Deep Reductions in Greenhouse Gas Emissions from the California Transportation Sector: Dynamics in Vehicle Fleet and Energy Supply Transitions to Achieve 80% Reduction in Emissions from 1990 Levels by 2050

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ABSTRACT

California's "80in50" target for reducing greenhouse gas emissions to 80 percent below 1990 levels by the year 2050 is based on climate science rather than technical feasibility of mitigation. As such, it raises four fundamental questions: is this magnitude of reduction in greenhouse gas emissions possible, what energy system transitions over the next 40 years are necessary, can intermediate policy goals be met on the pathway toward 2050, and does the path of transition matter for the objective of climate change mitigation? Scenarios for meeting the 80in50 goal in the transportation sector are modelled. Specifically, earlier work defining low carbon transport scenarios for the year 2050 is refined by incorporating new information about biofuel supply. Then transition paths for meeting 80in50 scenarios are modelled for the light-duty vehicle sub-sector, with important implications for the timing of action, rate of change, and cumulative greenhouse gas emissions. One aspect of these transitions – development in the California wind industry to supply low-carbon electricity for plug-in electric vehicles – is examined in detail. In general, the range of feasible scenarios for meeting the 80in50 target is narrow enough that several common themes are apparent: electrification of light-duty vehicles must occur; continued improvements in vehicle efficiency must be applied to improving fuel economy; and energy carriers must de-carbonize to less than half of the carbon intensity of gasoline and diesel. Reaching the 80in50 goal will require broad success in travel demand reduction, fuel economy improvements and low-carbon fuel supply, since there is little opportunity to increase emission reductions in one area if we experience failure in another. Although six scenarios for meeting the 80in50 target are defined, only one also meets the intermediate target of reducing greenhouse gas

emissions to 1990 levels by the year 2020. Furthermore, the transition path taken to reach any one of these scenarios can differ in cumulative emissions by more than 25 percent. Since cumulative emissions are the salient factor for climate change mitigation and the likelihood of success is an important consideration, initiating action immediately to begin the transitions indicated for achieving the 80in50 goal is found to be prudent.

TABLE OF CONTENTS

LIST OF FIGURES

LIST OF TABLES

LIST OF ACRONYMS

80in50	80% reduction in greenhouse gas emissions from 1990 levels by the year 2050 (Executive Order S-3-05)
AB32	California Global Warming Solutions Act of 2006
BAU	Business as usual
BEV	Battery electric vehicle
BRMP	Biological Resources Management Plan
CAFE	Corporate average fuel economy
CAISO	California Independent System Operator
CCA	Community Choice Aggregator
CCS	Carbon capture and storage
CEC	California Energy Commission
CPUC	California Public Utilities Commission
CUP	Conditional Use Permit
CWEA	California Wind Energy Association
EER	Energy Economy Ration (in LCFS)
EIR	Environmental Impact Review
EIS	Environmental Impact Statement
EPRI	Electric Power Research Institute
ESP	Energy Service Provider
ETOH	Ethanol
FAA	Federal Aviation Administration
FCV	Hydrogen fuel cell vehicle
FERC	Federal Energy Regulatory Commission
FFV	Flex-fuel vehicle
gge	gallons gasoline equivalent (in energy content)
GHG	Greenhouse Gas
GIS	Geographic Information System
GWh	Giga Watt Hours, a unit of electric energy
HEV	Hybrid electric vehicle
HDV	Heavy-duty vehicle
HOV	High-Occupancy Vehicle
HROC	Historical Rate of Change
ICE	Internal combustion engine
IOU	Investor Owned Utility
IPCC	Intergovernmental Panel on Climate Change
IRR	Internal Rate of Return
ISO4	Interim Standard Offer 4 contracts for electric power purchase.
kWh	kilo Watt hour, a unit of electrical energy
LCFS	Low carbon fuel standard
LDV	Light-duty vehicle
LEVERS	Long-term Evaluation of Vehicle Emission Reduction Strategies model, developed by Yang et al. (2009)
MJ	Mega Joule, a unit of energy

$MMTCO_2e$	Million metric tons of carbon dioxide equivalent greenhouse gas emissions; CO_2e includes CO_2, CH_4 and N_2O weighted by their respective global warming potentials
mpgge	Miles per gallon gasoline equivalent
MPR	Market Price Referent
MSW	Municipal Solid Waste
NBSM	National Biorefinery Siting Model, developed by Parker et al. (2010)
NIST	National Institute of Standards and Technology
NPV	Net Present Value
NREL	National Renewable Energy Laboratory
O&M	Operation and Maintenance
PATH	Projected Accessible Transition Headings model, developed in this dissertation
PG&E	Pacific Gas and Electric
PHEV	Plug-in hybrid electric vehicle
PPA	Power Purchase Agreement
PRT	Personal Rapid Transit
PTC	Production Tax Credit
PURPA	Public Utility Regulatory Act
QF	Qualifying Facility
RFS	Renewable Fuel Standard
RPS	Renewable Portfolio Standard
SCADA	Supervisory Control and Data Acquisition
SCE	Southern California Edison
SUV	Sport utility vehicle
USD	United States Dollars
VAR	Reactive Power caused by phase shift in alternating current
VISION	A vehicle fleet stock turnover model, developed by Argonne National Laboratory
VMT	Vehicle miles of travel
WPR	Wind Performance Report
WECS	Wind Energy Conversion System
ZEV	Zero Emission Vehicle

EXECUTIVE SUMMARY

Responding to the potential impact of climate change on the California economy, ecosystems, and human health and mortality, the state of California has established ambitious targets of reducing greenhouse gas emissions to 1990 levels by 2020 and to 80% below 1990 levels by 2050. The target for 2050 raises four fundamental questions: is the reduction in GHG emissions possible, what transitions over the next 40 years are necessary to hit the target, can intermediate policy goals be met on the pathway toward 2050, and does the particular transition path followed to the target matter for the objective of climate change mitigation. A fifth related question is what development of key low-carbon energy resources and technologies will be necessary for meeting California's GHG goals.

This dissertation focuses on answering these questions for California's transportation sector, building upon earlier work by researchers at the UC Davis Institute of Transportation Studies (Yang et al., 2009; McCollum et al., 2009). Although the 2020 and 2050 targets for reducing GHG emissions in California are economy-wide goals that are not specific to the transportation sector, I begin from the premise that these targets must be met within the transportation sector. In other words, I assume that GHG emissions from transportation must be reduced to 1990 levels by 2020 and to 80% below 1990 levels by 2050. This assumption is generally supported by economic modeling of GHG emission reduction alternatives, which shows that while many emission reductions from transportation are not among the least-cost alternatives for modest levels of reduction, all sectors must participate significantly in order to achieve deep reductions like the 80in50 goal (Yeh et al., 2008).[1]

In earlier work, Yang et al. (2009) developed a static scenario model of California's transportation system that was designed to investigate the first question for California's transportation sector. This model was named the 80in50 LEVERS model. They used this tool to explore the range of potential scenarios for achieving an 80% reduction from 1990 levels in transportation GHG emissions by 2050. Although "silver bullet" strategies employing individual mitigation options to the maximum feasible extent failed to reach the 80% reduction goal, Yang et al. found that a portfolio approach combining multiple strategies can yield success. In fact, they defined three "80in50 scenarios" to characterize the range of portfolio approaches that could achieve the 2050 goal. These *80in50 scenarios* vary, but all are characterized by a light-duty vehicle fleet in 2050 that relies on highly efficient vehicles and decarbonized transportation fuels. Meeting the 80in50 goal will require a revolution in light-duty vehicles and fuel supply over the next 40 years. This study found that the availability of low carbon biofuels was a major factor determining the light duty fleet mix in 2050.

These static results suggest that a portfolio strategy is needed to reach the 80in50 goal, but do not include dynamics or cost, and do not address transition issues and paths. The availability of low carbon transportation fuels is found to be a critical requirement for meeting the 80in50 goal, but the earlier study does not incorporate California-explicit estimates of key resources such as biofuel availability or windpower potential.

[1] Note, the "blue map" scenarios in the IEA Energy Technology Perspectives report (IEA, 2008) show a major role for transportation, but one that begins later than measures in other sectors (e.g., electric power generation and buildings).

The Three Chapters of this Dissertation

In this dissertation, I improve the 80in50 model to address the four research questions posed at the beginning of this section.

First, I provide a more detailed consideration of one key low carbon fuel supply option – biofuels. I build on the prior work of Yang et al. by refining treatment of biofuel supply in the 80in50 LEVERS model to create three new *80in50 scenarios*.

I worked with Nathan Parker to modify his spatially-explicit model of biofuel supply in the United States to calculate biofuel supply curves for the year 2050 under three scenarios (pessimistic, middle, optimistic). I then used this model to isolate the supply curves for 15 different biofuel feedstock pathways available in California under each scenario.

These California-specific estimates of biofuel supply are a refinement of the original estimates used by Yang et al. in two ways. First, the estimates incorporate newer information about feedstock supplies and conversion technologies. Second, both the *quantity* and *composition* of biofuel available in California are estimated with optimization modeling rather than the more approximate method of assumed fractions of total biofuel supply in the United States used by Yang et al.

Furthermore, when multiplied by the estimated carbon intensity for each feedstock pathway, these supply curves provide the basis for dynamic modeling of biofuel carbon intensity when defining 80in50 scenarios with the 80in50 LEVERS model. As parameters in the 80in50 scenario affecting the quantity of biofuel required are changed, the average composition and carbon intensity of biofuel available changes as well. This provides more realistic feedback to the researcher during the process of defining 80in50 scenarios. I revised the original 80in50 LEVERS model developed by Yang et al. to include this new biofuel supply module and then used this model to create three new 80in50 scenarios, one for each of the biofuel supply scenarios for 2050.

Second, I add dynamics to the static 80in50 LEVERS model in order to investigate the transition needed to meet the 80in50 targets. To do so, I assume that the composition of the light-duty vehicle fleet and fuel supply in 2050 is defined by each *80in50 scenario* (three from Yang et al. plus the three I created based on refined treatment of biofuel supply). I then develop an adaptation of the VISION stock turnover model to model transition paths for light-duty vehicles and fuels that would produce the requisite mixes in 2050.

Inputs to this modeling include the following. Based on a literature survey, I develop estimates for the maximum rates of market penetration and performance improvement for key light-duty vehicle and fuel technologies considering historical experience with technological development, cost reductions with learning and scale up, consumer adoption and stock turnover. I also develop rules for selecting the new vehicle sales mix over time. These rules are based on my judgment about how change might occur, and likely technology progressions (for example, from hybrid electric to plug-in to full battery electric vehicles). The VISION model then accounts for vehicle stock turnover rates, which allows us to explore how fast change might occur and whether the transitions in the light-duty sector required for each *80in50 scenario* are feasible.

A variety of policy goals provide waypoints for these transition paths that enable assessment of the potential feasibility of policy targets for intermediate dates between 2010 and 2050. In general, existing policy goals in California are feasible but the combination of existing intermediate and longer-term policy goals constrain the range of scenario alternatives. Sensitivity analysis for key parameters in the 2050 fleet mix and transition pathways is used to examine each *80in50 scenario* and to characterize the range of possible pathways forward.

Finally, I provide a more detailed consideration of a second key low carbon fuel supply option – windpower. With *80in50 scenarios* and transition paths defined at a macro-level, the final chapter of this dissertation considers one element of this revolution at the micro-scale of activities at an individual project level required to realize the macro-level transitions. Specifically, I consider the barriers and benefits to repowering and new development in the California wind industry as a potential source of low-carbon renewable-source electricity for plug-in vehicles.

Findings Summary

In general, I find that the range of feasible sustainable biofuel supply for California in 2050 is 5.4 to 8.4 billion gallons gasoline equivalent, with average carbon intensity of 28.5 to 39.4 gCO_2e/MJ. With the biofuel supply constrained as such, the range of feasible 80in50 scenarios is narrow enough that common themes are apparent. First, electrification of light-duty vehicles must occur, with some combination of plug-in hybrid electric (PHEV), battery electric (BEV), and fuel cell vehicles (FCV) because most of the available biofuels are needed in other transportation sub-sectors such as heavy duty trucks (HDV), aircraft and marine applications where electricity is not as feasible. Second, all improvements in vehicle efficiency must be applied to improving fuel economy rather than vehicle performance. Fuel economy improvement of approximately 80% from 1990 across all vehicle technologies is needed, reversing the trend of the past 25 years where energy efficiency improvements in vehicles were applied to improving performance rather than fuel economy (NRC, 2002). Third, all energy carriers must de-carbonize to less than half of the carbon intensity of gasoline and diesel (i.e., less than about 40 gCO_2e/MJ). Finally, sensitivity analysis implies that attention in policy and industry to ensure success on all fronts – in travel demand reduction, efficiency improvements translated into fuel economy, and low-carbon fuel supply – is needed since there is little opportunity to pick up the slack in one area with increased action in another if we experience failure or greater than expected limitations. However, it is also important to recognize that the scope of this research does not include paradigm shifts in transportation that could open more potential for GHG reduction (e.g., telecommuting and online commerce or personal rapid transit).

Examination of the transition dynamics for transitioning from the current transportation system to those envisioned in each 80in50 scenario is important for understanding the timing and rate of changes required. Meeting the *80in50* goal requires transition paths in the light-duty vehicle sector that rapidly electrify vehicles and decrease total primary energy use while shifting from petroleum to low-carbon biofuels, hydrogen and electricity.

The combination of intermediate and longer-term policy goals constrains the range of acceptable 80in50 scenarios once transition dynamics are included in the modeling. Only one 80in50 scenario, the *Actor-Based*, meets both the 2020 and 2050 GHG emission reduction goals. This scenario requires vehicle efficiency to improve to 125 miles per gallon gasoline equivalent (mpgge; fleet average on-road for new vehicles) and aggressive electrification of light-duty vehicles that renders hybrid electric vehicles and biofuels use in the light-duty vehicle sub-sector “transitional” with relatively short periods of large market share.[2] It also requires rapid de-carbonization of primary energy sources and energy carriers and decrease in light-duty vehicle travel demand by 38% in VMT/capita from the business-as-usual trend. Thus, if binding, intermediate waypoints may begin to constrain the range of acceptable scenarios.

Furthermore, both the scenario and the transition path taken to 2050 do matter for effective climate change mitigation. Although the 80in50 scenarios are equal in meeting the 80 percent GHG emission reduction target for the transportation sector in the year 2050, they are not equal in upside potential for further emission reduction after 2050 nor in downside risk for missing the 80in50 goal if required levels in some parameters are not met, and differ by as much as 30 percent in cumulative GHG emissions over the period 2010 to 2050.

Transitions in vehicle technology, energy supply, and transportation infrastructure must begin soon and progress rapidly in order to meet the 80in50 GHG emission reduction goal. This is true because of the time lag in fleet turnover (i.e., the fraction of advanced vehicles in the fleet lags behind new car sales). Consequently, meeting the 2010 and 2020 GHG emission reduction goals requires early action. However, these transitions do appear feasible given the transition dynamics in my modeling and rely on logical technological evolutions (e.g., evolution in LDV technology from HEV to PHEV to BEV).

[2] The transitional role of some technologies (such as HEVs and PHEVs) is evident as their market share increases to achieve intermediate waypoints and then decreases. While these vehicles share many components with more advanced electric-drive vehicles (BEVs and FCVs), they do not provide sufficient emission reduction to play a major role in the 2050 transportation system that meets the 80in50 goal. It is important in any scenario to understand whether the technologies (and resulting infrastructures) used to achieve intermediate emission reduction goals lie along the path to achieving the long-term goals.

Furthermore, within each 80in50 scenario there is some *width* or “window of opportunity” in feasible transition paths. This width is defined at one extreme by acting as early as possible without exceeding maximum rates of change in the near term and at the other extreme by delaying action as long as possible without exceeding maximum rates of change in the long term. But initiating transitions early versus delaying action can cause up to a 27 percent difference in cumulative GHG emissions over the period 2010 to 2050 for each 80in50 scenario. Thus, while my study of transition paths shows that the 80in50 scenarios are feasible, the choice of which scenario to pursue and what transition path to follow may have potentially large impacts on success in mitigating climate change over the period 2010 – 2050. Future work in this area may consider other bases for distinguishing between 80in50 scenarios (e.g., optimization based on least societal cost).

The 80in50 scenarios require large quantities of low-carbon electricity to fuel plug-in vehicles, including 14,000-30,000 GWh/y of renewable-source electricity (for reference, the total electricity use in California is approximately 235,000 GWh/y). Wind power is one potential source for this electricity that may derive synergistic benefit from a fleet of plug-in vehicles operating as dispatchable load. Since California’s wind resource is concentrated in relatively few high-quality resource areas – generally mountain passes between desert and coastal areas – that were developed into “wind farms” in the 1980s, expansion of generating capacity to provide the incremental renewable-source electricity for the transportation sector from wind would require a combination of repowering and new development. The term “repowering” in wind generation development refers to the replacement of old, usually smaller wind turbines with new, usually larger ones. Depending on the numbers and sizes of old and new turbines, repowering may or may not create an increase in nameplate generating capacity.

Repowering and new development in the existing four wind resource areas that account for 99% of total installed capacity in California (Altamont, Tehachapi, San Gorgonio, Solano) can provide all of the low-carbon renewable-source electricity required for vehicle charging in five of the six 80in50 scenarios defined *if* the nameplate capacity is allowed to increase in the course of this repowering and new development. Without such capacity increase, repowering alone is likely to produce only 2.3 GWh/year incremental generation.

Project economics is a common barrier to more rapid repowering but economic profitability is a necessary but not sufficient condition for repowering. Other barriers like uncertainty in the federal production tax credit, costs associated with environmental permitting, delays in turbine procurement, contractual obligations and costs, setback requirements, and transmission constraints can all block repowering even when project economics are good.

Thus, there may be a role for government in promoting repowering by reducing or removing these other barriers to allow unfettered market selection of projects "ready" for repowering (i.e., those with extant equipment that is unreliable or outdated enough to make repowering profitable). But the highly project-specific nature of repowering makes crafting such policy complex since what is effective for one project may cause unintended consequences for another. There may also be a role for government in promoting *early* repowering through an explicit incentive or requirement (e.g., renewable portfolio standard), but such a policy is likely to be economically inefficient.

The desired outcome of repowering for the 80in50 scenarios – the ability to produce more electricity – is also one of the primary incentives to repower for the project owner. However, this incentive is often blunted by some combination of insufficient transmission capacity, regulatory limits on tower height and spacing, existing power purchase agreements, and eligibility rules for the federal production tax credit.

Returning to the original four research questions, this dissertation documents the following general conclusions.

1. Reduction in GHG emissions from the transportation sector to 1990 levels by 2020 and to 80% below 1990 levels by 2050 is feasible, even when low-carbon biofuel supply is constrained to pessimistic levels. Achieving these emission reductions requires large changes in all transportation sub-sectors and fuel supplies (with substantial switch to hydrogen and electricity), but changes that nevertheless do not require a paradigm shift.[3]
2. Transitions must begin soon and progress quickly in order to achieve the 2020 and 2050 goals for GHG emission reduction in the transportation sector. But these transitions do not exceed maximum rates of change and even allow for a few years of wiggle room in when the transitions begin. Furthermore, the transitions required to achieve each 80in50 scenario will not be possible without steady technological evolutions of key technologies like batteries, fuel cells, and electric drive.
3. The choice of which 80in50 scenario to pursue and what transition path to follow may have large impacts on cumulative GHG emissions – and, by extension, success in climate change mitigation – for the period 2010 to 2050.

[3] Unless the reader considers plugging a vehicle in at home, long charging times, shorter range, and other differences in fuel properties to be paradigm shifts.

4. Repowering and new development in the existing four primary wind resource areas of California could supply enough incremental renewable-source electricity to meet the needs of the transportation sector in five of the six 80in50 scenarios *if* nameplate capacity is allowed to increase *and* a variety of project-level barriers are removed.

INTRODUCTION

California Policy on Global Climate Change is the Motivation for this Study

Climate change could have large impacts on regional and national economies, natural and managed ecosystems, and human health and mortality. Studies suggest annual greenhouse gas (GHG) emissions must be cut 50 to 80% worldwide by 2050 in order to stabilize the climate and avoid the most destructive impacts of climate change (IPCC, 2007).

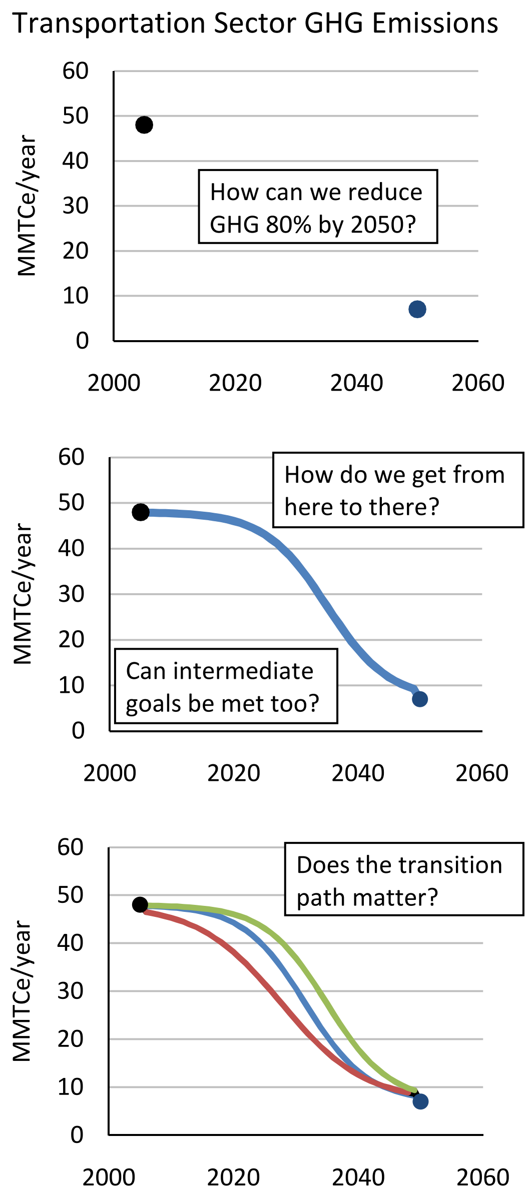

Figure 1: Four questions raised by California's ambitious *80in50* GHG emission reduction goals.

Responding to the potential impacts of climate change on the *California* economy, ecosystems, and human health and mortality (CalEPA, 2006), the state of California issued an executive order establishing aggressive targets of reducing GHG emissions to 1990 levels by 2020 and to 80% below 1990 levels by 2050 (Executive Order S-

3-05). (I will refer to the latter as the *80in50* goal throughout this dissertation.) The Global Warming Solutions Act (i.e., AB32) enacted in 2006 codified the 2020 targets in the Executive Order.

Although the California Global Warming Solutions Act of 2006 (AB 32) specifies economy-wide GHG abatement policy rather than sector-specific policies, considering how deep emission reductions could be achieved in each sector is salient. The transportation sector in California contributed over 40% of the state's total GHG emissions in 2006 (CARB, 2008), the largest of any sector in the state. California has established precedent for enacting transportation sector specific policies for GHG reduction and implementation of alternative fuels (Farrell and Sperling, 2007; ETAAC, 2008). Partial equilibrium economic modeling has shown that while the electric generation and buildings sectors may provide the lowest-cost GHG abatement for less aggressive GHG reduction requirements, the transportation sector in California must play a major role if statewide emissions are to be reduced 80% below 1990 levels (Lutsey and Sperling, 2009; Yeh et al., 2008; IEA, 2008; Creyts et al., 2007).[4] Consequently, the foundation of this research is the assumption that the *80in50* goal *within* the transportation sector is a binding constraint.[5]

While the 2020 goal was based on estimates of available policy and technology options for emission reduction, the 2050 goal was based on an emissions trajectory consistent with stabilization of atmospheric GHG concentrations below levels at which

[4] This finding is consistent with the global finding from the IEA (2008) that profound changes are needed in transportation by 2050 if GHG emissions are to be reduced by 50% from "business as usual."

[5] Framing in terms of distinct sectors of the energy system risks losing sight of the interactions between them. For example, I show that meeting the 80in50 goal in the transportation sector requires supply of a large quantity of low-carbon electricity from the electric generation sector. Thus, increasing electrification in the transportation sector required to meet the 80in50 goal creates interaction between the electric generation and transportation sectors' emission reductions.

damaging changes may occur (CalEPA, 2006). Consequently, the 2050 goal raises four primary questions (Figure 1). First, can we reduce GHG emissions 80% below 1990 levels by 2050 and with what changes in the transportation system? Second, how do we get from here to there in terms of the composition and timing of transitions in the transportation system? Third, can we meet intermediate 2020 policy goals on the pathway toward 2050? Fourth, does the transition path we take matter for the objective of mitigating climate change?

Understanding the underlying technologies that might be used to meet the 2020 and 2050 goals for GHG emission reduction is also important, to ensure logical technological evolutions that remain consistent for both short-term and long-term emission reduction goals. For example, if very low emissions vehicle technologies like FCV or BEV (fueled by renewable-source hydrogen and electricity) are needed to meet the 80in50 goal, achieving goals for 2020 and 2030 with increased use of biofuels in conventional ICE vehicles may *preclude* the 80in50 goal if there is insufficient near-term development in vehicle electrification technologies (e.g., if we choose to only develop biofuels). A similar situation can be envisioned on the fuels side, if investments in infrastructure to meet near term emission reduction goals (e.g., with natural gas fired electric generation) preclude adequate investment in fuels infrastructure needed to meet the 80in50 goal (e.g., renewable-source hydrogen and low-carbon biofuels). Thus, it is important to pursue development of underlying vehicle technologies and fuel supply infrastructures according to logical evolutions that will provide the best chances of meeting both short-term and long-term GHG emission reduction goals.

In earlier work, Yang et al. (2009) explored the first of the questions posed above with a static "snapshot" scenario model of the California transportation sector in 2050 that included all transportation sub-sectors (light-duty, heavy-duty, agriculture, aircraft, marine, rail, construction and off-road). This model was called the 80in50 Long-term Evaluation of Vehicle Emission Reduction Strategies (LEVERS) model.

Although "silver bullet" strategies employing individual mitigation options to the maximum feasible extent failed to reach the 80% reduction goal, Yang et al. identified three portfolio scenarios combining multiple strategies that yield success. These *80in50 scenarios* differ, but all are characterized by a 2050 light-duty vehicle fleet that relies on highly efficient vehicles, de-carbonized transportation fuels, and reduced travel demand. In other words, meeting the *80in50 goal* will require a revolution in light duty vehicles and fuel supply over the next 40 years.

This dissertation builds on the prior work by Yang et al. with three chapters that address critical questions for charting a course for the transportation system that will address the climate change hazard.

Chapter 1: Improved Modeling of Biofuel Supply in 80in50 Scenario Development

In the first chapter, I refine the treatment of biofuel supply in the static LEVERS model in order to create three new *80in50 scenarios* that reflect current thinking on this critical swing factor.

The availability of low-carbon biofuels is a key factor in the sensitivity of the LEVERS model developed by Yang et al (2009). But the potential quantity and carbon intensity of biofuel available in California in 2050 was addressed in the previous work only through the *Efficient Biofuels* scenario assumptions of using 15-20% of the total

United States supply as predicted under the USDA and DOE's "Billion-Ton Study" (85-92 billion gge), with 16.3 gCO2/MJ average carbon intensity.[6]

Subsequent modeling of biofuel supply curves for 15 feedstock pathways by Parker et al. (2010) has enabled a more sophisticated approach to including biofuel supply than used in modeling the original three *80in50 scenarios*. Consequently, I develop a new biofuel supply module in the LEVERS model based on Parker et al.'s supply curves, and then use the revised model to develop three new *80in50 scenarios* that more accurately represent the likely supply constraints on low-carbon biofuels supply in California. These constraints have major implications for the use of biofuels in transport, and particularly for the make-up of the LDV fleet in 2050.

Chapter 2: Transition Path Analysis for Light-duty Vehicles

In the second chapter, I explore the second two of the questions shown in Figure 1 for the LDV sub-sector with a dynamic model of vehicle fleet stock and turnover. The *80in50 scenarios* from the LEVERS model provide a transparent picture of the characteristics of a transportation sector in 2050 with 80% lower GHG emissions than 1990 levels. But what path of transition is necessary to make these changes by 2050, and does the scenario and transition path followed matter for the goal of mitigating climate change?

I develop a dynamic model of the transportation sector, based on my California-specific adaptation of the VISION stock turnover model (Argonne National Laboratory, 2009), which I call the 80in50 Projected Accessible Transition Headings (PATH) model.

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[6] "The USDA and DOE's "Billion-Ton Study" estimates 1.18 billion metric tones of dry biomass available in the US, which can be converted to approximately 85-92 billion gge of biofuels based upon reasonable conversion rates (Perlack et al., 2005). California currently accounts for nearly 18% of US ethanol consumption, 11% of US VMT and transportation fuels consumption and 13% of GDP; and California's population is expected to grow faster than the country as a whole (12% in 1990 growing to 14% in 2050; California Department of Finance, 2007, 2008; US Department of Transportation, 2007; California Energy Commission, 2008; US Census Bureau, 2008)" (Yang et al., 2009).

This model provides a tool for examination of the transition paths in the light-duty vehicle fleet and energy supply required to achieve each 80in50 scenario. The result is 80in50 transition pathway scenarios for getting from the current LDV fleet and energy supply mix to the 2050 mix(es) required to meet the 80in50 goal. A variety of implications for effective climate change mitigation (i.e., cumulative GHG emissions) are revealed along with specific milestones for interim policy waypoints (e.g., 2015, 2020, 2035) required to meet the 2050 goals, thereby ensuring compatibility in the underlying technologies used to meet medium- and long-term emission reduction goals.

While the scenarios defined by Yang et al. with the LEVERS model were constrained by plausible technological, resource and social limits in 2050 (as defined in the literature), scenarios for transition paths with the PATH model are also constrained by limits in rates of change for technology and infrastructure development and adoption (also defined in the literature), and measured against policy requirements in intermediate years (called "waypoints").[7]

Yang et al. wrote that their analysis was, "meant to be the first step in a series of studies to improve the understanding of the primary drivers and sectoral components of long-term transportation GHG emissions in California." They went on to say, "more research is needed to incorporate [the] dynamics … needed to realize the 2050 futures described here." The research presented in chapter two of this dissertation, where I examine those transition dynamics for achieving the *80in50* goal in the LDV sub-sector, is meant to be the next step in this important area of analysis.

[7] The only strict constraints in my analysis are the 80in50 endpoint and maximum rates of change; intermediate waypoints provide benchmarks for informing the shape of transition paths but are not binding.

Chapter 3: Repowering California Wind

The third chapter is a detailed look at one potential source of low-carbon electricity supply for electric vehicle charging, from repowering and new development in the California wind industry. Having defined *80in50 scenarios* and transition paths at a macro-level in the first two chapters, I turn in the third chapter to consideration of one specific element of this revolution at the micro-scale of individual projects. Specifically, I consider benefits and barriers to repowering in the California wind industry that will influence the potential contribution from this source of low-carbon renewable-source electricity to the total quantity required for each *80in50 scenario*.

The *80in50* scenarios all require more low-carbon electricity than currently available in California *just for use in the transportation sector*. Although California possesses ample total wind and solar resources to meet this demand, they are highly concentrated in just a few areas of high quality resource located close to demand. For wind, nearly all installed capacity (99%) is located in four areas: Altamont, Tehachapi, San Gorgonio and Solano. Current wind production from these areas is approximately 4,400 GWh/y whereas 14,000 to 30,000 GWh/y of zero-carbon renewable-source electricity is needed in 2050 just for electric-drive light-duty vehicles (depending on the 80in50 scenario). But with repowering and capacity expansion, the electricity production from these four areas might be increased over five times. Over half of the turbines in the Altamont, Tehachapi and San Gorgonio areas are more than 20 years old. Decisions about how and when to replace these old, small turbines with new, large ones (i.e., “repowering”) may play a large role in determining total wind-source electricity generation in California in the next several decades. The analysis in chapter three identifies the barriers and benefits that will influence this potential source of low-carbon electricity supply for plug-in electric vehicles in California.

Several research efforts have focused on modeling of wind integration into electric utility systems with and without BEVs (e.g., Short and Denholm, 2006; McCarthy and Yang, 2009). Such research is important for systems-level planning for the integration of more variable energy resources into electric transmission and distribution systems. However, these models require a simplified representation of electricity systems and the context in which they operate in order to be tractable. As a result, there is a noticeable lack of research on the complex context for project-level activity associated with developing more wind power in California, and for repowering of existing developments in particular. The third chapter of this dissertation is meant to address this deficiency.

Scope of Work

The modeling presented in this dissertation uses scenarios rather than optimization, consumer choice or cost estimates and therefore does not reach conclusions pertaining to the optimal or least-cost path to achieving the 80in50 goal. It is possible, however, to differentiate scenarios based on climate change mitigation and exposure to downside risk of not meeting the 80in50 goal. Given the high level of uncertainty in recent estimates of costs associated with the type of transitions needed to achieve the 80in50 goal (National Academies, 2009; National Academies, 2010), a scenario approach to inform debate appears appropriate to this range of future planning (40 years).[8]

[8] Both approaches have value, but will lead to different conclusions. Scenarios allow the researcher to look at a range of possible futures while cost optimization may give indications of the lowest cost or lowest carbon pathway.

The greenhouse gas analysis in this study is based on lifecycle emissions, which include upstream emissions and may differ from other inventories that only consider combustion emissions. The analysis is also limited to *instate* emissions only, which are produced from vehicle trips that take place entirely within California's borders. *Overall* emissions, which include instate trips plus half of emissions from all trips that originate or end in California but cross the state border, are not considered. This definition of emission boundaries is consistent with current policymaking in California (Farrell and Sperling, 2007; CARB, 2008a). However, *instate* transportation emissions in 1990 totaled 193 $MMTCO_2e$ while *overall* emissions were 264 $MMTCO_2e$ (CARB, 2008).[9] See Yang et al. (2009) for further discussion of *Overall* emissions.

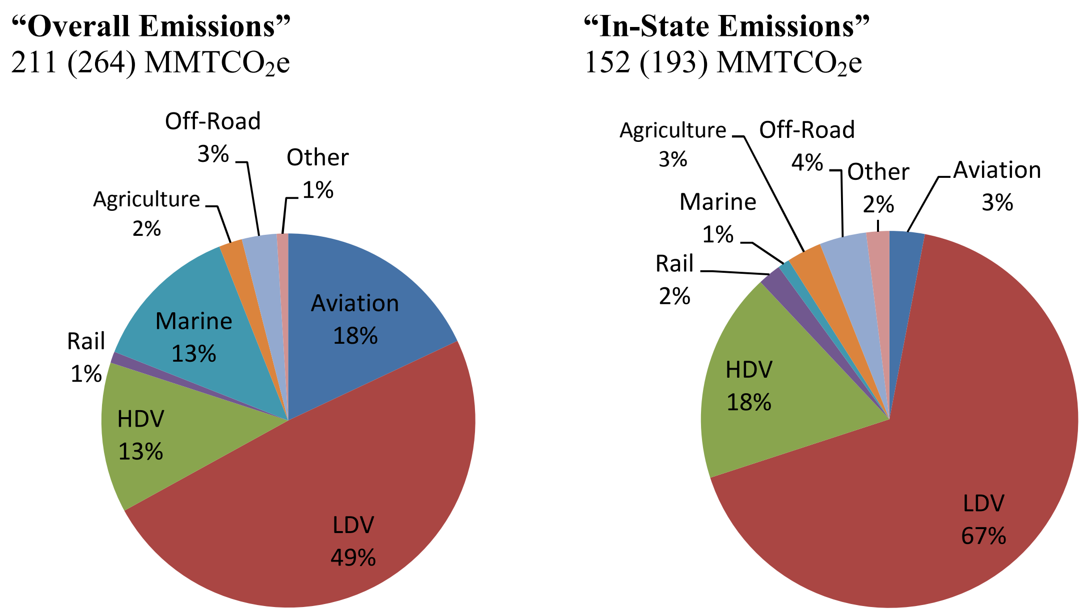

Figure 2: *Instate* and *Overall* GHG emissions in 1990 from transportation sources in California. Overall emissions include additional marine and aviation emissions for trips that travel out of California (CARB, 2008). Values not in parentheses are emissions from direct fuel combustion onboard the vehicles; values in parentheses are estimated lifecycle emissions, including fuel production, refining, and transportation (Yang et al., 2009).

[9] MMT = million metric tonnes; CO_2e includes CO_2, CH_4, and N_2O weighted by their respective global warming potentials

The focus of transition path modeling in chapter two is on the light-duty vehicle (LDV) transportation sub-sector, which accounts for approximately two-thirds of *instate* emissions (Figure 2). As Yang et al. (2009) showed, however, consideration of all transportation sub-sectors is imperative for accurately characterizing the role of LDV in overall emission reductions. In all 80in50 scenarios, the LDV sub-sector must reduce emissions more than 80% to compensate for other sub-sectors (e.g., aviation) that are more constrained in emission reduction opportunities. Consequently, the holistic approach of considering all transportation sub-sectors is carried throughout the research presented in this dissertation by using 80in50 scenarios from the enhanced LEVERS model as the basis for further analysis of the LDV sub-sector with the PATH model. See Yang et al. (2009) for further discussion of other transportation sub-sectors.

The three research topics covered in this dissertation are important for improving understanding of dynamics in the transportation sector related to deep reductions in GHG emissions and the implications for energy supply and use, including the investments required, investment timing decisions involved, and potential government and industry interaction to anticipate.[10] The research is also important for charting a course and successfully navigating the changes that must occur over the next several decades in order to hedge the risk of damaging climate change.

[10] Economics are not included explicitly, although economic studies in the literature influence the scenarios used and the results may be useful in developing scenarios that could be analyzed with respect to cost.

CHAPTER 1: IMPROVED MODELING OF BIOFUEL SUPPLY IN 80IN50 SCENARIO DEVELOPMENT

1.1 The Original Three 80in50 Scenarios

In earlier work, Yang et al. (2009) explored the question of how California can meet the *80in50* goal in the transportation sector by developing static "snapshot" scenarios for the year 2050 with a model including all transportation sub-sectors (light duty, heavy duty, agriculture, aircraft, marine, rail, off-road and construction). The static model of 2050 developed by Yang et al., called the *80in50* LEVERS Model, uses a transportation variant of the Kaya identity (Kaya, 1990; Ehrlich and Holdren, 1971) to decompose GHG emissions into the product of four major drivers—population (P), transport intensity (T), energy intensity (E), and carbon intensity (C) (Equations 1, 2; Table 1).

$$CO_{2,Transport} \equiv (Population)\left(\frac{Transport}{Person}\right)\left(\frac{Energy}{Transport}\right)\left(\frac{Carbon}{Energy}\right) \qquad (1)$$

$$CO_{2,Transport} \equiv \quad \mathrm{P} \quad \times \quad \mathrm{T} \quad \times \quad \mathrm{E} \quad \times \quad \mathrm{C} \qquad (2)$$

Transport Intensity (T)	"Transport intensity may be reduced through decreased travel demand from better land-use planning, higher-density developments, telecommuting and increased co-location of jobs and housing. Mode-shift to larger capacity vehicles can also decrease transport intensity (See Ribeiro et al. (2007) and Ewing et al. (2007) for good reviews)… changes in consumer and industrial purchasing behavior can reduce activity in the freight sector."
Energy Intensity (E)	"The energy required to propel a vehicle (i.e. energy intensity) can be reduced by reducing weight and dissipative losses (rolling resistance and drag) or increasing drivetrain efficiency. Hydrodynamic and aerodynamic drag dominate dissipative loss for marine and aircraft, respectively. For light-duty vehicles, advanced technologies including hybrid electric vehicles (HEVs), plug-in hybrid electric vehicles (PHEVs), battery electric vehicles (BEVs) and fuel cell vehicles (FCVs) can improve vehicle drivetrain efficiency."
Carbon Intensity (C)	"Reducing the carbon content of vehicle fuels by replacing higher-carbon content petroleum fuels (gasoline, diesel, jet fuel/kerosene, and marine bunker fuels) with lower-carbon fuels (biofuels, hydrogen, or electricity) can reduce GHG emissions. The carbon content of a particular fuel can vary with production method, especially for alternative fuels with flexible feedstock like biofuels, hydrogen and electricity. In this study, the carbon content of fuels is estimated on a lifecycle GHG-basis, using a version of the GREET model developed for California (CARB, 2007)."
Population (P)	Projections of population growth in California and the United States were taken as given in this research, not subject to modification as a means of emission reduction.

Table 1: Explanation of actions to change factors in the transport-specific Kaya identity used in the *80in50 LEVERS Model* (Yang et al., 2009).

Although no "silver bullet" strategies employing individual mitigation options to the maximum feasible extent achieved the 80% reduction goal, Yang et al. described three portfolio scenarios combining multiple strategies that could satisfy the *80in50* goal.[11]

- The *Efficient Biofuels* scenario relies on a large quantity (16 billion gallons) of low-carbon (17.7 gCO_2e/MJ) cellulosic biofuels with negligible land-use change impacts to supply more than 80% of fuel across all sub-sectors.
- The *Electric-Drive* scenario requires large scale use of electric drive LDV (PHEVs, BEVs, FCVs) supplied with low-carbon hydrogen (9.3 gCO_2e/MJ) and electricity (6.5 gCO_2e/MJ) while limited low-carbon biofuel supply (0.8 billion gallons; 23.7 gCO_2e/MJ) is directed toward sub-sectors where it is more challenging to use hydrogen or electricity (i.e., aviation, marine, agriculture, off-road).
- The *Actor-Based* scenario complements some degree of LDV electrification with economically-motivated shifts to smaller and more-efficient vehicles, reduced per-capita transportation activity, and increased vehicle occupancy factors.

All three scenarios are characterized by a LDV sub-sector in 2050 that relies on highly efficient vehicles and decarbonized transportation fuels. Regardless of the scenario, meeting the *80in50* goal will require a revolution in light duty vehicles and fuel supply over the next 40 years.

[11] Defining a scenario that meets the *80in50* goal with the *LEVERS Model* involves setting input parameters (i.e., travel demands, vehicle efficiencies, fuel carbon intensities for each vehicle type in every sub-sector) such that the output of total GHG emissions meets the target. The range for each parameter is constrained by technical and social feasibility limits based on extensive research, literature review, and expert judgment (Yang et al., 2009). Yang et al. used "a number of literature sources to bound the extent to which specific mitigation options could be applied and their impact on emissions in each of the transportation sub-sectors." The "silver bullet" scenarios described by Yang et al. are examples of setting certain parameters to their technical and social feasibility limits. The parameters for the *Multi-Strategy$_{pessimistic}$*, *Multi-Strategy$_{middle}$*, *Multi-Strategy$_{optimistic}$*, *Actor-Based*, *Efficient Biofuels* and *Electric Drive* scenarios are given in appendix A. These six scenarios illustrate a range in technical goals, assumptions about production methods, and resource constraints and behavior in 2050 that are consistent with meeting the *80in50* goal.

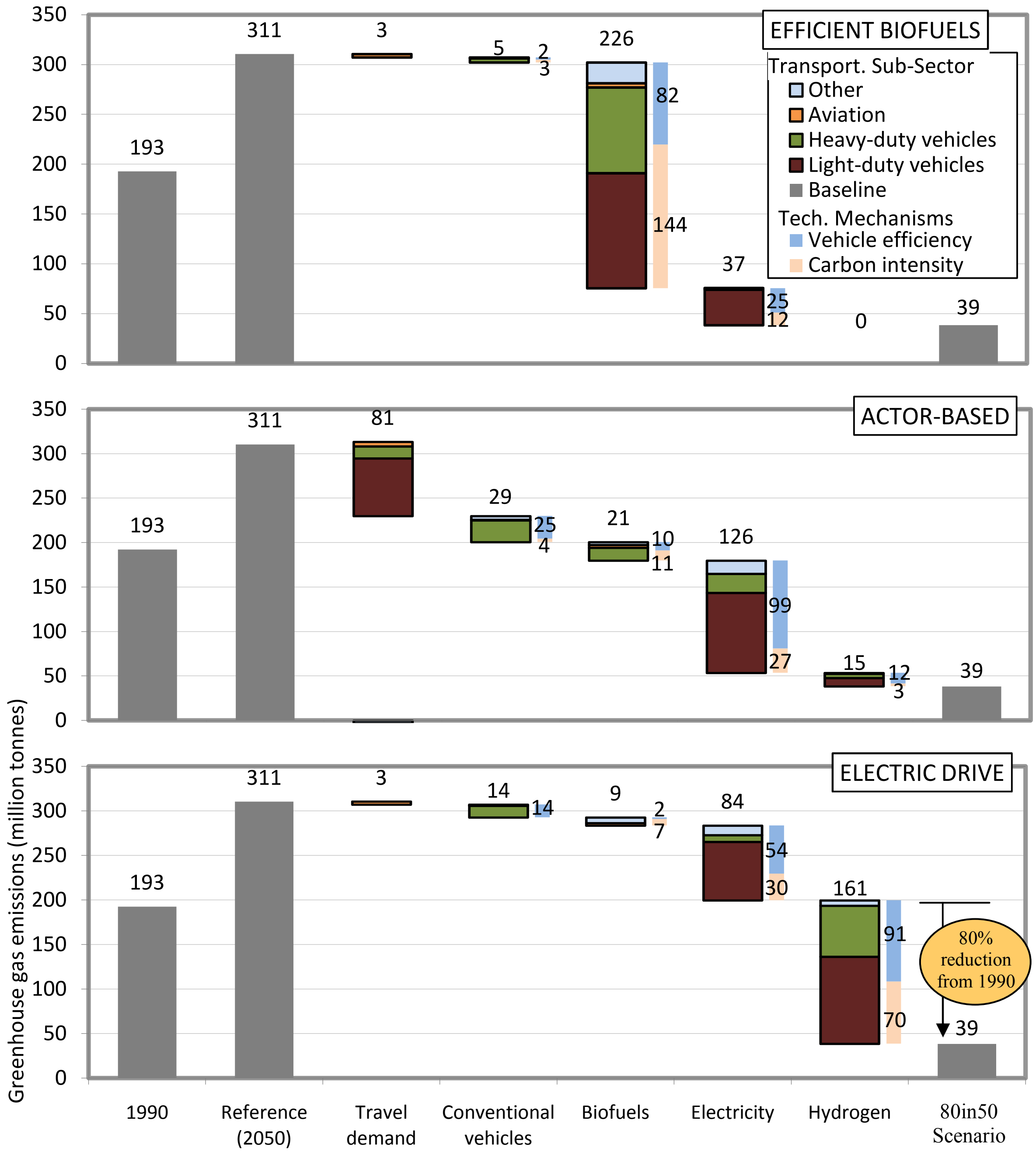

Figure 3: In-state GHG emission reduction from the *Reference* scenario by control strategy for the original three *80in50* scenarios defined by Yang et al. (2009). The *Reference* scenario shows business as usual while each successive column to the right shows emission reduction attributable to the factors of travel demand, efficiency, and carbon intensity of fuels (biofuels, electricity, and hydrogen). Within each column, the contribution from transportation sub-sectors is shown. For example, LDV contribute to emission reduction through reduced travel demand, vehicle efficiency, and reduced fuel carbon intensity from electrification and hydrogen. Heavy-duty vehicles (HDV) contribute through efficiency and low-carbon biofuels and hydrogen.

