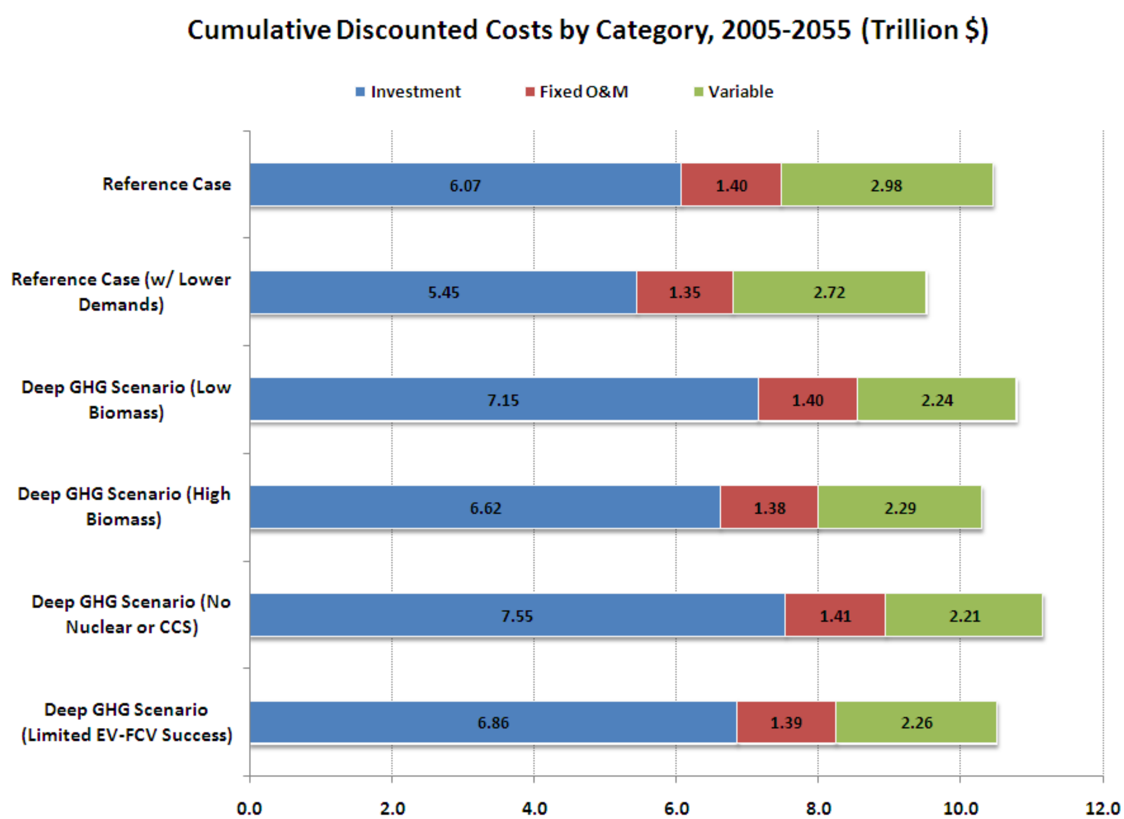

Figure 79 Comparison of Cumulative Total Discounted Energy System Costs for Scenario Variants with Modified Resource and Technology Potentials

Table 44 Comparison of Key Cost Indicators for Scenario Variants with Modified Resource and Technology Potentials

Cost Indicators			Notes
Cumulative Discounted System Costs, 2005-2055	Reference Case	9.8%	*Costs are relative to Reference Case (w/ Lower Demands)*
	Reference Case (w/ Lower Demands)	--	
	Deep GHG Scenario (Low Biomass)	13.3%	
	Deep GHG Scenario (High Biomass)	8.2%	
	Deep GHG Scenario (No Nuclear or CCS)	17.2%	
	Deep GHG Scenario (Limited EV-FCV Success)	10.4%	
Cumulative Discounted System Costs as a Share of Cumulative Discounted GSP, 2005-2055	Reference Case	1.5%	*Costs are relative to Reference Case (w/ Lower Demands)*
	Reference Case (w/ Lower Demands)	--	
	Deep GHG Scenario (Low Biomass)	2.1%	
	Deep GHG Scenario (High Biomass)	1.3%	
	Deep GHG Scenario (No Nuclear or CCS)	2.7%	
	Deep GHG Scenario (Limited EV-FCV Success)	1.6%	
Average Cost of GHG Abatement ($ per tCO_2e)	Reference Case	--	*Costs and GHGs are relative to Reference Case (w/ Lower Demands)*
	Reference Case (w/ Lower Demands)	--	
	Deep GHG Scenario (Low Biomass)	164	
	Deep GHG Scenario (High Biomass)	90	
	Deep GHG Scenario (No Nuclear or CCS)	225	
	Deep GHG Scenario (Limited EV-FCV Success)	114	

As in all the other scenarios and scenario variants discussed until now, the transportation sector, by far, comprises the lion's share of total capital investment costs (Figure 80). Electric sector investments are the second largest component, and it is this category that sees the largest cost increase in the No Nuclear or CCS scenario, which only achieves a 65% reduction in GHG emissions by 2050. This scenario is the most expensive of all the scenarios and variants discussed thus far, even more than the original Deep GHG Reduction Scenario with its 80% level of reduction. Lacking nuclear power and CCS as mitigation options, the model is forced to invest in an even greater amount of out-of-state wind and solar power, an action that requires significant investments in transmission lines in order to bring these renewable resources into the California market from their often distant locations.

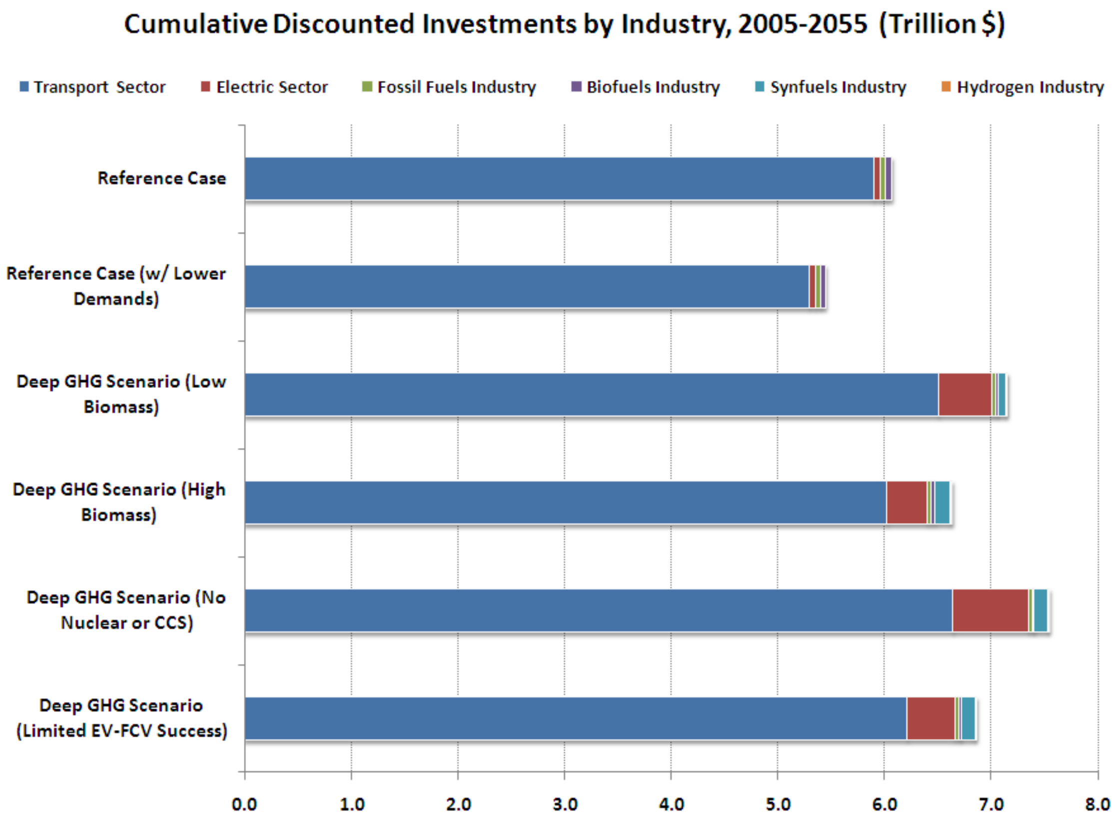

Figure 80 Comparison of Cumulative Discounted Energy Investments for Scenario Variants with Modified Resource and Technology Potentials