Figure 3 shows how GHG emissions are reduced in these original three *80in50* scenarios as compared to the *Reference* scenario, by different activity, fuel, and technology options.

The *Reference* scenario is defined by continued transportation activity and technology development according to historical trends (Yang et al., 2009). While vehicle fuel efficiency increases consistent with the 2008 CAFE rules (i.e., reduction in energy intensity, E, of 35%), a doubling in population and 23% increase in the transport activity per capita (T) produces a 2.5 times increase in total travel demand (PxT). The average carbon intensity (C) of transportation fuels increases 2% as petroleum-based fuels remain dominant and unconventional sources are utilized more. Overall, this leads to a 62% *increase* emissions from 1990 to 2050 in the *Reference* scenario (311 MMTCO$_2$e instate emissions in 2050).

In the *Electric-Drive* scenario, 59% of emission reductions from the *Reference* scenario come from the use of FCVs and hydrogen fuel (161 MMTCO$_2$e) in the LDV and HDV sub-sectors. Electric vehicles account for 31% of emission reductions from the *Reference* scenario (85 MMTCO$_2$e), mainly from the use of PHEVs and BEVs in the LDV sub-sector. Approximately two-thirds of the emission reductions result from improvements in fuel economy associated with electric-drive vehicles (FCVs, BEVs, and PHEVs), while the remainder can be attributed to the use of low-carbon intensity hydrogen and electricity. Limited low-carbon biofuels are used only in sub-sectors where hydrogen and electric vehicles are ill-suited.

The *Actor-Based* scenario employs high-efficiency electric vehicles (PHEVs, FCVs, BEVs) to a lesser extent than the *Electric-Drive* scenario (52% of emission reductions versus 90%, respectively), with the gap in emission reduction filled primarily with reductions in overall travel demand (29% of emission reductions from the *Reference* scenario) and further improvement in vehicle efficiency attributable to reduced performance (e.g., smaller, less power). Of the technology related GHG emission reductions (192 $MMTCO_2e$), vehicle efficiency accounts for the majority (147 $MMTCO_2e$). Biofuels consumption in this scenario is 1.7 billion gge in 2050, less than the 2.3 billion gge that California is capable of producing from residues that minimize food supply and land-use change impacts (e.g., agricultural, forestry, municipal wastes) (Jenkins, 2006).

In the *Efficient Biofuels* scenario, biofuels are responsible for 229 $MMTCO_2e$ of the emission reductions (84%) from the *Reference* scenario, and electricity for 37 $MMTCO_2e$ (14%) from the *Reference* scenario. Most of the reductions from the use of biofuels (146 $MMTCO_2e$) can be attributed to their lower lifecycle carbon intensity relative to conventional fuels in the *Reference* scenario (17.7 gCO_2e/MJ versus 95.3 to 96.4 gCO_2e/MJ for unblended diesel and gasoline or 90.8 to 91.8 with 6% biofuel blending). But the *Efficient Biofuels* scenario demands a quantity of low-carbon biofuels (16.2 billion gge) that is very large relative to current US ethanol consumption and future mandates (3.7 billion gge in 2006 (EIA, 2008); 36 billion gallons of renewable fuel or approximately 24 billion gge required by 2022 nationally). Although this quantity of biofuels could be available in California under optimistic estimates of US biofuels supply (85–92 billion gge) if the state is able to use 15–20% of the US total (Perlack et al., 2005), Yang et al. further assume an optimistically low *average* lifecycle carbon intensity for this entire supply (17.7 gCO_2e/MJ).

The emission reductions achieved through each factor in the transport-specific Kaya identity and from each transportation sub-sector in these three scenarios are shown in Figure 15 (section 1.6.2). The first two scenarios (*Efficient Biofuels* and *Electric-Drive*) emphasize technology, assuming that technology development can reduce GHG emissions from transportation with relatively little change in travel behavior. The third scenario (*Actor-Based*) considers actor-based decisions to reduce travel demand and energy intensity, while also employing advanced technologies.

The assumed make-up of the light duty sub-sector in each of these scenarios (described in more detail below) is summarized in Table 14 and Table 15. Complete lists of the assumptions that define each 80in50 scenario are given in Appendix A.

1.2 Sensitivity Analysis for the Original Three 80in50 Scenarios

To examine the sensitivity, tradeoffs, and constraints inherent in the original three *80in50* scenarios, I developed an approach to sensitivity analysis that attempts to capture the complexity of interactions in the LEVERS model.

The sensitivity for each parameter will depend on many other parameter values because of the multiplicative nature of the Kaya equation. For example, the sensitivity of GHG emissions to a given vehicle technology's fuel economy depends on the carbon intensity of the fuel used and the prevalence of that vehicle technology in 2050.

Consequently, the model sensitivity to each parameter is tested by varying the parameter over its feasible limits while holding all other parameters constant. The upper bound (lowest-emissions) limits for each parameter were determined from literature[12] by

[12] An and Santini, 2004; Ang-Olson and Schroeer, 2003; CARB, 2004; Little, 2002; EUCAR, 2007; Ewing et al., 2007; Eyring et al., 2005; Frey and Po-Yao, 2007; Greene and Schafer, 2003; Greszler, 2007; IUR,

assuming concerted effort for maximum improvement in the T, E and C factors is applied wholly to GHG emission reduction (e.g., no increase from current vehicle size or performance). Where literature provided a range of possible efficiency improvement, travel demand reduction, or fuel carbon intensity, I took the most optimistic (least-carbon) end of the range. The lower bound (highest-emissions) for transportation intensity (HDV truck miles per person, LDV VMT per capita, passenger-miles per capita and passengers per vehicle, Off-Road & Construction hours per capita, and Agriculture hours per capita), vehicle efficiency (LDV, HDV and Bus fuel economy, and Aircraft and Off-Road & Construction fleet efficiency), and fleet share of cars and trucks are defined by the *Reference* scenario in Yang et al. (2009), which presumes continuation of business as usual in the transportation sector.[13] For fuel carbon intensity, I use the pessimistic limits defined by Yang et al. (2009) and for population I use the range in published estimates (55 – 59.5 million in 2050; CARB, 2007; CDF, 2007).

Since each of the original three *80in50* scenarios are most readily characterized by the mix of vehicle technologies in the fleet in 2050, I held these parameters fixed during the sensitivity analysis (i.e., these are "defining parameters" for each scenario). As a result, the model sensitivity to some parameters differs dramatically between scenarios due to the magnitude of the role they play in the scenario. For example, an extremely low fleet share for a particular vehicle technology renders LDV GHG emissions insensitive to the efficiency of that technology and the carbon intensity of the fuel it uses.

2008; Ribeiro et al., 2007; Kasseris and Heywood, 2007; Kromer and Heywood, 2007; Leighty et al., 2007; Marintek, 2000; O'Connor, 2007.

[13] For example, vehicle energy efficiency continues to improve in the *Reference* scenario even without major changes in vehicle technologies, achieving a sector-wide reduction in energy intensity of 35% (on average approximately 66% of the feasible energy intensity reduction found in the literature for each vehicle technology in 2050).

In general, the overall sensitivity is relatively low for any single parameter because of the large number of transportation sub-sectors and parameters in play. Consequently, I aggregated the sensitivity analysis by general categories of parameters in order to create the summary in Table 2 and Table 10 (section 1.5). The maximum range in GHG emissions for each parameter category (shown in the maximum difference column of Table 10) provides an indication of the maximum sensitivity across the three original 80in50 scenarios. The result is a complete sensitivity analysis that includes the variation in the 2050 fleet mix of vehicle technologies represented in the original three *80in50* scenarios.

Parameter Category	GHG Emissions in 2050 (% of 1990) Actor-Based High - Low	Efficient Biofuels High - Low	Electric-Drive High - Low	Max. Diff.
Biofuel Lifecycle GHG Emissions (71.3 to 9.3 gCO2/MJ)[1]	24.4 - 19.3%	67.2 - 12.6%	22.4 - 19.3%	54.6%
Hydrogen Lifecycle GHG Emissions (100 to 7.6 gCO2e/MJ)[2]	21.8 - 18.9%	20.0 - 20.0%	59.3 - 19.3%	40.0%
Carbon Capture and Storage (0% to 80% effectiveness)[9]	28.0 - 20.0%	26.5 - 20.0%	41.4 - 20.0%	21.4%
Electricity Lifecycle GHG Emissions (149 to 6.5 gCO2e/MJ)[3]	28.5 - 16.7%	26.5 - 20.0%	26.3 - 20.0%	11.8%
HDV Truck Fleet Fuel Economy (mpgge) (75% to 100% of feasible limit)[9]	25.6 - 20.0%	21.4 - 20.0%	23.8 - 20.0%	5.6%
HDV Truck Miles per Person (612 to 398 mi./capita)[9]	25.1 - 20.0%	20.0 - 18.5%	20.0 - 16.0%	5.5%
LDV Occupancy & Transport Intensity[4]	21.9 - 20.0%	20.0 - 14.7%	20.0 - 18.0%	5.3%
LDV Fleet Fuel Economy (mpgge)[6]	24.8 - 20.0%	25.0 - 20.0%	21.9 - 20.0%	5.0%
PHEV share of miles in EV mode[7]	23.6%-19.7%	21.3%-18.9%	21.0%-20.0%	3.9%
Population (59.5 to 55 million)[10]	20.0%-17.9%	20.0%-18.2%	20.0%-17.7%	3.0%
Biofuel Blend in Gasoline & Diesel (0% to 20%)[9]	22.5%-20.0%	21.6 – 19.9%	20.0 - 18.4%	2.5%
Fleet Share: Cars (60% to 85% of fleet)[9]	20.7%-20.0%	20.0%-18.3%	20.0%-19.4%	1.7%
Off-Road & Construction Fleet Eff. (75% to 100% of feasible limit)[9]	21.4 – 20.0%	20.9 – 20.0%	20.3 – 20.0%	1.4%
Off-Road & Construction Intensity (38.9 to 23.3 hr/capita, 160% to 95% of 1990)	20.6 – 19.4%	20.0 – 18.9%	20.0 – 19.6%	1.2%
Agriculture Intensity (3.6 to 0.8 hr./capita, 100% to 22% of 1990)	21.2%-20.0%	20.7%-19.7%	20.7%-19.7%	1.2%
Bus Fleet Fuel Economy (75% to 100% of feasible limit)[9]	21.1%-20.0%	20.1%-20.0%	20.1%-20.0%	1.1%
Aviation Transport Intensity (instate)[8]	20.3%-19.9%	20.0%-19.6%	20.0%-19.4%	0.9%
Aircraft Fleet Efficiency (60% to 100% of feasible limit)[9]	20.5%-20.0%	20.5%-20.0%	20.8%-20.0%	0.9%
Marine Transport Intensity (75% to 100% of feasible limit)[9]	20.2%-19.8%	20.0%-19.9%	20.0%-19.6%	0.6%

$$CO_{2,\ Transport} = P \times T \times E \times C$$

P: Population; T: Transportation Intensity; E: Energy Intensity (LDV, HDV); C: Fuel Carbon Intensity

Transportation sub-sectors other than LDV & HDV (off-road, construction, ag., aircraft, marine, rail)

Carbon capture and sequestration (CCS)

Table 2: Sensitivity analysis for the maximum range in emission reductions across all three original *80in50* scenarios for general categories of scenario parameters. The maximum variation in emission reduction from 1990 levels is shown along with the corresponding range in parameter values, where meaningful. The parameters are color-coded according to the factors in the transportation variant of the Kaya identity used by Yang et al. (2009).

Notes:
[1] 9.3 gCO2/MJ is the most optimistic mix deemed feasible by Yang et al. with 35% ethanol (12.3 gCO2/MJ), 10% biodiesel (25.8 gCO2/MJ), 22.5% methanol (5.1 gCO2/MJ) and 22.5% DME (5.4 gCO2/MJ); 71.3 gCO2/MJ represents aggressive biofuel blending with gasoline (i.e., 80% of gasoline carbon intensity in 2050).
[2] The low end is 50% natural gas via pipeline with 80% CCS (15.2 gCO2/MJ) and 50% renewable electrolysis (0 gCO2/MJ); the high end is 100% onsite reformation from natural gas (100 gCO2/MJ). Note, 100% onsite electrolysis with the current California grid mix would produce 138.2 gCO2/MJ (Yang et al., 2009).
[3] The current California grid mix produces 149 gCO2/MJ while 6.5gCO2/MJ is the best deemed feasible in 2050 by Yang et al. with 30% natural gas combined cycle with 80% CCS (20.2 gCO2/MJ), 30% nuclear (1.6 gCO2/MJ) and 40% renewable (0 gCO2/MJ) (Yang et al., 2009).
[4] 60% - 120% of 2005 VMT/capita and passenger-miles/capita, and 100% - 125% of 2005 passengers/vehicle (Yang et al., 2009).
[5] For each vehicle technology, fuel economy ranges from the *Reference* scenario values in Yang et al. to 100% of feasible limits for 2050 (Yang et al., 2009).
[6] For each vehicle technology, fuel economy ranges from the 2050 *Reference* scenario values in Yang et al. to 120% of feasible limits for 2050, which corresponds to the assumption of decreased vehicle performance (e.g., smaller with slower acceleration) made in the *Actor-Based* scenario (Yang et al., 2009).
[7] Pessimistic and optimistic limits defined by Yang et al. are 43% - 58% in EV mode for LDV, 15% - 49% in EV mode for Buses (Yang et al., 2009).
[8] Aviation transport intensity is a combination of three parameters, with ranges defined by Yang et al. (2009): 80-100% of the *Reference* commercial passenger aviation (mi/capita), 65-100% of the *Reference* commercial freight aviation (ton-mi./capita), and 65%-100% of the *Reference* personal general aviation (mi/capita).
[9] Yang et al., 2009
[10] CARB, 2007 and CDF, 2007

In general, the original three *80in50* scenarios are most sensitive to fuel carbon intensity parameters, which indicates the importance of decarbonizing energy supply for meeting the *80in50* goal in these scenarios. All three scenarios rely heavily on fuels with very low-carbon intensity to achieve the 80in50 target. Production methods for biofuels, hydrogen or electricity that result in fuels with higher carbon-intensity could offset much of the emission reductions gained from the other transportation sector changes in these scenarios.

The *Efficient Biofuels* scenario is most sensitive to biofuel carbon intensity while the *Actor-Based* and *Electric-Drive* scenarios are more sensitive to hydrogen and electricity carbon intensity. This is due to the relative fraction of total fuel supplied from each source in these scenarios.

The sensitivity to biofuel carbon intensity is also due to a broad range in uncertainty in feedstock supply, production process, co-products, and indirect land-use change impacts from producing this fuel. The range for hydrogen and electricity carbon intensity is also broad due to the diversity and uncertainty in feedstock supply and to uncertainty in application and effectiveness of carbon capture and storage (CCS). Success with CCS is an important factor across all three scenarios, and is used extensively for fossil-fuel-based energy sources in all three.

The *Actor-Based* scenario is less sensitive to increases in fuel carbon intensity than the other scenarios since reductions in travel demand and greater vehicle efficiencies contribute more towards emission reductions. Transportation intensity is reduced near feasible limits in the *Actor-Based* scenario but is used less as an emission reduction strategy in the *Efficient Biofuels* and *Electric-Drive* scenarios.

In general, deviation from the *80in50* goal in the sensitivity analysis is greater on the low side of emission reduction (i.e., insufficient emission reduction to meet the 80in50 goal) than on the high side of emission reduction (i.e., additional reductions beyond 80%). This means that for these three scenarios, there are more parameters at or near the least-emission feasible limits than there are parameters at or near the highest-emission *Reference* scenario for business as usual. In other words, all three scenarios require success across several dimensions in order to achieve the *80in50* goal, and are susceptible to failing to reach this goal on many fronts.

Finally, we can consider an "upper bound" for emissions reductions in each scenario that is defined by setting all parameters (other than the fleet mix of vehicle technologies that defines each scenario) to the least-emission feasible limits. The resulting reduction in GHG emissions from 1990 levels for each scenario are as follows: 86% for the *Actor-Based*, 92% for the *Efficient Biofuels*, and 90% for the *Electric Drive* scenarios. These results show that the strategies highlighted in the *Efficient Biofuels* scenario, including success with very large quantities of very low-carbon biofuels, offers the greatest potential for GHG emission reductions beyond the required 80% after 2050. The strategies highlighted in the *Actor-Based* scenario offer the least potential for further GHG emission reductions beyond 80 percent.

The reason for this difference can be seen in the Kaya identify shown in equations one and two. With a large supply of low-carbon biofuels available in the *Efficient Biofuels* scenario, more emission reductions can be accomplished through fuel decarbonization, leaving more room for additional improvements in efficiency and reductions in transportation intensity. Success in reducing the average carbon intensity of biofuels to the lower bound of 9.3 gCO2e/MJ reduces emissions in the Efficient Biofuel scenario to 12.6% of 1990 levels and reductions in transportation intensity (e.g., HDV truck miles per capita and LDV occupancy and VMT per capita) can be made to reduce emissions even further. Conversely, limited biofuel supply leaves less room for additional fuel decarbonization in the *Actor-Based* scenario – success in reducing the carbon intensity of electricity to the lower bound of 6.5 gCO2e/MJ reduces emissions to 16.7% of 1990 levels – and potential improvements in efficiency and reductions in transportation intensity are already set near the lower bounds in this scenario.

Similarly, a "lower bound" for emissions reduction from each scenario's technology mix can be defined with the highest-emission *Reference* and pessimistic values for all parameters. This "lower bound" yields the following *increases* in GHG emissions from 1990 levels: 53% for the *Actor-Based*, 27% for the *Efficient Biofuels*, and 38% for the *Electric Drive* scenarios. These increases are generally less than for the *Reference* case described by Yang et al. (44% increase from 1990 levels) despite more pessimistic fuel carbon intensities due to the wide usage of more advanced vehicle technology.

From these sensitivity analyses, it is evident that relatively little opportunity exists in each of the original three *80in50* scenarios to further reduce GHG emissions below 20% of 1990 levels, while emissions could *increase* despite dramatic changes in vehicle technology if the other relevant factors like fuel carbon intensity and transportation activity in each scenario do not improve.[14]

[14] One reviewer noted that this observation may depend on one's perspective. For example, achieving 90% reduction in GHG emissions from 1990 levels is an additional 50% lower than the 80% reduction needed to meet the 80in50 goal. The perspective used here, however, is based on the objective of mitigating climate change, which depends on the absolute quantity of emissions. From this perspective, 90% reduction from 1990 levels is an additional 19.3 million metric tons CO_2e of avoided GHG emissions per year, which is relatively little compared to the 249 million metric tons per year of avoided emissions from business as

As GHG emissions are reduced closer to zero, it becomes more difficult to achieve further reductions of similar magnitude in $MMTCO_2e$. For example, although achieving 92% reduction from 1990 levels with the *Efficient Biofuels* scenario – the maximum amount feasible – would be a further 60% reduction relative to the *80in50* goal, it is only an additional 15% of the original magnitude of reduction in annual GHG emissions required to meet the 80in50 goal.

Thus, while all three of the original *80in50* scenarios are "equal" in achieving the *80in50* goal, they are not equal in upside potential for further emission reduction after 2050, nor in downside risk for missing the *80in50* goal if required levels in some parameters are not met.

1.3 The Role of Biofuels in 80in50 Scenarios

As shown in the sensitivity analysis of the original three 80in50 scenarios, the availability of low-carbon biofuels is the most influential input parameter that affects transportation GHG emissions and is subject to large uncertainty. The *Efficient Biofuels* scenario is particularly sensitive to the carbon intensity of the biofuel supply because of the relatively large quantity used – 16 billion gge, or approximately 60% of total transportation fuel across all sub-sectors used in this 80in50 scenario (Figure 4).

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usual already achieved by meeting the 80in50 goal. In other words, eliminating the last unit of GHG emissions is much more difficult than eliminating the first.

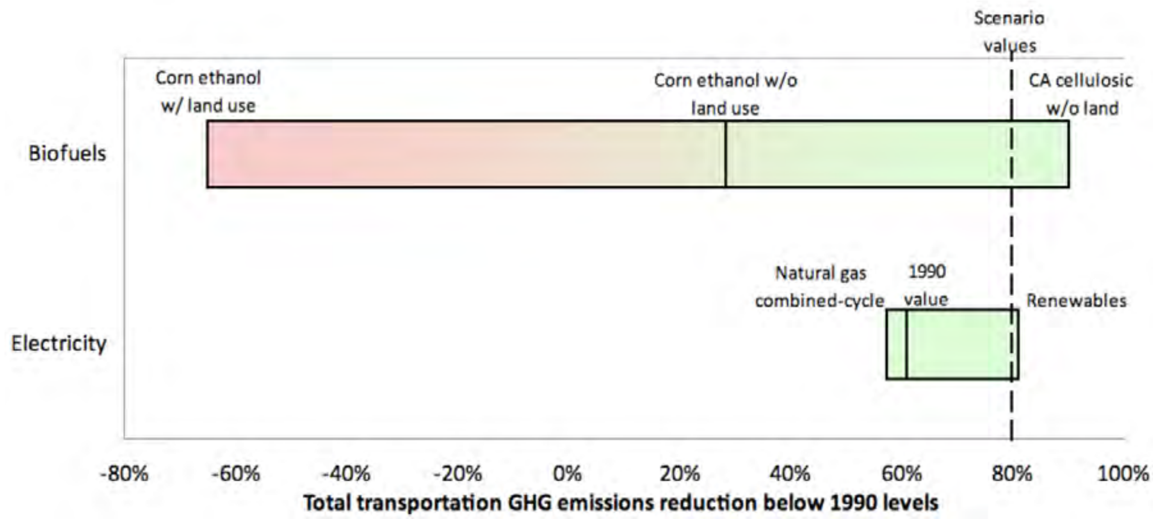

Figure 4: Sensitivity of in-state GHG emission reductions to fuel carbon intensity in the *Efficient Biofuels 80in50* scenario (Yang et al., 2009).

But the assumptions about biofuel supply that were made in the original *Efficient Biofuels 80in50* scenario were rather simple. First of all, the total quantity of 16 billion gge available in California was based on a 15-20% share of total potential U.S. supply (85-92 billion gge) under optimistic estimates.[15] However, as Yang et al. explained, there is a wide range of uncertainty in these estimates. Estimates of the total amount of biomass and biofuels production available in the U.S by Perlak et al. (2005), NRDC (2004) and NRC (2008) vary from tens of billions of gallons (gge) to over one hundred billion gge.[16] A recent US mandate requires 36 billion gallons of renewable fuel (24 billion gge if all

[15] Yang et al. (2009) argued a 15-20% share of total U.S. biofuel supply for California may be reasonable since California currently accounts for 11% to 18% of U.S. total on a variety of metrics (population, GDP, VMT, motor vehicles registrations, transportation fuels consumption, and ethanol consumption) and is expected to grow more quickly than most other areas of the country between now and 2050 (e.g., from 12% of U.S. population in 1990 to 14.2% in 2050).

[16] The estimate of 1.3 billion dry tons of biomass available in the U.S. from the "Billion Ton Vision" study implies 85-92 billion gge (127.5 billion gallons ethanol) could potentially be "sustainably" supplied (without impacting food, feed, and export demands or displacing corn croplands) by 2050, if competing demands for biomass are ignored (Perlak et al., 2005; Yang et al., 2009). The NRDC (2004) estimated up to 120 billion gge and the NRC (2008) estimated 39-51 billion gge. Differences in assumptions between these analyses include the cellulosic resource base, competing energy use demands for biomass from things like power generation, cost and water limitations, and conversion technologies and efficiencies.

ethanol) by 2022 (EISA, 2007). One study estimates California can produce just 2.3 billion gge of biofuel from waste residues and feedstocks grown on non-agricultural lands in the state (Jenkins, 2006).

Secondly, the assumed average carbon intensity of this biofuel supply was made *independently* from the resource assessment and feedstock supplies, despite wide variation in carbon intensity across feedstock and production processes. As Yang et al. acknowledged,

> "A number of different feedstocks (corn, sugar cane, soybean, palm oil, switchgrass, algae, agricultural and forest residues, and so on) and production processes (fermentation, trans esterification, cellulosic hydrolysis/fermentation, gasification, catalytic synthesis) can be used to make biofuels. Depending on the feedstock and process, lifecycle GHG emissions can vary dramatically—anywhere from well below those of petroleum-derived fuels to well above them."

The issue of potential emissions from changes in land use associated with biofuel production adds further complication (i.e., indirect land-use change).[17]

Yang et al. did not resolve these sources of uncertainty in biofuel carbon intensity, but rather assumed an optimistic average carbon intensity for all biofuel of 17.7 gCO2e/MJ, regardless of the total quantity, feedstock, or processing method used. Thus, the *Efficient Biofuels 80in50* scenario is quite optimistic about the quantity and carbon-intensity of the biofuels available in California. As such, refining the treatment of biofuels in this 80in50 scenario would improve its value in comparing feasible options for meeting the 80in50 goal for transportation.

A more recent and realistic study of biofuel supply in the United States by Parker et al. (2010; described in more detail below) includes additional constraints on biomass

[17] The debate surrounding estimating biofuel lifecycle GHG emissions shifted from assumptions regarding process fuels (coal, natural gas), nitrogen and lime application rates, co-product allocation, and several other uncertainties to emissions associated with indirect land-use changes with publication of preliminary estimates of the latter by Searchinger et al. (2008).

resources and affords the opportunity to refine the treatment of biofuel supply and carbon intensity in creating 80in50 scenarios. To do so, I revised the *80in50 LEVERS Model* developed by Yang et al. to add a biofuel module based on California-specific biofuel supply curves created with the spatial model developed by Parker et al. (2010) (Figure 10 in section 1.3.4), and feedstock-process pathway-specific carbon intensity estimates for 15 different biofuel production methods (Figure 11 in section 1.3.4).

1.3.1 Improved Modeling of Biofuel Supply

A national biorefinery siting model (NBSM) developed by Parker et al. (2010) provides the foundation for refining the modeling of biofuel supply used in creating 80in50 scenarios. I worked closely with Dr. Nathan Parker to adapt the original NBSM for use in modeling biofuel supply for California in 2050.

The modeling approach developed by Parker et al. uses national biomass resource assessment and biorefinery siting optimization to "assess potential biofuel supply across the United States from agricultural, forest, urban, and energy crop biomass for the next decade." Geographic information system (GIS) and infrastructure system cost optimization models were combined to assess biofuel supplies from biomass feedstocks in the United States. Parker et al. describe their NBSM methodology as follows.

> "Spatial information including feedstock resources, national fuel demand, existing and potential refinery locations and a transportation network model is provided to a mixed integer-linear optimization model that determines the optimal locations, technology types and sizes of biorefineries to satisfy a maximum profit objective function applied across the biofuel supply and demand chain from site of feedstock production to the product fuel terminal. This analysis has four main components – 1) geographically-explicit biomass resource assessments, 2) engineering/economic models of the conversion technologies, 3) models for multi-modal transportation of feedstock and fuels based on existing transportation networks, and 4) a supply chain optimization model that designs the fuel production system based on inputs from the other models.

> Costs considered are those associated with feedstock procurement, transportation, conversion to fuel, and fuel transmission to distribution terminals. Fuel production and selling price determine industry revenue. The selling prices of the product fuels are input parameters that are varied to create a supply curve… profit is defined here as the annual revenue from the sale of biofuels less the annual cost of producing those biofuels… additional revenue streams come from the sale of co-products."

For the purposes of this dissertation, we are interested in one of the results of the modeling by Parker et al. in particular – biofuel supply curves for 23 different combinations of feedstock types (14) and biofuel conversion technologies (5) (Table 3).

The original modeling by Parker et al. was for national biofuel supply and used the year 2017 as the "target for technology costs and feedstock availability, which is presumed to allow sufficient time for the development and initial deployment of second-generation biofuel production technologies." Consequently, for use in developing 80in50 scenarios for California, I needed to extract biofuel supply curves specific to California from the national model and needed to make several assumptions to extrapolate underlying parameters from 2017 to 2050.

Feedstock Category	Feedstock Type	Conversion Technologies
Clean Lignocellulosics	Forest biomass Pulpwood Herbaceous Energy Crops Straw and Stover Ag. Residues Orchard/Vineyard Wastes Municipal Solid Wastes • Mixed Paper • Wood Wastes • Separated Yard Wastes • Separated Food Wastes	Lignocellulosic ethanol through hydrolysis and fermentation (LCE) Lignocellulosic middle distillate, a.k.a. Fischer Tropsch diesel (LCMD)
Lignocellulosics	Remainder of biomass Municipal Solid Waste (MSW)	LCMD
Lipids	Seed Oils Yellow Grease Animal Fats	Fatty acid to methyl esters (FAME) Fatty acid to hydrocarbon fuel (FAHC)
Cereal grains	Corn	Dry and Wet Mill Ethanol

Table 3: Biofuel feedstock and conversion technology combinations considered by Parker et al (2010).

Finally, it is important to recognize that the NBSM developed by Parker et al. is an engineering-economic model, not a partial-equilibrium economic model. In other words, the “feedstock loops in the economics of the industry are not modeled explicitly.” Parker et al. explain this distinction as follows,

> “Demand for feedstock does not impact the cost of acquiring the feedstock [and] the feedstock providers are assumed to receive some of the total profit sufficient to motivate feedstock deliveries. The industry does not impact the value of co-products. Co-product value [does] impact the nominal cost of fuel production, however the impact of co-product price elasticity is not considered. The industry consuming waste and residue resources does not impact the industries producing the wastes and residues.”

The model does not include interactions with food markets even though commodity crops including corn and soybeans are treated as a feedstock. The implication is that circumstances in which competition for biomass feedstocks may exist, as with commodity crops for example, will require simplifying assumptions since competitive interactions are not endogenous to the modeling structure.

1.3.2 Extraction of Biofuel Supply Curves Specific to California from the National Model

To extract biofuel supply curves specific to California from the national model of biofuel feedstock collection, processing and distribution developed by Parker et al., a method of allocation was necessary. There are several ways one could allocate a national fuel supply among users in different states, including by population, VMT or fuel use, by lowest cost, or according to state-level policy requirements. For this dissertation, I allocated available biofuel supply in proportion to conventional fuel supplies. This allocation amounts to an assumption of "fair sharing" in biofuel distribution (i.e., each state receives a share of available biofuel in proportion to their current fuel demand).[18,19] Under this "fair share" requirement, each existing fuel distribution terminal in the United States receives a share of total biofuel supply proportional to existing conventional fuel supply (with +/- 5% allowance to speed model resolution). In other words, California

[18] The "fair share" requirement is based on the need for commensurate GHG emission reduction action in other states and nations in order for California policy to mitigate climate change. This implies other regions will also demand use of low-carbon biofuels, leading to competition for feedstock resources. The extent to which California uses more than its "fair share" will inhibit the ability of other regions to reduce their emissions if the whole system is resource constrained.

[19] Three alternative approaches were considered and rejected for the following reasons. First, simply scaling the national biofuel supply curves by California's fraction of total population (or VMT) would lose the spatial specificity of the NBSM regarding which fuels (i.e., derived from which feedstock pathways) are available at each fuel terminal. Second, running the NBSM without the fair share requirement, to approximate pure cost minimization for profit maximization assuming a level playing field across states, is intractable for solving the optimization problem. Third, the "blend wall" approach described by Parker et al. – wherein total biofuel quantity is limited by the maximum blend percentage in gasoline and diesel for use in conventional internal combustion engines – is less reasonable for the year 2050 because FFV fleet development can render blend limits for conventional ICE vehicles no longer constraining.

receives a share of total biofuel available in the United States that is proportional to its share of total fuel use. This approach is consistent with one method used by Parker et al.[20]

With the fair share requirement imposed on the NBSM model, the California-specific biofuel supply was isolated from the national modeling by simply saving biofuel supplied to California in a separate output file. Although the biofuel industry is expected to concentrate in the Midwest to take advantage of corn and agricultural residue resources, there is also significant development near metropolitan areas to take advantage of municipal wastes and in regions with large forestry operations to make use of the residues from these industries. In addition, biofuel may be transported some distance to market. See Figure 5 and Figure 6 for examples of the spatial layout of optimized biorefinery siting, biomass collection, and biofuel distribution produced by the NBSM model.

Several implications of the fair-share rule are important to acknowledge. First, the fair-share rule does *not* imply equality in which biomass resources and conversion technologies are used to supply the biofuel available at each terminal. Consequently, equality in biofuel carbon intensity is not imposed. This poses the potential for some inherent contradiction in the rationale for the fair share requirement based on a need for commensurate GHG emission reduction actions across all states and nations (see footnote 18). However, retaining the spatially-explicit profit-maximizing matching of biomass

[20] Parker et al. used "a simplified case of evenly distributing the fuels produced across the country by VMT" as one method of biofuel allocation, which is approximately equal to total fuel demand since fleet average fuel economy does not differ much between states. Parker et al. explain this method as follows: "…a proportion of fuel deliveries of a specific fuel type to each terminal must not be greater than 5% more than the proportional vehicle fuel demand allocated to the terminal. The fuel demand is allocated by the fraction of the national VMT within the terminal's service territory. The model considers the spatial limits of biofuel demand. This is worked into the model as a constraint to the quantity of each type of biofuel that may be sold from each fuel distribution terminal. The fuel demand is based on a projection of vehicle miles traveled (VMT) by census tract for the year 2015." The inherent assumption in extrapolating this framework to 2050 is that total VMT stays proportional by census tract from 2015 to 2050. Although certainly not accurate, this assumption provides a reasonable approximation for implementing the fair share rule for modeling California biofuel supply in 2050. To the extent California VMT actually grows more or less than elsewhere in the nation, its "fair share" of biofuel would increase or decrease slightly.

resources and biofuel supply to demand produced by the NBSM is a more appropriate approximation of biofuel market development than imposing strict “fairness” in biofuel carbon intensity as well as quantity.

Due to transportation costs for feedstock and biofuel, California receives less corn-based ethanol than Midwestern states. Consequently, the average carbon intensity for biofuels in California will tend to be lower than for some Midwestern states. Although the “lipid resources, which have a high yield of fuel per ton, [can] be economically transported further than for example, a straw feedstock,” relatively little biomass is transported across California state borders in the modeling by Parker et al. (2009). There are, however, large amounts of biofuel importation into California (Table 4), which come mostly from neighboring states.

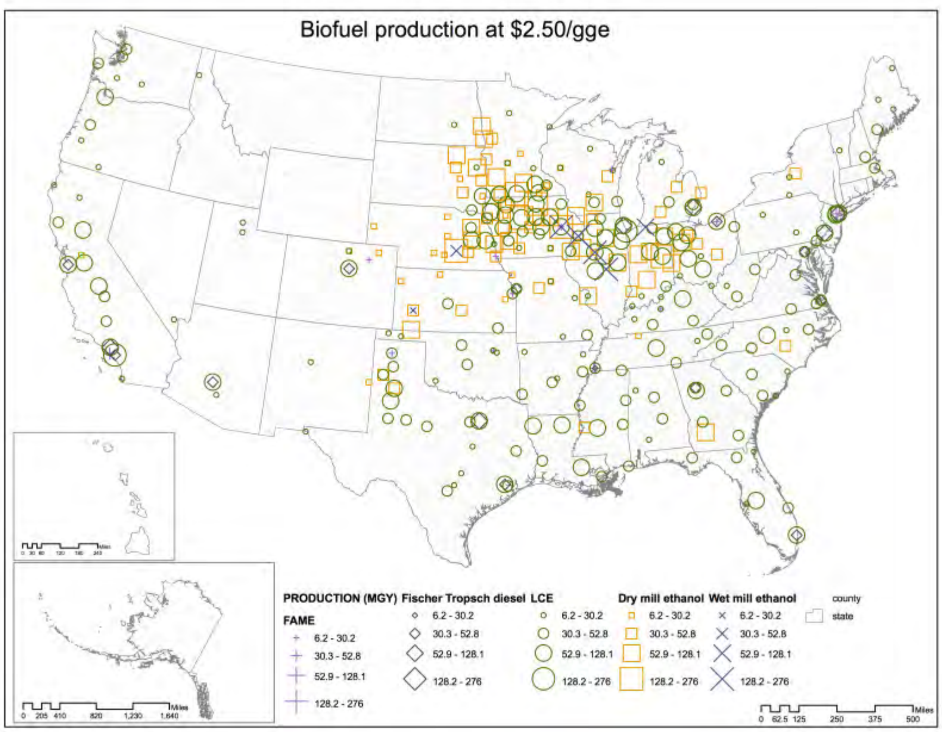

Figure 5: Optimized biorefinery siting for production at $2.50/gge fuel price in the baseline case for the year 2017 modeled by Parker et al. (2010).

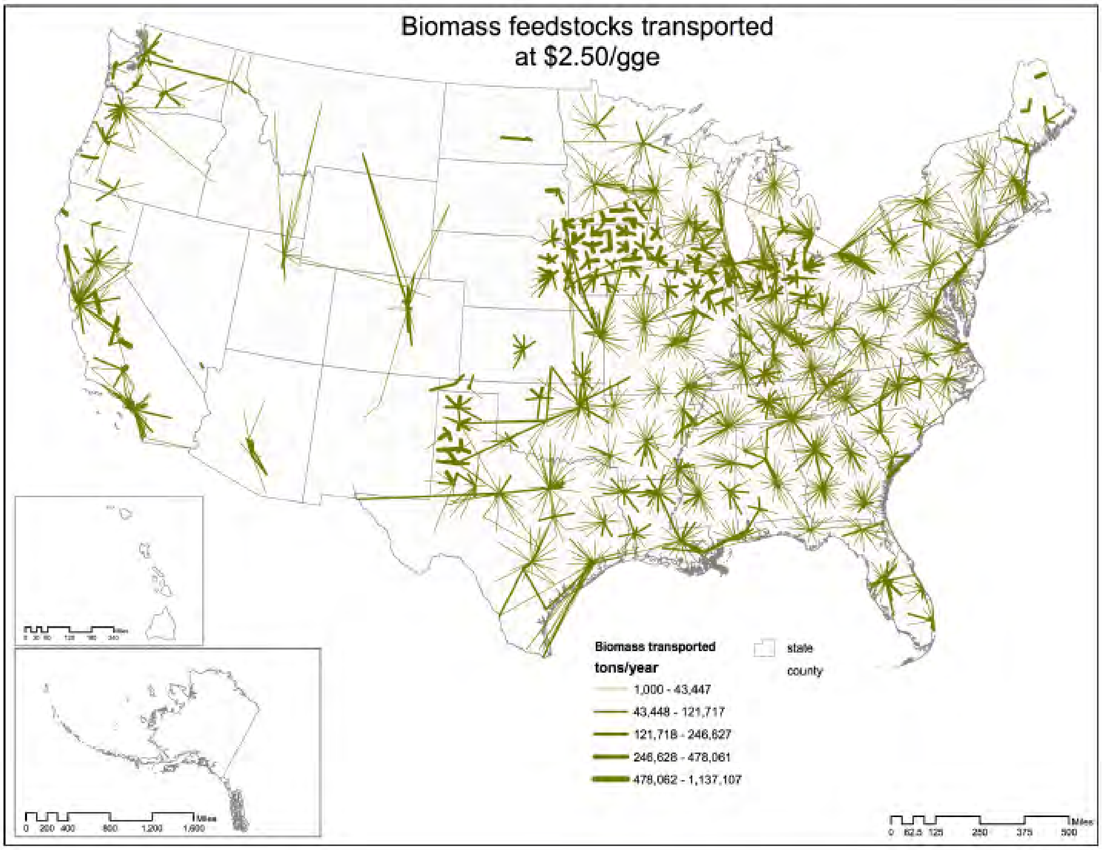

Figure 6: Biomass deliveries to biorefineries for the optimal system at $2.50/gge in the baseline case for the year 2017 modeled by Parker et al. (2010).

From a policy perspective, it is also important to note that 80 – 88% of the total biofuel used in California is imported to the state (under the three *Multi-Strategy* 80in50 scenarios described in section 1.4.1) and only 12 – 20% is made with in-state biomass in in-state production facilities. Imports to the state are mostly ethanol produced from corn and lignocellulosic agricultural residues while in-state production utilizes mostly municipal solid wastes and forest and orchard/vineyard wastes (Table 4).

Production-Feedstock	Multi-Strat$_{Pessimistic}$ % of Total Supply	Multi-Strat$_{Pessimistic}$ % from InState Sources	Multi-Strat$_{Middle}$ % of Total Supply	Multi-Strat$_{Middle}$ % from InState Sources	Multi-Strat$_{Optimistic}$ % of Total Supply	Multi-Strat$_{Optimistic}$ % from InState Sources
Dry Mill ETOH Corngrain	35-41%	2%	13-36%	2-7%	11-27%	2-5%
Cellulosic ETOH Ag. Residues	31-37%	0%	31-53%	0%	32-46%	0%
Cellulosic ETOH Herb. Energy Crop	8-9%	0%	13-28%	0%	17-31%	0%
Cellulosic ETOH Orch. Vineyard Waste	5%	99%	4-7%	99%	3-5%	99%
Cellulosic ETOH Forest	2%	73-82%	2-3%	77-82%	2%	80-82%
FAME Diesel Seed Oils	2%	0%	1-2%	0%	1-2%	0%
Cellulosic ETOH MSW (Wood)	3%	59%	2-4%	59%	4-5%	59-63%
FT Diesel MSW (Dirty)	3%	105-109%	1-2%	89-126%	2-4%	97-112%
Cellulosic ETOH MSW (Paper)	2%	67-71%	2-4%	66-71%	5-7%	68-76%
Cellulosic ETOH MSW (Food)	1%	68-72%	1%	67-71%	1-2%	69-77%
Cellulosic ETOH MSW (Yard)	1%	67-71%	1%	66-71%	1-2%	68-76%
Weighted Average In-State:		**14-15%**		**12-17%**		**16-20%**

Table 4: Composition and in-state production share of total biofuel used in California by production-feedstock pathway in three 80in50 scenarios. Ranges are given because the composition of biofuel changes with total quantity. Pathways contributing less than two percent of total biofuel have been omitted. Greater than 100% in-state production indicates net export from California.

Second, as Parker et al. observe, “the predicted [biofuel refinery] industry concentrates in the Midwest where there are large resources of corn and corn stover and the potential for significant switchgrass production. In the cornbelt region, the feedstock transportation distance [from field to biorefinery] is shorter than in other regions of the country due to dense distributions of feedstock.” Consequently, if the fair-share requirement was relaxed to allow for allocation of available biofuels by market forces alone, it may be that more of the available biofuel would be used in the Midwest while coastal states including California would need to rely on more electrification of transportation systems in order to meet the 80in50 goal. This pattern would also be consistent with differences in population density and the relatively limited range of electric vehicles vis-à-vis biofueled vehicles. Regional infrastructure development with, for example, more charging infrastructure for BEV and hydrogen fueling stations for FCV in densely-populated coastal states and more biofuel available in Midwestern agricultural states could be more cost effective than a fair share requirement. Thus, without the requirement for a proportionate share of total biofuel allocated to California, the state may have even less biofuel available in 2050 than shown in my *Pessimistic* scenario (described in section 1.3.3). But since evaluation of this line of reasoning requires modeling of competitive interactions, national modeling in a partial-equilibrium economic framework would be needed to investigate this observation further in order for endogenous competition between states for the available resource to determine the allocation.

However, Parker et al. also observe that, "due to the municipal solid waste resource, a portion of the total biorefinery capacity is located to match the population centers of the country. These biorefineries benefit from being near both the supply of a concentrated resource and the demand centers." Thus, it is likely that even in a competitive marketplace unconstrained by fair-share requirements, California would still have some biofuel available and that biofuel would likely be relatively low-carbon since the MSW feedstock-technology pathways yield relatively low-carbon biofuels (Figure 11 in section 1.3.4).

Third, the NBSM framework and fair share assumption do not allow for import (or export) of biomass or biofuel from outside the United States (for example, from Brazil). Once again, this assumption is based on the need for commensurate GHG emission reduction action in other states and nations in order for California policy to mitigate climate change. However, to the extent other nations face different biofuel supply options and demand conditions, some export/import trade may occur in a manner that is consistent with efficient climate change mitigation.

Finally, it is important to keep in mind that most biofuel, especially when total supply is constrained, is used in the aviation, marine, and HDV sub-sectors where alternatives are more limited. Although the extent of this allocation will vary between 80in50 scenarios, the fair-share rule should generally be viewed in the context of all of these activities rather than with just the LDV fleet in mind. This fact raises two complications not addressed in this dissertation.

First, differences in chemical composition between types of biofuel can limit the range of application for use in transportation sub-sectors (e.g., jet vs. distillate vs. gasoline like fuels). Furthermore, specific biomass resources may or may not be useful in making all types of biofuels. The simplifying assumption is made in the modeling presented in this dissertation that the biofuel produced from each feedstock-production pathway can be used in any transportation sub-sector.