V. Conclusions

The specter of climate change looms large as one of the most critical global issues to address in the twenty-first century. Its varied impacts are likely to be felt in California in a very direct way, and for this reason the state has taken important, initial steps over the past several years to enact a suite of policies that will ultimately reduce its contribution of greenhouse gas emissions. California's current energy and climate policies (e.g., emissions trading program, renewable portfolio standard for electricity, vehicle efficiency and emissions standards, low carbon fuels standard) tend to have a near-term time horizon of 2020 and are fairly modest in their level of stringency. Yet, they will nevertheless have a worldwide effect since climate change is a global phenomenon. While making an important contribution to U.S. and global mitigation efforts, the policies will undoubtedly provide a solid foundation for transitioning to a lower-carbon economy. In the long term, however, it is clear that far greater reductions will ultimately be required – not only in California but worldwide – to keep global temperature change to below 2º C over the course of this century, which the science indicates is necessary in order to avoid the most destructive impacts of climate change (IPCC, 2007). To this end, California has an aspirational goal of reducing its GHG emissions 80% below 1990 levels by 2050. Such a target would necessitate a dramatic transformation in how energy is produced and consumed within the state – an "energy revolution" in the truest sense of the phrase.

The overarching challenge is that the technology and policy options for making a dramatic energy transformation are not well enough understood at the present time, and in addition the (publicly-available) tools for modeling this kind of transition at the level of California's entire energy system have been, to date, rather limited. The analysis described in this report has attempted to fill this void by developing an energy-engineering-environmental-economic (4E) systems optimization model to represent the vast majority of energy and emission flows within, to, and from California. The CA-TIMES model, as it is called, is built within the well-established MARKAL-TIMES framework and is, thus, extremely rich in bottom-up technological detail. The main application of the model is to develop scenarios for how California's energy system could potentially evolve over the next several decades, in light of strong policies to reduce energy use and greenhouse gas emissions. With a few notable exceptions, most technologies and policies can be represented within CA-TIMES.

A variety of scenarios have been developed in this analysis, ranging from a business-as-usual Reference Case to a Deep GHG Reduction Scenario, in which a mixed-strategy, portfolio approach allows California emissions to be reduced 80% below 1990 levels by 2050. Several variants of the Deep GHG scenario are then also developed, in order to explore important sensitivities related to the stringency of the emissions cap (i.e., less stringent than an 80% reduction) and the ultimate potential of key resources and technologies to contribute to greenhouse gas mitigation (e.g., sustainable biomass supply, nuclear power, carbon capture and storage, and electricity and hydrogen as transportation fuels).

In sum, this analysis shows that deep reductions on the order of 50% to 80% appear to be technically feasible at reasonable costs (e.g., 1.0% to 2.7% of California Gross State Product over the 2005-2055 time period, relative to the baseline scenario – only considering the transportation, electricity, and fuel conversion sectors). Policy cost estimates of this magnitude are in line with those of other studies for decarbonization of the U.S. and global energy systems (IEA, 2010; NRC, 2010). The bulk of the costs would be incurred in the medium to long term (between 2025 and 2050), as increasingly advanced technologies are used to make deeper and deeper reductions. The challenge for policy, however, is perhaps the next ten years (2010-2020). This analysis shows that whether policymakers ultimately decide to pursue a reduction target of 80% or something much less stringent (say, 50%), the types of technologies that need to be introduced in the near term are for the most part the same; hence, the emissions trajectories up to 2025 would be fairly similar. Furthermore, results of this study indicate that California's current target for 2020 – the AB32 goal of bringing emissions back down to 1990 levels – may not be stringent enough. To allow time for significant market penetration of the kinds of transformational technologies that will be needed in the long term (due to the inertia of energy system infrastructure and investments), advanced technologies must be introduced over the next ten years at a quicker rate than what the existing 2020 target is likely to motivate. More specifically, over the coming decade a significant expansion in, or at least the introduction of, the following mitigation options are likely needed: renewable electricity generation, specifically from wind, solar, and geothermal resources; advanced transportation technologies and fuels, including biofuels, hybrid-electric vehicles, plug-in hybrid electric vehicles, battery-electric vehicles, and hydrogen fuel cell vehicles; and a shift toward greater utilization of electricity as an end-use fuel in the industrial, commercial, residential, and agricultural sectors. Demand reduction is also likely to play an invaluable role in mitigating future emissions, both through energy efficiency and conservation efforts and reduced vehicle travel. The latter, which could be achieved by strong transit, land use, and auto pricing policies, deserves a considerably more attention in the development of energy and climate scenarios for California.

At the present time, it is not exactly clear what a declining cap on GHG emissions after 2020 would actually cover, if such targets were ever to be codified into law. The existing 2020 cap excludes emissions from interstate and international aviation and marine activities. However, because this emissions category is fairly large and growing quickly, I have decided to include it in the emissions caps envisioned by the scenarios in this analysis. After all, in reality these emissions would somehow have to be covered, no matter which entities have jurisdiction over them. Perhaps they might be included in a federal emissions cap, or maybe the international component of the emissions could be dealt with under the auspices of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO) (McCollum et al., 2009). Either way, the emissions must ultimately be controlled, and advanced technologies and fuels will be required for this purpose. While CA-TIMES is not able to explicitly model the impact of policies enacted outside of the California energy system, it is nevertheless important to capture the fuel use and investment decisions that might be made in these important transport segments if such policies were in place. Of course, had emissions from interstate and international aviation and marine transport not been included in the scenarios developed in this study, it would certainly have been a bit easier and cheaper to achieve the 50-80% reduction targets.

In terms of decarbonizing California's energy system, the transportation sector poses perhaps the biggest challenge and is therefore the most costly. Over half of the state's GHG emissions are attributable to transport at present, resulting primarily from the combustion of fossil fuels (gasoline, diesel, jet fuel, and residual fuel oil). Of course, because fossil fuels are relied upon so heavily, the potential for reducing transport GHGs via alternative fuel and vehicle technologies is quite huge. Biofuels are the most cost-effective option for making these emission cuts, both from the perspective of a single vehicle or when viewed at the energy systems level, the latter including fuel production and distribution infrastructure and considering competition for biomass from other sectors, such as electric generation and industry. The challenge with biomass is that total resources, while renewable on an annual basis, are actually rather limited. Only if California were to have access to biomass supplies far beyond its "fair share" of the national or global total (e.g., >30% of all U.S. consumption), would the state be able to fuel its entire transport sector with biofuels. This is perhaps unlikely in a future where other U.S. states and countries are also counting on biomass/biofuels to mitigate their GHG emissions. Given constraints on biomass resources, the results of this analysis indicate that the most optimal use of biofuels is in the non-light duty subsectors, namely in the form of bio-derived gasoline, diesel, jet fuel, and residual fuel oil. The reason for this is fairly intuitive: there are fewer alternative technological/fuel options to reduce GHG emissions in these other transport subsectors, hence the value of a tonne of biomass is higher. In fact, a marked advantage of light-duty vehicles is that there are quite a few alternatives for technology- and fuel-switching. Specifically, electric-drive vehicles could feasibly be used to satisfy a large portion of total VMT demand, whereas electricity and/or hydrogen are simply not realistic alternatives in some of the other subsectors, due to range limitations and refueling issues. The GHG reduction scenarios developed here rely heavily on HEVs and PHEVs (Gasoline and E-85), as well as Hydrogen FCVs to some extent, to make deep emission cuts in the light-duty subsector. In contrast, BEVs do not penetrate the LDV market to any significant degree, a result that may have more to do with model dynamics than anything else. BEVs are not favored by the model because of the various inputs that are currently assumed for the efficiencies and costs of vehicles and plug-in recharging infrastructure. The assumed costs for BEVs, for instance, are higher than for other advanced vehicle technologies because, in an effort to be fair, all vehicles in CA-TIMES are assumed to have roughly the same size, weight, range, power, etc. While this aggregated level of vehicle class representation for the most part makes sense within the modeling framework, it potentially disadvantages BEVs, which may be particularly well suited to the small car and small light truck markets or to urban driving, where travel distances are shorter. The current version of CA-TIMES is not able to capture this possibility, though future work may attempt to address this issue.