Second, constraining the analysis in this dissertation to in-state transportation only significantly reduces the amount of fuel needed for aircraft since trans-state travel is omitted. Consequently, more of the limited supply of biofuel appears available for use in

LDV and other sub-sectors in this modeling than if the system boundaries were defined at the national level (McCollum and Yang, 2009).

1.3.3 Three Scenarios for Extrapolation of Underlying Parameters from 2017 to 2050

A scenario approach is used to evaluate uncertainty in projections for the underlying parameters in modeling biofuel supply in 2050, with "pessimistic", "middle" and "optimistic" cases. These scenarios are meant to bound the feasible range of biofuel supply in 2050 and, as such, each should not be interpreted as any more likely to occur than the others.

What might change between 2017 and 2050 affecting biofuel supply? Crop yields, conversion efficiencies and costs are the big three, with other important factors including the acreage available for use (due to changes in yields, policy, agricultural methods or markets, or diet), and handling losses. Since the 80in50 LEVERS and PATH models are scenario based, without optimization on cost (or other objective function), forecasting reduction in biofuel production cost is not necessary.[21] Consequently, developments in crop yields and conversion efficiency are the primary factors of interest for extrapolating biofuel supply to 2050 for my purposes (Figure 7).[22]

The three scenarios developed for biofuel supply in 2050 are described briefly below, with further detail about the assumptions involved in each provided in the following sections and summarized in Table 5.

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[21] Note, however, that *relative* costs do matter for my use of biofuel supply modeling in developing 80in50 scenarios due to the "least-cost" loading order rule (i.e., profit maximizing behavior) to calculate average carbon intensity (see section 1.3.4). Consequently, the inherent assumption made in omitting cost reduction forecasting from this analysis is that all technologies follow similar cost reduction pathways over time.
[22] The acreage available for biofuel production can have an important influence on biomass supply as well. As explained in the following sections, however, the acreage is modeled as a function of crop yields (i.e., I do not make assumptions about changes in policy or diet over the next 40 years, which are highly uncertain).

- The *Pessimistic* scenario for biofuel supply in 2050 is a future in which little progress in biofuel production is made after the initial ramp-up in production and second-generation technologies through 2017 modeled by parker et al. (2009). The *Baseline* scenario used by Parker et al. for the year 2017 assumes 50% of idle cropland and 50% of cropland in pasture are put into biofuel production. The acreage available for biofuel production in 2050 has remained unchanged and process efficiencies have not improved since 2017 while crop residue yields have not increased and energy crop yields have increased only 0.5 percent annually. The failure to improve agricultural yields and process efficiencies increases incentives for efficient recycling and composting since agricultural commodities have become more scarce. This leads to decreases in the per-capita quantity of municipal solid waste that keep the total quantity constant as population increases and a decrease to approximately half of what it was in 2017 for the fraction of MSW that is paper.

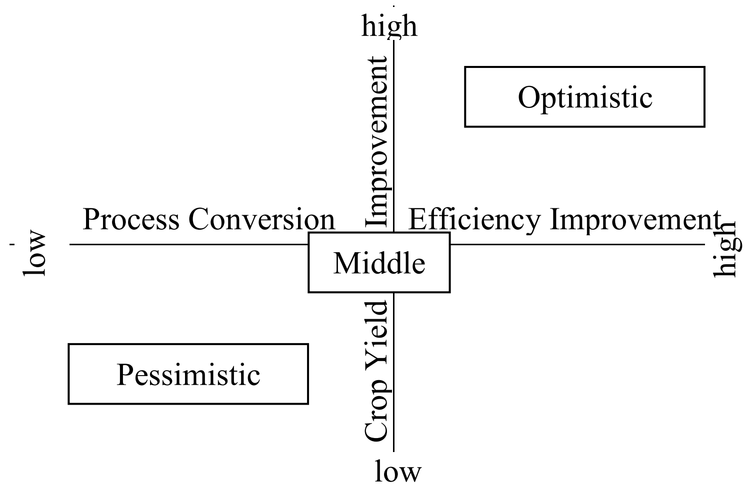

Figure 7: The primary two dimensions for defining three scenarios for biofuel supply in 2050 are improvements in crop yield and in conversion efficiency.

- The *Optimistic* scenario for biofuel supply in 2050 describes a future in which large improvements in several aspects of biofuel production are made between 2017 and 2050. An additional 18 million acres have been put into biofuel production due to increased commodity crop yields[23] and process efficiencies have improved to 98% of theoretical maxima while crop residue yields have continued to increase at historical rates and energy crop yields have improved 1.5 percent annually. These successes in agriculture cause a relative abundance of agricultural commodities which reduces the incentive for efficient recycling and composting, leading to an increase in the quantity of municipal solid waste in proportion to population (i.e., per-capita quantity remains unchanged) and no change from 2017 in the paper fraction. The rates of increase in crop yields and residues in this scenario reflect continuation of the best historical experience with improving crop yields through dedicated research into breeding, genetic engineering and agricultural methods (USDA, 2010). The increase in conversion process efficiencies implies achieving very nearly the maximum theoretical efficiency in all stages of biorefining processes (i.e., converting cellulose and hemi-cellulose to sugars and converting sugars to ethanol) (USDOE, 2010).

- The *Middle* scenario is, as it sounds, approximately in the middle between the *pessimistic* and *optimistic* scenarios for individual parameter values that vary between the scenarios. Specifically, an additional nine million acres have been put into biofuel production due to increased commodity crop yields and process efficiencies as a percentage of theoretical maxima have improved to the "long-term" case described by Parker et al. (2009). Crop residue yields continue to increase at approximately half of historical annual rates and energy crop yields have improved one percent annually. The per-capita quantity of municipal solid waste decreases such that the total quantity

[23] In all scenarios, I assume no *additional* land is made available for agriculture through things like expanded irrigation, forest clearing, reduction in Conservation Reserve Program withholdings, or suburban land reclamation. This assumption is based on the notion that competing uses for scarce resources like agricultural land and fresh water supplies will intensify over the next 40 years rather than slacken.

increases at ½ the rate of population growth and the paper fraction is halfway between the fractions in 2017 and the *Pessimistic* scenario.

Parameter	Parker et al. Baseline	Pessimistic	Middle	Optimistic
Modeled Year	2017	2050	2050	2050
Population, USA (000s)	328,000	422,000	422,000	422,000
Population, CA (000s)	41,000	59,500	59,500	59,500
Municipal Solid Waste (Avg. ton/person/yr.)	1.26	0.63	0.945	1.26
MSW, Paper Fraction	20.7%	10.1%	15.4%	20.7%
MSW Food Fraction	18.6%	23.7%	21.2%	18.6%
Crop Residue Yield (Annual Rate of Increase)	N/A	0% corn 0% wheat 0% sorghum	0.63% corn 0.2% wheat 0.77% sorghum	1.26% corn 0.39% wheat 1.54% sorghum
Cropland, Idle (% of acres)	50%	50%	50%	50%
Cropland, Pasture (% of acres)	50%	50%	50%	50%
Additional Acres Freed from Commodity Crop	N/A	0	9.1 million	18.2 million
Yield, Switchgrass (annual rate of increase)	77.4 gallons EtOH per ton	0.5% annual increase	1.0% annual increase	1.5% annual increase
Results: Total Biofuel Quantity Available in California / United States (Bgge)				
… at $3.20 per gge	2.85 / 25.77	4.85 / 38.85	5.70 / 45.69	8.05 / 64.57
… at $3.40 per gge	2.96 / 26.28	4.93 / 39.45	5.78 / 46.33	8.27 / 66.33
… at $3.60 per gge	3.00 / 26.68	5.01 / 40.13	5.86 / 46.92	8.33 / 66.80
… at $3.80 per gge	3.03 / 26.98	5.08 / 40.65	5.93 / 47.54	8.33 / 66.81
… at $4.00 per gge	3.07 / 27.28	5.15 / 41.23	6.08 / 48.72	8.33 / 66.82
… at $4.50 per gge	3.16 / 27.96	5.38 / 43.09	6.18 / 49.54	8.33 / 66.83
… at $5.00 per gge	3.33 / 29.87	5.39 / 43.15	6.18 / 49.54	8.33 / 66.84
… at $5.50 per gge	3.45 / 30.30	5.39 / 43.18	6.18 / 49.55	8.33 / 66.84

Table 5: Resource Assessment Assumptions that characterize the *Pessimistic*, *Middle* and *Optimistic* biofuel supply curves for 2050. The assumptions used in the baseline scenario modeled by Parker et al. (2010) are shown for reference. All other assumptions not shown in this table remain constant across scenarios and are as described in Parker et al. The *Pessimistic*, *Middle* and *Optimistic* scenarios for biofuel supply are used to create the $\text{MultiStrategy}_{\text{pessimistic}}$, $\text{MultiStrategy}_{\text{middle}}$ and $\text{MultiStrategy}_{\text{optimistic}}$ 80in50 scenarios, respectively. Results for the total quantity of biofuel available in California and the United States at selected marginal cost points (constant 2008 USD) are given for each scenario to facilitate comparison with the underlying parameter assumptions.

1.3.3.1 Resource Assessment

In this section, I review the biomass resources that can be used to produce different types of biofuels. These resources include tallow/lard/grease, municipal solid waste, forest biomass and pulpwood, commodity crops, and energy crops. In particular, I identify the pertinent factors that affect biomass resource supplies for each biofuel feedstock type, and the assumptions made for each factor in the *Pessimistic*, *Middle* and *Optimistic* biofuel supply scenarios. The assumptions that differ between these scenarios and from the assumptions made by Parker et al. for modeling biofuel supply in 2017 are summarized in Table 5 at the end of this section.

1.3.3.1.1 Tallow, Lard and Grease (1-2% of total biofuel supply in CA in 2050)

Biodiesel can be produced from edible and inedible tallow, lard and choice white grease feedstocks, which are byproducts of the meat processing and slaughter industries. To the extent these industries grow or shrink, so will the quantity of these biodiesel feedstocks. For modeling biofuel supply in the year 2050, I assume per-capita meat consumption remains at current levels with no change in process efficiency such that the per-capita generation of tallow, lard and grease feedstocks remains constant. As a result, the total quantity of these feedstocks available for biofuel production in all three biofuel supply scenarios increases in direct proportion to population growth.

Waste grease feedstocks (e.g., restaurant greases) are also a potential feedstock for biofuel production, although of lesser magnitude than tallow, lard and grease from the meat processing industry. The waste grease resource is generally proportional to urban population. Consequently, I assume the availability of these feedstocks also increases in direct proportion to population growth.

1.3.3.1.2 Forest Biomass and Pulpwood (2-3% of total biofuel supply in CA in 2050)

Forest biomass available for biofuel production is derived from thinning of timberland with high fire hazard, logging residues, treatment of Pinyon Juniper woodland, general thinning of private timberland, pre-commercial thinning on National Forest land in western Oregon and Washington, and unused mill residues (subject to sustainability principles and constraints). I assume no changes in these mature industries and associated lands management that would increase or decrease these feedstocks between 2017 and 2050.

Pulpwood is derived from additional forest treatments designed for bioenergy supply (i.e., main stem material from 5-9 inch diameter at breast height (dbh) trees harvested) and from shifting pulpwood use from current users to bioenergy users. Once again, I assume no changes in these mature industries and associated lands management (i.e., in the cultivation or allocation of pulpwood) that would increase or decrease the availability of these feedstocks for biofuel production between 2017 and 2050.[24]

1.3.3.1.3 Municipal Solid Waste (10-16% of total biofuel supply in CA in 2050)

Parker et al. forecast an average quantity of Municipal Solid Waste (MSW) generation in 2017 of 1.26 metric tons per capita per year (Parker et al., 2010). Total generation of this resource has remained approximately constant over the last 20 years as decreases in discard per capita due to increases in recycling (and slightly lower generation rates) have been offset by population growth (Figure 8).[25] However, these trends are relatively recent and it is difficult to predict whether they will continue over

[24] A partial equilibrium economic framework is more appropriate for considering competition between potential uses of a particular feedstock than the modeling structure used in this dissertation.
[25] The term "generation" refers to the total quantity of MSW created while the term "discard" refers to that fraction of the total quantity of MSW that is discarded into waste collection systems (as opposed to the fraction diverted into recycling, composting or other systems).

the next 40 years. Consequently, I made the following three assumptions in the biofuel supply scenarios to bound the likely range of future changes in MSW feedstock supply.

In the *Optimistic* scenario, I assume the generation *rate* per capita stays constant, with the total quantity of MSW available for biofuel production increasing in direct proportion to population growth. In the *Pessimistic* scenario, I assume the generation rate per capita continues to decline such that the total quantity of MSW available for biofuel production remains constant at 2017 levels in 2050. For the *Middle* scenario, I use the average of the *Optimistic* and *Pessimistic* per-capita MSW generation rates. Finally, since MSW generation rates vary by location, the method just described is applied state-by-state and city-by-city rather than with the nationwide average MSW generation rate.

The composition of MSW is also important for biofuel production efficiency and yield. The composition of MSW has been shifting over the past 10-20 years, with the paper fraction dropping (due to increased recycling) and food and plastics fractions increasing (Figure 8).[26] Since paper is a relatively good biofuel feedstock and food wastes are not (due to high water content), these trends move toward decreasing quality of MSW feedstocks for use in biofuel production. Once again, however, these trends are relatively recent and it is difficult to predict whether they will continue over the next 40 years. It is also unlikely the trends will continue unabated (or increase) over the next 40 years since this would imply near complete elimination of paper and yard trimmings from the waste stream (i.e., 100% recycling and composting), and dramatic increases in textiles and plastics fractions (Table 6). Consequently, I made the following three assumptions in the

[26] Fractions of MSW (and availability for use in biofuel) assumed in Parker et al. were 8.9% (75%) wood wastes, 20.7% (50%) unrecycled paper, 7% (75%) yard and green wastes, 18.6% (50%) food wastes, and 18.4% (75%) which is the organic fraction (plastics, textiles, paper, wood, yard and food wastes) of the remaining “dirty” MSW. The rest is unusable for biofuel production.

biofuel supply scenarios to bound the likely range of future changes in MSW feedstock composition.

For the *Optimistic* scenario, I assume the composition of MSW available for use in biofuel production (i.e., the MSW discarded into waste systems) does not change from 2017 to 2050. For the *Pessimistic* scenario, I assume historical shifts in MSW composition continue at 50% average annual rate observed from 1990 to 2008. The *Middle* scenario uses the average component fractions between the Optimistic and Pessimistic Scenarios (Table 5).

Finally, I did not alter the MSW fraction that is recoverable for energy production from what was assumed by Parker et al. in any of the three scenarios for biofuel supply in 2050 for two reasons. First, the assumptions made by Parker et al. – 50% for paper and food and 75% for wood, yard and mixed – represent optimistic recovery rates for 2017 (Parker, personal communication). Second, we lack information or basis for refining these estimates for the year 2050.

	Paper	Food	Glass	Metals	Plastics	Rubber/ Leather	Textiles	Wood	Yard	Misc. Inorg.	Other
Generation											
Tons, 1990	72730	20800	13100	16550	17130	5790	5810	12210	35000	2900	3190
Tons, 2008	77420	31790	12150	20850	30050	7410	12370	16390	32900	3780	4500
Annual Rate of Change	0.3%	2.4%	-0.4%	1.3%	3.2%	1.4%	4.3%	1.6%	-0.3%	1.5%	1.9%
Tons, 2050 (100% HROC)	89573	85537	10193	35740	111527	13177	72136	32578	28477	7015	10043
2050 Fraction (100% HROC)	18.1%	17.2%	2.1%	7.2%	22.5%	2.7%	14.5%	6.6%	5.7%	1.4%	2.0%
Tons, 2050 (50% HROC)	83281	52298	11129	27322	58188	9891	30150	23140	30611	5155	6736
2050 Fraction (50% HROC)	24.6%	15.5%	3.3%	8.1%	17.2%	2.9%	8.9%	6.8%	9.1%	1.5%	2.0%
Discards											
Tons, 1990	52500	20800	10470	12580	16760	5420	5150	12080	30800	2900	2510
Tons, 2008	34480	30990	9340	13630	27930	6350	10480	14810	11600	3780	3350
Annual Rate of Change	-2.3%	2.2%	-0.6%	0.4%	2.9%	0.9%	4.0%	1.1%	-5.3%	1.5%	1.6%
Tons, 2050 (100% HROC)	12928	78570	7155	16434	91960	9189	54995	23825	1188	7015	6570
2050 Fraction (100% HROC)	4.2%	25.4%	2.3%	5.3%	29.7%	3.0%	17.8%	7.7%	0.4%	2.3%	2.1%
Tons, 2050 (50% HROC)	21173	49472	8117	14968	50894	7642	24204	18797	3770	5155	4698
2050 Fraction (50% HROC)	10.1%	23.7%	3.9%	7.2%	24.4%	3.7%	11.6%	9.0%	1.8%	2.5%	2.2%

Table 6: Forecast MSW composition in 2050 based on continuation of the average annual Historical Rate of Change (HROC, 50% and 100%) in the quantity of each component for the period 1990 to 2008.

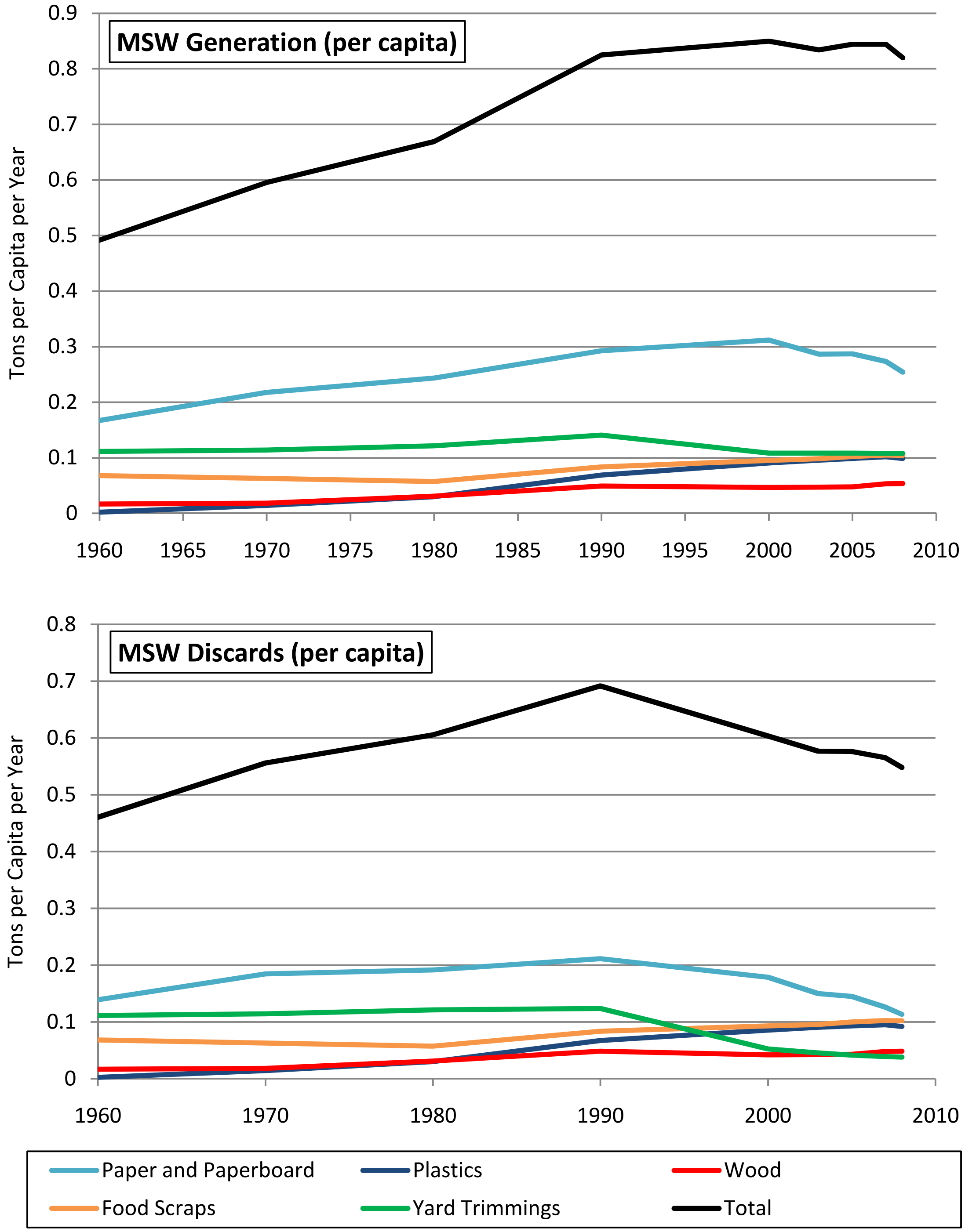

Figure 8: Trends in MSW quantity and composition in the United States. MSW discarded into waste collection systems (bottom panel) is MSW generation (top panel) net of recycling (USEPA, 2008).

1.3.3.1.4 Energy Crops (8-31% of total biofuel supply in CA in 2050)

Energy crops are one of the more important sources of lignocellulosic feedstocks, but are also difficult to anticipate in quantity or cost for 2017, let alone 2050. Parker et al. used switchgrass as a representative energy crop for all lignocellulosic feedstock crops; I continue with this assumption in calculating biofuel supply in the three scenarios for 2050.

The total quantity of energy crop production depends on acreage planted and total biomass yield per acre (as opposed to the grain yields often measured for commodity crops).

For the acreage planted to energy crop production, I begin with the assumption made by Parker et al. that only non-irrigated land would be used for switchgrass production and that the land used for production would not be in direct competition with other crops (i.e., it may currently be idle and/or pasture land).[27] Specifically, Parker et al. assumed 50% of idle cropland and 50% of pasture would be planted to switchgrass in their baseline scenario (Table 5).

These assumptions are meant to approximate the potential for "sustainable" energy crop production. Although a general definition of sustainability – meeting current needs without compromising the ability of future generations to meet their needs (WCED, 1987) – does not offer much guidance for identifying sustainable biofuels, there are some clear ways in which biofuels can be environmentally *un*sustainable. Examples include habitat loss/deforestation, soil degradation, greenhouse gas emissions, pollution

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[27] Although it is conceivable that biofuels become of high enough value to cause some farmers to choose to grow energy crops instead of other products, the modeling framework developed in this dissertation does not allow for investigation of such partial equilibrium economic questions. The assumption taken from Parker et al. is logical in that it allocates switchgrass production to non-irrigated land to which this crop is well suited and limits food-vs.-fuel competition while still allowing for dietary or other changes that make 50% of pasture land and 50% of idle cropland available for switchgrass production (in the baseline scenario). I modify this assumption in extending the modeling from 2017 to 2050 to account for potential increases in crop yields, as described below.

of water and air, aquifer depletion, and competition for land between food and energy crops. Since productive agricultural land is a limited and valuable resource that provides nourishment to a growing global population, the question of whether it is a good idea to create another major use for this scarce resource is important.

There is a great deal of variability in the potential impact of biofuel production pathways on food production and the environment and, consequently, in assessments of “sustainable” biofuel production potential. Perlack et al. (2005) estimated the potential for sustainable cellulosic biomass production in the United States to be 1.3 billion tons per year or approximately 30% of the US petroleum consumption by energy. An economic model of U.S. agriculture found that domestic agricultural and forest resources could provide 60 billion gallons of ethanol and 1.6 billion gallons of biodiesel (De La Torre Ugarte et al., 2007). See Parker et al. (2009) for more discussion of other energy crop estimates and how methodologies compare.

Between 2017 and 2050, the acreage available for energy crop production could increase if annual yield increases for commodity crops outpace population growth in the United States, implying an ability to increase consumption per capita (perhaps through dietary changes), increase exports, or decrease acreage planted to commodity crops. If the latter occurs, the acreage freed from commodity crop production could be put into energy crop production.

Thus, to extrapolate the original work by Parker et al. for 2017 to the year 2050, I estimated the net difference between projected commodity crop yield increases and population growth rates. For example, the US Department of Agriculture projects 1.3% annual corn yield increase through 2018 (USDA, 2010b) and the US Census projections for population growth imply a long-term annual growth rate of approximately 0.8% (US Census Bureau, 2004). These projected growth rates imply up to a net 0.4% annual increase in land area available for energy crop production if corn crop exports and per-capita consumption do not change. A similar analysis for other commodity crops is shown in Table 7.

	Corn	Sorghum	Barley	Oats	Wheat	Soybean	Rice	Cotton	Total
Yield/harvested acre									
3- year average: 2007 - 2010	153.9	67.0	63.2	62.6	42.9	41.2	7092.5	848.7	N/A
2018/2019	175.0	64.0	71.0	66.8	45.7	46.5	7725.0	950.0	N/A
Annual Rate of Increase	1.29%	-0.45%	1.17%	0.65%	0.64%	1.23%	0.86%	1.13%	N/A
Planted acres (million)									
2007/08	93.6	8.3	4.0	3.8	60.4	64.7	2.8	10.5	248.1
2018/2019	90.5	7.3	4.0	3.4	59.5	71.0	3.1	10.3	249.1
2050 (population growth rate = 0%)	59.9	6.9	2.8	2.9	56.2	41.4	2.2	6.6	178.9
Change, 2018-2050 (pop. growth rate = 0%)	-30.6	-0.4	-1.2	-0.5	-3.3	-29.6	-0.9	-3.7	-70.1
2050 (population growth rate = 0.8%)	77.3	9.0	3.6	3.7	72.6	53.5	2.9	8.5	231.1
Change, 2018-2050 (pop. growth rate = 0.8%)	-13.2	1.7	-0.4	0.3	13.1	-17.5	-0.2	-1.8	-18.1
Harvested acres (million)									
2007/08	86.5	7.4	3.5	1.5	51.0	64.1	2.7	10.2	226.9
2018/2019	83.3	6.3	3.5	1.5	50.6	70.1	3.1	9.3	227.7
2050 (population growth rate = 0%)	55.1	6.0	2.5	1.3	47.8	40.9	2.2	6.0	161.8
Change, 2018-2050 (pop. Growth rate = 0%)	-28.2	-0.3	-1.0	-0.2	-2.8	-29.2	-0.9	-3.3	-65.9
2050 (population growth rate = 0.8%)	71.1	7.7	3.2	1.6	61.7	52.8	2.8	7.7	208.6
Change, 2018-2050 (pop. Growth rate = 0.8%)	-12.2	1.4	-0.3	0.1	11.1	-17.3	-0.2	-1.6	-19.0

Table 7: Change in acreage planted to commodity crops through 2050 if historical trends in yield increase continue and population increases at 0.8% annually. The total net change in acreage planted to commodity crops could be available for energy crop production if commodity crop exports and per-capita consumption do not change.

However, since extrapolating historical trends over a long time period comes with a high degree of uncertainty, I made the following assumptions regarding potential increases in acreage planted to energy crop production in the three scenarios of biofuel supply in 2050 in order to bound this uncertainty.

- For the *Optimistic* scenario, I assume historical rates of annual yield improvements continue for all commodity crops (i.e., 1.29% for corn, 0% sorghum, 1.17% barley, 0.65% oats, 0.64% wheat, 1.23% soybean, 0.86% rice, 1.13% cotton), the long-term annual rate of population growth is 0.8%, and no change in commodity crop exports or per-capita consumption occurs. In this case, the amount of land planted to the commodity crops with annual yield increase greater than 0.8% will decrease while the amount of land planted to crops with annual yield increase less than 0.8% will increase. Although more than 22 million acres currently in corn and soybean rotations and one million acres in cotton production would be freed up for use in energy crop production, 5.2 million additional acres would be needed for wheat and sorghum production. The net increase in acreage available for use in energy crop production in this scenario is 18.2 million acres, after accounting for other smaller changes in the acreage needed to produce barley, oats and rice, which is approximately 6.5% of the total acreage currently in commodity crop production (Table 7).
- For the *Pessimistic* scenario, I assume zero annual increase in acreage planted to energy crop production (i.e., the status quo assumed by Parker et al. for 2017 persists through 2050). Note, however, that I am not assuming zero increase in commodity crop yield, but rather that the weighted average annual rate of yield

increase across all commodity crops exactly offsets the projected 0.8% annual population growth rate such that the total acreages in commodity crop and available for energy crop production do not change (assuming no change in commodity crop exports or per-capita consumption).

- For the *Middle* scenario, I assume the rates of commodity crop yield increases *net* of population growth is exactly half of historical rates. This produces half of the net increase in acreage available for use in energy crop production assumed in the *Optimistic* scenario, or 9.1 million acres.

Finally, when identifying *which* acres to remove from commodity crop production and put into energy crop production, the most marginal (i.e., lowest yield-per-acre) acres were found using a simple crop allocation model. The model maximizes the quantity of land freed from commodity crop production while meeting the demand for commodity crops. Several additional constraints are imposed in order to solve the model: 1) crops can only be grown in counties where they are currently grown; 2) crops that require less land in 2050 cannot expand area within a county; 3) crops that require additional land in 2050 can only grow by 40% within an individual county; 4) only land in the 2018 commodity crop rotation are available.

To solve the model, the county-level yields are adjusted upwards by the 2050 growth factor. The model is then run to maximize the quantity of land freed from commodity crop production given these yields. However, crop yields in this first iteration of modelling increase beyond the projection for 2050 as crops are shifted to higher-yielding counties. Consequently, a correction is made to the county crop yields after the first iteration and the model is iterated until the resulting crop yields match the projected crop yields.

For energy crop yield, I began with the supposition that improvements similar to those realized over the past two decades for commodity crops can be achieved for energy crops if they become cultivated at the scale foreseen under the 80in50 scenarios.[28] Historical annual yield increases for *total biomass* – which is the appropriate metric for energy crops rather than the grain yields often measured for commodity crops – range from 0.5% to 1.9% for commodity crops (Johnson et al., 2006). For the *Optimistic*, *Middle* and *Pessimistic* scenarios, I assume 1.5%, 1% and 0.5% annual increase in energy crop total biomass yield, respectively.

1.3.3.1.5 Commodity Crops (11-41% of total biofuel supply in CA in 2050)

Estimating the supply of biomass available for biofuel production from commodity crops – corn, soybeans and canola – is complex given the many alternative uses in traditional agricultural markets for these feedstocks. Furthermore, annual production of these crops is sensitive to potential changes in exports, agriculture and energy legislation, alternative fuel demand, and market price in each region of the country.[24]

Since the modeling by Parker et al. was not a partial equilibrium framework in which the allocation of a particular feedstock to competing uses could be modeled, a simplified approach was required. Instead of developing supply curves, Parker et al. limited the quantity of commodity crops like corn and soy oil used for biofuel production in the following ways: the fraction of soy oil provided to biodiesel was limited to no more

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[28] Yield increases may be achieved through some combination of breeding, genetic engineering, and agricultural methods.

than 50% above projections from the Food and Agricultural Policy Research Institute (FAPRI, 2009); corn ethanol was limited to 15 billion gallons per year (nationally), which is the limit for receiving credit under the federal Renewable Fuel Standard (RFS) (USEPA, 2010). I did not alter this structure in any of the three biofuel supply scenarios calculated for California.

1.3.3.1.6 Crop Residues (31-53% of total biofuel supply in CA in 2050)

The total quantity of commodity crop residue (i.e., stalks, stems, cobs, etc.) generated depends on crop yields, harvest indexes (i.e., the percent of aboveground biomass that is grain), and acres planted. The resource supply will increase from 2017 to 2050 if crop yield or acres planted increase or if harvest indexes decrease. The quantity of crop residue *available for use* in biofuel production was estimated by Parker et al. as gross residue less the portion left behind in order to sustain soil quality.[29]

To extrapolate this resource assessment to 2050, trends in annual yield increase for grains and residues (Johnson et al., 2006) were used to estimate annual historical rates of increases in gross *residue* yields of 1.26% for corn, 0.39% for wheat, and 1.54% for sorghum.[30] The historical residue yield growth for these crops is a fraction of the historical grain yield growth. For example, corn stover yields grew at a rate of 50% of the corn grain yields (24% for wheat, 63% for sorghum, 10% for barley and 28% for oats).

[29] The proportion of residue that must be left behind in order to sustain soil quantity is related to the selection of agricultural methods like tillage, crop rotations and fertilization.

[30] Simply extrapolating a proportional increase in residue with grain yield increase to 2050 would likely over-estimate the availability of residues since some of the means for increasing yields will come through reduced residues. In general, grain yield may be increased through rapidly-sprouting seeds that maximize growing season, increased seed-to-stalk ratio (which reduces residue-to-grain ratio), increase irrigation and fertilization to maintain soil nutrients and hydration, increased pesticide and herbicide use to reduce crop loss, and improved forecasting to optimize planting/harvesting to reduce crop loss.

To estimate net residue available for use in biofuel production, I assume the fraction of residue left behind to sustain soil quality remains constant.[31]

The resulting projections for increase in residue yield available for use in biofuel production between 2017 and 2050 are, of course, uncertain due to extrapolation of historical trends over a long time period. Consequently, I made the following assumptions in the three scenarios of biofuel supply in 2050 in order to bound this uncertainty. For the *Optimistic* scenario, I assume residue yields increase in proportion to grain yields (this assumes constant harvest index over time). For the *Pessimistic* scenario, I assume zero annual increase in residues (i.e., the status quo persists). The Middle scenario assumes that residue yield increases at the historical ratio between residue and grain yield growth, given the grain yield growth projections discussed in the next section.

Finally, it is important to recognize that the total resource base of residue from commodity crops will depend on the acreage planted to these crops. If that acreage decreases due to yield increases outpacing population growth, as argued in the next section, the decrease in total acreage will offset some of the increase in residue yields.

1.3.3.2 Biofuel Conversion Technologies

Biofuel conversion technologies were chosen by Parker et al. to be "representative of the types of biofuel production processes that can be commercial in the mid-term." In

[31] To the extent realizing continued yield increases requires more fertilization, the assumption of constant residue leave-behind implies increasing artificial fertilization, which is currently derived mostly from natural gas feedstocks. Consequently, this assumption is an example of GHG emission reduction from the transportation sector that may come at a cost in emission increase in another sector, namely the agricultural sector through increased input requirements. Another example of such cross-sector "stealing" of emission reductions is with the transportation sector using low-carbon renewable-source electricity generation sources for plug-in vehicle charging that could otherwise be used to reduce emissions from the electric generation sector.

extrapolating this modeling to the year 2050, I evaluated the potential for improvement in conversion efficiency of biomass to biofuel (i.e., improved yield).

The conversion efficiencies for each feedstock-technology combination, given by Parker et al. for 2017 and assumed in the *Pessimistic*, *Middle*, and *Optimistic* scenarios for 2050 are shown in Table 8. Yields for the *Pessimistic* and *Middle* scenarios are equal to the Mid-Term and Long-Term cases described by Parker et al., respectively, with the percentage of maximum theoretical yield equal to 90% for converting C5 sugars to ethanol, 94% for converting C6 sugars to ethanol, and 85% for converting cellulose to sugars, and 85% for converting hemi-cellulose to sugars in the *Pessimistic* scenario and 95%, 95%, 90% and 85% for these processes in the *Middle* scenario. The *Optimistic* scenario assumes further improvement to 95% of maximum theoretical yield for all process pathways.

Biomass Type	Grain Ethanol (2017 / Pess. / Mid. / Opt.)	Lignocellulosics to Ethanol (2017 / Pess. / Mid. / Opt.)	Lignocellulosics to Middle Distillates (2017 / Pess. / Mid. / Opt.)	Fatty Acid Methyl Esters (2017 / Pess. / Mid. / Opt.)
Corn				
• **Dry Mill**	100 / 100 / 100 / 100	-	-	-
• **Wet Mill**	89.0 / 89.0 / 89.0 / 89.0	-	-	-
Corn Stover	-	78.7 / 78.7 / 84.0 / 90.7	38.7 / 38.7 / 38.7 / 38.7	-
Straws	-	78.7 / 78.7 / 84.0 / 90.7	38.7 / 38.7 / 38.7 / 38.7	-
O-V Waste	-	85.2 / 85.2 / 91.9 / 98.6	40.6 / 40.6 / 40.6 / 40.6	-
Forest	-	90.2 / 90.2 / 96.4 / 103.7	42.0 / 42.0 / 42.0 / 42.0	-
MSW				
• **Mixed Paper**	-	86.0 / 86.0 / 92.1 / 98.6	37.1 / 37.1 / 37.1 / 37.1	-
• **Wood Waste**	-	85.2 / 85.2 / 91.9 / 98.6	41.5 / 41.5 / 41.5 / 41.5	-
• **Yard Waste**	-	70.0 / 70.0 / 74.4 / 81.4	38.4 / 38.4 / 38.4 / 38.4	-
• **Food Waste**	-	77.5 / 77.5 / 83.2 / 88.4	-	-
• **Mixed Waste**	-	-	31.6 / 31.6 / 46.4 / 46.4	-
Herb. Energy Crops	-	77.4 / 77.4 / 82.6 / 89.4	37.7 / 37.7 / 37.7 / 37.7	-
Yellow Grease	-	-	-	249 / 249 / 249 / 249
Virgin Seed Oils	-	-	-	260 / 260 / 260 / 260
Tallow and Lard	-	-	-	260 / 260 / 260 / 260

Table 8: Assumed conversion rates (gallons fuel per dry ton biomass) for process technologies that characterize 2017 (Parker et al., 2009) and the *Pessimistic*, *Middle* and *Optimistic* scenarios for biofuel supply curves in 2050. Conversion rates are assumed to not improve from 2017 in the Pessimistic scenario and only improve for cellulosic ethanol pathways in the Middle and Optimistic scenarios.

Since only the *relative* costs of biofuel production are salient for modeling 80in50 scenarios – for use in the loading order of biofuel production pathways for profit maximization through cost minimization (as described below) – I did not attempt to forecast cost reductions through 2050 for each feedstock-technology combination. The inherent simplifying assumption is that costs for all technologies remain proportionately similar such that the profit maximizing loading order does not change over time.

Thus, supply curves shown for California in the next section should be interpreted in constant 2008 USD for technology costs in 2017. To the extent production costs come down through technological improvement, the curves will shift downward by 2050. However, Parker et al. assumed widespread deployment of biofuel production by 2017 in their modeling, meaning the bulk of economies of scale and learning had been realized for the technologies used in biofuel production by 2017 (Figure 9). Consequently, I assume the downward shift in biofuel supply curves from 2017 to 2050 through continued processing cost reduction is likely to be relatively minor.

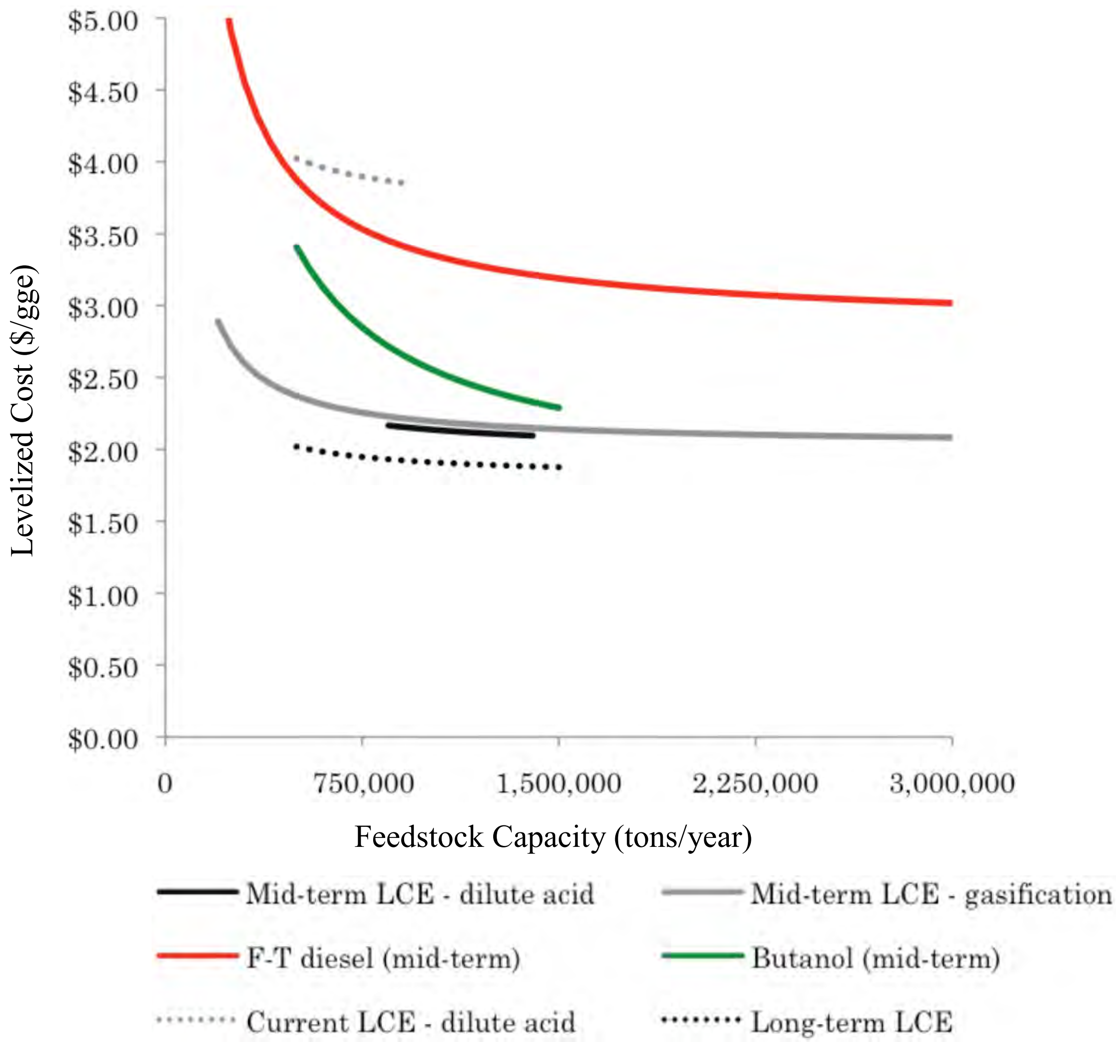


Figure 9: Levelized cost of production versus scale for lignocellulosic conversion technologies with constant $50/ton feedstock cost (Parker et al., 2010).

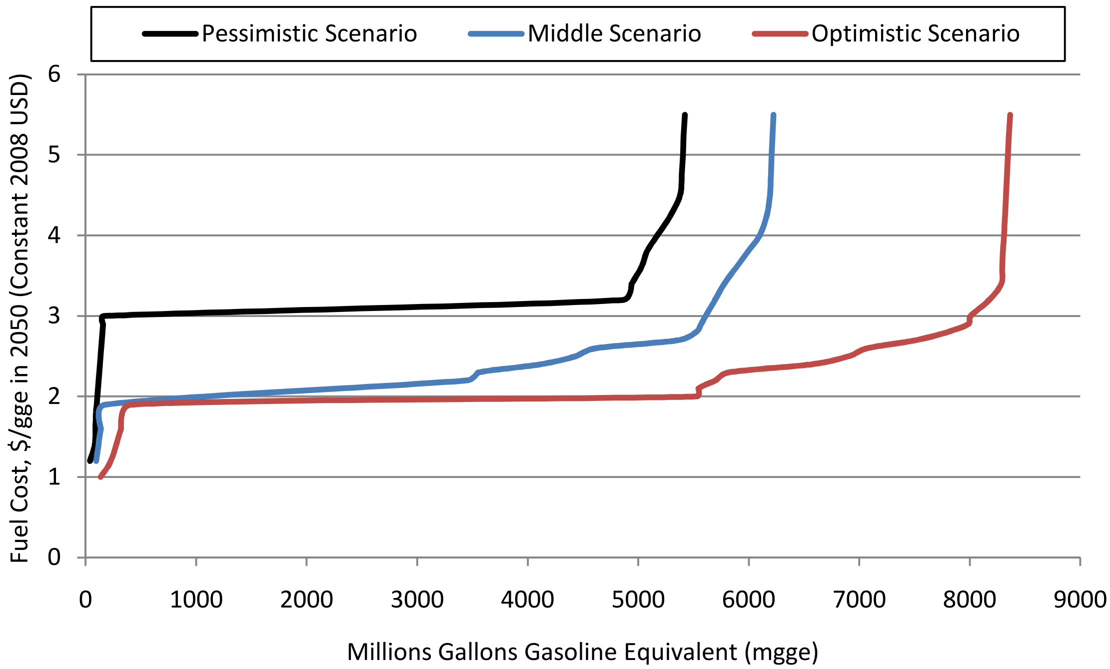
1.3.4 California-specific Biofuel Supplies in 2050

The assumptions specified for the *Pessimistic*, *Middle* and *Optimistic* scenarios were set in the NBSM in order to calculate national biofuel supply in 2050 under each scenario; the California-specific biofuel supply curves shown in Figure 10 were isolated from the model results as described above. Lignocellulosic energy crops and dry mill corn-based ethanol show the largest potential for high-volume production, with inelasticity due to binding resource constraints evident in the other 13 feedstock sources (Figure 10).