As the transport sector is decarbonized, emissions from the energy supply/conversion sector are likely to be reduced significantly as well, since the types of facilities that produce low-carbon transport fuels (e.g., bio-refineries, FT syn-fuels poly-generation plants, hydrogen plants, zero- and low-carbon electricity generation) tend to emit low levels of greenhouse gases, or at least they would in a low-carbon future. The exact carbon signature of these fuels, of course, depends on which energy resources are used for generating heat and electricity at these plants, and also whether or not carbon capture and storage is utilized. Bio-CCS technologies appear to be an especially attractive means by which to decarbonize the energy system, since they allow for negative emissions (i.e., permanently storing biomass carbon underground). In the scenarios developed in this study, bio-CCS play a major role in reducing GHG emissions while at the same time taking the burden off of other sectors, namely transport, which have higher abatement costs. When bio-CCS technologies are eliminated from the potential technology portfolio, however, the transport sector is forced to decarbonize much more significantly, and in the light-duty sector in particular, more advanced electric-drive vehicles (PHEVs and Hydrogen FCVs) become a preferred option for making these emissions cuts.

Emissions from the industrial, commercial, residential, and agricultural (ICRA) end-use sectors are reduced in this study through energy efficiency and fuel switching. In particular, drawing on other scenario studies by the IEA (2010), the Deep GHG Reduction Scenario assumes that an increasing share of energy demand is met by electricity and natural gas in the ICRA sectors in the future. How authentic these emission reductions actually are depends in large part on the simultaneous decarbonization of the electric sector, which also appears to be a likely outcome of stringent climate policy, as found in this and numerous other studies.

Comparatively, reducing emissions from electric generation is fairly straightforward and can be done at abatement costs that are lower than in the transport and energy supply sectors (IEA, 2010). Nonetheless, significant hurdles still remain, particularly with respect to spatial and temporal issues. For example, it could potentially be quite expensive to tap solar, wind, and geothermal resources in distant out-of-state locations, owing to the substantial capital investments required for long-distance transmission lines. In addition, it is still not entirely clear whether intermittent renewables, especially solar and wind, can be relied upon to contribute a majority share of total electric generation, unless significant storage and/or back-up capacity is built as well. For these reasons, the availability of nuclear power and fossil and/or biomass CCS is critical, so that low-carbon options for baseload generation remain in play. If nuclear and CCS are wholly absent from the technology portfolio, as one variant of the Deep GHG Reduction Scenario illustrates, then it will likely become considerably more difficult, and indeed more costly, to achieve a deep reduction target, if it is even possible. Other scenario variants lead to similar conclusions when biomass resources are significantly constrained or when the potential for electricity and hydrogen to be used in the transport sector is considerably limited.

An important caveat to this analysis is that it only does a partial economic accounting. In other words, it attempts to capture the total energy system *costs* of climate mitigation but largely ignores the significant economic *benefits* of pursuing this goal. For instance, the analysis does not consider the avoided costs (i.e., benefits) of climate change (e.g., more frequent extreme weather events, impacts on global agriculture and food production) or of climate adaptation (e.g., construction of sea walls, relocation of coastal populations). Similarly, the benefits accruing from reduced health expenditures and increased life expectancies, to the extent they can attributed to climate mitigation, have not been monetized here. Given this partial accounting, it is highly likely that the cost figures shown in this report are somewhat overestimated, a practice that is a known issue with integrated assessment models used to inform energy and climate policymaking (Nemet et al., 2010).