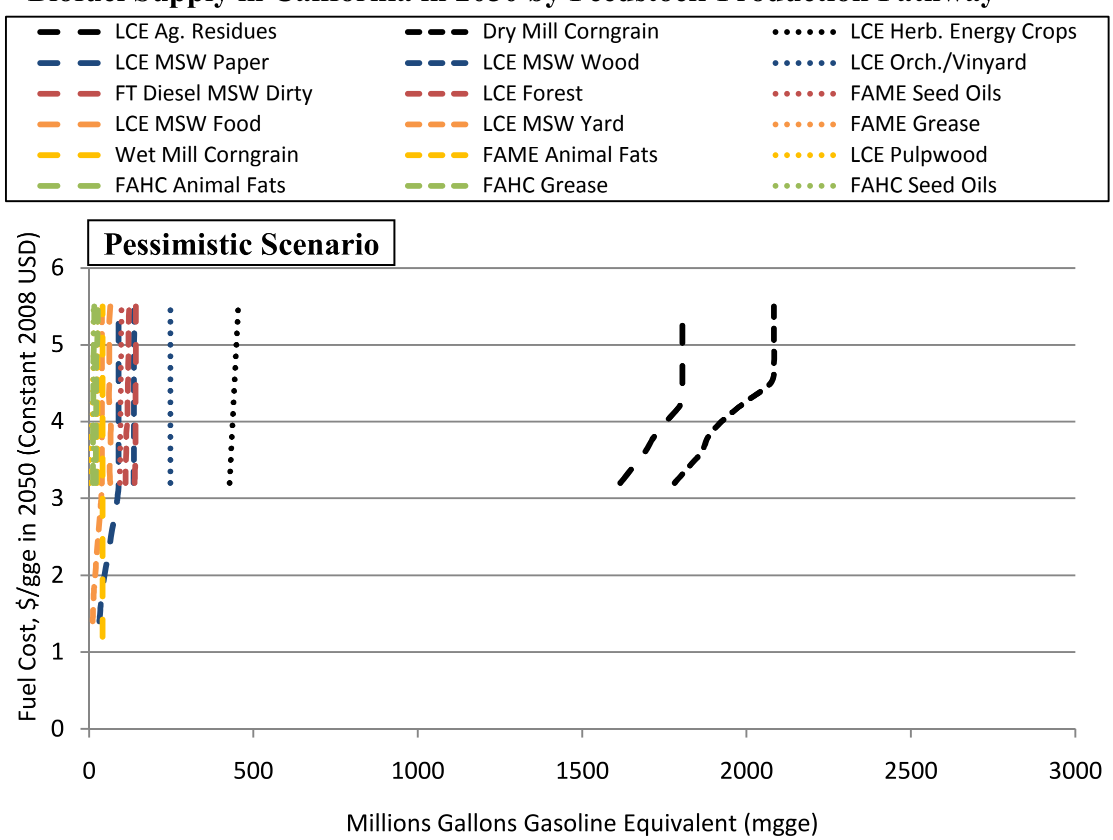
Differences between scenarios in the assumptions regarding processing efficiency, agricultural yield and feedstock supply appear in Figure 10 as shifts to the right in the biofuel supply curves. These shifts are important for the intended application of these supply curves in modeling 80in50 scenarios since the available biofuel supply is generally used up almost completely in pursuit of the 80in50 goal. Thus, differences in the point at which a biofuel supply curve becomes inelastic (i.e., supply constraints become binding), is the most important difference between the three scenarios of biofuel supply in 2050 for the purposes of 80in50 scenario development.[32]

[32] The scale of the y-axis, whether $3.00 per gge or $6.00 per gge, is largely irrelevant for the 80in50 scenario modeling where optimization for minimal cost (or other objective function) is not done.

Total Biofuel Supply in California in 2050



Biofuel Supply in California in 2050 by Feedstock-Production Pathway



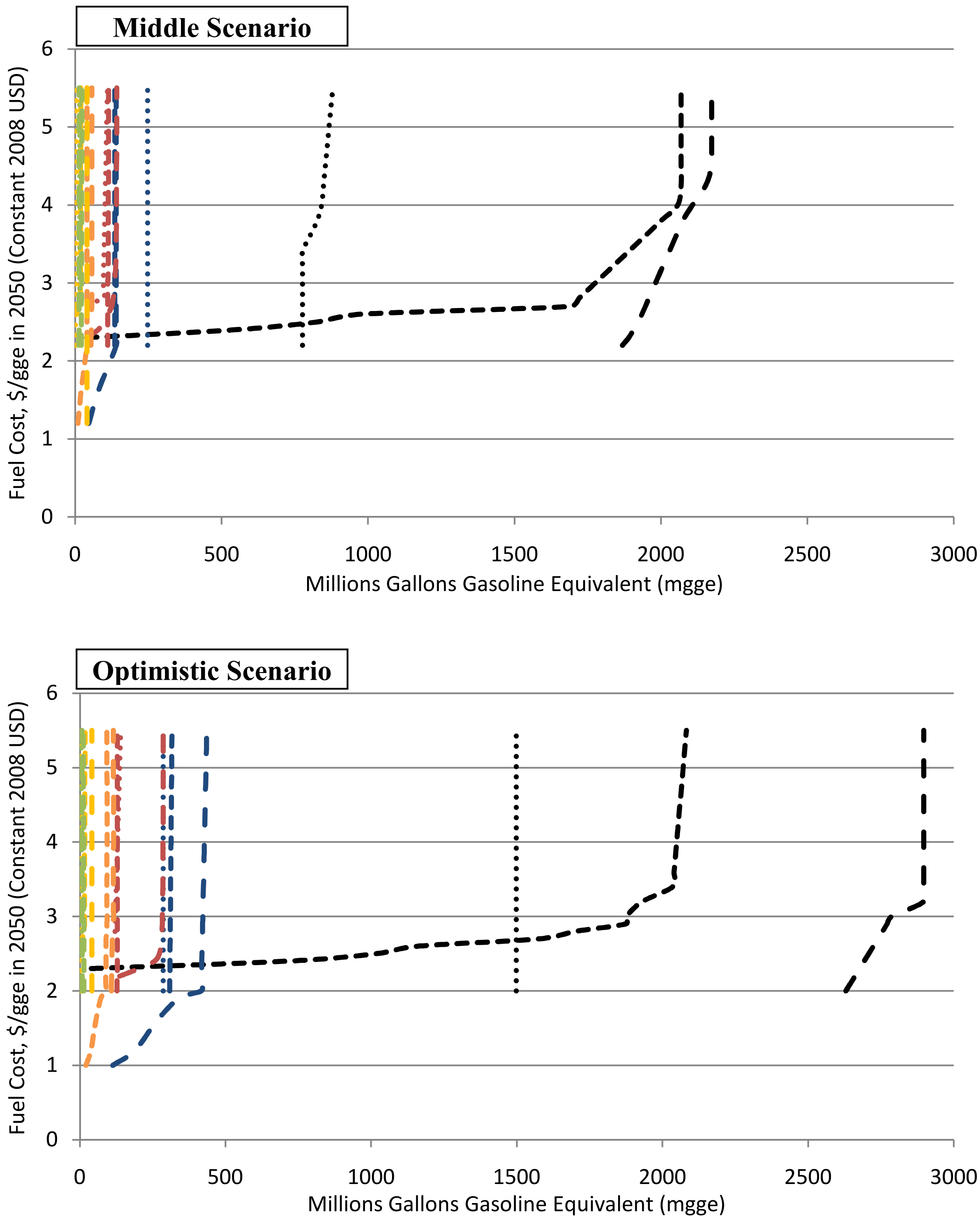


Figure 10: Total potential biofuel supplies available in California in 2050 (top panel) and from 15 different sources (bottom three panels) under three scenarios (adapted from Parker et al., 2010). Abbreviations are used for lignocellulosic ethanol (LCE), Fischer-Tropsch (FT) process, fatty acid methyl ester (FAME) biodiesel, and fatty acid hydro-cracking (FAHC) biodiesel.

1.3.5 Biofuel Carbon Intensity by Feedstock-Production Pathway

To apply these supply curves in modeling biofuel supply for defining 80in50 scenarios, the carbon intensity of each supply curve (i.e., each of the 15 different feestock supply pathways) is needed. These carbon intensities were estimated as an average of results from life cycle analysis developed for the California Low-Carbon Fuel Standard (CARB, 2004; CARB, 2010; Yeh, 2009), life cycle analysis developed for the federal Renewable Fuel Standard (US EPA, 2009), research on ethanol from municipal solid waste sources by Kalogo et al. (2007), and research on biodiesel from tallow and grease by S&T^2 Consultants (2005). The point estimates from these studies and average values are shown in Figure 11. It is important to note that these values do not consider potential changes in biofuel production methods that may occur by the year 2050 and may increase or decrease the GHG intensity of biofuels. If carbon constraints influence development in biofuel industries, these may be conservative numbers for 2050 (i.e., assuming no decrease in GHG intensity over the next 40 years).

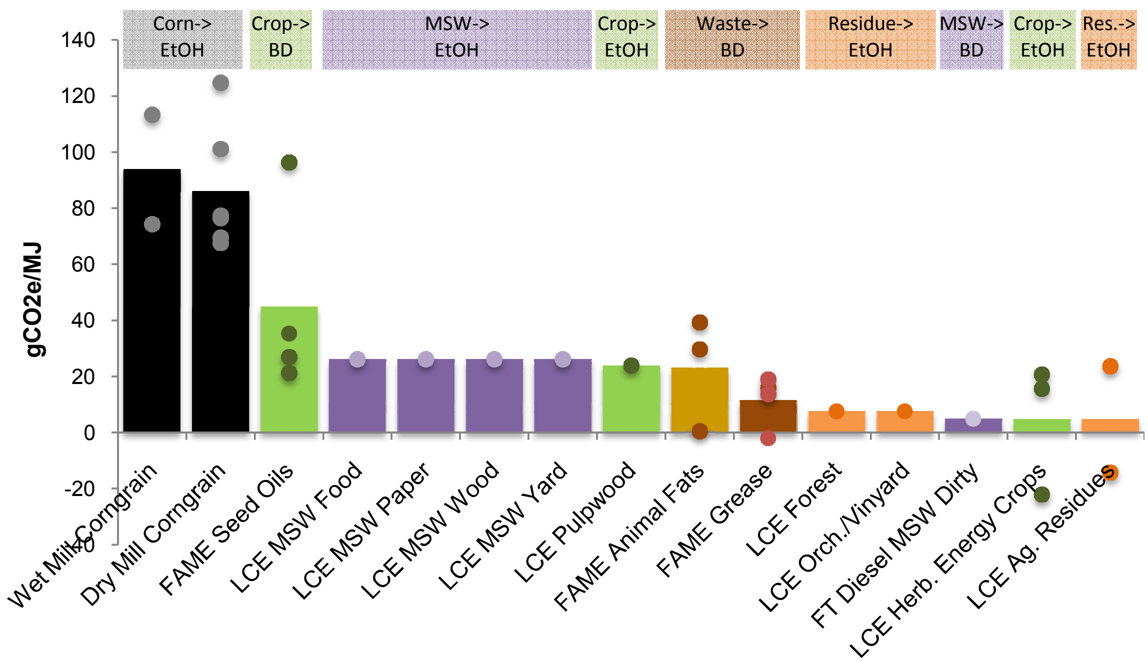


Figure 11: Estimated biofuel carbon intensity by pathway, calculated as the average estimates from prior literature shown as dots in the figure (CARB, 2004; CARB, 2010; US EPA, 2009; Kalogo et al., 2007; $(S\&T)^2$ Consultants, 2005; Yeh, 2009). All estimates are on a well-to-wheels lifecycle basis. For comparison, the average carbon intensity of gasoline is approximately 92 gCO_2e/MJ.

Both variation and uncertainty in estimates of pathway-specific biofuel carbon intensity are evident in Figure 11. For example, the carbon intensity of a given pathway may vary as one moves along the supply curve and the marginal unit of feedstock changes. In other words, factors causing the marginal cost of a particular biofuel pathway to increase as the quantity increases (e.g., transport distance, yield) may also cause the carbon intensity of the marginal unit of biofuel to change. However, given the variation and uncertainty in published estimates for pathway-specific biofuel carbon intensity, I used a single estimate of carbon intensity for each biofuel supply pathway rather than attempting to model changes in carbon intensity with total quantity to match the supply curves shown in Figure 10. Incorporation of this second-order effect is left to future work.

1.3.6 Biofuel Carbon Intensity Supply Curves

The pathway-specific California biofuel supply curves derived from the NBSM model (Figure 10) were combined with the estimated pathway-specific carbon intensities (Figure 11) to create the carbon intensity supply curves shown in Figure 12. These "supply curves" give the average biofuel carbon intensity for any price and quantity combination. The conventional price-quantity supply curves are shown as dashed lines in this figure as well, for easy reference.

However, merging the 15 different biofuel supply curves into a single carbon intensity supply curve required a rule for the loading order of biofuel feedstock pathways (i.e., which feedstock would be used first, second, third for increasing total quantity). I considered three potential rules: 1) the least-carbon rule requires that the least-carbon feedstocks are used first[33]; 2) the least-cost rule stipulates that a combination of the least-cost feedstocks are used to meet total biofuel demand[34]; 3) the least-cost rule in a future where CO_2 emissions are taxed at $75 per metric ton (Figure 12).[35] An example of how the biofuel composition changes as quantity increases under the *Pessimistic* scenario with the *least-cost* rule for loading order is shown in Figure 13.

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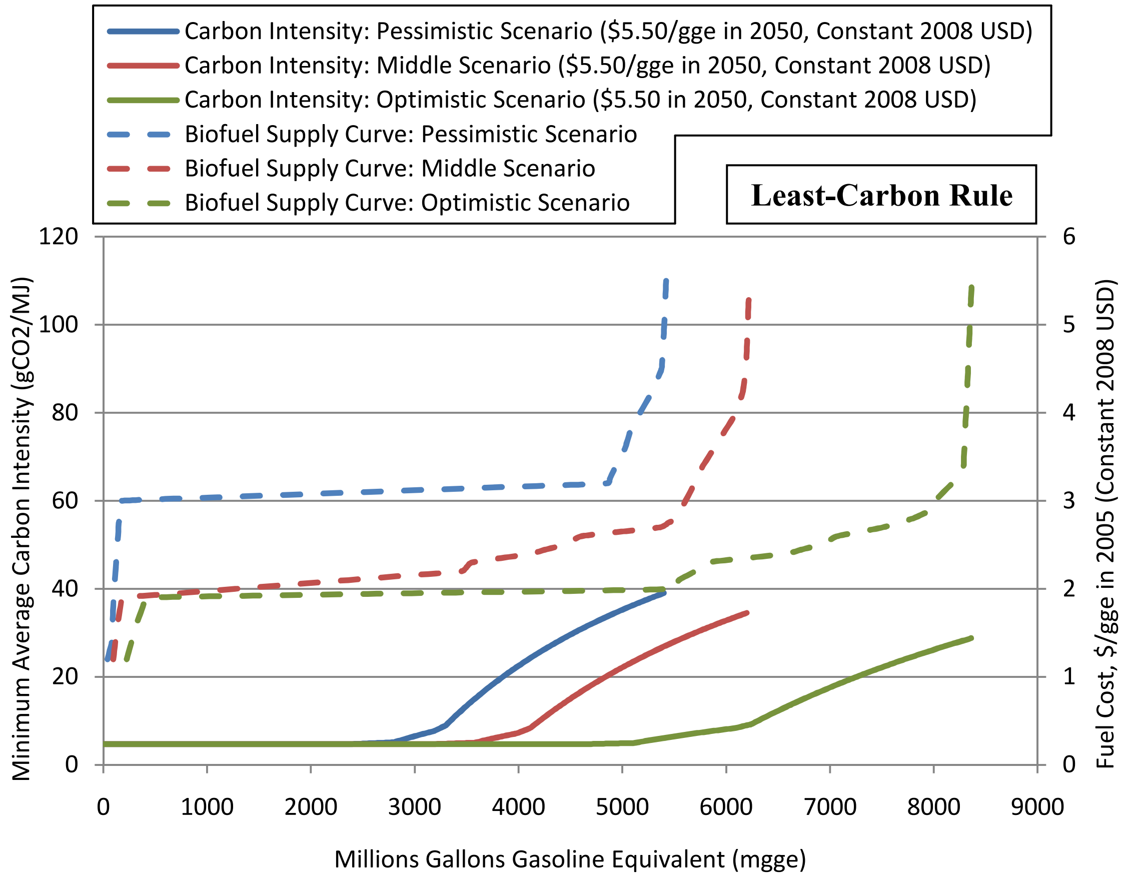
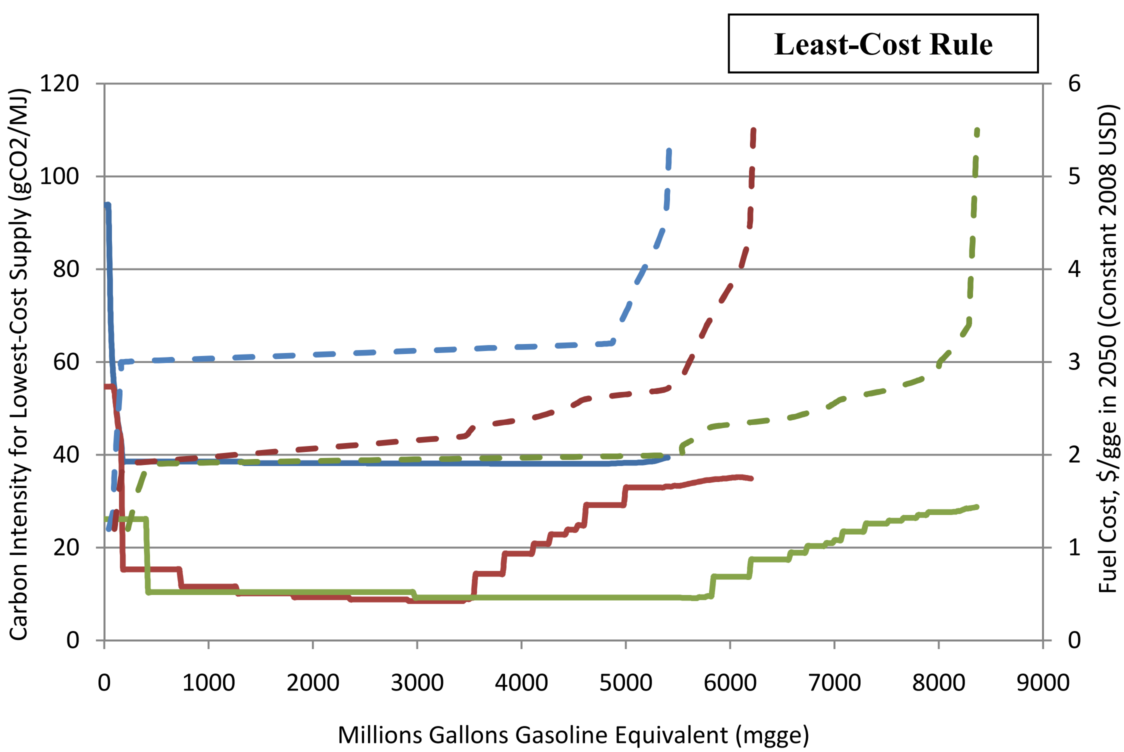
[33] For example, a "carbon police" regulatory mechanism forces production from all available least-carbon feedstocks, up to the point where marginal cost equals the market price (i.e., zero economic profit), before moving to higher carbon feedstocks.

[34] This rule is meant to approximate the rational production decisions of a profit-maximizing firm.

[35] The marginal cost of production for each feedstock pathway is increased by the amount of carbon tax assessed, which is a function of the tax rate ($75 per metric ton) and carbon intensity of the biofuel pathway.



Carbon Intensity: Pessimistic Scenario ($5.50/gge in 2050, Constant 2008 USD)
Carbon Intensity: Middle Scenario ($5.50/gge in 2050, Constant 2008 USD)
Carbon Intensity: Optimistic Scenario ($5.50 in 2050, Constant 2008 USD)
Biofuel Supply Curve: Pessimistic Scenario
Biofuel Supply Curve: Middle Scenario
Biofuel Supply Curve: Optimistic Scenario
Least-Carbon Rule
Minimum Average Carbon Intensity (gCO2/MJ)
Fuel Cost, $/gge in 2005 (Constant 2008 USD)
Millions Gallons Gasoline Equivalent (mgge)



Least-Cost Rule
Carbon Intensity for Lowest-Cost Supply (gCO2/MJ)
Fuel Cost, $/gge in 2050 (Constant 2008 USD)
Millions Gallons Gasoline Equivalent (mgge)

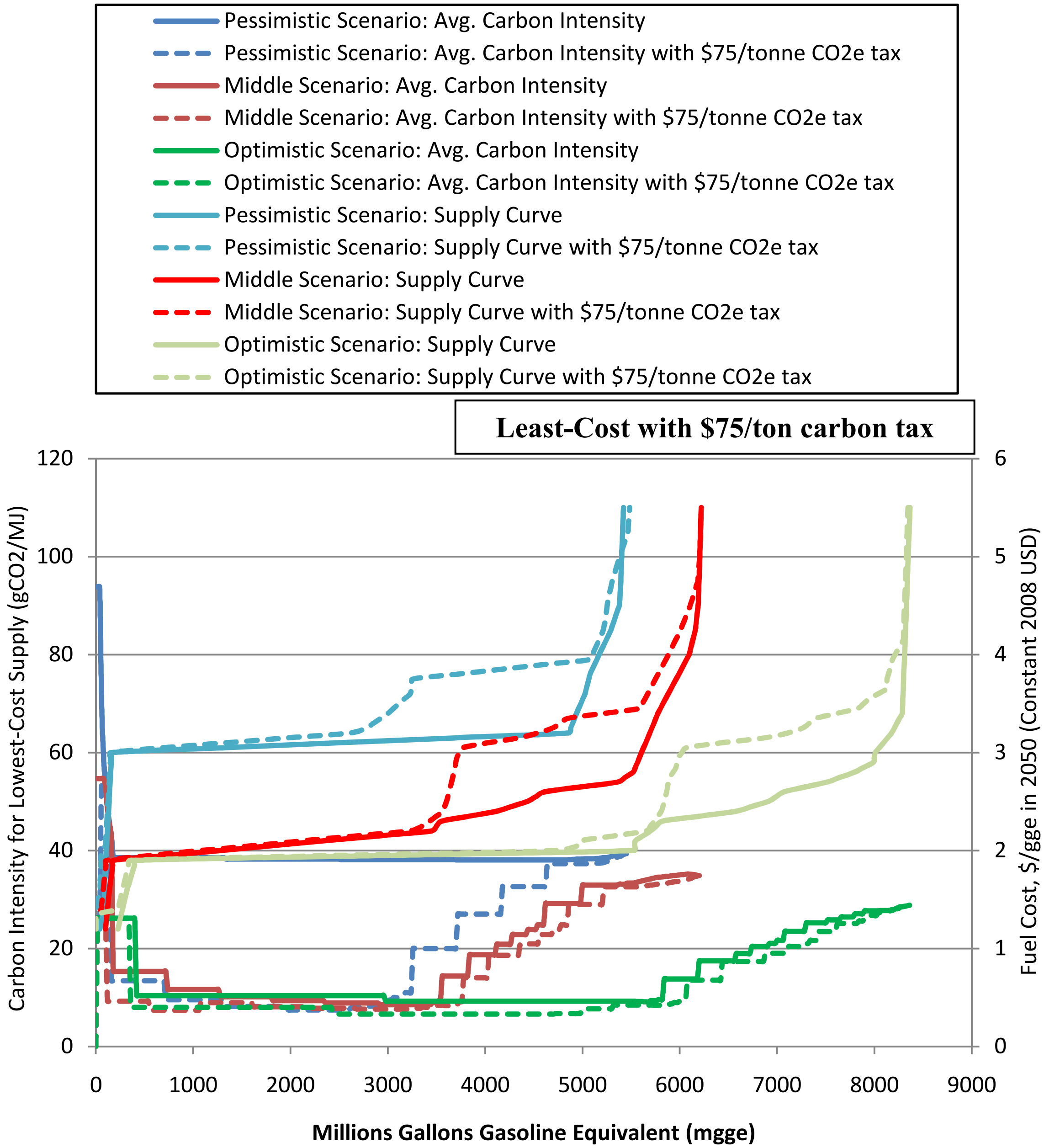


Figure 12: Average biofuel carbon intensities and total biofuel supply curves for three scenarios of biofuel supply in 2050 under three rules for loading order: the *least-carbon* (top panel), *least-cost* (middle panel) and *least-cost* with $75 per metric ton carbon tax (bottom panel). With the carbon tax, some low-cost high-carbon biofuel pathways become more costly and are produced only at higher levels of fuel cost, which flattens the average biofuel carbon intensity curve but shifts the supply curve inward.

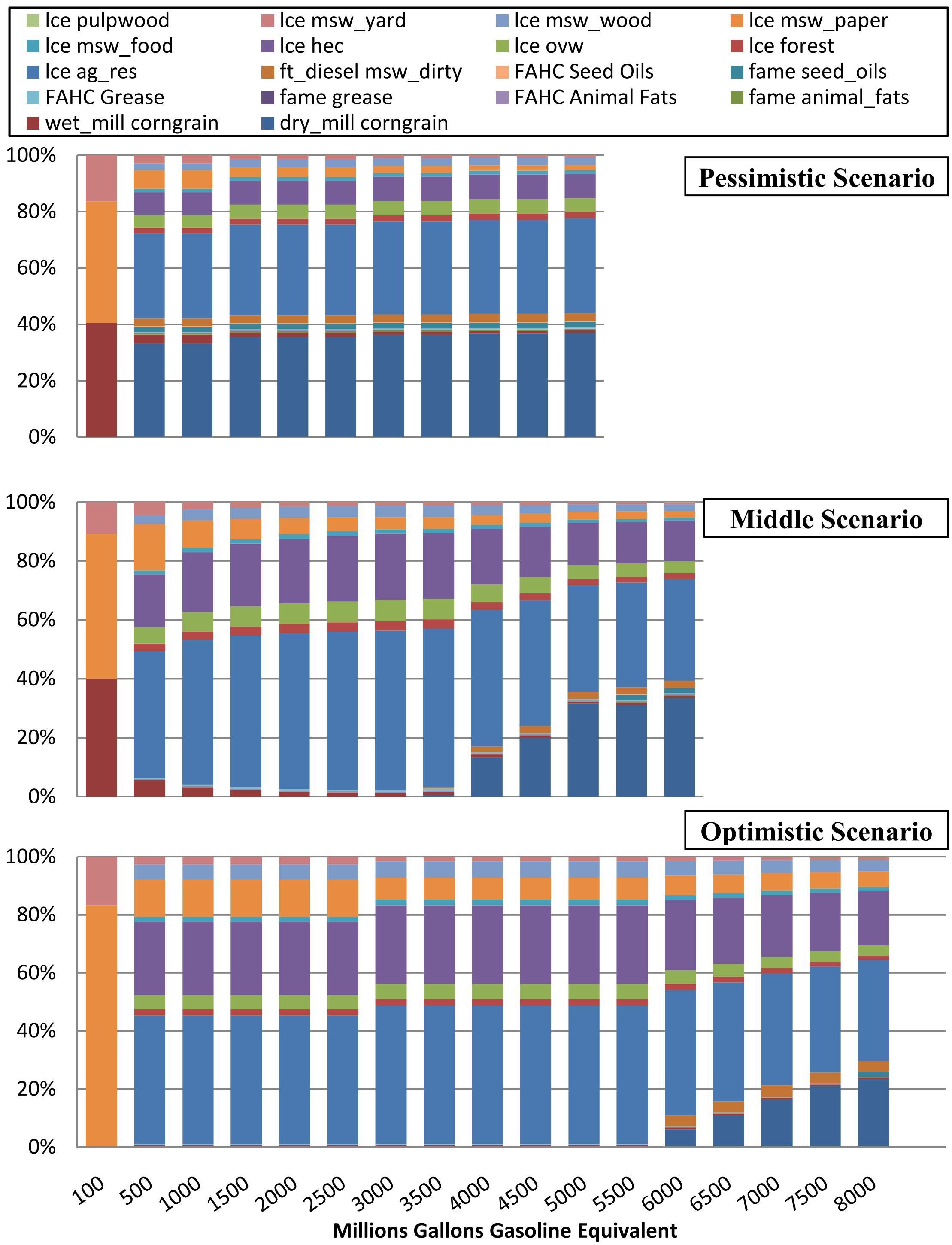


Figure 13: Changes in biofuel composition as total quantity increases using the *least-cost rule* with $5.50/gge marginal fuel cost in 2050 (constant 2008 USD) for the *Pessimistic* (upper panel), *Middle* (middle panel) and *Optimistic* (lower panel) scenarios. The average carbon intensity curves shown in Figure 12 are a result of these shifts in composition and the carbon intensity for each pathway (Figure 11).

1.4 Three New 80in50 Scenarios with Improved Modeling of Biofuel Supply

The biofuel carbon intensity supply curves for 2050, based on the least-cost loading order rule, were used to create a new biofuel supply module in the 80in50 LEVERS model. As the total quantity of biofuel required changes according to 80in50 scenario parameters, the average carbon intensity of that biofuel – and consequent GHG emissions for the scenario – changes according to the biofuel carbon intensity supply curve (Figure 12). Thus, feedback regarding biofuel supply and composition is given to the researcher using the revised 80in50 LEVERS model to define 80in50 scenarios.

The least-cost loading order rule was used as an approximation of profit maximizing behavior among biofuel industry participants. However, sensitivity analysis for each 80in50 scenario created with the revised 80in50 LEVERS model was performed with the least-carbon and least-cost-with-carbon-tax rules in order to assess the impact of policies directed at ensuring production of only low-carbon biofuels.

1.4.1 Three Multi-Strategy 80in50 Scenarios

The revised 80in50 LEVERS model, with the new biofuel supply module, was used to define three new 80in50 scenarios, one for each of the *Pessimistic*, *Middle* and *Optimistic* scenarios for biofuel supply. These scenarios are meant to replace the original *Efficient Biofuels* scenario with scenarios built on refined treatment of biofuel supply. As such, the general approach taken was to use biofuel to the maximum extent possible, with other strategies employed as needed to achieve the remaining emission reduction required to meet the 80in50 goal.

This group of scenarios is called the “Multi-Strategy” sequence because a relatively balanced combination of the strategies employed in the original three 80in50 scenarios is required. Although biofuels are used to the maximum extent possible, limited supply and increasing average carbon intensity constrain use well before the 80in50 goal is achieved. Consequently, the *Multi-Strategy* scenarios combine elements of LDV electrification, VMT reduction, and vehicle efficiency in order to meet the *80in50* goal with biofuel supply constrained in quantity and carbon intensity by a "fair share" of feedstock supply in the United States. The *Multi-Strategy$_{pessimistic}$* scenario requires more LDV electrification, VMT reduction, and vehicle efficiency improvement in order to meet the *80in50* goal than does the *Multi-Strategy$_{optimistic}$* scenario. A detailed summary of scenario parameters for the original three 80in50 scenarios and three new *Multi-Strategy* scenarios is given in Appendix A.

The distinguishing feature between the three *Multi-Strategy* scenarios is the quantity and composition of biofuel supply available, as indicated by the subscript for biofuel supply scenario – *pessimistic*, *middle* and *optimistic*. Marginal fuel cost in 2050 for all three *Multi-Strategy* scenarios was assumed to be \$5.50/gge (constant 2008 USD) based on the EIA Energy Outlook 2009 forecast of \$5.47 per gallon gasoline in 2030 and a logarithmic fit to extend the forecast through 2050 (EIA, 2009).[36] Other assumptions that define these scenarios are shown in Table 9 and Appendix A.

[36] Absent an economic model or foresight into policy-forcing mechanisms that might alter price parity, we assume biofuel price equals gasoline price on an energy basis. As one reviewer noted, the AEO forecasts for gasoline price may not be indicative for a carbon-constrained future since they are reflective of relatively high petroleum usage. However, the fuel price forecast has minimal impact on my modelling of biofuel supply for 80in50 scenario development since inelasticity of supply occurs below \$5.50 per gge.

	Actor-Based	Electric-Drive	Efficient Biofuels	Multi-Strategy			Multi-Strategy w/ C-tax		
				Pess.	Middle	Opt.	Pess.	Middle	Opt.
LDV Fleet									
Gasoline ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%
Biofuel ICE	0%	0%	75%	0%	0%	10%	0%	1%	11%
Diesel ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%
Gasoline PHEV	50%	5%	3%	2%	2%	2%	2%	2%	5%
Biofuel PHEV	0%	0%	22%	15%	27%	35%	24%	31%	39%
Diesel PHEV	30%	0%	0%	3%	3%	3%	4%	4%	5%
H2FCV	10%	60%	0%	50%	45%	30%	45%	40%	25%
Battery EV	10%	35%	0%	30%	23%	20%	25%	22%	15%
Truck/SUV share	10%	40%	40%	35%	35%	38%	35%	35%	40%
Car share	90%	60%	60%	65%	65%	62%	65%	65%	60%
Pass-mi./cap./yr.	9.49	15.3	15.3	13.0	13.8	14.5	13.0	13.8	14.5
Pass./vehicle	2.08	1.66	1.66	1.83	1.75	1.66	1.83	1.75	1.66
Bus Fleet									
HEV (gas/diesel)	10%	0%	75%	0%	0%	5%	0%	0%	5%
PHEV (gas/diesel)	25%	0%	0%	0%	0%	5%	0%	0%	5%
Biofuel PHEV	5%	0%	25%	30%	40%	40%	30%	40%	40%
H2FCV	10%	50%	0%	50%	45%	40%	50%	45%	40%
Battery EV	50%	50%	0%	20%	15%	10%	20%	15%	10%
HDV Fleet									
Diesel ICE	0%	0%	0%	0%	0%	0%	0%	0%	0%
Diesel HEV	65%	35%	0%	0%	0%	10%	0%	0%	10%
Biofuel HEV	25%	0%	100%	55%	60%	60%	55%	60%	60%
H2FCV	5%	60%	0%	40%	35%	30%	40%	35%	30%
Battery EV	5%	5%	0%	5%	5%	0%	5%	5%	0%
Agriculture									
Gasoline	20%	0%	0%	0%	0%	5%	0%	0%	5%
Diesel	30%	30%	25%	5%	5%	10%	5%	5%	10%
Biofuel	30%	40%	75%	65%	70%	75%	65%	70%	75%
Hydrogen	10%	20%	0%	20%	20%	10%	20%	20%	10%
Electricity	10%	10%	0%	10%	5%	0%	10%	5%	0%
Constr.& Off-Road									
Gasoline	10%	0%	0%	0%	0%	10%	0%	0%	10%
Diesel	30%	0%	25%	10%	10%	10%	10%	10%	10%
Biofuel	20%	30%	75%	40%	50%	50%	40%	50%	50%
Hydrogen	10%	40%	0%	30%	25%	20%	30%	25%	20%
Electricity	30%	30%	0%	10%	5%	0%	10%	5%	0%
Natural Gas	0%	0%	0%	10%	10%	10%	10%	10%	10%

Table 9: Selected parameter assumptions that define the original three 80in50 scenarios described by Yang et al. (2009), the three Multi-Strategy 80in50 scenarios developed in this dissertation, and the three Multi-Strategy 80in50 scenarios under a carbon tax of $75 per metric tonne CO_2e imposed on biofuel production only. Rail is 100% electrified and aircraft are 100% biofueled across all scenarios. Annual passenger miles per capita is given in thousands of miles.

For the *Multi-Strategy*$_{pessimistic}$ scenario, LDV are 80% electric-drive (BEV or FCV) and fleet-average new-vehicle on-road fuel economy is 90 mpgge. The fleet mix has shifted to 65% cars and VMT/capita has decreased 7% from 1990 levels while population has doubled. In order to meet the *80in50* goal, the carbon intensity in the energy supply must also be very low, with 23 gCO_2e/MJ for electricity, 24 gCO_2e/MJ for hydrogen, and 38 gCO_2e/MJ for biofuels. This requires widespread use of carbon capture and sequestration (CCS) across nearly all carbon-based energy sources and/or extensive use of renewable energy sources. Annual consumption of biofuel is 4.4 billion gge, of which only 8% is used in the LDV subsector (64% is used in the HDV subsector, 17% in marine, agriculture, construction and off-road subsectors, and 11% in the aircraft subsector). In total, biofuels account for 38% of the total energy used in the instate transportation sector.[37]

For the *Multi-Strategy*$_{middle}$ scenario, increased biofuel supply reduces electrification of the LDV fleet to 68% BEV and FCV, and fleet-average new-vehicle on-road fuel economy is 87 mpgge. Although the fleet mix is still 65% cars, travel demand (VMT/capita) has increased 4% from 1990 levels. The carbon intensity of electricity and hydrogen are held constant across all *Multi-Strategy* scenarios while the average carbon intensity of the biofuels used in this *Multi-Strategy*$_{middle}$ scenario has decreased to 32.9 gCO_2e/MJ. Annual consumption of biofuel is 5.2 billion gge, of which 14% is used in the LDV subsector (60% is used in the HDV subsector, 17% in marine, agriculture, construction and off-road subsectors, and 10% in the aircraft subsector). In total, biofuels account for 41% of the total energy used in the instate transportation sector.

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[37] One study of biomass residues available in California (i.e., feedstocks not grown on agricultural land) estimate the state is capable of producing 2.3 billion gge (Jenkins, 2006).

For the *Multi-Strategy*$_{optimistic}$ scenario, even more biofuel supply enables electrification of only half of the LDV fleet as BEV and FCV, and fleet-average new-vehicle on-road fuel economy is 82 mpgge. The fleet mix is now 62% cars and 38% light trucks, and travel demand (VMT/capita) can increase 15% from 1990 levels. Due to larger supply, the average carbon intensity of biofuels in this scenario has decreased to 19.0 gCO_2e/MJ and 31% of the annual consumption of 6.6 billion gge is used in the LDV subsector (48% is used in the HDV subsector, 13% in marine, agriculture, construction and off-road subsectors, and 8% in the aircraft subsector). In total, biofuels account for nearly half (48%) of the total energy used in the instate transportation sector.

Comparing these three scenarios, it is evident that more success with low-carbon biofuels reduces the pressure to achieve success with advanced vehicle technologies (i.e., PHEV, BEV, FCV) and with increasing availability of low-carbon electricity and hydrogen. Furthermore, a larger supply of biofuel means a larger fraction can be used in LDV, after other subsectors that have fewer alternatives (e.g., aircraft, HDV, marine) have been provided adequate supply. However, even in the optimistic scenario for biofuel supply in 2050, some electrification of the LDV fleet with PHEV, BEV and FCV is needed. Hence, even the *Multi-Strategy*$_{optimistic}$ scenario requires a portfolio approach with actions taken on all fronts to reduce emissions. Finally, a carbon tax imposed on biofuel production has the effect of reducing the average carbon intensity of biofuel by moving less carbon intense pathways up in the least-cost loading order that approximates profit maximizing behavior in the industry.

Figure 14 is similar to Figure 3 (section 1.1) in showing, for each *Multi-Strategy* scenario, the emission reductions achieved through each factor in the transport-specific

Kaya identity and each transportation sub-sector. The three scenarios are relatively similar, with reduction in overall travel demand accounting for only 4-11% of emission reductions from the *Reference* scenario and vehicle efficiency accounting for 53-55% of emission reductions. Like the *Electric-Drive* and *Efficient Biofuels* scenarios, vehicle performance is held constant at current levels in all *Multi-Strategy* scenarios (i.e., no improvement in vehicle efficiency is achieved through smaller, less powerful vehicles). On the fuels side, vehicles using electricity account for 30-33% of emission reduction in the *Multi-Strategy* scenarios, low-carbon biofuels account for 20-33% of the reduction, and low-carbon hydrogen accounts for 27-39% of the reduction.

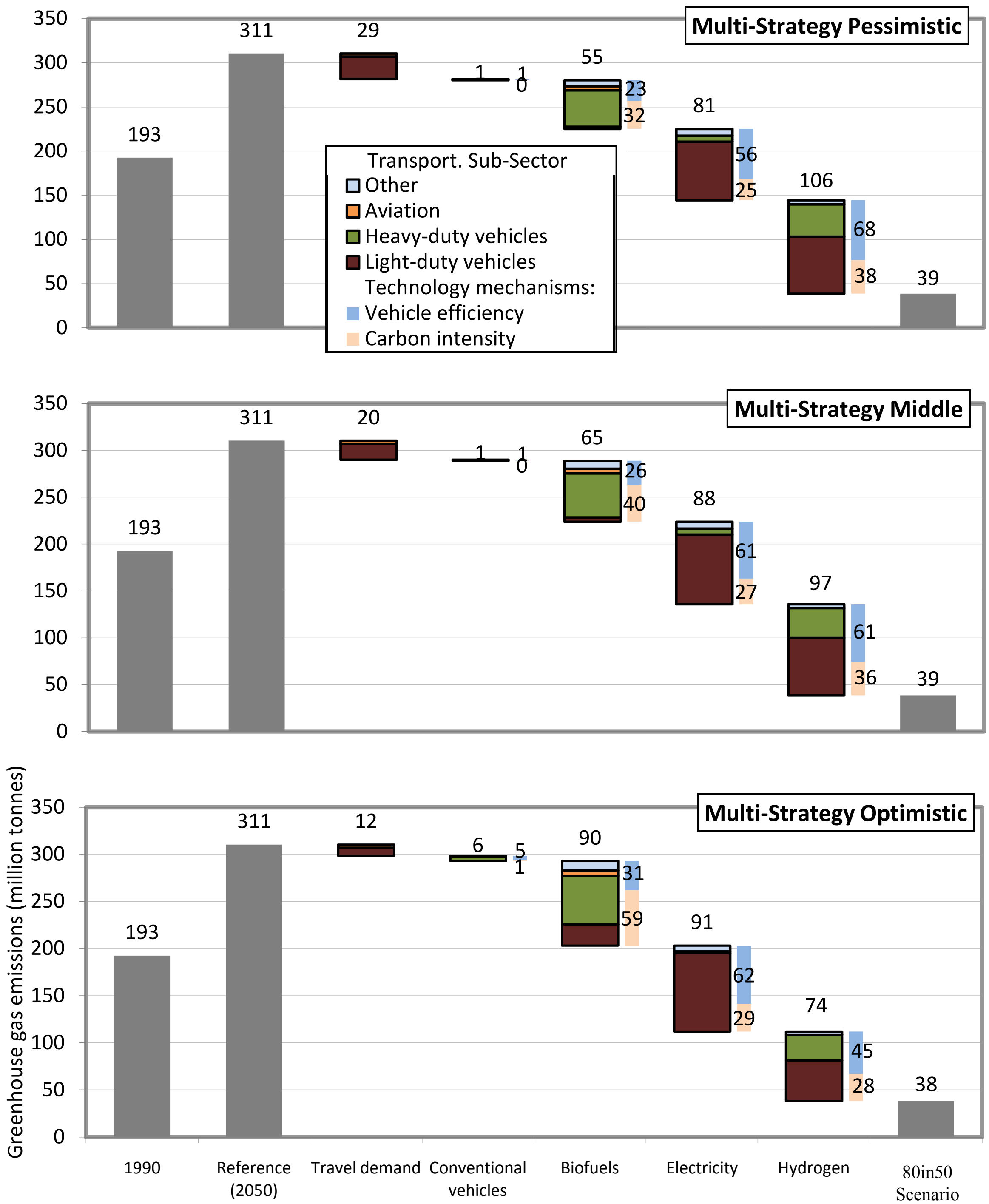

Figure 14: In-state GHG emission reduction from the *Reference* scenario by control strategy for the three *Multi-Strategy 80in50* scenarios created with improved modeling of biofuel supply. The *Reference* scenario shows business as usual while each successive column to the right shows emission reduction attributable to the factors of travel demand, efficiency, and carbon intensity of fuels (biofuels, electricity, and hydrogen). Within each column, the contribution from transportation sub-sector is shown.

1.5 Sensitivity Analysis for Three New 80in50 Scenarios

I followed the same approach to sensitivity analysis as described for the original three 80in50 scenarios in order to examine the sensitivity, tradeoffs, and constraints inherent in the three *Multi-Strategy 80in50* scenarios defined with the revised 80in50 LEVERS model. I also assessed the sensitivity to loading order rule – least-cost, least-carbon, or least-cost with a carbon tax – used in creation of the biofuel carbon intensity supply curves.

The results of this analysis, shown in Table 10, are comparable to results for the original three 80in50 scenarios (Table 2). The maximum range in GHG emissions for each parameter category (shown in the maximum difference column) provides an indication of the maximum sensitivity across all three of the new *Multi-Strategy* 80in50 scenarios.

For evaluation of the model sensitivity to the loading order rule used in creating the biofuel carbon intensity supply curves, Table 11 shows how the quantity and carbon intensity of biofuel used in each *Multi-Strategy* scenario would differ under each of the three loading order rules described above.

Parameter Category	GHG Emissions in 2050 (% of 1990) Multi-Strategy Pessimistic High - Low	Multi-Strategy Middle High - Low	Multi-Strategy Optimistic High - Low	Max. Diff.
Electricity Lifecycle GHG Emissions (149 to 6.5 gCO2/MJ)[3]	44.8 – 20.0%	47.3 – 20.0%	49.1 – 20.0%	29.1%
Hydrogen Lifecycle GHG Emissions (100 to 7.6 gCO2/MJ)[2]	41.7 – 15.2%	40.5 – 15.6%	36.2 – 16.4%	26.5%
Carbon Capture and Storage (0% to 80% effectiveness)[9]	45.4 – 20.0%	45.0 - 20.0%	41.6 - 20.0%	25.4%
Biofuel Lifecycle GHG Emissions (71.3 to 9.3 gCO2/MJ)[1]	28.3 – 12.8%	31.3 – 13.0%	39.9 – 16.3%	23.6%
LDV Occupancy & Transport Intensity[4]	23.4 – 17.7%	22.9 – 15.9%	23.7 – 13.3%	10.4%
LDV Fleet Fuel Economy (mpgge)[6]	23.3 – 20.0%	24.4 - 20.0%	27.8 - 20.0%	7.8%
HDV Truck Miles per Person (612 to 398 mi./capita)[9]	20.0 – 17.3%	20.0 – 14.6%	20.0 – 14.2%	5.8%
HDV Truck Fleet Fuel Economy (mpgge) (75% to 100% of feasible limit)[9]	22.9 – 20.0%	23.1 - 20.0%	25.4 - 20.0%	5.4%
Population (59.5 to 55 million)[10]	20.0 – 18.0%	20.0 – 15.9%	20.0 – 16.2%	4.1%
PHEV share of miles in EV mode[7]	20.7 - 18.1%	21.1 - 18.2%	22.7 - 18.6%	4.1%
Off-Road & Construction Intensity (38.9 to 23.3 hr/capita, 160% to 95% of 1990)	20.0 – 18.8%	20.0 – 17.8%	20.0 – 18.2%	2.2%
Agriculture Intensity (3.6 to 0.8 hr./capita, 100% to 22% of 1990)	20.6 - 19.8%	20.6 – 19.8%	21.1 – 19.2%	1.9%
Fleet Share: Cars (60% to 85% of fleet)[9]	20.2 - 19.2%	20.2 – 19.1%	20.0 – 18.4%	1.6%
Off-Road & Construction Fleet Eff. (75% to 100% of feasible limit)[9]	20.9 – 20.0%	21.0 – 20.0%	21.5 – 20.0%	1.5%
Marine Transport Intensity (75% to 100% of feasible limit)[9]	20.0 – 19.8%	20.0 – 19.8%	20.0 – 19.2%	0.8%
Aviation Transport Intensity (instate)[8]	20.0 – 19.6%	20.0 – 19.7%	20.0 – 19.2%	0.8%
Aircraft Fleet Efficiency (60% to 100% of feasible limit)[9]	20.5 – 20.0%	20.5 – 20.0%	20.8 - 20.0%	0.8%
Bus Fleet Fuel Economy (75% to 100% of feasible limit)[9]	20.2 - 20.0%	20.2 - 20.0%	20.2 - 20.0%	0.2%
Biofuel Blend in Gasoline & Diesel (0% to 20%)[9]	20.0 - 20.0%	20.0 – 19.9%	20.0 – 19.6%	0.4%

$$CO_{2,\,Transport} = P \times T \times E \times C$$

P: Population

T: Transportation Intensity

E: Energy Intensity (LDV, HDV)

C: Fuel Carbon Intensity

Transportation sub-sectors other than LDV & HDV (off-road, construction, ag., aircraft, marine, rail)

Carbon capture and sequestration (CCS)

Table 10: Sensitivity analysis for the maximum range in emissions across all three new *Multi-Strategy 80in50* scenarios for general categories of scenario parameters. The maximum variation in emission reduction from 1990 levels is shown along with the corresponding range in parameter values, where meaningful. The parameters are color-coded according to the factors in the transportation variant of the Kaya identity used by Yang et al. (2009).

Notes:
[1] 9.3 gCO2/MJ is the most optimistic mix deemed feasible by Yang et al. with 35% ethanol (12.3 gCO2/MJ), 10% biodiesel (25.8 gCO2/MJ), 22.5% methanol (5.1 gCO2/MJ) and 22.5% DME (5.4 gCO2/MJ); 71.3 gCO2/MJ represents aggressive biofuel blending with gasoline (i.e., 80% of gasoline carbon intensity in 2050).
[2] The low end is 50% natural gas via pipeline with 80% CCS (15.2 gCO2/MJ) and 50% renewable electrolysis (0 gCO2/MJ); the high end is 100% onsite reformation from natural gas (100 gCO2/MJ). Note, 100% onsite electrolysis with the current California grid mix would produce 138.2 gCO2/MJ (Yang et al., 2009).
[3] The current California grid mix produces 149 gCO2/MJ while 6.5gCO2/MJ is the best deemed feasible in 2050 by Yang et al. with 30% natural gas combined cycle with 80% CCS (20.2 gCO2/MJ), 30% nuclear (1.6 gCO2/MJ) and 40% renewable (0 gCO2/MJ) (Yang et al., 2009).
[4] 60% - 120% of 2005 VMT/capita and passenger-miles/capita, and 100% - 125% of 2005 passengers/vehicle (Yang et al., 2009).
[5] For each vehicle technology, fuel economy ranges from the *Reference* scenario values in Yang et al. to 100% of feasible limits for 2050 (Yang et al., 2009).
[6] For each vehicle technology, fuel economy ranges from the *Reference* scenario values in Yang et al. to 120% of feasible limits for 2050, which corresponds to the assumption of decreased vehicle performance (e.g., smaller with slower acceleration) made in the *Actor-Based* scenario (Yang et al., 2009).
[7] Pessimistic and optimistic limits defined by Yang et al. are 43% - 58% in EV mode for LDV, 15% - 49% in EV mode for Buses (Yang et al., 2009).
[8] Aviation transport intensity is a combination of three parameters, with ranges defined by Yang et al. (2009): 80-100% of the *Reference* commercial passenger aviation (mi/capita), 65-100% of the *Reference* commercial freight aviation (ton-mi./capita), and 65%-100% of the *Reference* personal general aviation (mi/capita).
[9] Yang et al., 2009
[10] CARB, 2007 and CDF, 2007

	Biofuel Qty. Used (Mgge)	Biofuel Qty. Available (Mgge)	Avg. Biofuel Carbon Intensity (gCO2e/MJ)
Actor-Based 80in50	1,683	N/A	17.7
Electric Drive 80in50	829	N/A	23.7
Efficient Biofuels 80in50	15,993	N/A	17.7
Multi-Strategy$_{\textbf{pessimistic}}$			
Least-Cost	4,438	5,422	38.1
Least-Cost, \$75/ton CO_2e tax	4,648	5,417	37.1
Multi-Strategy$_{\textbf{middle}}$			
Least-Cost	5,196	6,223	32.9
Least-Cost, \$75/ton CO_2e tax	5,390	6,220	32.6
Multi-Strategy$_{\textbf{optimistic}}$			
Least-Cost	6,590	8,367	19.0
Least-Cost, \$75/ton CO_2e tax	6,849	8,367	20.4

Table 11: Biofuel quantity and carbon intensity under two potential loading order rules for each Multi-Strategy 80in50 scenario, with the original three *80in50 scenarios* shown for reference.

Many of the general observations made for the sensitivity analyses of the original three 80in50 scenarios remain true for the *Multi-Strategy* scenarios. The scenarios are most sensitive to fuel carbon intensity parameters, although the sensitivity to biofuel carbon intensity is diminished due to refinement in the supply constraints. Unlike the original three 80in50 scenarios, each of which emphasized different strategies for emission reduction, the three *Multi-Strategy* scenarios are relatively similar except for the quantity of biofuel supply available. Consequently, the sensitivities of these scenarios to each parameter category remain more consistent than in the original three 80in50 scenarios.

The "upper bounds" for emissions reduction in each *Multi-Strategy* scenario, calculated with the same method used for sensitivity analysis of the original three 80in50 scenarios, are as follows: 95.6% for *Multi-Strategy$_{pessimistic}$*, 95.5% for *Multi-Strategy$_{middle}$*, and 93.6% for *Multi-Strategy$_{optimistic}$*. These results show that the strategies highlighted in the Multi-Strategy scenarios, including a portfolio approach with action on all available fronts, offer even greater potential for further GHG emission reductions beyond the 80% reduction goal than any of the original 80in50 scenarios. Furthermore, the scenario with the least available biofuel supply (i.e., *Multi-Strategy*$_{Pessimistic}$) offers the most potential for further GHG emission reductions.

Similarly, "lower bounds" for emissions reductions in each *Multi-Strategy* scenario, calculated with the same method used for sensitivity analysis of the original three *80in50* scenarios, yield the following *increases* in GHG emissions from 1990 levels: 37.3% for *Multi-Strategy*$_{pessimistic}$, 42.1% for *Multi-Strategy*$_{middle}$, 47.2% for *Multi-Strategy*$_{optimistic}$. These increases are generally less than for the *Reference* case described by Yang et al. (44%) despite more pessimistic fuel carbon intensities due to more deployment of advanced vehicle technology in the fleet.

From this analysis, it is again evident that relatively little opportunity exists in each scenario to further reduce GHG emissions below 20% of 1990 levels and that emissions could *increase* despite dramatic changes in vehicle technology if the other relevant factors in each scenario do not improve. As stated previously, the equality across all six *80in50* scenarios in achieving the *80in50* goal does not carry over into equality in upside potential for further emission reduction after 2050, nor in downside risk for missing the *80in50* goal if required levels in some parameters are not met.

1.6 Discussion

1.6.1 Biofuel Supply Model

Two caveats about the NBSM model noted by Parker et al. are salient for application of the model to generating biofuel supply curves in the year 2050 for use in defining 80in50 scenarios.

First, Parker et al. note that their analysis, “does not consider competition for the biomass resources for alternative uses. The potential for using biomass for electricity is also considerable but will depend mainly on the same resource base.” I avoided internal conflict on this issue in my modeling by specifying zero biomass use in the generation mix for the large quantity of low-carbon electricity used in the transportation sector to charge plug-in vehicles (Table 12, Table 15). But the inherent assumption in the *80in50* scenarios is that biomass is also not used for generating low-carbon electricity for use in other sectors of the economy. In other words, 100% of the available biomass resources are going into biofuel production and the electric generation sector will have to look elsewhere for low-carbon resources for use in meeting its own *80in50* goal. One argument in support of this assumption is that there are many low-carbon renewable energy source alternatives for electricity generation but very few low-carbon sources of liquid fuels, so the “value” or “opportunity cost” is higher in the transportation sector. But to the extent competition for biomass resources from the electric generation sector increases, constraining biofuel production to some fraction less than 100% of total available biomass resource, the available supply of biofuels for use in transportation may be constrained below even my *pessimistic* case for 2050.

80in50 Scenario	Generation Mix for Hydrogen used in Transportation in 2050 Natural Gas Pipeline	 Truck	 Onsite	 Electrolysis Onsite (CA Grid)	 (Renewable)	 Biomass (Pipeline)	 Coal (Pipeline)
Multi-Strategy$_{pessimistic}$	30% (15.2)	0% (16.8)	0% (100)	0% (138.2)	5% (0)	35% (17.3)	30% (45.7)
Multi-Strategy$_{middle}$	30% (15.2)	0% (16.8)	0% (100)	0% (138.2)	5% (0)	35% (17.3)	30% (45.7)
Multi-Strategy$_{optimistic}$	30% (15.2)	0% (16.8)	0% (100)	0% (138.2)	5% (0)	35% (17.3)	30% (45.7)
Actor-Based	0% (15.2)	20% (16.8)	40% (100)	0% (138.2)	40% (0)	0% (17.3)	0% (45.7)
Efficient Biofuels	30% (15.2)	0% (16.8)	0% (100)	0% (138.2)	5% (0)	35% (17.3)	30% (45.7)
Electric-Drive	40% (15.2)	0% (16.8)	0% (100)	0% (138.2)	41% (0)	19% (17.3)	0% (45.7)

80in50 Scenario	Generation Mix for Electricity used in Transportation in 2050 NG CC	 Nuclear	 Renewables	 Biomass	 Coal IGCC
Multi-Strategy$_{pessimistic}$	30% (20.2)	30% (1.5)	40% (0)	0% (14.5)	0% (63.4)
Multi-Strategy$_{middle}$	30% (20.2)	30% (1.5)	40% (0)	0% (14.5)	0% (63.4)
Multi-Strategy$_{optimistic}$	30% (20.2)	30% (1.5)	40% (0)	0% (14.5)	0% (63.4)
Actor-Based	30% (20.2)	30% (1.5)	40% (0)	0% (14.5)	0% (63.4)
Efficient Biofuels	30% (20.2)	30% (1.5)	40% (0)	0% (14.5)	0% (63.4)
Electric-Drive	30% (20.2)	30% (1.5)	40% (0)	0% (14.5)	0% (63.4)

Table 12: Generation mixes and carbon intensities (in parentheses; gCO_2e/MJ) for electricity and hydrogen used in the transportation sector in 2050 for six 80in50 scenarios. Different assumptions regarding deployment and efficacy of carbon capture and sequestration could change the carbon intensity for fossil fuel based generation and different assumptions regarding the overall generation mix could change the average carbon intensity for each fuel. These assumptions were not held constant for hydrogen in the three 80in50 scenarios developed by Yang et al. but were held constant for both electricity and hydrogen in the Multi-Strategy scenarios in order to facilitate comparison with the Efficient Biofuels scenario.

Second, the shape of the biofuel carbon intensity supply curve under the least-cost loading order rule (Figure 12 in section 1.3.4), with high initial carbon intensity followed by rapid decrease as quantity increases, is partly due to considerations regarding existing infrastructure that are relevant for modeling biofuel supply in 2017 but perhaps not in 2050. Parker et al. noted that the high-carbon corn-based ethanol is the least-cost feedstock pathway in part because existing wet mill facilities have high value co-products and both wet mill and dry mill facilities have sunk capital expense that is not charged to production in the NBSM model. Consequently, existing corn-based ethanol facilities enjoy a cost advantage. Once this relatively small capacity is used, the next least-cost feedstock pathways are very low-carbon pathways for production of biodiesel from waste lipids (utilizing low-cost waste feedstocks), which brings the average biofuel carbon intensity down quickly.[38]

1.6.2 Comparison of Six 80in50 Scenarios

In this section, I discuss the results of the revised modeling of biofuel supply in creating 80in50 scenarios by comparing the three new *Multi-Strategy* scenarios with the original three *80in50* scenarios. This comparison elucidates the impact of refining treatment of biofuel supply on the feasible range for *80in50* scenarios

The importance of the holistic modeling approach, including all transportation sub-sectors, developed by Yang et al. (2009) in the 80in50 LEVERS model is evident in Table 13. The LDV sub-sector must reduce emissions more than 80% below 1990 levels to compensate for other sub-sectors that face more challenges for emission reduction. Other models of the 80in50 goal that consider the LDV sector in isolation (e.g., Thomas, 2008, CARB, 2009d, Grahn et al., 2009, Sutherland, 2010) underestimate the emission reduction required from LDV to meet the 80in50 goal for transportation. Furthermore, comparison across the *Efficient Biofuels* and *Multi-Strategy* scenarios shows that the LDV sub-sector must reduce emissions more when biofuel supply is more limited because other sub-sectors like aircraft and marine have even fewer options for emission reductions.

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[38] The least-cost cellulosic ethanol, utilizing MSW paper and yard waste resources, is also relatively low in carbon intensity.

	Multi-Strategy *pessimistic*	Multi-Strategy *middle*	Multi-Strategy *optimistic*	Actor-Based	Efficient Biofuels	Electric-Drive
LDV	9%	10%	10%	5%	15%	6%
HDV	44%	42%	43%	60%	25%	63%
Aircraft	39%	34%	19%	27%	38%	61%
Rail	8%	8%	8%	72%	35%	8%
Marine, Ag., Off Road	59%	57%	56%	48%	48%	34%
All Transport	20%	20%	20%	20%	20%	20%

Table 13: In-state Transportation GHG emissions in 2050 by sub-sector (percent of 1990 level) for six 80in50 scenarios. In-state emissions are reduced 80% from 1990 levels in all scenarios but the LDV sub-sector must reduce emissions more than 80% because other sub-sectors fall short of the *80in50* goal.

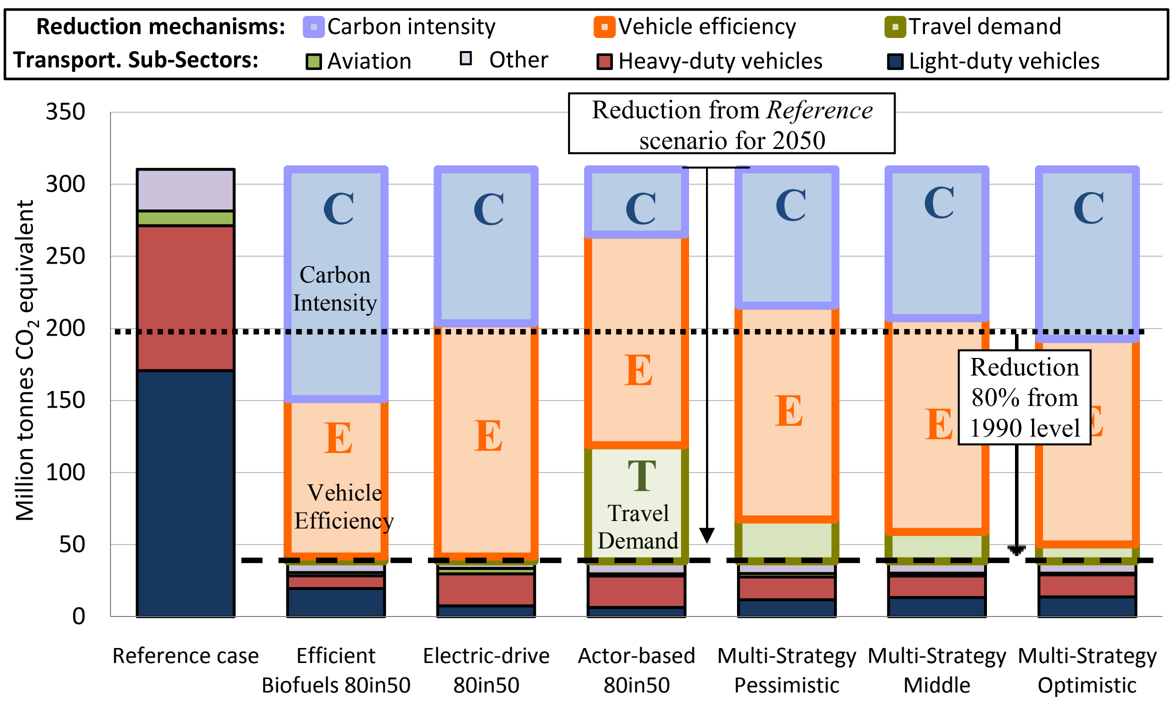

Figure 15: Comparison of six *80in50* scenarios, with emissions in 2050 by transportation sub-sector (e.g., LDV) and emission reductions by each factor in the transport-specific Kaya identity (e.g., vehicle efficiency) shown. The *80in50* scenarios are compared to the *Reference* scenario for 2050, where no advanced technologies or fuels are employed. The dashed bar meets an 80% reduction in GHG emissions from the 1990 level (dotted bar).

The sources of GHG emission reduction in each *80in50* scenario are shown according to the factors in the transport-specific Kaya identity in Figure 15. This provides a high-level summary of how the scenarios differ in emphasis on available strategies for emission reduction. Only with large quantities of low-carbon biofuel in the *Efficient Biofuels* scenario or of low-carbon electricity in the *Electric-Drive* scenario is the *80in50* goal achieved without reduction in per-capita travel demand.

Comparison of the assumed make-up of the LDV sub-sector in each of the 80in50 scenarios provides a more intuitive feel for how the world in 2050 would differ between them (Table 14). With abundant low-carbon biofuel supply in the *Efficient Biofuels* scenario, the future looks rather unchanged, with 75% of the LDV fleet being biofueled ICE and 22% biofueled PHEV. Weighted average new-vehicle on-road fuel economy has increased to 56 mpgge in 2050, through a combination of efficiency gains in internal combustion engine design, hybridization, coaster aerodynamics, some electrification in PHEVs, and fleet shift toward cars rather than trucks. Vehicle performance in terms of passenger room, acceleration and top speed are maintained at current levels.

In contrast, the internal combustion engine has all but disappeared in the *Electric-Drive* scenario, where 60% of the LDV fleet is FCV and 35% is BEV by 2050. Weighted average new-vehicle on-road fuel economy has increased to 89 mpgge in 2050, through electric drivetrains with regenerative braking, coaster aerodynamics, and fleet shift toward cars rather than trucks (vehicle performance is maintained at current levels). In the Actor-Based scenario, fuel economy increases even more to 125 mpgge through more aggressive shift toward cars in the vehicle fleet composition and decrease in vehicle performance (i.e., vehicles in 2050 are smaller and less powerful than today).

The LDV fleet compositions in the *Multi-Strategy* scenarios cover a range in between these extremes, with more electrification of LDV when biofuel supply is more constrained in the *Multi-Strategy*$_{pessimistic}$ scenario than in the *Multi-Strategy*$_{optimistic}$ scenario.

LDV technology	Multi-Strategy *pessimistic*	Multi-Strategy *middle*	Multi-Strategy *optimistic*	Actor-Based	Efficient Biofuels	Electric-Drive
Gasoline ICE	0% (53)	0% (53)	0% (52)	0% (77)	0% (51)	0% (51)
Biofuel ICE	0% (53)	0% (53)	10% (52)	0% (77)	75% (51)	0% (51)
Diesel ICE	0% (67)	0% (67)	0% (66)	0% (101)	0% (65)	0% (65)
Gasoline PHEV	2% (77)	2% (77)	2% (75)	50% (117)	3% (81)	5% (81)
Biofuel PHEV	15% (77)	27% (77)	35% (75)	0% (117)	22% (81)	0% (81)
Diesel PHEV	3% (88)	3% (88)	3% (87)	30% (133)	0% (91)	0% (91)
FCV	50% (79)	45% (79)	30% (77)	10% (114)	0% (76)	60% (76)
Battery EV	30% (115)	23% (115)	20% (113)	10% (156)	0% (112)	35% (112)
LDV Fleet Avg. Fuel Economy (mpgge)	89.6	86.9	81.5	125.8	58.6	89.0
LDV Fleet % cars	65%	65%	62%	90%	60%	60%

Table 14: Vehicle technology fleet shares and weighted average new-vehicle on-road fuel economy (mpgge, in parentheses) for LDV in 2050 for six *80in50* scenarios. Fuel economy is a weighted average according to car and light truck fleet shares for new-vehicle on-road efficiency. Noticeably higher fuel economy is achieved in the *Actor-Based* scenario through reduced vehicle performance (e.g., smaller, less powerful vehicles); the other five scenarios hold vehicle performance constant at current levels. For ICE vehicle fuel economy, hybridization is assumed to be incorporated from mild to full HEV by 2050.

However, the refinement of biofuel supply modeling presented in this research suggests the *Efficient Biofuels* scenario is not feasible in total quantity or in average carbon intensity of the biofuel supply. Table 15 shows the total fuel use across all transportation sub-sectors by fuel type; the 16 billion gge biofuels used in the Efficient Biofuels scenario is nearly double the quantity available even under optimistic assumptions with the refined modeling of biofuel supply presented in this chapter. Furthermore, achieving the average carbon intensity of 18 gCO_2e/MJ assumed in the

Efficient Biofuels scenario appears infeasible when the supply is modeled by individual feedstock-production pathways.

The summary of biofuel composition and usage across the 80in50 scenarios given in Table 16 shows the impact of such a large supply of low-carbon biofuel on the degree of change required in the LDV sub-sector to meet the *80in50* goal. With 16 billion gge of biofuel available for use, over half can be allocated to the LDV sub-sector, whereas nearly all available biofuel is needed for other sub-sectors when the total supply is more constrained in the other *80in50* scenarios. As a result, the LDV sub-sector in the *Efficient Biofuels* scenario differs dramatically in composition from the other *80in50* scenarios because of the availability of approximately eight billion gge more biofuel for use in the LDV sub-sector.

To the extent the biofuel supply in the *Efficient Biofuels* scenario is overly optimistic, both in quantity and carbon intensity as shown by the refined modeling of biofuel supply presented in this chapter, this scenario should be removed from consideration as feasible for meeting the *80in50* goal. If the *Efficient Biofuels* scenario is removed from consideration, and replaced with the three *Multi-Strategy* scenarios that cover the range in feasible biofuel supply in 2050, the feasible range of options in the LDV sub-sector for meeting the 80in50 goal is dramatically narrowed. Specifically, a large share of the vehicle fleet must be electrified with PHEV, BEV and FCV unless consumers are willing to sacrifice vehicle performance and make large reductions in per-capita travel demand as assumed in the *Actor-Based* scenario.

80in50 Scenario	Fuel Use (billion gge) in 2050 for all Sub-Sectors Petroleum	Biofuels	Hydrogen	Electricity	VMT/capita/yr. (% of BAU scenario)
Multi-Strategy$_{pessimistic}$	0.3	4.4	4.6	2.4	85%
Multi-Strategy$_{middle}$	0.3	5.2	4.4	2.7	90%
Multi-Strategy$_{optimistic}$	1.0	6.6	3.4	2.9	95%
Actor-Based	2.7	1.7	0.5	3.0	62%
Efficient Biofuels	0.5	16.0	0.0	1.2	100%
Electric-Drive	2.3	0.8	7.0	2.9	100%

Table 15: Total fuels mix across all transportation sub-sectors and annual LDV VMT per capita in six *80in50* scenarios.

80in50 Scenario	Total Qty. of All Trans. Fuels (B gge)	Total Biofuel Quantity (B gge)	Biofuel Carbon Intensity (gCO2e/MJ)	Percent of Total Biofuel used in LDV
Multi-Strategy$_{pessimistic}$	11.8	4.4	38.1	8.0%
Multi-Strategy$_{middle}$	12.6	5.2	32.9	13.6%
Multi-Strategy$_{optimistic}$	13.9	6.6	19.0	30.9%
Actor-Based	7.8	1.7	17.7	5.6%
Efficient Biofuels	17.8	16.0	17.7	53.3%
Electric-Drive	13.0	0.8	23.7	0.0%

Table 16: Total quantity of all transportation fuels and of biofuel used in the whole transportation sector in 2050, including LDV and all other sub-sectors; percent of total biofuel used in the LDV sub-sector; and average biofuel carbon intensity. The *Efficient Biofuels* scenario differs dramatically from the other three scenarios in total quantity of biofuel used in transportation and in the share of total biofuel used for LDV.

1.7 Conclusions

A more realistic and conservative view of the potential biofuel supply in 2050 than portrayed in the original *Efficient Biofuels* 80in50 scenario described by Yang et al. constrains the range of scenarios that can meet the 80in50 goal. This leads to some general conclusions about the direction that LDV transportation must take if the goal is to be met.

Based upon the modeling work described here, the range of feasible biofuel supply for California in 2050 is approximately 5.4 to 8.4 billion gge, the level at which biofuel supply curves become inelastic under pessimistic and optimistic assumptions, with average carbon intensity of 28.5 to 39.4 gCO_2e/MJ at maximum quantity under these assumptions. Even if the cost of other energy sources increases above the $5.50 per gge marginal biofuel cost assumed in the *Multi-Strategy* scenarios, perhaps due to policy imposing constraints on carbon emissions, it is unlikely biofuel supply in California could increase beyond this maximum range unless the "fair share" rule is removed.

Flexibility in the fair share rule may be warranted if there is some regional specialization in low-carbon transportation systems in accord with local energy resources. In the United States, for example, the transport of biofuels would be reduced if more than the fair share were to be used in Midwestern states, with coastal states relying more on electrification of transportation. Such specialization, however, is likely to be relatively minor due to the relatively small cost of transporting biofuels.[39]

The refined modeling of potential biofuel supply in California in 2050 presented in this chapter shows that the original *Efficient Biofuels 80in50* scenario presented by Yang et al. (2009) may be overly optimistic both in quantity and average carbon intensity of biofuel. With this scenario removed from consideration and replaced by the three *Multi-Strategy* scenarios, the feasible range for 80in50 scenarios is significantly narrowed and similarity between scenarios is accentuated.

Thus, some general themes for changes that must occur regardless of what strategies are pursued for meeting the 80in50 goal emerge. These themes were not entirely clear in the work by Yang et al. (2009) because of the potential for the large supply of low-carbon biofuel assumed in the *Efficient Biofuels* scenario.

[39] One reviewer noted that such specialization could be driven by the adoption level of BEVs rather than the cost of transporting biofuels. If coastal areas adopt more BEVs than elsewhere in the country, perhaps due to more dense land use ameliorating range concerns, these areas would not need as much biofuels for LDVs and the Midwest could use more.

First, electrification in LDV must occur – with some combination of PHEV, BEV and FCV – because much of the available biofuels are needed in other transportation sub-sectors. This will likely require policy to support both technological development (e.g., for batteries, fuel cells and hydrogen storage) and infrastructure buildout (e.g., for hydrogen distribution and enhancements to the electric grid that include transformers, in-home and public charging points and smart grid capabilities).

In addition to rebates for vehicle purchases, tax credits, and other direct subsidies, government can act by establishing regulatory certainty and standards for interoperability, and can use other policy tools to enhance the benefits of electric vehicles like granting access to HOV lanes. These types of policy support are needed to facilitate the early adoption of electric vehicles, to span the “chasm” between early adopters and early majority (Figure 16), and help cover the buydown cost of these advanced technologies (Figure 17).

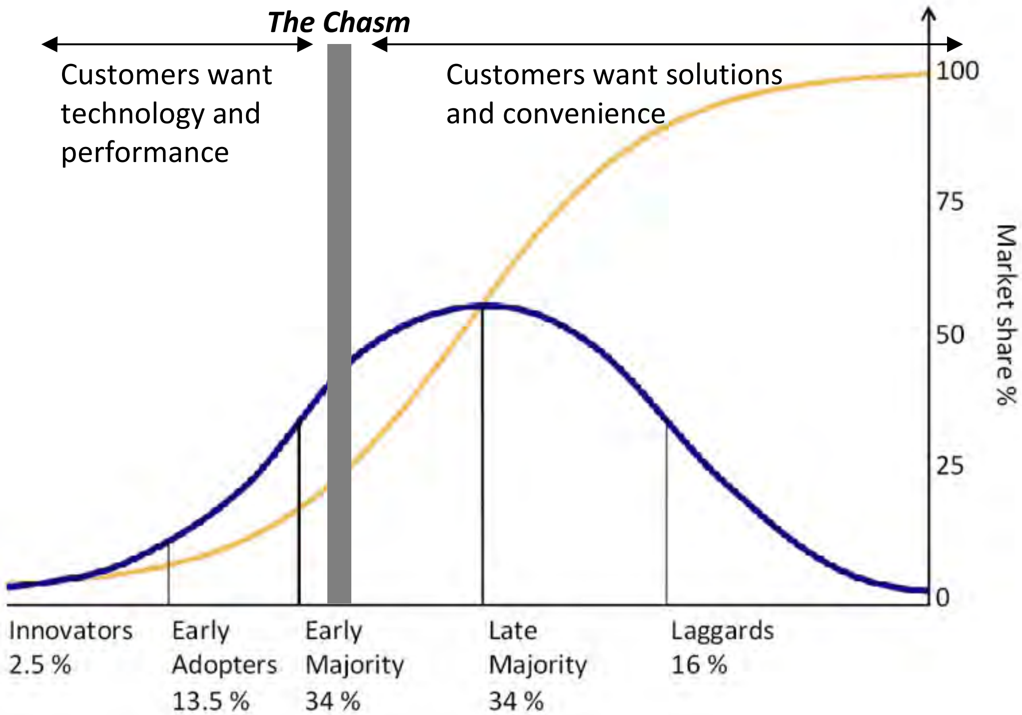

Figure 16: Theoretical diagram of new product diffusion in the marketplace, originally proposed by Rogers (1962), showing the chasm to be bridged between early adopters and early majority consumers (adapted from Moore, 1991).

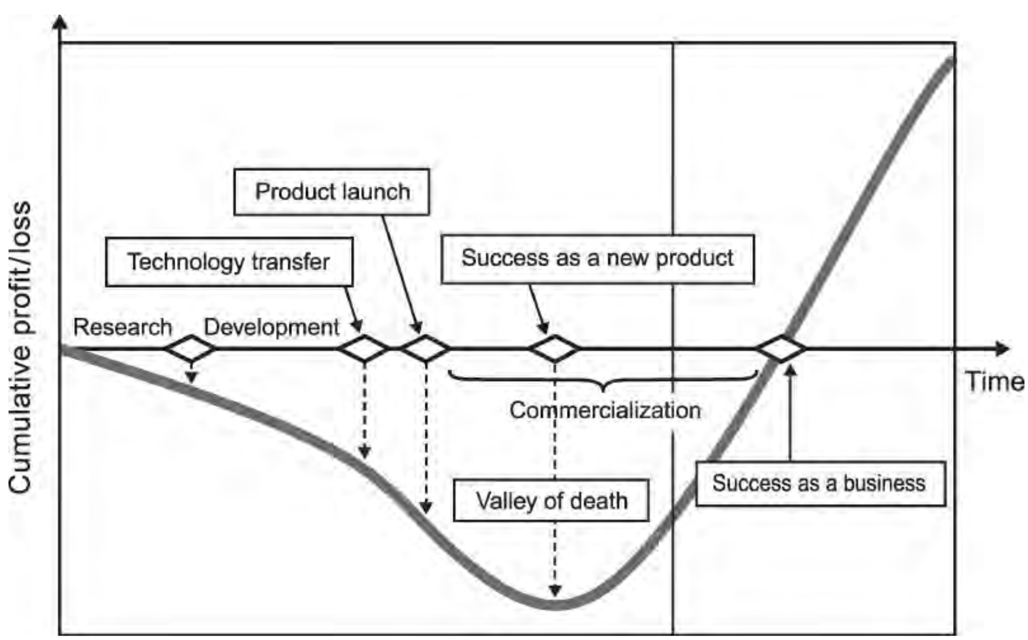

Figure 17: Theoretical diagram of stages involved in new product development leading to commercial success, with the nadir of cumulative profit/loss indicating the total investment or "buydown cost" needed for the technology (Osawa and Miyazaki, 2006).

For example, in 2010 the National Institute of Standards and Technology (NIST) was working on interoperability standards for smart grid technologies, the American Recovery and Reinvestment Act of 2009 provided funds for tax credits for the purchase of hybrid and plug-in electric vehicles, and the California legislature was fine-tuning regulations regarding what types of PHEV and BEV would qualify for HOV lane access (SB 535, enrolled in August of 2010).[40] A series of recent research papers by the National Research Council of the National Academies has estimated buydown costs for PHEV, BEV and FCV (National Academies, 2010; National Academies, 2009).

Second, all improvements in vehicle efficiency must be applied to fuel economy rather than improving vehicle performance. Fuel economy improvement of approximately 80% from 1990 across all vehicle technologies is needed, reversing the trend of the past 25 years where energy efficiency improvements in vehicles were applied to improving performance rather than fuel economy (NRC, 2002). But historical experience suggests that achieving this result may be difficult without continuing to increase fuel economy requirements with policies like the Corporate Average Fuel Economy (CAFE) standards at the national level and the California Clean Car Standards (e.g., Pavley AB 1493) at the state level. For the period 1985 through 2002, CAFE standards remained relatively constant and average fuel economy did not improve while performance did.

> "In the period since 1975, manufacturers have made considerable improvements in the basic efficiency of engines, drive trains, and vehicle aerodynamics. These

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[40] Individuals and businesses who bought or leased a new hybrid gas-electric car or truck were eligible for an income tax credit for vehicles purchased before January 1st, 2011. The amount of the credit varied based on the fuel economy and weight of the vehicle and whether the credit was being phased out for a particular manufacturer. The tax credit was phased out over 15 months once a manufacturer had sold 60,000 eligible vehicles. Other alternative-fuel vehicles including FCV and diesel with advanced lean-burn technologies were eligible for tax credits as well. For plug-in electric drive vehicles, the minimum credit was $2,500 and maximum was $7,500, depending on the battery capacity (http://www.energy.gov/taxbreaks.htm).

> improvements could have been used to improve fuel economy and/or performance. Looking at the entire light-duty fleet, both cars and trucks, between 1975 and 1984, the technology improvements were concentrated on fuel economy: it improved by 62 percent without any loss of performance as measured by 0-60 mph acceleration times. By 1985 vehicles had improved enough to meet CAFE standards. Thereafter, technology improvements were concentrated principally on performance and other vehicle attributes (including improved occupant protection). Fuel economy remained essentially unchanged while vehicles became 20 percent heavier and 0-60 mph acceleration times became, on average, 25 percent faster" (NRC, 2002).

This historical experience shows that consumer preference for increased performance over fuel economy will direct the design of products available in the marketplace absent technology-forcing regulatory requirements for improved fuel economy.

Third, all energy carriers must de-carbonize to less than half of the carbon intensity of gasoline and diesel (i.e., to less than about 40 gCO_2e/MJ). Meeting the 80in50 goal for the *transportation* sector requires large change in the *energy* sectors supplying vehicle fuels. To the extent competition from other sectors for limited supplies of low-carbon energy sources emerges, causing the average carbon intensity of fuels available for use in the transportation sector to increase, improvements in efficiency and reductions in travel demand even greater than those specified in the 80in50 scenarios will be required.

In other words, limitations in any of the travel demand (T), efficiency (E), or carbon intensity (C) parameters in the *80in50 LEVERS* model to less than what I assume in the 80in50 scenarios will require compensating improvements in other parameters to more than what I assume in the 80in50 scenarios. Such constraints and compensating changes in other parameters are evident in the refinement of biofuel supply presented in this chapter. With the supply of biofuels constrained to less than the 16 billion gge that was assumed in the Efficient Biofuels scenario, much greater electrification in LDV was necessary in the *Multi-Strategy* scenarios than the *Efficient Biofuels* scenario.

The implications of such restrictions that were revealed in the sensitivity analyses performed on the 80in50 scenarios are quite sobering. It appears there is significantly more downside risk of not meeting the 80in50 goal than upside potential for exceeding it in all but the *Efficient Biofuels 80in50* scenario. In other words, there is little room to achieve improvements in some parameters beyond what I assumed in the 80in50 scenarios to compensate if other parameters prove to be more limited than I assumed. Consequently, success is needed on all fronts – in travel demand reduction, efficiency improvements translated into fuel economy, and low-carbon fuel supply – since none offer much potential to pick up the slack if we experience failure or greater than expected limitation on others.

On the positive side, it is also importation to acknowledge that the scope of this research does not include paradigm shifts in the transportation sector. For example, widespread deployment of highly efficient personal rapid transit (PRT) systems or success with video conferencing technologies that replace face-to-face meetings (and reduce demand for local and long-distance travel) could effectively *relax* the requirements for improvements in T, E and C parameters of the *80in50 LEVERS* model. Unfortunately, PRT still faces large challenges and telecommunication technologies have little effect on travel demand as expanding personal and professional networks offset the substitution of teleconferencing for face-to-face meetings (Choo et al., 2005).

Fourth, some reduction in travel demand (i.e., VMT per capita) is required unless electrification of vehicles occurs to a large degree across many transportation sub-sectors (i.e., as portrayed in the *Electric-Drive* scenario). Thus, changes will be needed in land-use patterns and in the telecommunication sector in order to meet the 80in50 goal in the transportation sector. As traditional sectors of the economy blur, jurisdictional boundaries in regulatory responsibility will need to become flexible in order to accomplish the coordination of policy necessary to achieve the 80in50 goal in just the transportation sector. When one considers pursuit of this goal across all sectors, the need for coordination across traditional sectoral boundaries is even more apparent.

Regardless of whether some strategies are emphasized in policy or find more success in technology or the marketplace (i.e., which 80in50 scenario is pursued), meeting the 80in50 goal in the transportation sector requires action on many fronts: 1) in land use change and telecommunications to support travel demand reduction; 2) in advanced vehicle technology R&D and market adoption to support efficiency improvements that translate into fuel economy; and 3) in generation and distribution infrastructure for low-carbon fuel supplies. A "portfolio" approach with vigilance in policy and industry on all these fronts will be required to minimize downside risk and ensure we meet the ambitious 80in50 goal.

CHAPTER 2: TRANSITION PATH ANALYSIS FOR LIGHT-DUTY VEHICLES, GETTING TO 80% REDUCTION IN TRANSPORT-RELATED GHG EMISSIONS IN CALIFORNIA BY 2050

2.1 Introduction

In this chapter, I address the second and third basic research question posed by the 80in50 goal: what are possible transition paths for achieving the *80in50* scenarios in the year 2050, and does the transition path matter for achieving societal and policy goals?

For the dynamics of change involved in achieving the 80in50 scenarios, I investigate several questions. Based on what is known about the time constants for change in the transport sector, is it feasible to reach the low carbon scenarios envisioned in each 80in50 scenario by 2050? What constraints are imposed by time constants required to: 1) implement new vehicle technologies and gain fleet share, 2) change the fuel mix supplied to these vehicles, 3) decarbonize primary energy supplies for transportation fuels, and 4) change behavior and reduce VMT?

In the static 80in50 study described in chapter one, we found that changing assumptions (for example about VMT reduction or the amount and carbon intensity of biofuels available in 2050) gave a very different picture of the LDV fleet mix in 2050. Is it possible to reach each of these different future states by 2050? What are the rate-limiting factors on how fast a transition could proceed to each of these futures?

My emphasis in this research has been on the target for deep reduction in GHG emissions by 2050. But intermediate goals for GHG emission reduction in 2010 and 2020 and the Low-Carbon Fuel Standard must be met as well. These intermediate "waypoints" may constrain the allowable shape of pathways to the 2050 target. Are these intermediate goals feasible? Can we meet both the 2020 and 2050 goals for GHG emission reductions?

For evaluation of whether transition paths matter for societal and policy goals, I focus on cumulative GHG emissions as the salient metric for climate change mitigation.

From the static modeling of 2050 described in chapter one, we created six scenarios that all appear "equal" in terms of reaching the 80in50 goal. But are these scenarios equal in climate change mitigation? The salient questions here are in cumulative GHG emissions from 2010 to 2050, in potential for continued emission reductions beyond the *80in50* goal (upside potential), and in risk for failing to meet the *80in50* goal (downside risk). What is the effect of different transition scenarios on total cumulative GHG emissions? What range in the timing for action to initiate changes is allowable in each 80in50 scenario (a question I consider with "act early" and "act late" sensitivity cases)? If we need to pick the surest path to the *80in50* goal in order to have the best chance of averting damaging climate change, which scenario should we pick and pursue?

2.2 A New Model for Defining Transition Pathways to 2050

To investigate these questions, I adapted the VISION model developed by Argonne National Laboratory (Argonne National Laboratory, 2009) to create the *80in50 PATH Model* for modeling transition paths in the California transportation sector that produce the target parameters in the year 2050 defined for each *80in50* scenario in the *LEVERS Model*. The heart of the VISION model is a stock turnover module that tracks annually new LDV vehicles entering the fleet, the use and performance of the vehicle demographics in the fleet, and old vehicles exiting the fleet. The stock turnover model allows us to build a description of California's on-road light duty vehicle fleet at any year, incorporating light duty vehicles of different vintages and types (passenger cars and light trucks/SUVs).

I created the *80in50 PATH Model* by linking the *80in50 LEVERS* and VISION models and adding modules that describe the following processes: new vehicle technology market penetration (Figure 21 - Figure 26 in section 2.2.1.3); change in vehicle fuel economy (Figure 19 in section 2.2.1.1); change in fuel carbon intensity (Figure 20 in section 2.2.1.2); change in car and light truck/SUV market shares; change in fuels used in PHEV as all-electric range increases; and change in the biofuel blend in gasoline and diesel. I also adapted the VISION model to California with California-specific parameters for population, current electric generation mix, projected total LDV sales, and current LDV stock (CARB, 2009b).

In using the revised 80in50 LEVERS model to model the *80in50* goal, we included all transportation sub-sectors. This holistic approach is important because it reveals the need to allocate scarce resources (especially low-carbon liquid biofuels) to sub-sectors that require them (aviation, marine) and the need for some sub-sectors to achieve greater than 80% reduction (e.g., LDV) to compensate for others that fall short (e.g., aircraft, marine, HDV). In studying the dynamics of change in the transportation sector however, I model transition paths for LDV only (i.e., not including other transportation sub-sectors). Light duty vehicles are an important sub-sector which accounts for 67% of in-state transportation GHG emissions (Figure 2). Furthermore, the composition of the LDV fleet and GHG emission reduction from LDV that must be achieved by 2050 is as specified in each 80in50 scenario developed in the holistic 80in50 LEVERS model. Hence, in this chapter I am focusing on transition paths in the LDV sector to meet the 80in50 goal, given a holistic view of meeting the 80in50 goal for the entire transportation sector as a whole.

The general research approach was to define the 2050 target in terms of transportation system parameters (such as LDV vehicle fleet mix, fuels mix and travel activity) as specified in each *80in50* scenario and then examine the range of transition paths that could achieve these parameters by the year 2050.

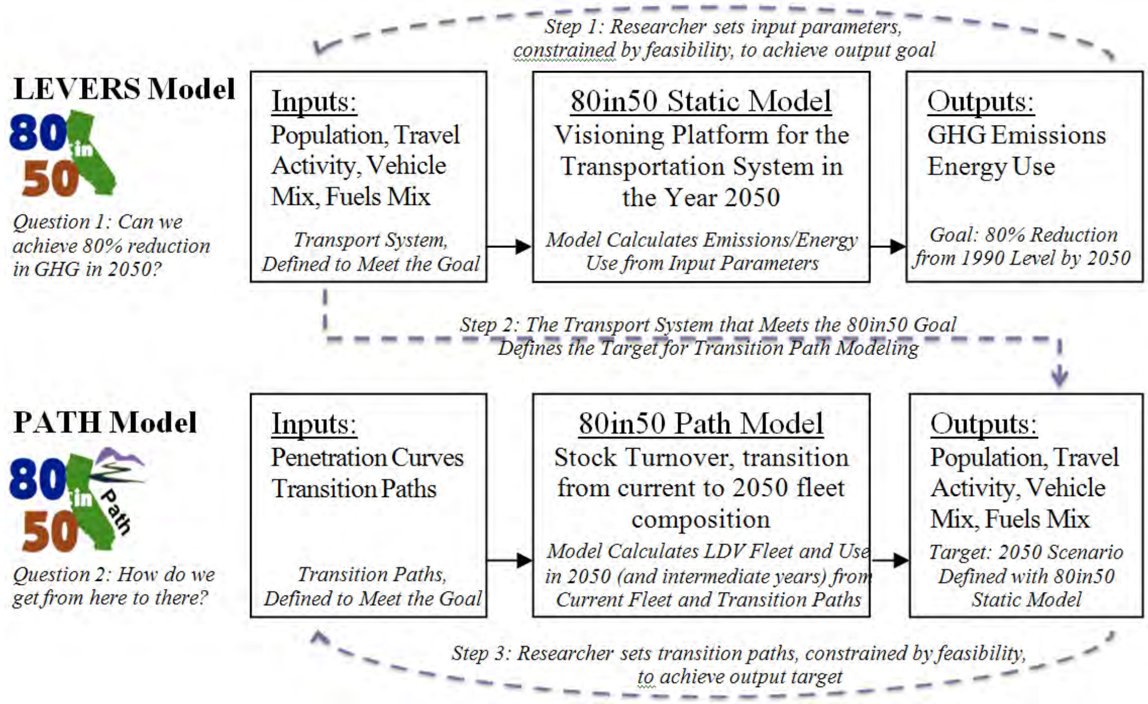

Figure 18: The integration of two models, the *80in50 LEVERS Model* that provides a snapshot of 2050 and the *80in50 PATH* dynamic transition model. Solid arrows indicate the direction of model calculation, dashed arrows indicate the direction of research inquiry.

The researcher using the integrated *80in50* modeling tool depicted in Figure 18 begins by defining the desired GHG emission and/or energy use in 2050, which is the *80in50* goal in this case. Using the *80in50 LEVERS Model*, the researcher defines scenarios for combinations of population, travel activity, vehicle mix, and fuels mix that deliver the GHG emissions target in 2050. These are the 80in50 scenarios discussed in the first chapter of this dissertation. The 80in50 scenario parameters then define the target *output* for the *80in50 PATH Model*.