Like any study, this one has probably created more questions than it has answered. (At least that should be the goal of good research in my opinion.) And for this reason a number of issues must be left for future work. These issues have already been discussed in the appropriate sections of the text, but they are summarized again here. First, and probably foremost, the level of technological detail in the ICRA end-use sectors must be improved. Even though they account for only 15% of current fuel combustion-related emissions in California, it is still important to understand the fuel use and investment decisions that might be made in these sectors under stringent climate policy. Then, once this model improvement has been made, it would be very interesting to look more deeply into the timing of electricity supply and demand, specifically with respect to the intermittency of renewables, electric vehicle recharging, and “smart” appliances. In terms of behavioral changes and transport demand reduction, the development of more sophisticated low-VMT scenarios is probably desirable, if possible harnessing the capabilities of travel demand modeling experts, such as those in the UC-Davis Urban Land Use and Transportation (ULTRANS) Center. At the same time, our group would like to be able to explicitly model transport mode-switching (i.e., between LDVs and transit buses/rail) and also class-switching within particular subsectors (i.e., between compact, small, mid-size, and large cars). Such endogenous representation of consumer behavior in the transport sector is not a common feature of typical energy systems models, despite its obvious importance. Therefore, it could be a ripe area for research. Other ideas for future research include bringing endogenous technological learning (ETL) into the model for certain key technologies (e.g., fuel cells, batteries, solar, wind, nuclear, IGCC, CCS) and better representing the staged development of vehicle refueling infrastructure (namely biofuels, hydrogen, and electricity). In the latter case, our group plans to draw upon previous work by other UC-Davis STEPS Program researchers, such as Yang and Ogden (2007) for hydrogen and Parker (2010) for biofuels. The CA-TIMES model would also be substantially improved if the emissions accounting framework were overhauled so that dynamic lifecycle analyses could be conducted, thereby making it possible for policies such as an LCFS to be explicitly and endogenously represented. Lastly, although they account for only 11% of California's total emissions at the present time, non-energy greenhouse gases also need to be accounted for in the modeling framework, even if there are no technologies in the model that are able to reduce them.

VI. Acknowledgements

I have many people and organizations to acknowledge for the success of the CA-TIMES project up to this point. This portion of my dissertation work was supported by a grant from the Sustainable Transportation Center at the University of California Davis, Institute of Transportation Studies, as well as the continued support of the UC-Davis Sustainable Transportation Energy Pathways (STEPS) Program. External funding was also made available by the Achievement Rewards for College Scientists (ARCS) Foundation, the private fellowship support of Mr. Ernest E. Hill, and the California Air Resources Board.

On a personal level, I am extremely grateful to Sonia Yeh, Christopher Yang, and Joan Ogden for guiding me through the entirety of the CA-TIMES project. Ryan McCarthy, Nathan Parker, Wayne Leighty, Ben Sharpe, Marc Vayssières, Kevin Eslinger, Cynthia Gage, Rebecca Doddard, and several other generous researchers at UC-Davis, U.S. EPA, CARB, and elsewhere also proved instrumental in my research, in the sense that they provided me with a considerable amount of technology, resource, and emissions data, which I was eventually able to incorporate into the model. Amit Kanudia, Antti Lehtila, and Gary Goldstein provided technical expertise with respect to the TIMES-VEDA modeling platform, specifically how best to set up the model structure and accurately represent technologies and policies (not to mention debugging the model time and again). Without all of this generous help, this initial version of the CA-TIMES model would have never come to fruition.

ACKNOWLEDGEMENT

The research was supported by a grant from the Sustainable Transportation Center at the University of California Davis, which receives funding from the U.S. Department of Transportation and Caltrans, the California Department of Transportation, through the University Transportation Centers program.

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The contents of this report reflect the views of the authors, who are responsible for the facts and the accuracy of the information presented herein. This document is disseminated under the sponsorship of the Department of Transportation University

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