As with the *80in50 LEVERS Model*, the researcher using the *80in50 PATH Model* begins with a target for the model output and then manipulates model parameters in order to produce that output (i.e., the *80in50 PATH Model* is also a scenario analysis tool, not an optimization model). For the *80in50 LEVERS Model*, the target result was 80% reduction in GHG emissions from 1990 levels in the year 2050. The parameters available for manipulation were the relevant P, T, E, and C factors for each transportation sub-sector, subject to feasibility constraints defined in the literature.[41] For the *80in50 PATH Model*, the target result is the transportation system description in 2050 that meets the *80in50* goal, as defined by the P, T, E, and C parameters specified each *80in50* scenario (appendix A). The researcher using the PATH model defines vehicle technology penetration curves and other transition paths that deliver the 2050 scenario parameters in the year 2050. The parameters available for manipulation in the *80in50 PATH Model* include new vehicle technology market penetration rates (Figure 21 - Figure 26 in section 2.2.1.3), rates of vehicle efficiency improvement (Figure 19 in section 2.2.1.1), and rates of change in fuel carbon intensity (Figure 20 in section 2.2.1.2). As with the parameters in the *80in50 LEVERS Model*, the parameters in the *80in50 PATH Model* are subject to maximum rate constraints defined in literature.[42] (For example, the model will not allow a certain vehicle attribute to change at an unreasonably fast rate or a new technology to enter the market too soon). Thus, the researcher's specification of inputs for both the LEVERS and PATH models is constrained by the desired model results and also by feasibility limits for all parameters as established in literature.

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[41] Sources include the following: CARB, 2007; An and Santini, 2004; Ang-Olson and Schroeer, 2003; CARB, 2004; Little, 2002; EUCAR, 2007; Ewing et al., 2007; Frey and Kuo, 2007; Greene and Schafer, 2003; Greszler, 2007; IUR, 2008; Ribeiro et al., 2007; Kasseris and Heywood, 2007; Kromer and Heywood, 2007; Leighty et al., 2007; Marintek, 2000; O'Connor, 2007; and CDF, 2007.

[42] Sources include the following: Jackson, 2007; Farrell and Sperling, 2007; Zhang, 2007; Greencar Congress, 2008; Greene et al., 2007; National Academies, 2004; EPRI, 2007a; Hooks and Jackson, 2007; National Academies, 2009.

The transition paths are also compared to policy requirements in intermediate years, which I call "waypoints," in order to benchmark the shape of these paths (Table 17).[43]

The results produced by the *80in50 PATH Model* include transition paths over time for vehicle market and fleet share (Figure 27 in section 2.3.1), GHG emissions (Figure 32 in section 2.3.6), fuel carbon intensity (Figure 30 in section 2.3.4), and total energy use (Figure 33 in section 2.3.7).

Waypoints	Sources
California Global Warming Solutions Act (AB 32): reduce GHG emissions economy wide to 2000 levels by 2010 and to 1990 levels by 2020.	1, 2
Pavley Phase I (AB 1493): GHG emission standards in gCO_2e/mile for passenger cars/small trucks and for large trucks/SUVs, phased in over the period 2009-2016 (appendix B); 30% GHG reduction by 2016 with ~37 mpg for the fleet.	2, 3
Pavley Phase II: GHG emission standards in gCO_2e/mile, planned for model years 2017-2020 with ~44 mpg for the fleet in 2020.	2, 4, 5
Federal Corporate Average Fuel Economy (CAFE) standards: the Energy Independence and Security Act of 2007 required 35 mpg average for all passenger automobiles (including light trucks) by 2020 (subsequently moved up to the year 2016).	4, 5
California Low-Carbon Fuel Standard (LCFS): 10% reduction in average GHG intensity of transportation fuels sold in California (gCO_2e/MJ for gasoline, diesel, and substitutes, adjusted for vehicle efficiency), phased in from 2010 to 2020.	6
California State Alternative Fuels Plan: policy goals include reducing transportation fuel demand 15% below 2003 level by 2020, increasing alternative fuels to 20% of total on-road transportation fuel use by 2020 and 30% by 2030, and specific targets (billion gge) for biofuel consumption and in-state production for 2007 (0.9, 0.0045), 2010 (0.93, 0.186), 2020 (1.6, 0.64), and 2050 (2, 1.5); a 2050 vision includes quantity (billion gge) for gasoline/ diesel (~2), biofuels (~2), and electricity & hydrogen (~2.5) and a potential transition path in terms of percentage of total for these fuels in 2022 (AB 1007), 2030, and 2050.	7
Technical potential for GHG emission reductions in the electric sector; *national* generation mix for 2030 of 39% coal without CCS, 13% advanced coal with CCS, 5% natural gas, 29% nuclear, 5% hydro, and 9% non-hydro renewables. I assume current carbon intensities for these generation technologies (gCO_2e/kWh) in Figure 20.	8
Current California electric grid mix, approximately 21% coal, 58% natural gas, 7% nuclear, 2% biomass, and 12% renewable.	9
California Renewable Portfolio Standard for 20% renewable electric generation by 2010 and 33% by 2020. I assume renewable energy offsets the highest-emitting existing generation to produce "optimistic" waypoints for 2010 and 2020 in Figure 20.	10, 11[44]

Table 17: Waypoints on transition paths to the *80in50* goal. Sources include the following: 1) Executive Order S-3-05; 2) CARB, 2008a; 3) CARB, 2004; 4) CARB, 2008b; 5) CARB, 2008c; 6) CARB, 2009c; 7) CARB, 2007; 8) EPRI, 2007b; 9) CARB, 2009b; 10) CPUC, 2008; 11) CPUC, 2009.

[43] Sources include the following: CARB, 2004; CARB, 2008a; CARB, 2008b; CARB, 2008c; CARB, 2009; CPUC, 2008; CPUC, 2009; EPRI, 2007b; EPRI, 2008; Lutsey, 2009; IPCC, 2007.
[44] Senate Bill 1078 created the California RPS in 2002, which was accelerated to 20% by 2010 by Senate Bill 107 in 2006.

2.2.1 Transition Pathways

In Chapter 1, I made the case for five *80in50* scenarios that bound the range of feasible options for meeting the 80in50 goal. The *Multi-Strategy$_{pessimistic}$*, *Multi-Strategy$_{middle}$* and *Multi-Strategy$_{optimistic}$* scenarios address uncertainty in future biofuel supply available in California and effectively replace the *Efficient Biofuels* scenario originally proposed by Yang et al. (2009). The *Electric-Drive* and *Actor-Based* scenarios were developed by Yang et al. to represent futures in which electrification of transportation proceeds and in which high energy prices motivate consumer action to reduce travel demand and accept diminished vehicle performance, respectively. However, in this chapter I model and explore transition pathways for all six of the 80in50 scenarios described in Chapter One.

As with the *80in50 LEVERS Model*, I surveyed the literature to obtain plausible ranges for the major market penetration rate and transition path parameters that define possible transition paths leading to realization of each *80in50* scenario. The key parameters for modeling transitions to the 2050 fleets defined by the *80in50* scenarios are the rate of improvement in vehicle efficiency (i.e., fuel economy), rate of decrease in fuel carbon intensity, and market penetration rate for each vehicle technology. Transition paths in these parameters are inputs to the 80in50 PATH model of transitions to the 80in50 scenarios. The next three sections contain detailed explanation of the assumptions made in each of these model inputs.

2.2.1.1 Vehicle Fuel Economy Assumptions

Fuel economy for LDV is one of many parameters in the *80in50 LEVERS Model* that must transition from current levels to those specified for 2050 in each *80in50* scenario in order to achieve the *80in50* goal. Figure 19 shows the transition paths assumed for on-road new vehicle fuel economy in cars for each vehicle technology (light trucks/SUVs follow similar paths). The literature provides a plausible range for the rate of change in fuel economy improvement, based on technical considerations.[45] The policy waypoints summarized in Table 17 provide a check on the shape of these transition paths. In other words, the technical feasibility for rates of change established by the literature review are compared against policy goals shown in Table 17.

The increase in on-road fuel economy[46] of new vehicles translates into fleet average fuel economy through accounting for "stock turnover" and changes in annual mileage and performance as the vehicle ages. New vehicle sales replace approximately 6-7% of the vehicle fleet each year, slowly changing fleet composition according to the stock turnover. The fleet average fuel economy is a function of the fuel economy of vehicles sold in the past that are active in the fleet as well as declining on-road fuel economy and declining annual mileage as a vehicle ages. These dynamics are tracked in the stock turnover module of the *80in50 PATH Model*.

It is important to note that ICE vehicle technologies are assumed to include an increasing degree of hybridization over time that brings fuel economy equal to full HEV by 2050. In other words, ICE vehicles begin to incorporate mild hybrid technology (e.g., Stop / Start and Integrated Starter Alternator) and eventually full hybridization.[47] For example, since the biofueled ICE in the *Efficient Biofuels* scenario are undergoing such a process, these vehicles should be interpreted as biofuel HEV in the year 2050.

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[45] Sources include the following: Kromer and Heywood, 2007; Leighty et al., 2007; National Academies, 2009; US EPA, 2006; NRC, 2002.

[46] The term "on-road fuel economy" is used to distinguish from the window sticker value established by testing on the EPA test cycle. The actual fuel economy drivers realize can be up to 20% less than the tested value.

[47] "Full hybridization" refers to vehicles with sufficient electric drivetrain components to enable engine shut-off during a variety of driving conditions (i.e., not just when the vehicle is stopped) and regenerative braking.

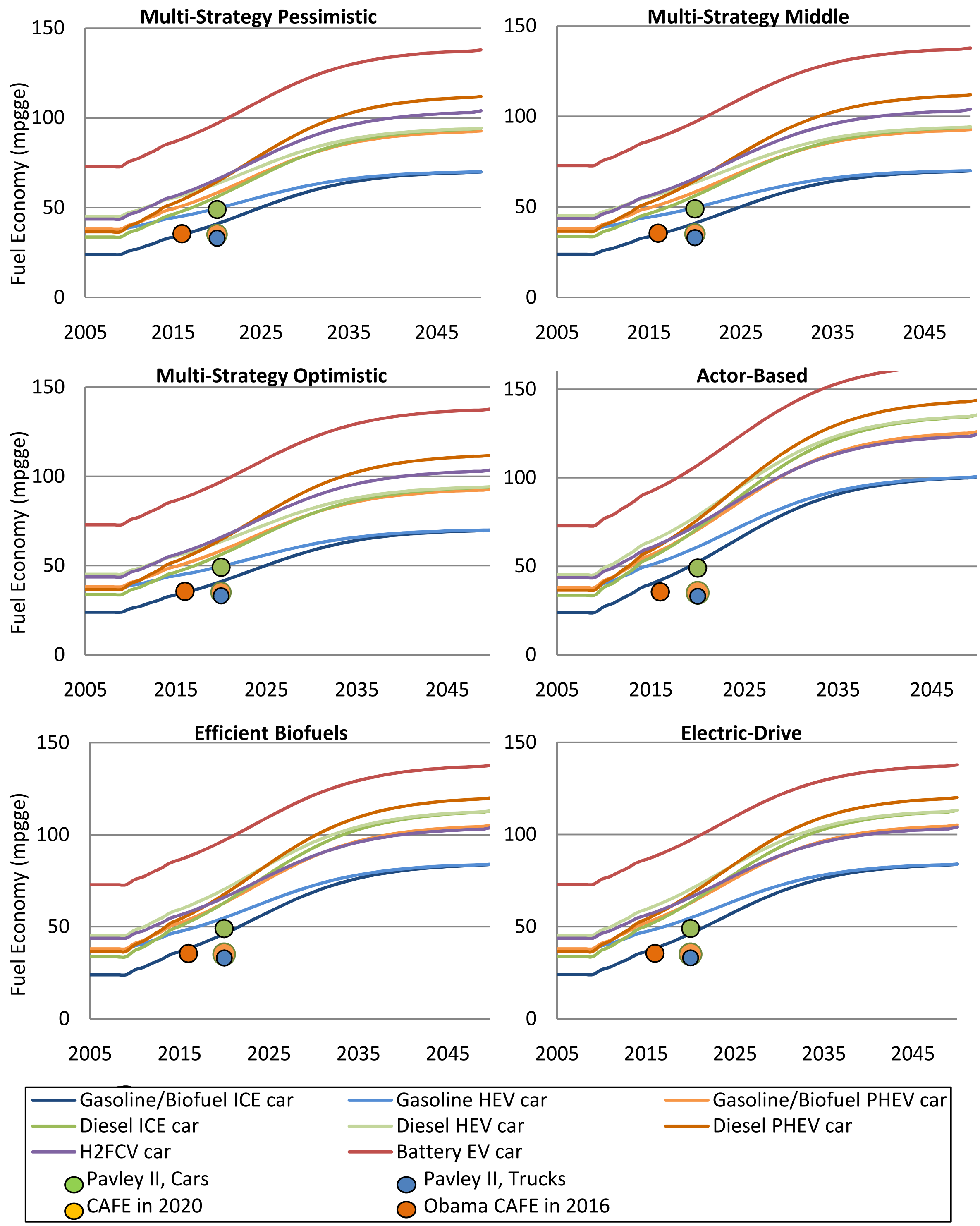

Figure 19: On-road new vehicle fuel economy improvement assumed for cars, 2005 to 2050. Several policy waypoints are shown as colored dots (CARB, 2008a; CARB, 2008b). The rate of change is constrained by technical feasibility (National Academies, 2009; Plotkin and Singh, 2009; Leighty et al., 2007).

Two additional assumptions pertaining to the fuel economy transitions shown in Figure 19 deserve mention. First, for PHEV, the all-electric range increases over time from 20 to approximately 40 miles by the year 2050. This technical specification is combined with average drivecycle information to estimate the share of total PHEV mileage in 2050 driven in charge-depleting electric vehicle mode at approximately 58 percent (Yang et al., 2009). The remaining mileage is driven in charge-sustaining hybrid mode. Second, fuel economies for all energy carriers are converted to the common metric of gallons gasoline equivalent, which is based on the energy content of one gallon of gasoline (i.e., 121.3 MJ). For example, a BEV with 100 mpgge fuel economy can travel 100 miles on 121.3 MJ of electricity, or about 34 kWh (340 watt-hours per mile). This tank-to-wheels fuel economy is influenced by the efficiency of energy conversion and drivetrain efficiency onboard the vehicle but not by energy conversion losses that may occur in supplying energy to the vehicle (e.g., electricity generation and transmission).

2.2.1.2 Assumptions about Fuel Carbon Content over Time

Energy sources and production methods for transportation fuels must transition from current systems to lower-GHG alternatives in order to reduce fuel carbon intensity to the levels specified for 2050 in each *80in50* scenario (Yang et al., 2009). Figure 20 shows the transition paths assumed for carbon intensity by fuel type used in the transportation sector.

The carbon intensity of gasoline and diesel decreases slightly in some scenarios as more low-carbon biofuels are blended in while the carbon intensity of electricity and hydrogen decrease dramatically as generation shifts from the current mix that includes fossil-fueled generation to mixes in 2050 that use carbon capture and sequestration and rely heavily on low-carbon nuclear and renewable energy sources (Table 12, Appendix A). Biofuel carbon intensity decreases as second-generation feedstocks and processes mature and improve (see section 1.3.3 and 1.3.4).

The literature provides a plausible range in the rate of change in fuel carbon intensity[48] while the waypoints summarized in Table 17 provide policies that could constrain the shape of these transition paths. It is important to note that the shapes of these transition paths are uncertain due to relatively little information on stock turnover rates in energy supply infrastructure in the literature. This implies that the shape of fuel decarbonization transition paths is a large source of uncertainty in my modeling of intermediate GHG emission reduction goals (e.g., the 2020 goal) and has implications for cumulative carbon emissions, which in turn influences atmospheric concentrations of CO_2. My approach to handling this and other sources of uncertainty in transition paths was to bound it with the sensitivity analysis described in section 2.2.1.3.4 (i.e., *act-early* and *act-late* scenarios). I do not explicitly model stock turnover in the fuels supply sectors for gasoline, diesel, biofuels, and electricity and hydrogen generation. Rather, I assume transitions in carbon intensity of fuel pathways over time that link the two endpoints of current and future carbon intensity (as specified in each 80in50 scenario), subject to constraints imposed by policy and literature waypoints, and then examine the sensitivity of model outputs to deviations in these transition paths.

The 33% RPS is a goal established by Executive Order S-14-08 and, as such, may represent an "optimistic" waypoint. I calculated carbon intensity for the RPS waypoints shown in Figure 20 by assuming renewables replace coal and natural gas based

[48] Sources include the following: CARB, 2007; EPRI, 2007a; EPRI, 2007b; EPRI, 2008; National Academies, 2009; CPUC, 2008; CPUC, 2009; EPRI, 2007b; Brandt and Farrell, 2008; Jenkins, 2006; Perlack et al., 2005; Searchinger et al., 2008; Delucchi, 2008; NRDC, 2004.

generation such that the ratio of natural gas to coal generation in California remains at 2.7 to 1 (i.e., a generation mix with 58% natural gas and 21% coal in 2000; 44% natural gas and 16% coal at 20% RPS; 35% natural gas and 13% coal at 33% RPS).[49] In other words, new renewables meet increasing demand and, if necessary, existing natural gas and coal generation is decommissioned proportionately.

In contrast, the EPRI results for the *national* electricity mix in 2030 represent a “pessimistic” waypoint for California in 2050 because the California generation mix is already much less carbon intense than the national mix (CPUC, 2008; CPUC, 2009; EPRI, 2007b; EPRI, 2008). The EPRI low-carbon intensity case for electricity represents a world in which carbon constraints and power plant retirements progress quickly, advanced generation technology is available and retrofit of existing power plants with CCS equipment is possible (EPRI, 2007a).

[49] Currently, nearly all coal power in California comes from out-of-state imports. California policy also limits any new coal power imports to no higher emissions than a natural gas combined cycle power plant. Consequently, phasing out coal could also be interpreted as requiring implementation of carbon capture and sequestration for imported coal power.

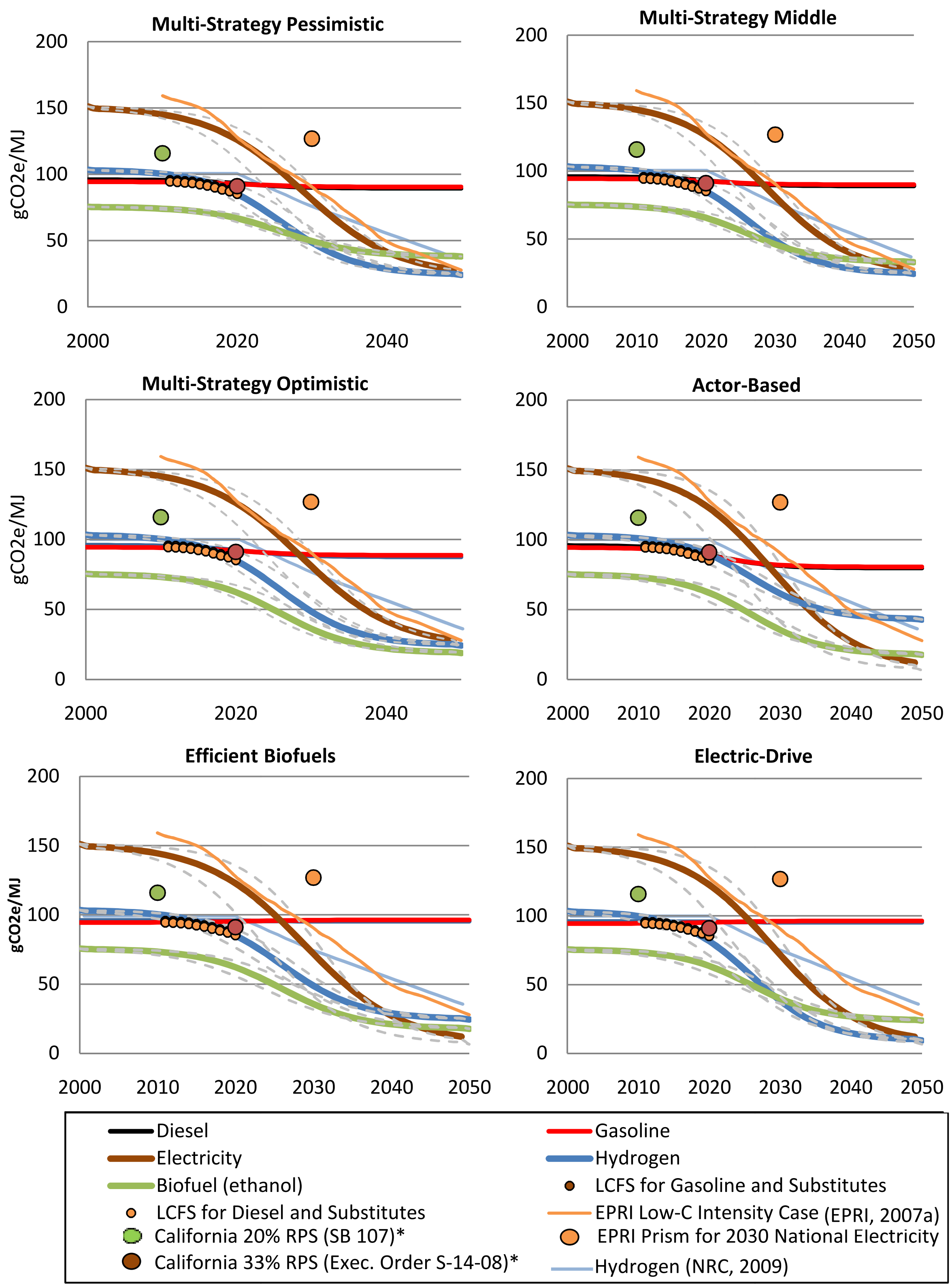
Multi-Strategy Pessimistic
Multi-Strategy Middle
Multi-Strategy Optimistic
Actor-Based
Efficient Biofuels
Electric-Drive
gCO2e/MJ
0
50
100
150
200
2000
2010
2020
2030
2040
2050
Diesel
Gasoline
Electricity
Hydrogen
Biofuel (ethanol)
LCFS for Gasoline and Substitutes
LCFS for Diesel and Substitutes
EPRI Low-C Intensity Case (EPRI, 2007a)
California 20% RPS (SB 107)*
EPRI Prism for 2030 National Electricity
California 33% RPS (Exec. Order S-14-08)*
Hydrogen (NRC, 2009)

Figure 20: Carbon intensity by fuel type used in the transportation sector, 2000 to 2050. Solid lines show the paths used in the *80in50 PATH* modeling while the dashed lines show the *act-early* and *act-late* scenarios described in section 2.2.1.3.4. For comparison of carbon intensity in terms of the California Low Carbon Fuel Standard (LCFS), the trends shown here for electricity should be divided by the 3x EER and for hydrogen should be divided by the 2.3x EER. These adjustment factors are not applied directly to the fuel carbon intensity trends in this research because the differences in vehicle onboard energy conversion efficiency for which the EER factors are meant to adjust are taken into account directly in the vehicle efficiency trends.

2.2.1.3 Market Penetration Scenarios for Alternative Fueled Light-Duty Vehicles

In this section, I describe four steps in the creation of market penetration curves for each LDV technology in each one of the six *80in50* scenarios. The steps are: 1) use literature to define a plausible range in market penetration rate; 2) use stock turnover dynamics and a simple competition rule to define a market penetration curve that will produce the *fleet* share in 2050 required in each 80in50 scenario; 3) plot the actual market share over time when all advanced vehicle technologies follow their market penetration curves and the simple competition rule; 4) examine uncertainty in the shape of the market penetration curves defined in steps 1-3 with sensitivity analysis described in step 4.

The result of each step is shown in the bottom six panels of Figure 21 - Figure 26 (compiled at the end of this section). In these figures, the plausible range is shaded in yellow, the market penetration curve is a dashed red line, the actual market share over time is a solid red line, and the sensitivity analysis is shown as grey dashed and solid lines. Thus, Figure 21 - Figure 26 show a combination of model inputs (dashed-line market penetration rates) and model outputs (solid-line actual market shares). My intent in combining model input and output plots in one chart is to make more evident the four-step process involved in modeling the *market* penetration of advanced vehicle technology necessary for meeting the *fleet* shares for advanced LDV technologies specified in each *80in50* scenario.

2.2.1.3.1 Step 1: Literature Review

I conducted an extensive literature review of possible rates for market penetration for alternative fueled LDV including flex-fueled vehicles using biofuels (FFV), hybrid electric vehicles (HEVs), plug-in hybrid electric vehicles (PHEVs), battery electric vehicles (BEVs) and hydrogen fuel cell vehicles (FCVs). The results of this literature survey are shown in the top panel of Figure 21 - Figure 26.

The studies I reviewed generally considered the question of how fast a technology could gain market share, limited by things like technology development, infrastructure build-out and consumer adoption, but generally without competition from other advanced vehicle technologies.[50] As such, these studies may be "optimistic" in considering the "maximum" rate of penetration assuming concerted effort to promote the technology, absent competition from alternative technologies, and absent real-world uncertainty and complexity. The results of individual studies are indicated as solid lines in the top panel of Figure 21 - Figure 26, and the range spanned by these individual studies that is assumed to be the feasible range of market penetration is shaded in yellow. As discussed below, for each 80in50 transition scenario, the market penetration curves for each type of vehicle technology were constrained to stay within this yellow region.

2.2.1.3.2 Step 2: Determine the Light-Duty Vehicle Fleet Mix Over Time

In this section I describe how dynamics in the LDV fleet mix over time were used to define a market penetration curve for each vehicle technology that would produce the fleet share in 2050 required in each 80in50 scenario.

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[50] Some studies focused more on infrastructure build-out and technological readiness (National Academies, 2009) while others include more consideration of consumer acceptance and adoption (Greene et al., 2007). The latter study did include market competition in the form of a consumer choice model. Salient factors for assessing maximum penetration rate and maximum ultimate market share also differ between vehicle technologies. For example, FCV may face more constraints in infrastructure development while BEV may face more constraints in consumer adoption due to limited range and in-home charging equipment. In general, the market penetration rate for a new vehicle technology could be limited by a combination of R&D and technological development, complementary infrastructure development, learning curves and buy-down costs, and consumer adoption. The range in published literature forecasts of potential market penetration for advanced vehicle technologies results from differences in assessments of the magnitude of these barriers. Historical experience with new technologies like automatic transmissions and hybrid-electric vehicles can provide additional insight, but care in extrapolating to different circumstances is warranted. For example HEV adoption occurred largely absent of forcing policy (except CAFE standards and high-occupancy vehicle (HOV) lane access in some locations).

2.2.1.3.2.1 Stock Turnover Dynamics

The *market* penetration paths for advanced LDV technology shown in Figure 21 - Figure 26 translate into transition paths in *fleet* share through inertia in the vehicle fleet. New vehicle sales replace approximately 6-7% of the LDV fleet each year, slowly changing fleet composition according to the stock turnover. These dynamics are tracked in the stock turnover module of the *80in50 PATH Model*. Since each *80in50* scenario specifies the *fleet* share for each vehicle technology required in 2050 to meet the 80in50 goal, the stock turnover module of the *80in50 PATH Model* was used to find market penetration curves that would produce the desired 2050 fleet shares for each vehicle technology.

2.2.1.3.2.2 A Simple Competition Rule

The ranges for potential LDV market penetrations shown in Figure 21 - Figure 26 come from independent studies that consider the potential rate of market penetration for each vehicle technology in isolation from competing advanced vehicle technologies. As a result, these curves are independent of one another and cannot simply be summed since the total new vehicle market share across all vehicle technologies would quickly exceed 100 percent.[51] However, without explicitly modeling consumer or economic decisions about vehicle choices and competitiveness, my analysis required combination of these market penetration profiles to understand the potential evolution of a diverse vehicle fleet. To do so, a decision rule was necessary for competing technologies in the *80in50 PATH* modeling.

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[51] Two independent projections showing individual vehicle technologies achieving 50% does not necessarily mean that together they can achieve 100%. There may be important limitations to the combination and there is likely to be significant overlap in the adopters of these two vehicles.

Since my modeling is motivated by the assumption that GHG policy requirements and goals are binding (rather than optimization according to an objective function like achieving the lowest cost), transitions in the vehicle fleet were modeled assuming higher emission vehicle technologies (e.g., conventional gasoline ICE and HEV) are squeezed out of the marketplace by lower-emission alternatives (e.g., FCV and BEV) in order to try to achieve intermediate waypoints (policy requirements) in GHG emissions. In practice, this means that as a lower carbon vehicle type becomes available, it begins to replace the highest-carbon type still available in the marketplace.

Such a decision rule should be used only in scenarios that don't achieve the intermediate waypoints, since it forces switching to lower-emission vehicle technologies as fast as possible. But since none of the *80in50* scenarios exceed the intermediate requirements for GHG emission reduction, I was able to use this rule for modeling transition paths for all six 80in50 scenarios.[52] In other words, I find that given the assumed constraints on LDV market penetration rates, it is difficult to meet intermediate policy waypoints for GHG emissions reduction even when low carbon emitting vehicles are introduced as fast as possible (in addition to all other transitions occurring rapidly). Consequently, the aggressive decision rule for lower-emission alternatives replacing higher-emission alternatives as rapidly as possible is not excessive in the context of equally aggressive and binding GHG emission reduction policy requirements.

2.2.1.3.3 Step 3: Modeling Actual Market Share Over Time

Under the simple competition rule described above, each vehicle technology starts off following a market penetration curve defined by a logistic function (the dashed lines

[52] Note, only the *Actor-Based* scenario meets the 2020 requirement; Figure 32.

in Figure 21 - Figure 26) but will drop off from this path if lower-emission technologies following their respective market penetration curves squeeze it out of the market.[53] A transitional technology like HEV, for example, that offers some reduction in GHG emissions from conventional vehicles but not enough to be included in the 2050 fleet mix, will increase in market share until higher-emission vehicles have been squeezed out of the marketplace. Then, as even lower-emission technologies begin to accelerate in market share, the HEV market share will plummet (Figure 27 in section 2.3.1).

Hence, the solid lines in Figure 21 - Figure 26 show the actual market share over time in the *80in50* PATH modeling (the *80in50 PATH Model* output) derived from the model inputs of the dashed-line market penetration curves for each vehicle technology. The dashed lines show what market penetration a vehicle technology could achieve in isolation while the solid lines show the market penetration achieved in the context of competition with other advanced technologies under the pressure of constraining GHG emission limits (i.e., as lower-emission vehicle technologies gain market share and limit the actual market penetration of higher-emission technologies to below their potential market penetration). The researcher modeling transition paths for each 80in50 scenario adjusts the shape of the logistic functions that determine the dashed-line market penetration curves for each type of vehicle until the 2050 fleet mix specified for the 80in50 scenario being modeled is produced.

The transition paths in market share for each vehicle technology differ between *80in50* scenarios (i.e., differ between the bottom six panels in Figure 21 - Figure 26)

[53] The endpoint and shape for these logistic functions is determined by the fleet share required in 2050 for the 80in50 scenario being modeled and by the fleet turnover dynamics that introduce a lag between market penetration and fleet share, subject to constraints found in literature for maximum rates of change. The difficulty of meeting the intermediate 2020 GHG emission reduction target generally further constrained these logistic functions toward the maximum endpoint and rate of change found in literature.

because the role each vehicle technology plays in 2050 differs between the *80in50* scenarios. For example, FFVs are an important part of the 2050 fleet in the *Efficient Biofuels* scenario because reliance on low-carbon biofuels is heavy, but are not present in the 2050 fleet in the *Electric-Drive* scenario because the use of biofuels is much more limited. Such differences in 2050 *fleet* shares for each vehicle technology cause differences in the market penetration rates required to achieve them.

2.2.1.3.4 Step 4: Market Penetration Sensitivity Study with "Act-Early" and "Act-Late" Scenarios

The quantity and variety of parameters that define each 80in50 scenario produce many degrees of freedom in defining transition paths for each scenario. To examine the range of possible pathways toward each particular 80in50 scenario, I developed *act-early* and *act-late* scenarios that are variants of the transition path inputs defined for each *80in50* scenario.

The *act-early* scenario assumes *all* transition path inputs in the *80in50 PATH Model* progress at maximum feasible rates in early years, which allows a more gradual rate of change in later years. The *act-late* scenario assumes *all* transition path inputs begin as slowly as possible in early years while still meeting the 2050 target without exceeding feasible limits to the rate of change in intermediate and later years. In other words, the *act-early* and *act-late* scenarios bound uncertainty in the shape of the pathway of change between the same two endpoints: the current LDV fleet and the LDV fleet in 2050 for each *80in50* scenario.

The red lines (dashed and solid) in Figure 20 and the bottom six panels of Figure 21 - Figure 26 show the transition path inputs used in my *80in50 PATH* modeling while the grey lines (dashed and solid) in these figures show the *act-early* and *act-late* scenarios. The grey dashed lines in Figure 27 (section 2.3.1), Figure 32 (section 2.3.3) and Figure 33 (section 2.3.4) also show transition path outputs for the *act-early* and *act-late* scenarios.

The plausible range for *act-early* and *act-late* scenarios was defined differently depending on whether a particular type of vehicle remains present in the fleet in 2050 (some types of vehicles are phased out by 2050 depending on the scenario). For vehicle technologies that are present in the fleet in 2050, the *act-early* and *act-late* scenarios for market penetration rates are constrained to a narrow range by the requirement to deliver the specified fleet share in 2050, subject to maximum rates of change from the literature and the stock turnover dynamics in the 80in50 PATH model. Examples of this situation include FCV in the *Electric-Drive* scenarios or FFV in the *Efficient Biofuels* scenario (Figure 25, Figure 21).

For vehicle technologies with zero fleet share in 2050, the spread between the *act-early* and *act-late* scenarios for market penetration rates is much wider due to greater uncertainty in the transitional role these technologies may play. (For example, in some scenarios HEV play a transitional role, but are ultimately supplanted by PHEV, BEV and FCV). In this case, the *act-early* and *act-late* scenarios for market penetration were defined within the limits of published literature according to my best judgment, with consideration of intermediate waypoints and other relevant policy requirements. For example, the act-early scenario for FFV in the *Actor-Based* and *Electric-Drive* scenarios was set below the maximum penetration rate found in literature due to the improbability of the dramatic increase and subsequent crash in vehicle production that it would imply (Figure 21). Similarly, the *act-late* scenario for FFV in these scenarios was set above the minimum penetration rate found in literature because, although no FFV exist in 2050 for these scenarios, requirements for the quantity of biofuels used in intermediate years set by policy like the Low Carbon Fuel Standard and federal Renewable Fuel Standard along with limits in the biofuel blend percentage for conventional vehicles imply a transitional role for FFV.[54] Thus, transitional technologies play a role in meeting intermediate waypoints like reducing emissions to 1990 levels by 2020 even when the technologies are not included in the 2050 fleet mix.

The *act-early* and *act-late* scenarios for fuel economy improvement and fuel decarbonization were defined within the limits of published literature according to my best judgment with consideration of intermediate waypoints (Figure 21, Figure 20).

The most clearly defined constraints in my transition path modeling are the current fleet characteristics, the fleet characteristics in 2050 defined for each *80in50* scenario, and the timing and maximum rate of introduction for new vehicle technologies. The intermediate waypoints in Table 17 provide some additional constraints for refining the shape of transition path inputs. Hence, many degrees of freedom remain in defining a transition path. The sensitivity analysis described in this section, with *act-early* and *act-late* scenarios, is meant to quantify the impact on cumulative GHG emissions of variation in the shape of transition paths to the *80in50* goal, since cumulative emissions are the salient factor for climate change mitigation (see section 2.3.8). However, more research is needed to define maximum rates of change for vehicles in a competitive market with multiple advanced vehicle technologies being developed and also feasible rates of change

[54] Note, these policies influenced how I set the act-late scenario parameters in a qualitative manner only. In fact, the California LCFS and federal RFS *could* be met without FFVs if a large share of conventional ICE vehicles used a higher blend of biofuel in gasoline (e.g., E16). For example, if 150-200 billion gge of total fuel used nationally is E16, 24-32 billion gge biofuel would be used.

in fuel supply infrastructure in order to narrow the range between *act-early* and *act-late* scenarios shown in Figure 20.

Finally, it is important to note that the *shape* of transition paths will not impact the GHG emissions *rate* in 2050, but will impact *cumulative* GHG emissions.[55] Since the long residence time for GHG in the atmosphere renders cumulative emissions the salient metric for climate change, differences in cumulative emissions between alternative transition paths may be an important consideration. I will consider differences in cumulative GHG emissions between the *act-early* and *act-late* scenarios in section 2.2.1.3.5.

[55] This observation may also be true for behavioral and socio-cultural parameters like VMT/capita, average vehicle occupancy, and mode shift that need not follow an orderly and gradual transition path. However, underlying rate-limited infrastructure and land-use change may dictate a narrower range of transition paths for these parameters. A number of changes, from smart growth and land-use planning to telecommuting and availability of alternate transportation modes are necessary for deep reductions in the demand for passenger light-duty vehicle travel [18]. More research to improve understanding of the transition paths for these factors is needed to refine estimation of *cumulative* emissions, but not the 2050 endpoint.

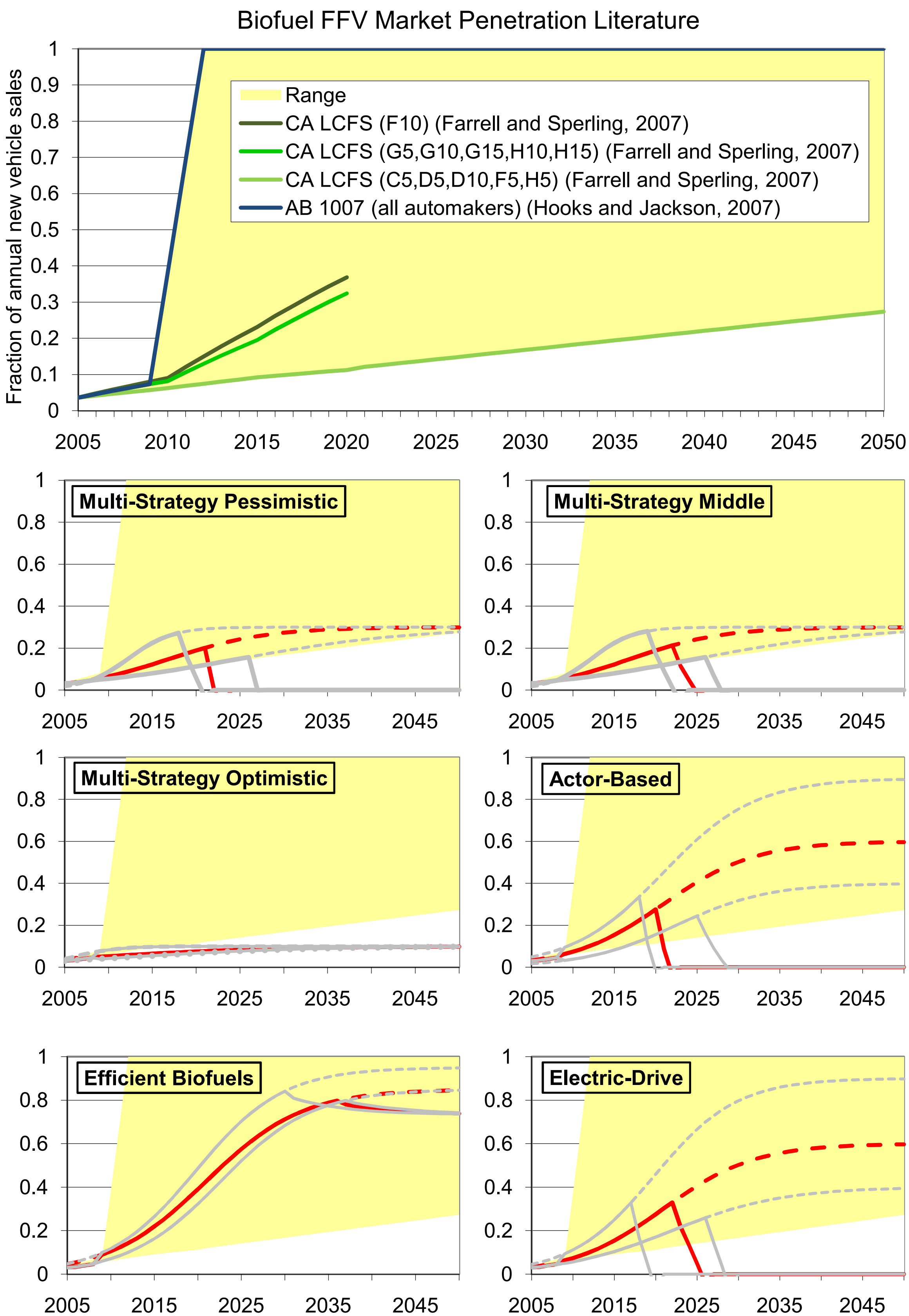

Biofuel FFV Market Penetration Literature
Fraction of annual new vehicle sales
Range
CA LCFS (F10) (Farrell and Sperling, 2007)
CA LCFS (G5,G10,G15,H10,H15) (Farrell and Sperling, 2007)
CA LCFS (C5,D5,D10,F5,H5) (Farrell and Sperling, 2007)
AB 1007 (all automakers) (Hooks and Jackson, 2007)
Multi-Strategy Pessimistic
Multi-Strategy Middle
Multi-Strategy Optimistic
Actor-Based
Efficient Biofuels
Electric-Drive

Figure 21: Market shares for biofuel flex-fuel vehicles (FFV).

The plausible range in market penetration paths is shaded in yellow in the top panel, based on a literature survey. The range in market penetration paths is bounded by maximum scenarios in AB 1007 studies (the California State Alternative Fuels Plan) and the minimum scenario in California low-carbon fuel standard (LCFS) studies (Jackson, 2007; Farrell and Sperling, 2007).

The market penetration curves used in the 80in50 PATH modeling for each 80in50 scenario are shown as dashed red lines in the bottom panels. (These are the values assumed if there were no competition with other vehicle technologies.) The actual market shares over time (with competition from other technologies) for these scenarios are solid red lines.

Sensitivity analysis for penetration curves and actual market shares under the *act-early* and *act-late* cases for each 80in50 scenario are shown as grey dashed and solid lines.

The range in *act-early* and *act-late* scenarios for flex-fuel vehicle market penetration is wide in all but the *Efficient Biofuels* scenario, where the requirement for 75% fleet share in 2050 constrains it to a narrower range.

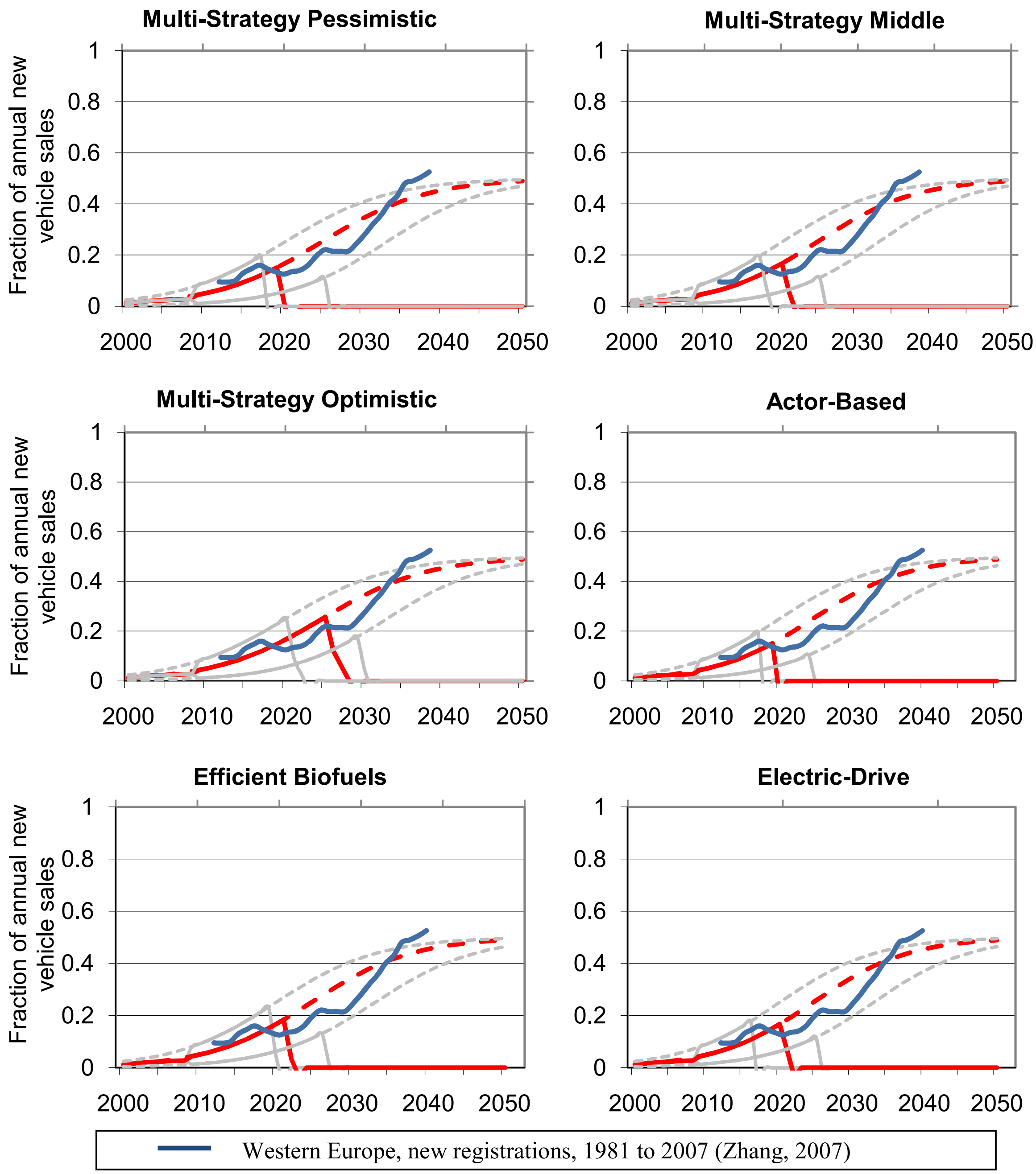


Figure 22: Market shares for diesel ICE vehicles. A plausible path in market penetration based on historical experience in Western Europe for new vehicle registrations is shown in blue (Zhang, 2007; Greencar Congress, 2008). No other studies are available with which to define a plausible range in market penetration paths. The market penetration curves used in the 80in50 PATH modeling for each 80in50 scenario are shown as dashed red lines, the actual market shares over time (with competition from other technologies) for these scenarios are solid red lines, and the sensitivity analysis for penetration curves and actual market shares under the *act-early* and *act-late* cases for each 80in50 scenario are shown as grey dashed and solid lines.

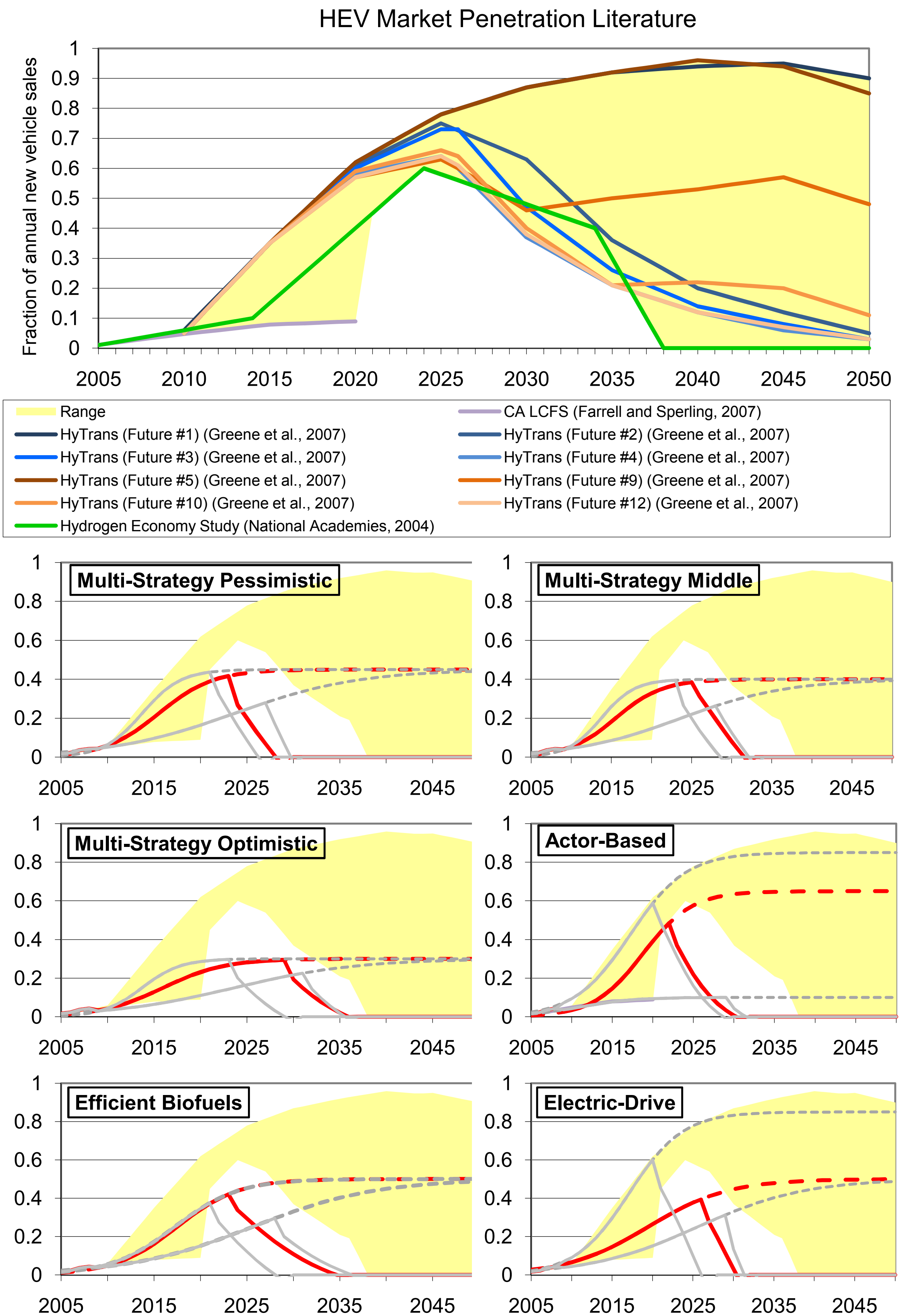

HEV Market Penetration Literature
Fraction of annual new vehicle sales
Range
CA LCFS (Farrell and Sperling, 2007)
HyTrans (Future #1) (Greene et al., 2007)
HyTrans (Future #2) (Greene et al., 2007)
HyTrans (Future #3) (Greene et al., 2007)
HyTrans (Future #4) (Greene et al., 2007)
HyTrans (Future #5) (Greene et al., 2007)
HyTrans (Future #9) (Greene et al., 2007)
HyTrans (Future #10) (Greene et al., 2007)
HyTrans (Future #12) (Greene et al., 2007)
Hydrogen Economy Study (National Academies, 2004)
Multi-Strategy Pessimistic
Multi-Strategy Middle
Multi-Strategy Optimistic
Actor-Based
Efficient Biofuels
Electric-Drive

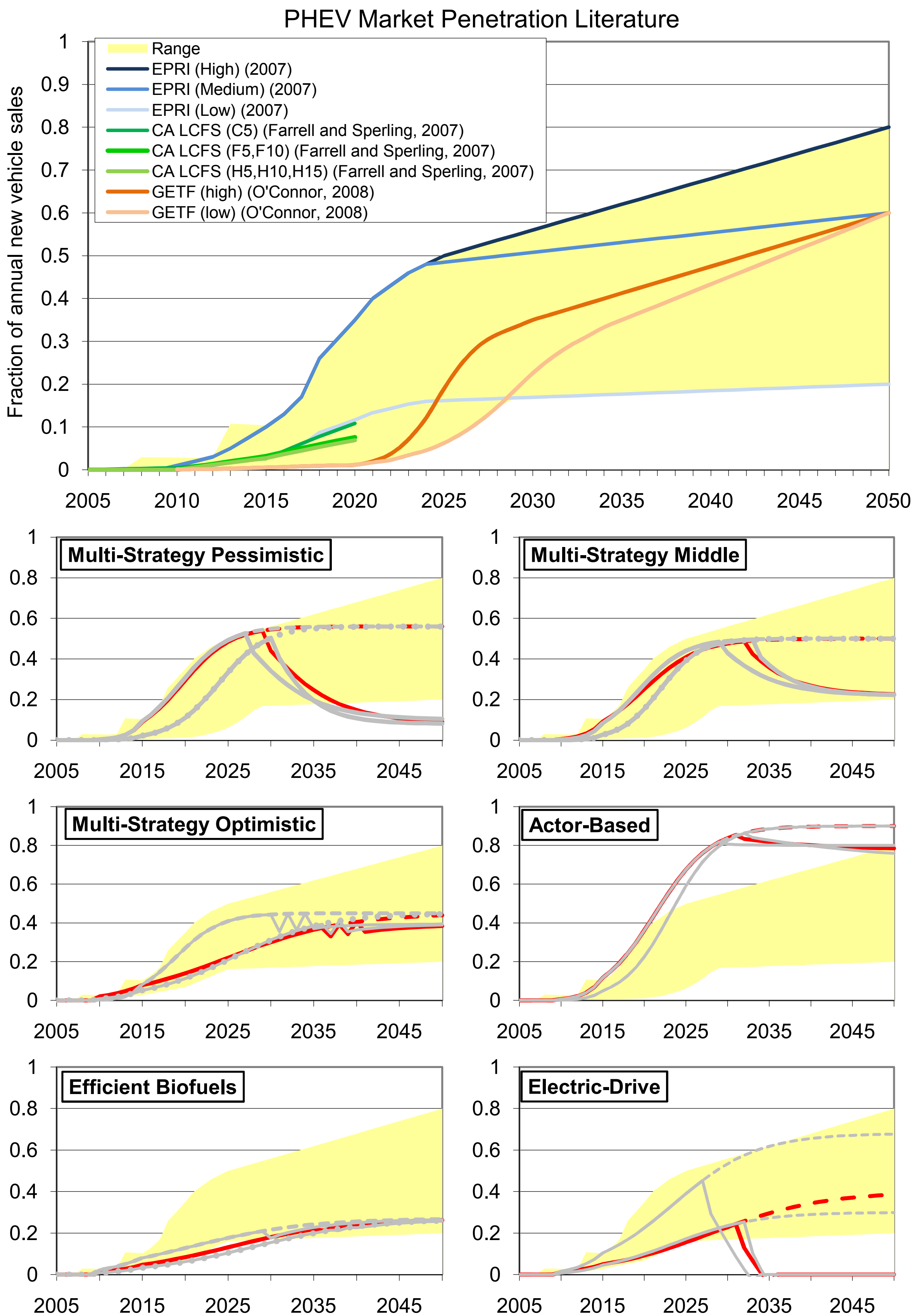
Figure 23: Market shares for hybrid-electric vehicles (HEV).

The plausible range in market penetration paths is shaded in yellow in the top panel, based on a literature survey. The range in market penetration paths is bounded by maximum and minimum scenarios in the HyTrans study (Greene et al., 2007), with other scenarios from HyTrans, the California LCFS studies, and National Academies studies shown as well (Farrell and Sperling, 2007; Greene et al., 2007; National Academies, 2004).

The market penetration curves used in the 80in50 PATH modeling for each 80in50 scenario are shown as dashed red lines in the bottom panels. (These are the values assumed if there were no competition with other vehicle technologies.) The actual market shares over time (with competition from other technologies) for these scenarios are solid red lines.

Sensitivity analysis for penetration curves and actual market shares under the *act-early* and *act-late* cases for each 80in50 scenario are shown as grey dashed and solid lines.

While the range in published market penetration forecasts is narrow in early years, divergence between these studies is apparent in whether HEV will prove to be a transitional technology that begins losing market share as other technologies become available or not.



PHEV Market Penetration Literature
Fraction of annual new vehicle sales
Range
EPRI (High) (2007)
EPRI (Medium) (2007)
EPRI (Low) (2007)
CA LCFS (C5) (Farrell and Sperling, 2007)
CA LCFS (F5,F10) (Farrell and Sperling, 2007)
CA LCFS (H5,H10,H15) (Farrell and Sperling, 2007)
GETF (high) (O'Connor, 2008)
GETF (low) (O'Connor, 2008)
Multi-Strategy Pessimistic
Multi-Strategy Middle
Multi-Strategy Optimistic
Actor-Based
Efficient Biofuels
Electric-Drive

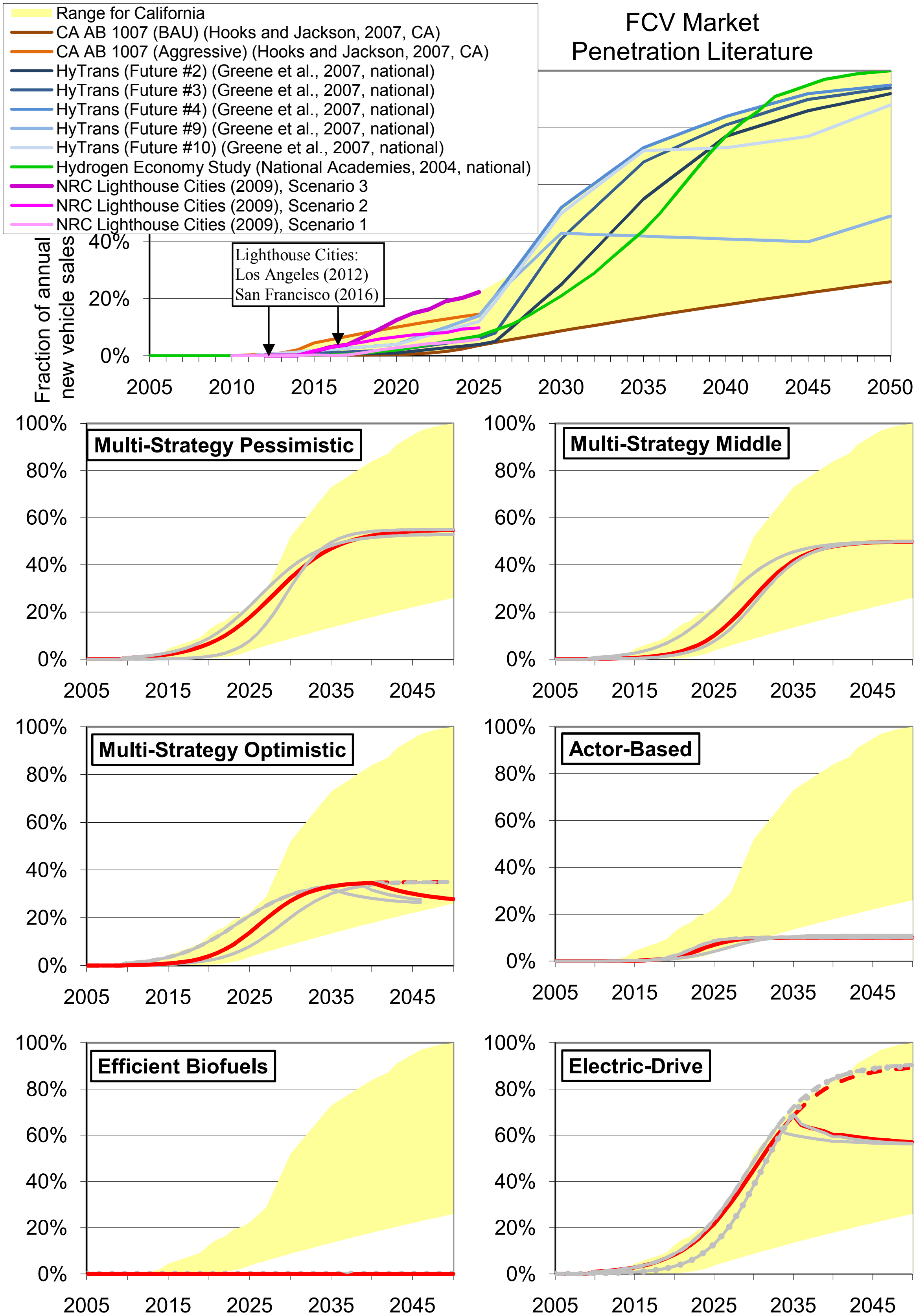
Figure 24: Market shares for plug-in hybrid-electric vehicles (PHEV).

The plausible range in market penetration paths is shaded in yellow in the top panel, based on a literature survey. The range in market penetration paths is bounded by the EPRI low and high penetration scenarios (EPRI, 2007a), with the California LCFS study shown as well (Farrell and Sperling, 2007; National Academies, 2004).

The market penetration curves used in the 80in50 PATH modeling for each 80in50 scenario are shown as dashed red lines in the bottom panels. (These are the values assumed if there were no competition with other vehicle technologies.) The actual market shares over time (with competition from other technologies) for these scenarios are solid red lines.

Sensitivity analysis for penetration curves and actual market shares under the *act-early* and *act-late* cases for each 80in50 scenario are shown as grey dashed and solid lines.

The PHEV market penetration rate needed in the *Actor Based* scenario may be infeasible in that it exceeds the yellow plausible range of market penetration as defined in the literature. This is one case where it may not be possible to implement a LDV technology fast enough to meet the requirements for one 80in50 scenario.



FCV Market
Penetration Literature
Range for California
CA AB 1007 (BAU) (Hooks and Jackson, 2007, CA)
CA AB 1007 (Aggressive) (Hooks and Jackson, 2007, CA)
HyTrans (Future #2) (Greene et al., 2007, national)
HyTrans (Future #3) (Greene et al., 2007, national)
HyTrans (Future #4) (Greene et al., 2007, national)
HyTrans (Future #9) (Greene et al., 2007, national)
HyTrans (Future #10) (Greene et al., 2007, national)
Hydrogen Economy Study (National Academies, 2004, national)
NRC Lighthouse Cities (2009), Scenario 3
NRC Lighthouse Cities (2009), Scenario 2
NRC Lighthouse Cities (2009), Scenario 1
Lighthouse Cities:
Los Angeles (2012)
San Francisco (2016)
Fraction of annual new vehicle sales
Multi-Strategy Pessimistic
Multi-Strategy Middle
Multi-Strategy Optimistic
Actor-Based
Efficient Biofuels
Electric-Drive

Figure 25: Market shares for hydrogen fuel cell vehicles (FCV).

The plausible range in market penetration paths is shaded in yellow in the top panel, based on a literature survey. The range in market penetration paths is bounded by the California AB1007 business as usual scenario (Hooks and Jackson, 2007) and HyTrans future #4 (Greene et al., 2007), with the National Academies Hydrogen Economy study (National Academies, 2004) and a National Academies study of lighthouse cities (Los Angeles and San Francisco in California) shown as well (National Academies, 2009).[56]

The market penetration curves used in the 80in50 PATH modeling for each 80in50 scenario are shown as dashed red lines in the bottom panels. (These are the values assumed if there were no competition with other vehicle technologies.) The actual market shares over time (with competition from other technologies) for these scenarios are solid red lines.

The sensitivity analysis for penetration curves and actual market shares under the *act-early* and *act-late* cases for each 80in50 scenario are shown as grey dashed and solid lines.

---

[56] The National Academies Hydrogen Economy (National Academies, 2004) and AB 1007 studies (Hooks and Jackson, 2007) were focused on California specifically while the HyTrans was national in scope but gave region-specific results that included California (Greene et al., 2007). The National Academies Hydrogen Economy (National Academies, 2004) and HyTrans (Greene et al., 2007) studies were related in methodology, meaning the AB 1007 study (Hooks and Jackson, 2007) provides the only true second opinion.

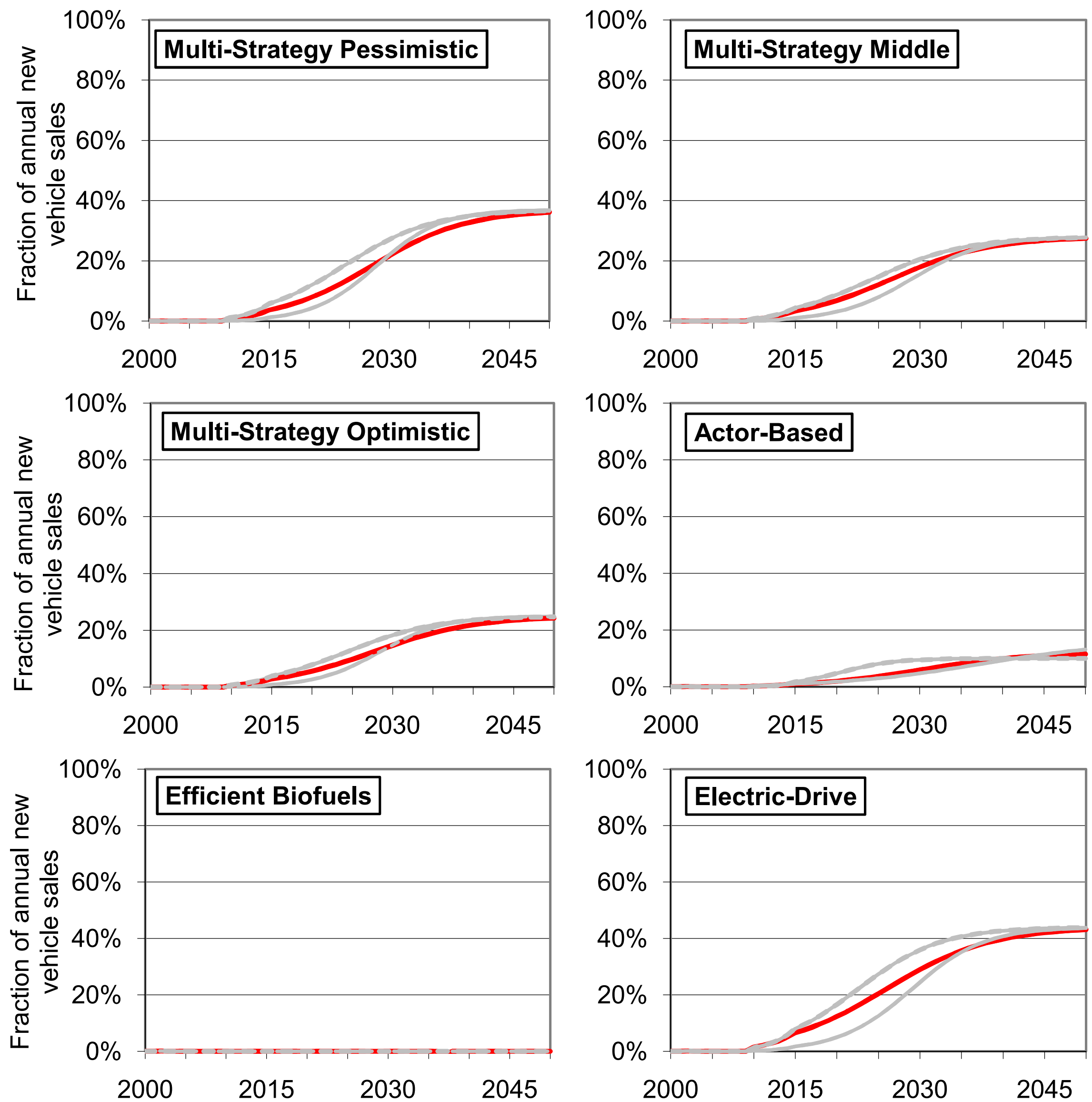


Figure 26: Market shares for battery-electric vehicles (BEV). Absent guidance from literature on market penetration rates for BEV, I assumed early penetration for BEV greater than for FCV due to fewer infrastructure limitations, but ultimate market share below that of FCV due to continued range limitation and higher long-run cost for BEV (Kromer and Heywood, 2007), potential limits to at-home charging for people who live in apartment buildings or use on-street parking, and the role of hydrogen as an energy carrier in bringing stranded renewable-source energy to market (Appendix A) (Leighty, 2008). The market penetration curves used in the 80in50 PATH modeling for each 80in50 scenario shown as dashed red lines are hidden beneath the actual market shares over time (with competition from other technologies) shown in solid red lines because BEV are the least-emission LDV technology (provided electricity with low carbon intensity). The sensitivity analysis for penetration curves and actual market shares under the *act-early* and *act-late* cases for each 80in50 scenario are shown as grey dashed and solid lines.

2.2.1.3.5 Vehicle Technology Evolution

The preceding sections described the range of market penetration rates in the literature and established a decision rule for bringing new low carbon vehicle technologies into the marketplace. They did not, however, describe the progression of underlying technologies that might develop (e.g., HEV → PHEV → BEV).

The potential issue is whether there is adequate consistency of modeled transition paths in terms of timelines for technology development and evolution. The "simple decision rule" for competing technologies – going with lower carbon technologies as they become available – does not explicitly take technology evolution into account. But for various reasons including the fact that the more advanced vehicle technologies also tend to be progressively lower carbon and require increasing electrification, the PATH model yields results (Figure 27) that appear to make sense in terms of technology evolution.

For example, the progression from HEV to PHEV to BEV in many of the 80in50 scenarios allows for development in the performance of battery and other electric drivetrain components necessary for success with BEV and FCV (Figure 27). Similarly, the transitional role of biofuels in LDV in many of the 80in50 scenarios allows for development of supply and production infrastructure to supply these fuels in increasing quantity to the aircraft, HDV and marine sub-sectors (Figure 33).

However, the logical technological evolution produced from the PATH modeling is also somewhat tautological. After all, the simple decision rule uses lower carbon technologies *as they become available*, which is gleaned from literature that is based on *technology evolution* and market adoption. So one reason the PATH modeling produces a logical progression from HEV to PHEV to BEV is because those who have researched the technology evolution of electrification have concluded that this progression makes sense in terms of developing battery technology (the primary constraint).

But in this literature, it is unique that I *started* from the “simple decision rule” of needing the least-emitting technologies in order to meet the 80in50 goal and then produced results that are *consistent* with technological evolution. In other words, my method provides a check on whether aggressive GHG emission reduction targets are technologically feasible. Most other studies begin with evaluation of logical technology evolutions and then see where these evolutions would lead. Conversely, in the research presented in this dissertation, I am not trying to *plan* a progression of technology evolution exogenously, but rather am modeling what GHG policy may force. In the process, I am discovering that the progression in vehicle technologies appears logical across all 80in50 scenarios. This is a somewhat surprising (and encouraging) result: that when the low-carbon decision rule is imposed to meet our GHG emission reduction goals, the result is a logical path of technological evolution. This occurs because the lower carbon technologies are also the next logical technological steps. This implies that ratcheting up of GHG emission constraints by policy makers could be consistent – in and of itself – with technology evolution.

In this context, it is also important to consider whether any of the transitional technologies (e.g., HEV) imply barriers for manufacturing investments. For example, if BEV batteries require substantially different battery chemistry and/or manufacturing processes than HEV batteries, will industry invest in the manufacturing capacity for HEV and PHEV batteries if the expected lifespan in the marketplace for these technologies is relatively brief? Ensuring transfer and evolution in manufacturing may be as important as ensuring logical technological evolution for the success of transitions that achieve the 80in50 goal.

Finally, when interpreting the divergence between solid and dashed lines in Figure 27 (i.e., divergence between potential and actual market penetration), it is important to recognize that what appear to be dramatic losses in market share are in some cases actually indications of logical evolution in vehicle technology and manufacturing. For example, declines in HEV market share are offset by increases in PHEV market share, which may in practice be a blended grey area of vehicles with increasing hybridization, battery size and all-electric range all produced from similar components in the same manufacturing facilities.

2.3 Results

The output of the *80in50 PATH Model* includes transition paths over time for market and fleet share for each vehicle technology (Figure 27 in section 2.3.1), total annual VMT (Figure 28 in section 2.3.2), fleet average vehicle emissions per mile (Figure 31 in section 2.3.5), total GHG emissions (Figure 32 in section 2.3.6), average fuel carbon intensity (Figure 30 in section 2.3.4) and total energy use (Figure 33 in section 2.3.7).

The transition paths in market shares and annual VMT describe a range in potential answers to the question of how to get from the current transportation system to one in 2050 that meets the *80in50* goal. The transition paths in GHG emissions enable assessment of the viability for meeting near-term policy goals while staying on a path for meeting the 80in50 goal and also reveal that the path taken *does* matter for cumulative emissions and the potential for continued emission reduction past 2050. Finally, the transition paths in vehicle technology market shares and in total energy use reveal stark implications for dramatic changes in the automotive and energy industries necessary for meeting the 80in50 goal.

The following general trends for reducing GHG emissions in the transportation sector are apparent in Figure 19 - Figure 27: 1) increasing vehicle efficiency through improvements in internal combustion engine technology, hybridization, and a shift in fleet composition toward cars; 2) increasing vehicle electrification, with HEV giving way to PHEV and then to FCV and BEV (unless plentiful low-carbon biofuels are available); and 3) decarbonization of the fuel mix as it shifts from petroleum to biofuels to hydrogen and electricity.

Meeting both the 2020 and 2050 GHG emission reduction goals is even more challenging than meeting the 80in50 goal alone. Only one of the six 80in50 scenarios achieves both goals: the Actor-Based scenario. This scenario requires vehicle efficiency to improve to 125 mpgge (fleet average on-road for new vehicles), aggressive electrification of LDV that renders HEV and biofuels use in LDV "transitional" with relatively short periods of large market share, rapid de-carbonization of primary energy sources and energy carriers, and decrease in LDV travel demand by 38% in VMT/capita from the business-as-usual trend. This scenario also produces 16-29% less cumulative GHG emissions over the period 2010 through 2050 than the other five 80in50 scenarios (see section 2.3.8). Thus, the 2020 and 2050 goals *in combination* constrain *cumulative* GHG emissions to a much lower amount than does the 80in50 goal alone.

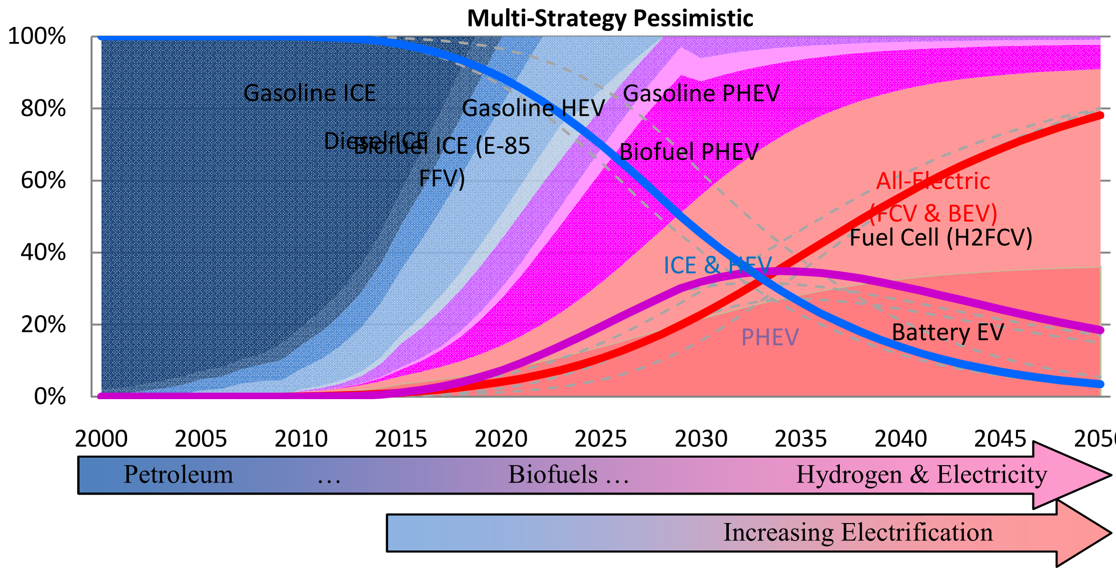
The following sections offer analysis in greater depth for each of the transition paths produced by the *80in50 PATH Model*.

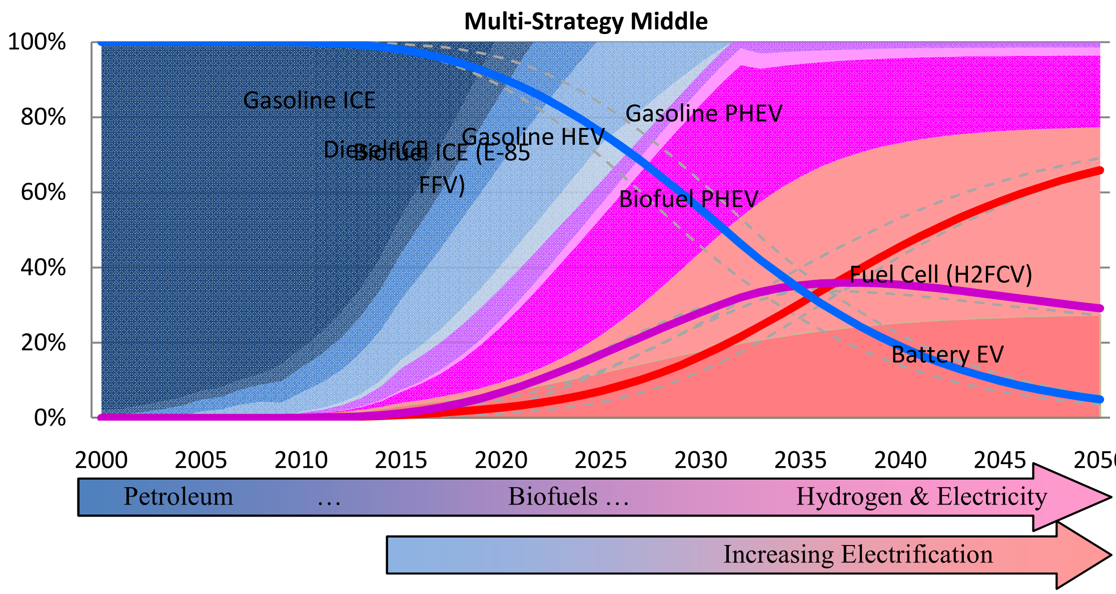
2.3.1 Transition Paths in Market and Fleet Share for Advanced Vehicle Technologies

The operation of the simple decision rule used to compete advanced vehicle technologies (i.e., lower-emission technologies like BEV and FCV squeezing higher-emission ICE and HEV out of the market) is apparent in Figure 27. Since there is no objective function embedded in this rule, the *80in50 PATH Model* produces scenarios rather than optimization. But the aggressive intermediate waypoints, especially reducing GHG emissions to 1990 levels by 2020, leave little room for less aggressive competition among technologies. Specifically, Figure 32 shows that adherence to the decision rule of lower-emission technologies squeezing higher-emission alternatives out of the market as fast as possible is just sufficient for meeting the 2020 target for GHG emissions in the *Actor-Based* scenario. The *Efficient Biofuels* and *Electric-Drive* scenarios cannot meet this intermediate waypoint even in the *act-early* scenario.

But the intermediate goal for GHG emission reduction by 2020 does leave room for a range in 80in50 scenarios if the act-early cases of the *Multi-Strategy* scenarios are considered. Even between the Actor-Based and Multi-Strategy scenarios there are large differences in the 2050 fleet mix for competing technologies. The Actor Based scenario envisions a LDV fleet in 2050 comprised mostly of PHEV while the fleet in the *Multi-Strategy* scenarios use a combination of PHEV, BEV and FCV. The importance of developing zero-emission vehicle technologies is very different between these scenarios, all of which can satisfy both the 2020 and 2050 goals for GHG emission reductions. However, all of these scenarios envision maximum increase in vehicle efficiency (with the Actor Based scenario compromising vehicle performance increase efficiency even further), significant reduction in per-capita VMT, and transitions in market share that progress very quickly. Thus, regardless of which 80in50 scenario we choose, achieving both the 2020 and 2050 GHG emission reduction goals in the transportation sector will require rapid change in the vehicle fleet. Achieving *both* of these goals will also likely require per-capita VMT reduction, large increases in vehicle efficiency, and rapid decreases in fuel carbon intensity (as discussed in section 2.3).[57]

[57] It is important to note, however, that the 2020 target for reducing GHG emissions to 1990 levels is an economy-wide goal that is not specific to the transportation sector and one which most analysts do not believe will be met on an equal share by the transportation sector (e.g., Yeh et al., 2008).


Multi-Strategy Pessimistic
100%
80%
60%
40%
20%
0%
2000
2005
2010
2015
2020
2025
2030
2035
2040
2045
2050
Gasoline ICE
Gasoline HEV
Gasoline PHEV
Biofuel PHEV
FFV)
All-Electric
(FCV & BEV)
Fuel Cell (H2FCV)
PHEV
Battery EV
Petroleum
Biofuels …
Hydrogen & Electricity
Increasing Electrification


Multi-Strategy Middle
100%
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2000
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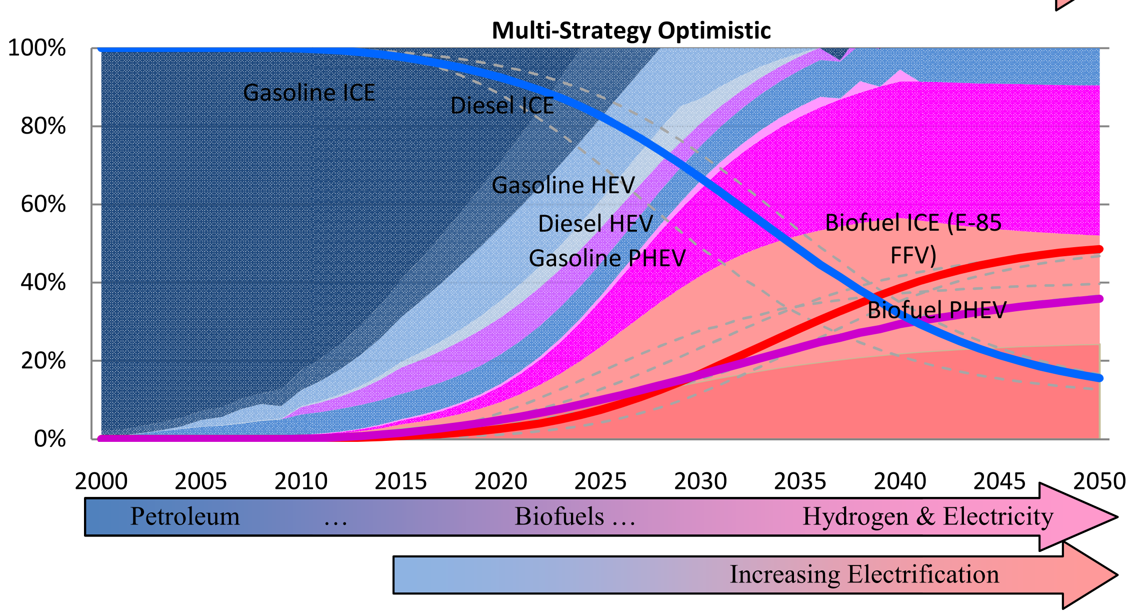
2050
Gasoline ICE
Gasoline PHEV
Gasoline HEV
FFV)
Biofuel PHEV
Fuel Cell (H2FCV)
Battery EV
Petroleum
Biofuels …
Hydrogen & Electricity
Increasing Electrification


Multi-Strategy Optimistic
100%
80%
60%
40%
20%
0%
2000
2005
2010
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2020
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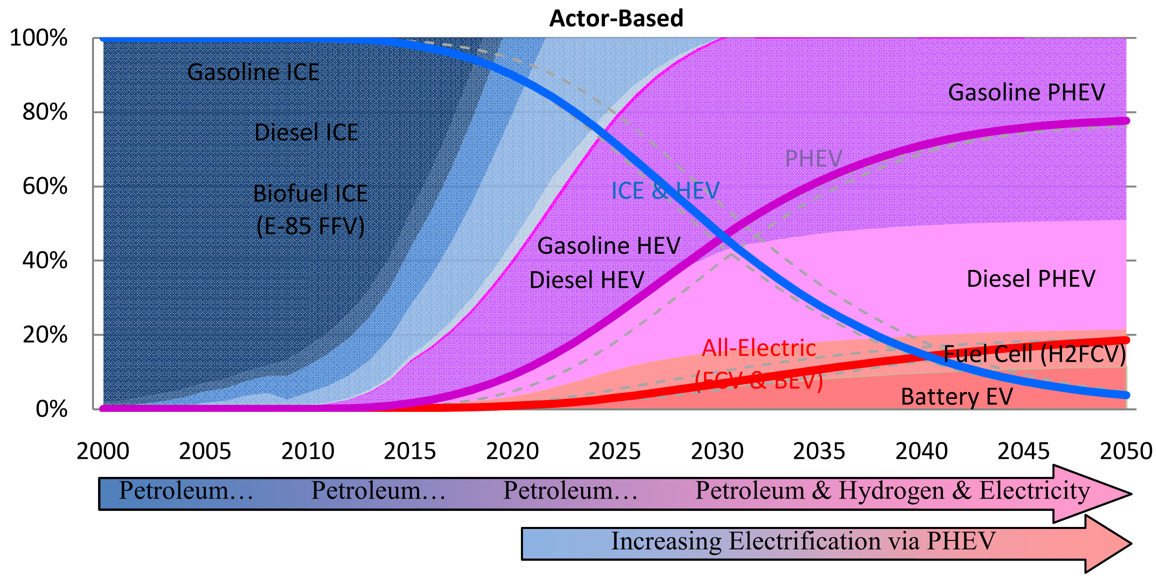
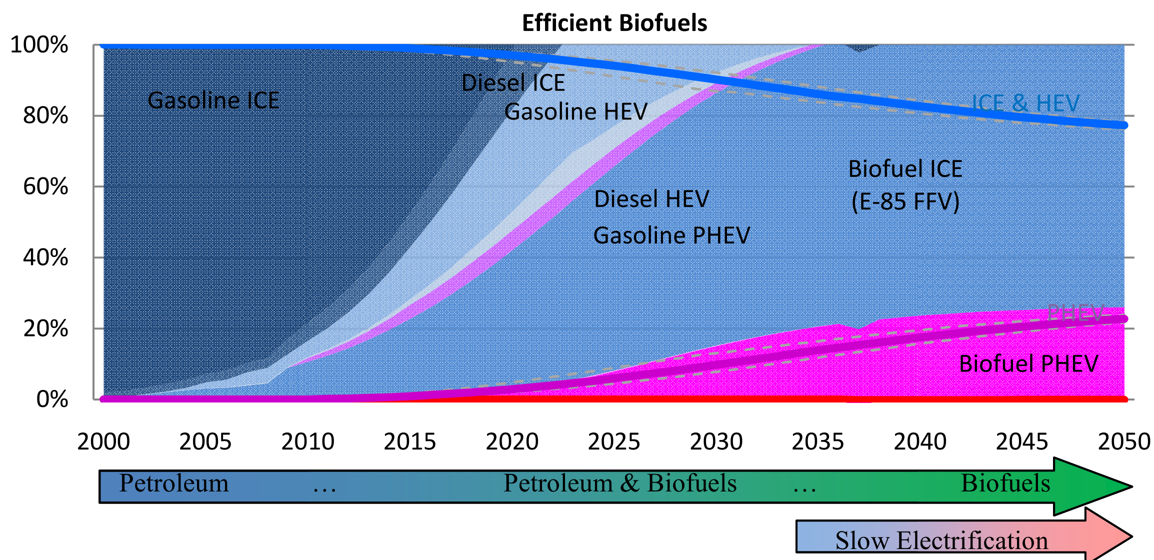
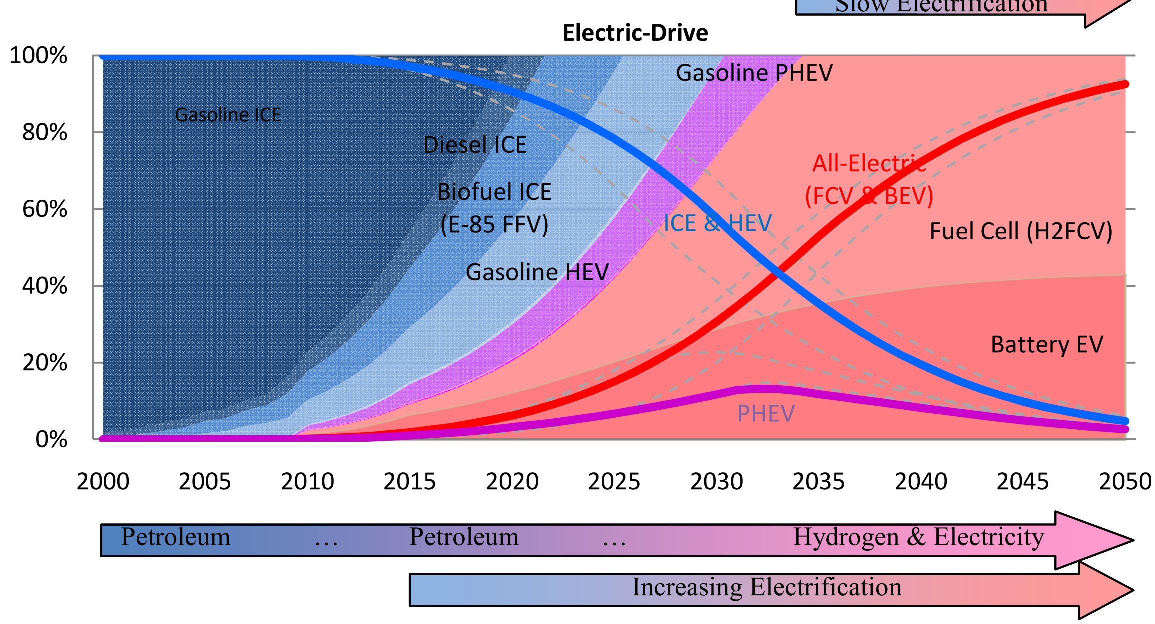
2035
2040
2045
2050
Gasoline ICE
Diesel ICE
Gasoline HEV
Diesel HEV
Gasoline PHEV
Biofuel ICE (E-85
FFV)
Biofuel PHEV
Petroleum
Biofuels …
Hydrogen & Electricity
Increasing Electrification


Actor-Based
100%
80%
60%
40%
20%
0%
Gasoline ICE
Diesel ICE
Biofuel ICE
(E-85 FFV)
ICE & HEV
PHEV
Gasoline PHEV
Gasoline HEV
Diesel HEV
Diesel PHEV
All-Electric
(FCV & BEV)
Fuel Cell (H2FCV)
Battery EV
2000 2005 2010 2015 2020 2025 2030 2035 2040 2045 2050
Petroleum… Petroleum… Petroleum… Petroleum & Hydrogen & Electricity
Increasing Electrification via PHEV


Efficient Biofuels
100%
80%
60%
40%
20%
0%
Gasoline ICE
Diesel ICE
Gasoline HEV
ICE & HEV
Diesel HEV
Gasoline PHEV
Biofuel ICE
(E-85 FFV)
PHEV
Biofuel PHEV
2000 2005 2010 2015 2020 2025 2030 2035 2040 2045 2050
Petroleum … Petroleum & Biofuels … Biofuels
Slow Electrification


Electric-Drive
100%
80%
60%
40%
20%
0%
Gasoline ICE
Gasoline PHEV
Diesel ICE
Biofuel ICE
(E-85 FFV)
Gasoline HEV
ICE & HEV
All-Electric
(FCV & BEV)
Fuel Cell (H2FCV)
Battery EV
PHEV
2000 2005 2010 2015 2020 2025 2030 2035 2040 2045 2050
Petroleum … Petroleum … Hydrogen & Electricity
Increasing Electrification

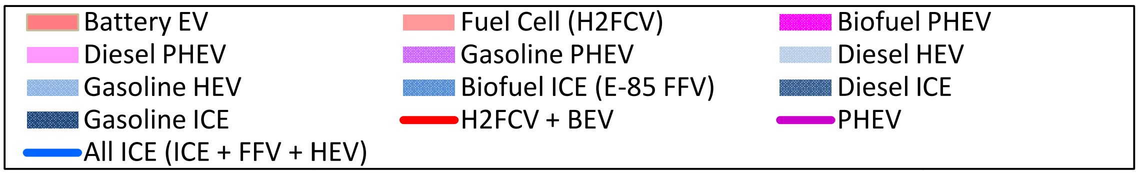


Figure 27: Transition in market share (shaded area) and fleet share (lines) of light-duty vehicles required to achieve the 2050 fleet mix that meets the *80in50* goal. Solid lines show the paths produced by the *80in50 PATH* modeling while the dashed lines show results from *act-early* and *act-late* scenarios. Higher-emission technologies (e.g., conventional gasoline ICE and HEV) are squeezed out of the marketplace by lower-emission alternatives (e.g., FCV and BEV) according to maximum market penetration rates (Figure 21 - Figure 26) in order to achieve intermediate waypoints. Although transformation of the light-duty market is rapid, transition in the fleet share is more gradual due to inertia in the existing fleet of vehicles. The "transitional" role of PHEV in the fleet is evident in some scenarios.

2.3.1.1 Variation in Transitions in LDV Technologies

Although variation between the *80in50* scenarios in the LDV technologies used to meet the *80in50* goal is evident, the transformation in the light-duty vehicle marketplace shown in Figure 27 is very rapid for all scenarios.[58]

The changes in vehicle technology required to meet the *80in50* goal in the *Efficient Biofuels* scenario are mitigated by plentiful supply of low-carbon biofuels. Likewise, the changes in vehicle technology in the *Actor-Based* scenario are mitigated by significant VMT reduction (Figure 32). These results are evidence of the multiplicative nature of the transportation variant of the Kaya identity used in the 80in50 LEVERS model by which more action to reduce emissions through VMT or fuel carbon intensity reduction can reduce the degree of change required in LDV fleets.

In contrast to the *Efficient Biofuels* scenario, the *Multi-Strategy* scenarios are constrained by low-carbon biofuel feedstock supply, the *Actor-Based* scenario assumes a high energy price future, and the *Electric-Drive* scenario assumes technological success with electric-drive vehicles. Consequently, these scenarios all rely on more dramatic changes in vehicle technology to compensate for less action on other major drivers of GHG emission reduction.

2.3.1.2 The Impact of Biofuel Supply on Transitions in LDV Technologies

If a very large quantity (16 billion gge) of low-carbon (17.7 gCO_2e/MJ) biofuel is available (i.e., the *Efficient Biofuels* scenario), then the new vehicle market in 2050 can be entirely biofueled ICE and PHEV vehicles. The increasing market share for biofueled ICE (22% in 2015, 39% in 2020, 71% in 2030) is offset by declining market share for

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58 Change in the vehicle fleet is more gradual than change in market share due to inertia in the fleet stock (Figure 16).

gasoline ICE (48% in 2015, 2% in 2020) while HEV play a transitional role (16% in 2015, 34% in 2020, 11% in 2030) and biofueled PHEV gain market share somewhat later (8% in 2025, 21% in 2035).

But if biofuel supply is feedstock-constrained such that 5.2 billion gge can be supplied at 32.9 gCO_2e/MJ average carbon intensity (i.e., *Multi-Strategy*$_{Middle}$ scenario), then biofueled PHEV, BEV and hydrogen FCV dominate the new vehicle market in 2050. The increasing market shares for PHEV (9% in 2015, 25% in 2020, 48% in 2030), BEV (3% in 2015, 7% in 2020, 18% in 2030) and FCV (1% in 2015, 3% in 2020, 26% in 2030) are offset by declining market share for gasoline ICE (47% in 2015, 0% in 2020) while HEV play a transitional role (18% in 2015, 33% in 2020, 8% in 2025) role.

2.3.1.3 Sensitivity Analysis for Transitions in LDV Technologies

In Figure 27, the *act-early* paths for PHEV, FCV and BEV are above the respective solid lines (i.e., accelerated introduction) while the *act-early* path for ICE and HEV is below the associated solid line (i.e., more rapid loss of market and fleet share) such that the total number of vehicles (and VMT) over time is consistent across scenarios (i.e., market shares and fleet shares always sum to 100%).

A similar pattern but reversed holds true for the *act-late* scenarios. Introduction of low-emissions PHEV, FCV and BEV are delayed while higher-emissions ICE and HEV linger in the marketplace and fleet longer.

2.3.2 Increasing Vehicle Miles of Travel

Total annual vehicle miles of travel increases in all six 80in50 scenarios, although the rate of increase and share of miles driven by cars and light trucks/SUVs varies

(Figure 28). Even when VMT/capita decreases, growth in population causes total VMT to increase. This puts additional pressure on other factors to reduce emissions.

In the *Actor-Based* scenario, a 25% decrease from 1990 levels in passenger miles per capita (9,490 vs. 12,650) and 25% increase in passengers per vehicle (2.08 vs. 1.66) produces an overall 40% reduction in VMT per capita (4,570 vs. 7,620). An aggressive shift to 90% cars in the fleet by 2050 also dramatically reduces the share of miles driven by relatively less fuel efficient light trucks/SUVs. But with population doubling from 1990 to 2050, total VMT in 2050 is still 20% higher than it was in 1990.

The change in LDV transportation intensity is less in the *Multi-Strategy* scenarios. Passenger miles per capita increase 3-15% from 1990 levels (less than the 21% increase in the baseline case) and passengers per vehicle increase 0-10%, producing a 6% reduction to 15% increase in VMT per capita (less than the 21% increase in the baseline case). With 62-65% cars in the 2050 fleet, the shift in mileage away from light trucks/SUVs is less dramatic as well, and total VMT in 2050 is 87% to 130% higher than it was in 1990 (compared to 142% increase in the baseline case).

In contrast, the *Electric-Drive* and *Efficient Biofuels* scenarios do not rely on changes in travel behavior to meet the 80in50 goal. With passenger miles per capita increasing 21% from 1990 levels and passengers per vehicle remaining constant, there is a steady increase in total VMT to 142% above the 1990 level in 2050 in these scenarios. Consequently, these scenarios require more improvement in efficiency and/or reduction in carbon intensity than the *Actor-Based* and *Multi-Strategy* scenarios in order to meet the *80in50* goal.

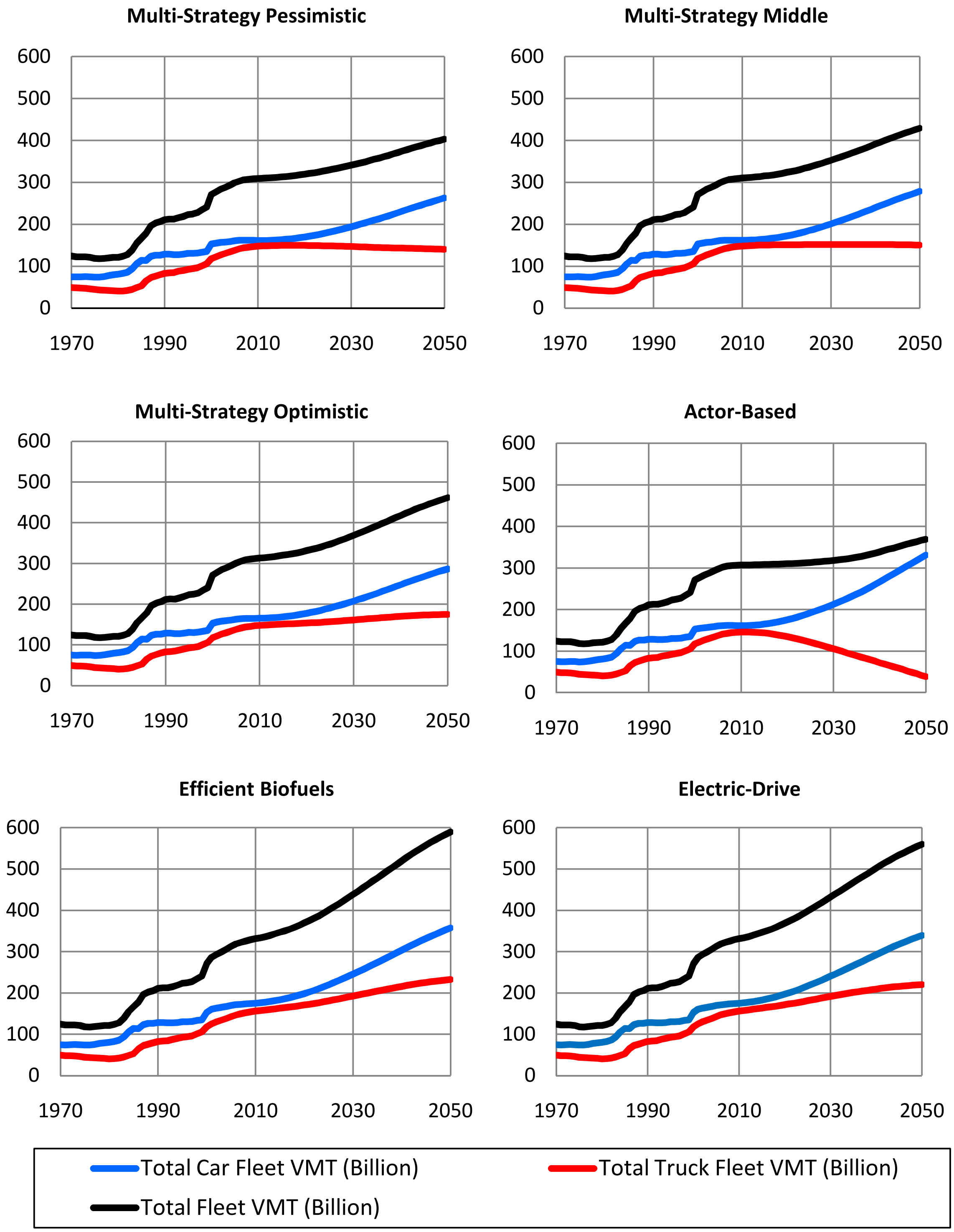


Figure 28: Total annual light-duty vehicle miles traveled under each *80in50* scenario. Miles of travel are highest in the *Efficient Biofuels* and *Electric Drive* scenarios due to less aggressive reduction in VMT per capita (100% of the business-as-usual baseline trend) while VMT per capita is reduced most in the *Actor-Based* scenario (62% of BAU).

2.3.3 Increasing Fuel Economy

In all of the 80in50 scenarios, technological improvements in engine, drivetrain, on board equipment, and glider efficiency are applied entirely to fuel economy (i.e., not to increasing vehicle size or performance). As a result, new vehicle on-road fuel economy for all types of LDV improves dramatically in all scenarios (Figure 29). Fleet average fuel economy increases more in the Actor-Based scenario than the other 80in50 scenarios because some *decrease* in vehicle performance is allowed (i.e., vehicles become smaller and/or slower) and the fleet shifts more toward cars than light trucks (Appendix A).

All of the 80in50 scenarios meet or exceed the national CAFE standards and California Pavley standards as currently defined. But all scenarios require continued increase in fuel economy well beyond these standards. Consequently, aggressive research, development and commercialization of vehicle efficiency technologies will be needed, perhaps motivated in part by continued increases in policy requirements for fuel economy like the CAFE and Pavley standards, in order to meet the 80in50 goal for the transportation sector.

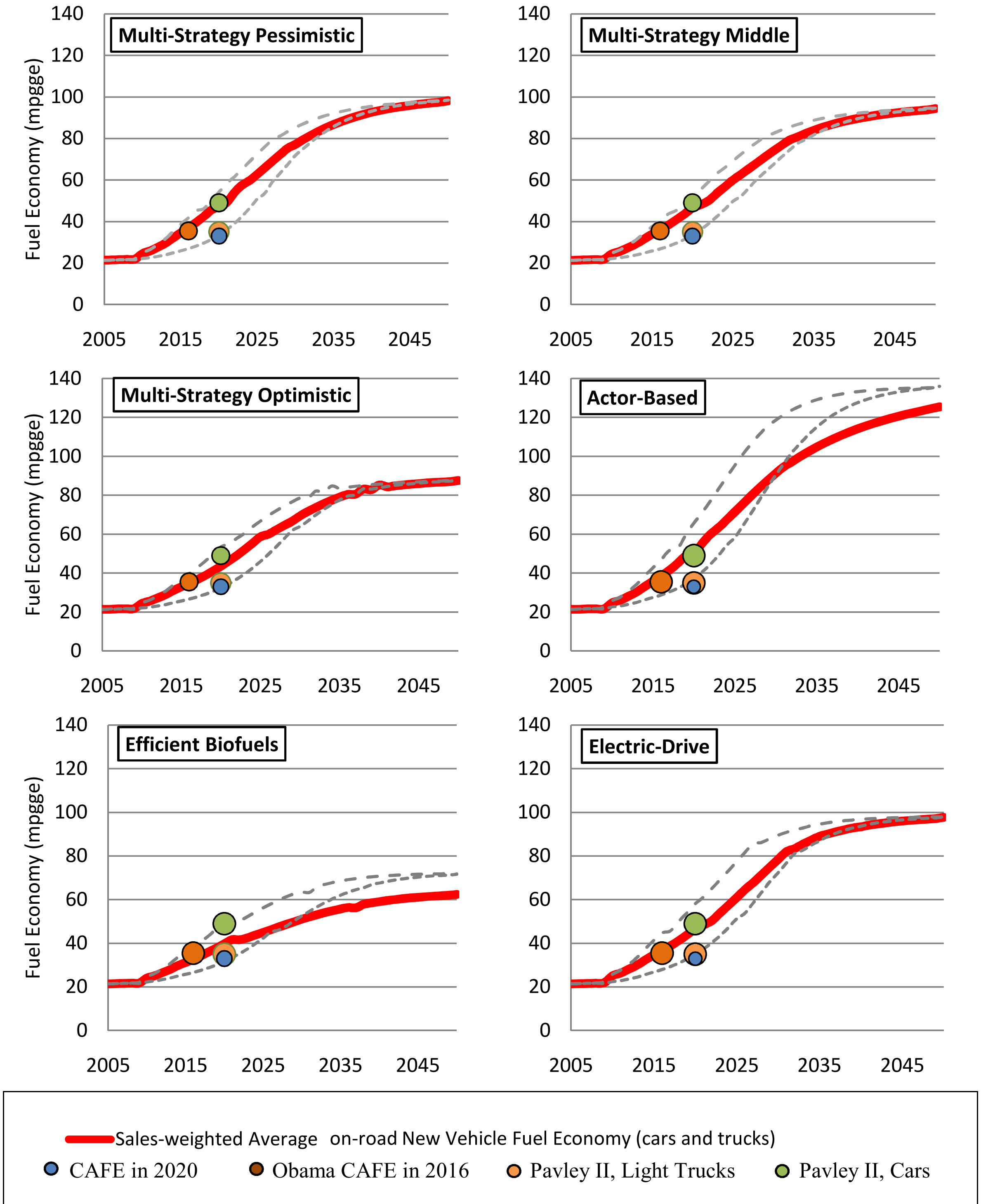


Figure 29: Fuel economy improvement for the sales-weighted average of all cars and light trucks, new vehicles on-road fuel economy, 2005 to 2050.

2.3.4 Decreasing Fuel Carbon Intensity

Transition paths in fuel carbon intensity for LDV in California are shown in Figure 30. Although not treated as a binding constraint in my modeling, the requirements for carbon intensity set forth in the California Low-Carbon Fuel Standard (LCFS) for gasoline and diesel (and their substitutes) (CARB, 2009c) and the California alternative fuels plan (CARB, 2007) are met (approximately), once adjusted by the LCFS Energy Economy Ratio (EER). The EER is meant to address differences across fuels in the efficiency of energy conversion onboard the vehicle. For example, electricity is converted into mechanical work through an electric motor much more efficiently that biofuel is converted through an internal combustion engine. Consequently, the GHG emissions per mile of travel will depend both on the carbon intensity of the fuel and the conversion efficiency onboard the vehicle. To account for the differences in conversion efficiency, electricity is granted a 3x EER factor in the California LCFS and hydrogen is granted a 2.3x EER. The EER adjustment factor has relatively little impact in the *Efficient Biofuels* scenario due to the predominance of ICE vehicles for which the EER is equal to one.

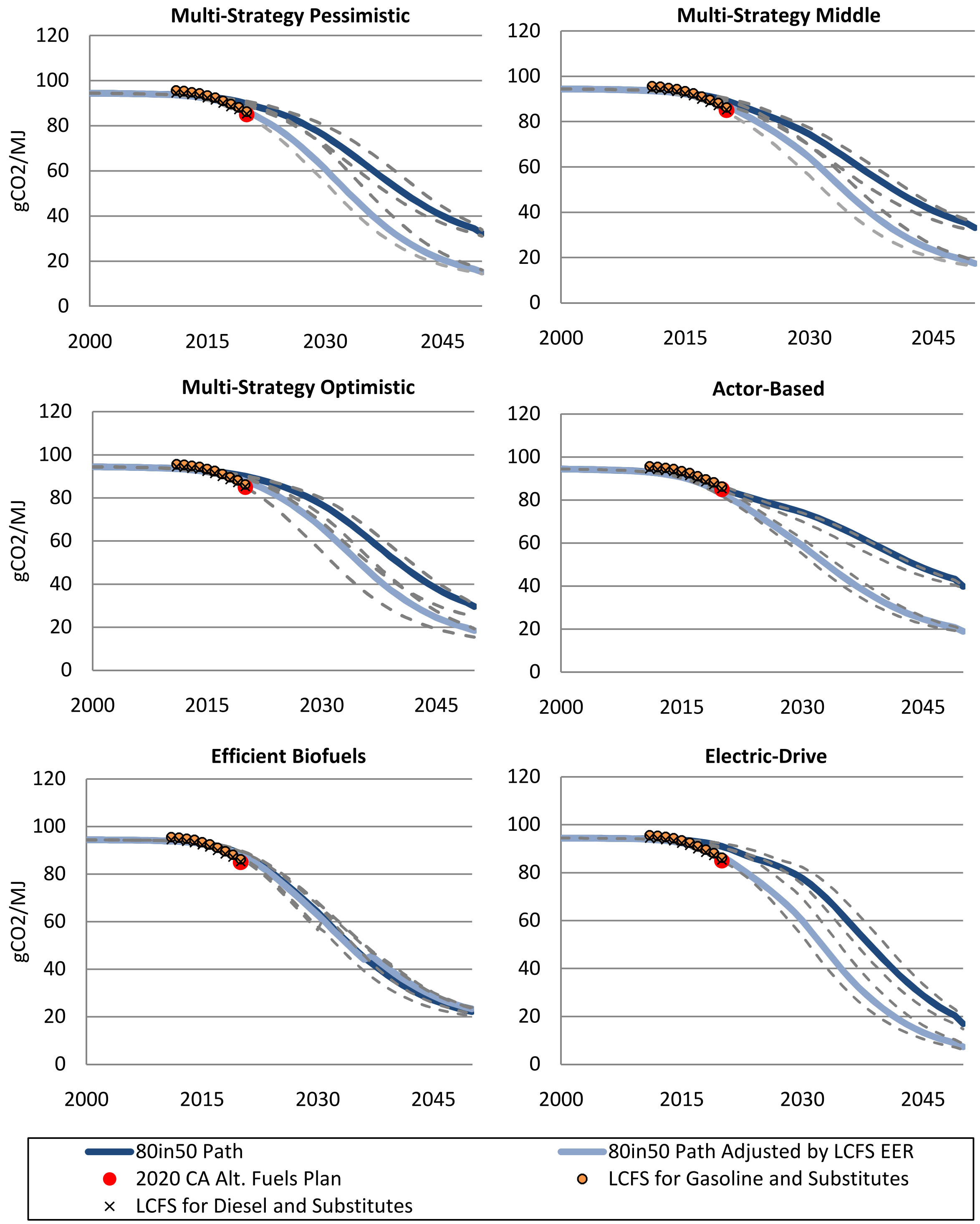


Figure 30: The transition path in fuel carbon intensity for LDV in California. The solid line shows the path produced by the *80in50 PATH* modeling while the dashed lines show results from *act-early* and *act-late* scenarios.

2.3.5 Decreasing New Vehicle On-road Well-to-wheel GHG Emissions per Mile

The GHG emissions per mile for each vehicle technology shown in Figure 31 are a function of energy efficiency (fuel economy, section 2.3.3) and fuel carbon intensity (section 2.3.4), both of which vary between the six *80in50* scenarios. Thus, GHG emissions per mile is a derived quantity which is regulated by the Pavley standards in California. All six 80in50 scenarios decrease to below the Pavley PCLDT1 emissions limits (for cars and small trucks) by about 2015.

The sales mix average new vehicle on-road GHG emissions per mile for all LDV in 2050 is 69.3 gCO_2e/mile in the *Actor-Based* scenario, 36.9 / 40.7 / 32.8 gCO_2e/mile in three *Multi-Strategy* scenarios (Pessimistic / Middle / Optimistic, respectively), 38.5 gCO_2e/mile in the *Efficient Biofuels* scenario, and 11.6 gCO_2e/mile in the *Electric-Drive* scenario. The underlying technologies and fuels used to achieve these very low emission rates also differ between scenarios, with heavy reliance on very low-carbon biofuels used in HEV and PHEV in the *Efficient Biofuels* scenario, heavy reliance on low-carbon electricity and hydrogen used in BEV and FCV in the *Electric-Drive* scenario, even greater vehicle efficiency in the *Actor-Based* scenario, and a blend of everything in the *Multi-Strategy* scenarios.

The approximate equivalence between FCV and BEV in GHG emissions per mile in 2050, given my assumptions in the *80in50* scenarios, implies the split in fleet share between these two technologies used to meet the *80in50* goal is somewhat arbitrary. Consequently, I use similar colors to represent BEV and FCV in the remaining figures. Absent guidance from literature on market penetration rate for BEV, I assumed early penetration for BEV greater than for FCV due to fewer infrastructure limitations, but ultimate market share below that of FCV due to continued range limitation and higher long-run cost for BEV (Kromer and Heywood, 2007), potential limits to at-home charging for people who live in apartment buildings or use on-street parking, and the role of hydrogen as an energy carrier in bringing stranded renewable-source energy to market (Leighty, 2008). There may also be limits to the share of renewable electricity generation the transportation sector can claim from an electric generation sector also struggling to meet emission reduction goals in the face of increasing population and demand. Hence my decision to portray the split as 50% / 30%, 45% / 23% and 30% / 20% FCV / BEV fleet shares in 2050 in the three *Multi-Strategy* scenarios (Pessimistic, Middle and Optimistic, respectively) and 60% / 35% in the *Electric-Drive*, 10% / 10% in the *Actor-Based* and 0% / 0% in the *Efficient Biofuels* scenarios (Appendix A). However, continued technological progress could render these assumptions incorrect, meaning one could argue for more BEV and fewer FCV.

If BEV remain niche vehicles with limited range and use (e.g., city-electric vehicles), then their annual mileage (and impact on GHG emission reductions) will be less than for other vehicles. In my current modeling, however, I assume the same mileage-age profile in the stock turnover model for each vehicle type (e.g., cars, light trucks/SUVs) regardless of technology (e.g., FCV, BEV). Future work could consider developing additional vehicle categories based on the type of use (and consequently the annual mileage driven).

Although BEV and FCV are more efficient than other vehicle technologies (Figure 19), other technologies can achieve similar reduction in GHG emissions per mile if the fuel carbon intensity is low enough to compensate for lesser fuel economy (e.g., biofuel HEV and PHEV in the *Efficient Biofuels* scenario). However, most vehicle technologies produce higher GHG emissions per mile than BEV and FCV under most scenario assumptions. When biofuel supply curves are imposed on the modeling (i.e., in the *Multi-Strategy* scenarios), it becomes difficult to develop a scenario that achieves the *80in50* goal with more than 40-50% PHEV in 2050, even when these vehicles are biofueled.[59] Yet HEV, PHEV and biofuels play an important role in meeting intermediate emission targets for 2020 (Figure 19, Figure 31, Figure 32, Figure 33). Consequently, HEV, PHEV, and biofuels are “transitional” technologies in the LDV sub-sector.

[59] Biofuels achieve equivalently low emissions per mile only when supply quantity is restricted to waste and cellulosic energy crops, which limits their role in the light-duty vehicle sub-sectors since other sub-sectors (e.g., aircraft) need these low-carbon liquid fuels more.

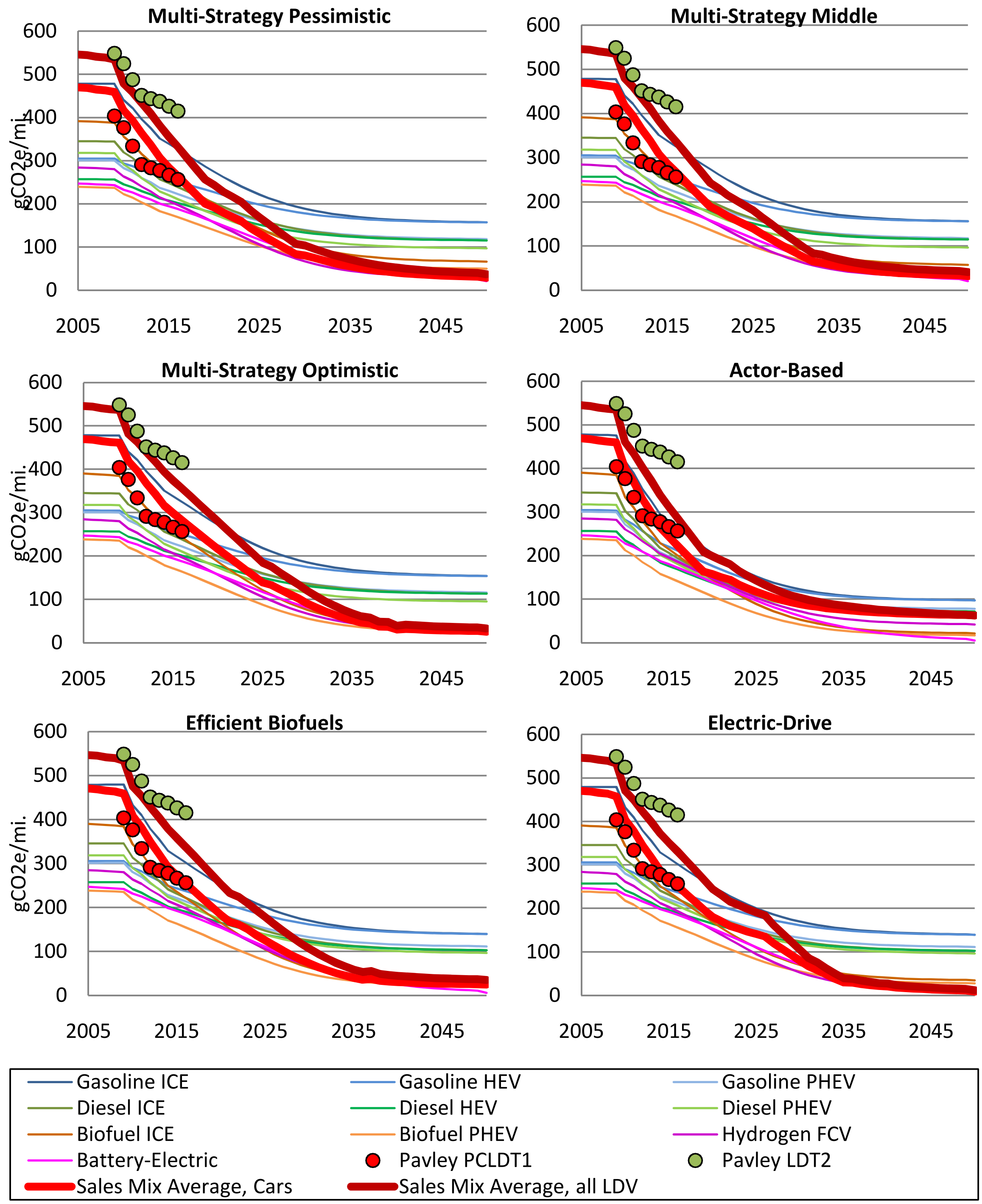


Figure 31: New Vehicle On-road well to wheels GHG emissions per mile for cars from 2000 to 2050 is shown for each vehicle technology by thin lines. Thick lines show the sales-weighted average for all cars and all LDV (cars and light trucks/SUVs). The phase-in of Pavley emission standards from 2009 to 2016 provides waypoints for cars/small trucks (PCLDT1) and for large trucks/SUVs (LDT2) (CARB, 2004).

2.3.6 Transition Paths in Total GHG Emissions to 80% Below 1990 Levels in 2050

The transition paths of total GHG emissions from light-duty vehicles in California, from 2000 to the *80in50* goal in 2050, are shown in Figure 32. The annual GHG emission rate from LDV exceeds the intermediate waypoint for 2010 (i.e., returning to 2000 emissions levels) in all scenarios. GHG emissions in 2010 exceed this target by 9.4 to 15 MMTCO2e per year depending on the scenario, with the *Actor-Based* scenario coming closest to meeting the target.[60] Alternatively, these six scenarios meet the target of 2000 emissions anywhere between 7 and 15 years later than required (2017 to 2025).

GHG emissions are able to meet the waypoint for 2020 (i.e., emissions at 1990 levels) in only one of the six *80in50* scenarios – the *Actor-Based* scenario – although the *Multi-Strategy* scenarios come close if the *act-early* case is considered. The *Efficient Biofuels* and *Electric-Drive* scenarios are not able to meet the 2020 waypoint even with the *act-early* scenario. These two scenarios both exceed the target emissions by around 14 MMTCO_2e/yr. Alternatively, they achieve the goal of meeting 1990 emissions, seven years later than required (i.e. 2027). In 2050, LDV have reduced emissions more than 80% below 1990 levels in all six scenarios, more than the *80in50* goal, in order to compensate for other transportation sub-sectors that do not meet the goal (Table 13).

[60] The model results for 2010 are effectively moot since the year has come and gone during the writing of this dissertation. Results for 2010 are given for informational purposes only.

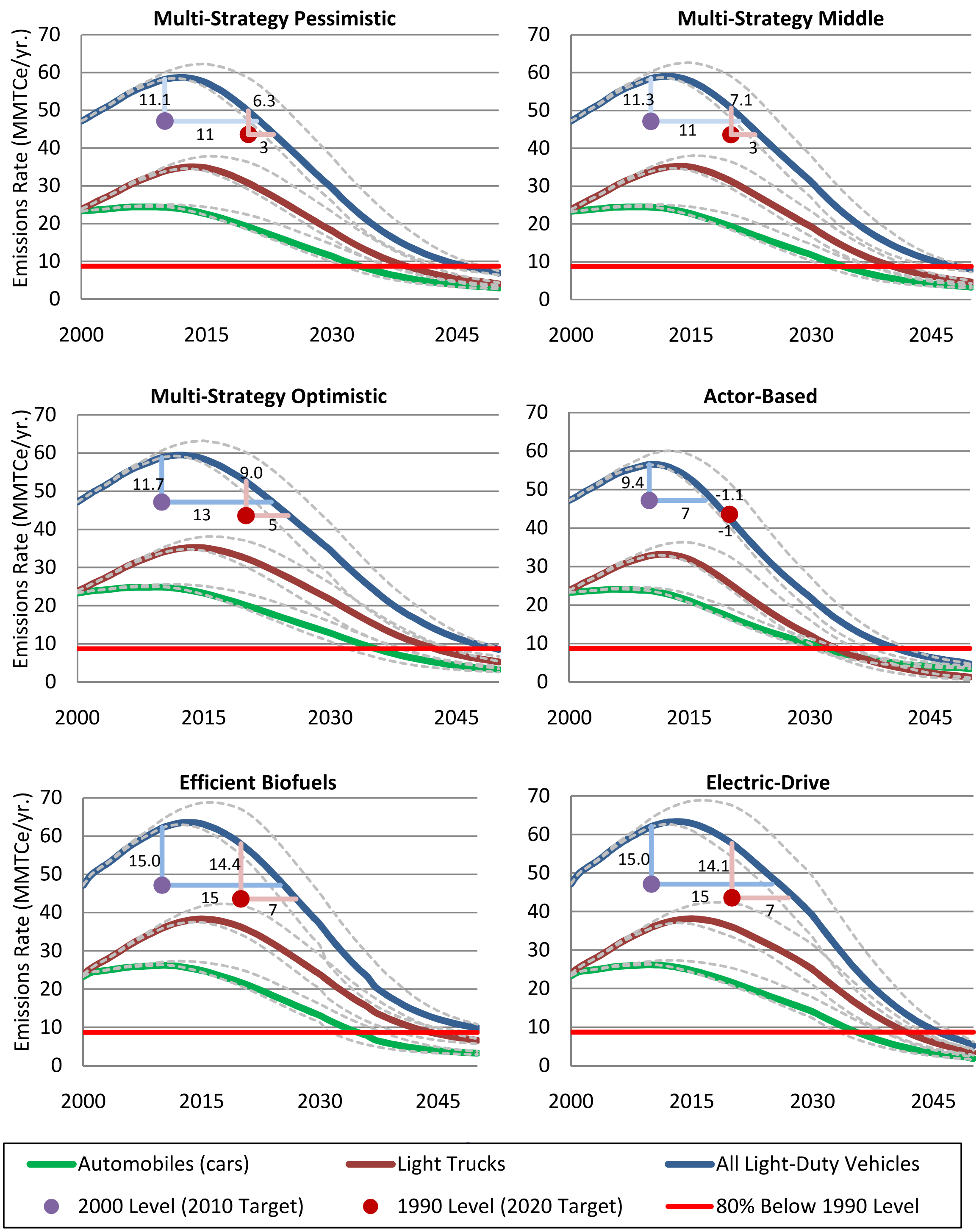


Figure 32: The transition path of GHG emissions from light-duty vehicles in California, from 2000 to the *80in50* goal in 2050. Solid lines show the paths produced by the *80in50 PATH* modeling while the dashed lines show results from *act-early* and *act-late* scenarios. The shortfall in GHG emission reduction for the 2010 and 2020 intermediate waypoints are shown in MMTCe in the target year (vertical line) and in the additional number of years required to meet the target (horizontal line).

2.3.7 Transition Paths in Total Energy Used by LDV, by Form

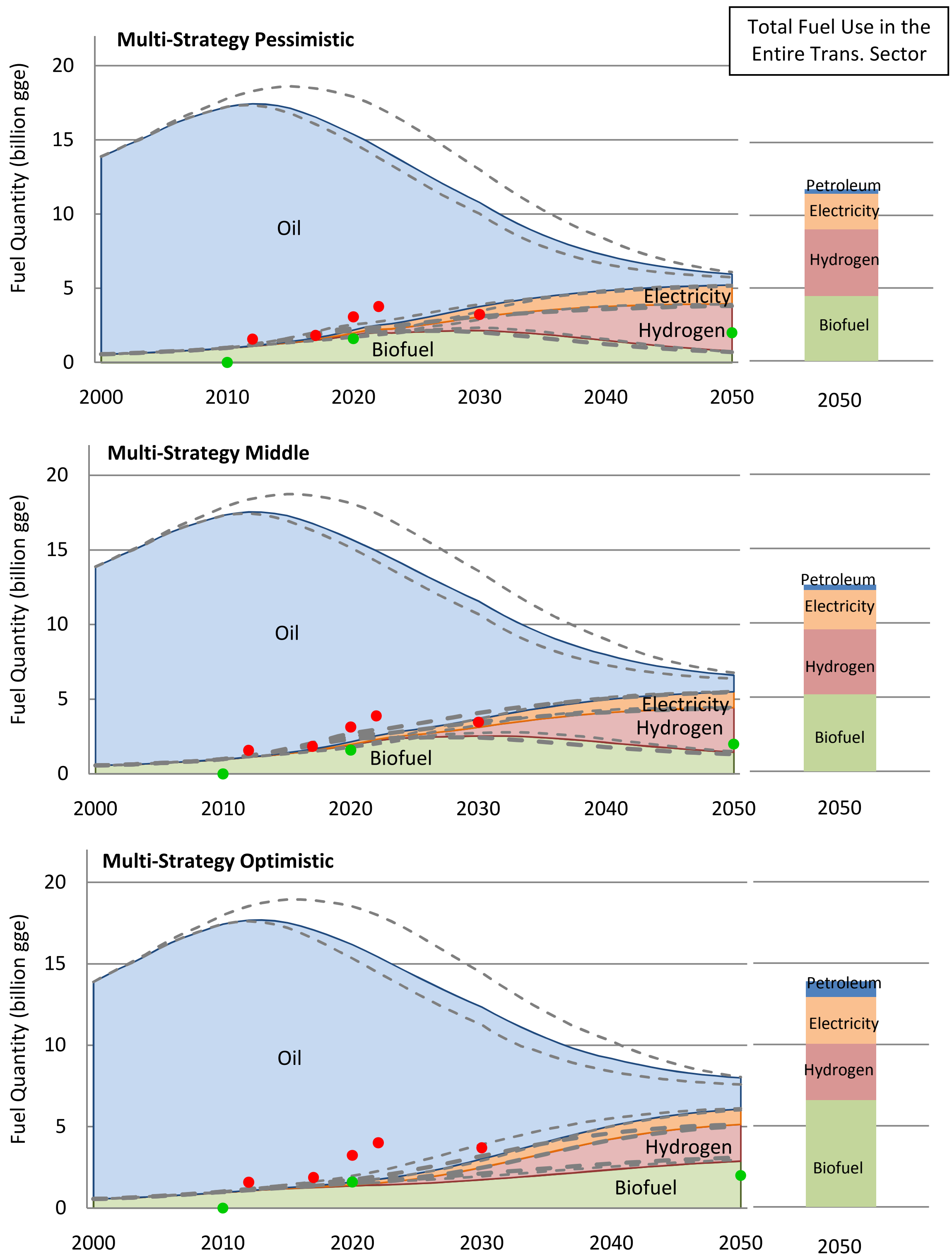
The total quantity of energy used by LDV decreases most dramatically in the *Actor-Based* scenario while the decrease is least in the *Efficient Biofuels* scenario (Figure 33). From 13.88 billion gge used for LDV in 2000 (96% from oil), the six *80in50* scenarios call for the following transitions:

- to 13.35 billion gge in 2050 in the *Efficient Biofuels* scenario (4% reduction in overall energy use from 2000; 72% supplied as biofuels);
- to 8.54 billion gge in 2050 in the *Electric-Drive* scenario (38% reduction in overall energy use from 2000; 64% supplied as hydrogen, 24% as electricity and 2% as biofuel);
- to 3.38 billion gge in 2050 in the *Actor-Based* scenario (76% reduction in overall energy use from 2000; 10% supplied as hydrogen, 47% as electricity, 5% as biofuels);
- to 11.78 billion gge in 2050 in the *Multi-Strategy$_{Pessimistic}$* scenario (15% reduction in overall energy use from 2000; 39% supplied as hydrogen, 21% as electricity, and 38% as biofuels);
- to 12.56 billion gge in 2050 in the *Multi-Strategy$_{Middle}$* scenario (10% reduction in overall energy use from 2000; 35% supplied as hydrogen, 21% as electricity, and 41% as biofuels); and
- to 13.87 billion gge in 2050 in the *Multi-Strategy$_{Optimistic}$* scenario (0% reduction in overall energy use from 2000; 25% supplied as hydrogen, 21% as electricity, and 48% as biofuels);

It is important to note that these figures quantify the energy content of transportation fuels, not the primary energy used to create them. This distinction is most salient for electricity and hydrogen.

Electricity and hydrogen become the dominant forms of energy used for LDV in the *Multi-Strategy$_{Pessimistic}$* and *Electric-Drive* scenarios while biofuels dominate in the *Efficient Biofuels* scenario and the *Actor-Based* scenario uses relatively little electricity and oil. Biofuels play a "transitional" role for LDV in the *Multi-Strategy$_{Pessimistic}$*, *Multi-Strategy$_{Middle}$*, *Actor-Based* and *Electric-Drive* scenarios because the limited quantity of low-carbon biofuel supply is used in other transportation sub-sectors (especially aviation and marine) in order to meet the *80in50* goal for the whole transportation sector. Consequently, the transitional role for biofuels in LDV in these scenarios is not in conflict with rational expansion of production capacity since overall use of biofuels in the transportation sector is increasing steadily over time. In other words, available low-carbon biofuel supply is shifted from LDV to other transportation sub-sectors like aviation and marine over time. Intermediate waypoints in the California Alternative Fuels Plan (CARB, 2007) for all alternative fuels and for biofuels are (approximately) met in early years for all six scenarios while biofuel use in the LDV sub-sector is far below goals in 2050 for all but the *Efficient Biofuels* scenario (Figure 33).[61] This finding is an example of the importance of considering the whole transportation sector in order to accurately characterize the role of the LDV sub-sector.

[61] Note, the California Alternative Fuels Plan for biofuel quantity could be met without advanced vehicle technology if a large share of conventional ICE vehicles used a higher blend of biofuel in gasoline (e.g., E20). For example, if 10 billion gge total fuel use is E16, then 1.6 billion gge biofuel would be used.


Total Fuel Use in the Entire Trans. Sector
Multi-Strategy Pessimistic
Fuel Quantity (billion gge)
20
15
10
5
0
Oil
Electricity
Hydrogen
Biofuel
2000
2010
2020
2030
2040
2050
Petroleum
Electricity
Hydrogen
Biofuel
2050
Multi-Strategy Middle
Fuel Quantity (billion gge)
20
15
10
5
0
Oil
Electricity
Hydrogen
Biofuel
2000
2010
2020
2030
2040
2050
Petroleum
Electricity
Hydrogen
Biofuel
2050
Multi-Strategy Optimistic
Fuel Quantity (billion gge)
20
15
10
5
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Electricity
Hydrogen
Biofuel
2050

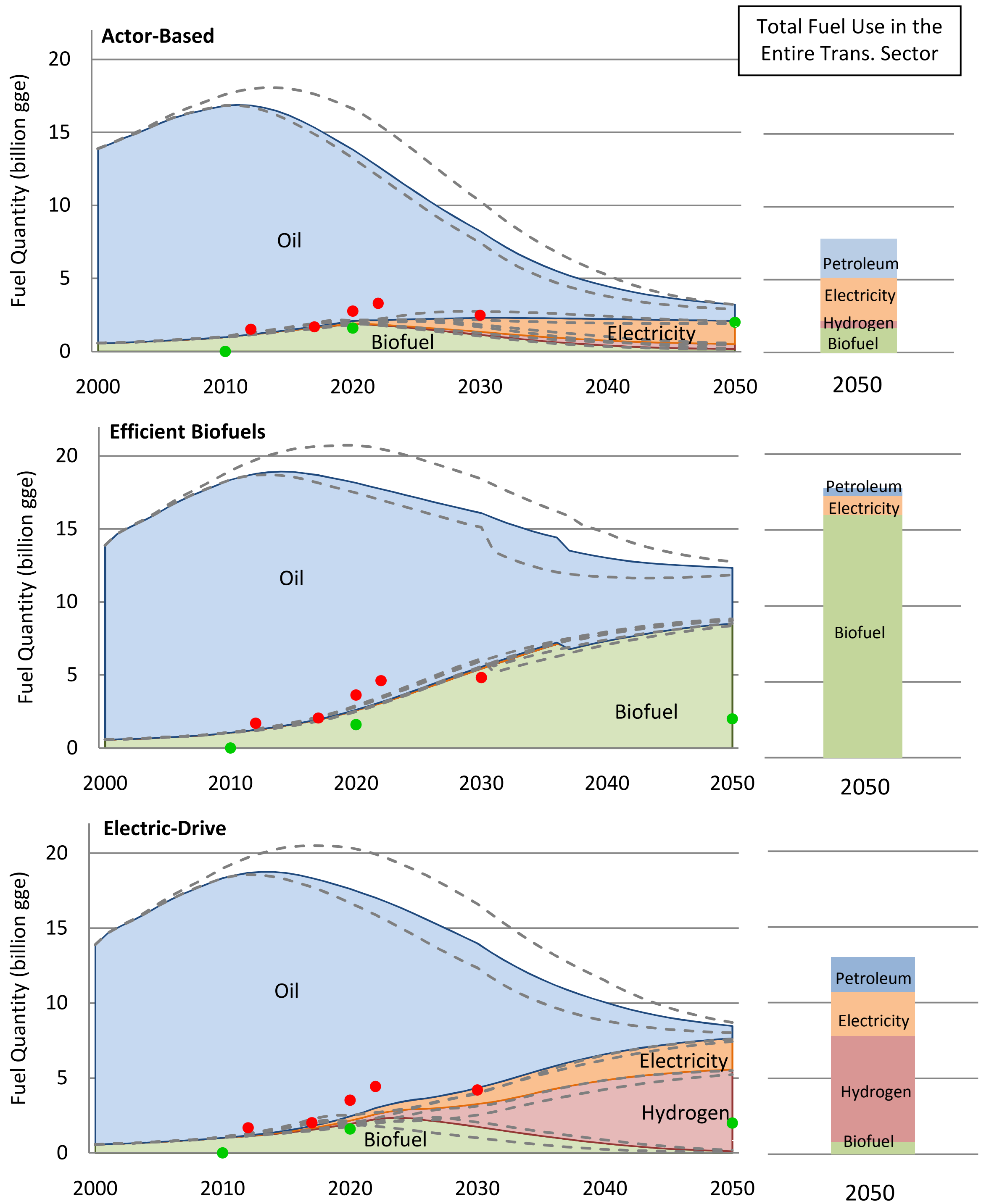

Figure 33: Total fuel quantities used for LDV from 2000 to 2050 (left) and the entire transportation sector in 2050 (right). The grey dashed lines show results for the act-early and act-late sensitivity cases while dots show policy waypoints from the California Alternative Fuels Plan (CARB, 2007) for biofuels (green) and all alternative fuels (red).

2.3.8 Comparison Across 80in50 Scenarios: Cumulative Emissions, Atmospheric GHG Concentration Stabilization Paths, and the Insurance of Acting Early

The difference in cumulative GHG emissions from LDV between the *80in50* scenarios with the lowest (*Actor-Based*) and highest (*Efficient Biofuels*) cumulative emissions is 439 MMTCe, approximately 30% variation (Table 18). Thus, to the extent policy goals are motivated by reducing cumulative GHG emissions to mitigate atmospheric concentration increases and climate change, the choice of scenario used to achieve the *80in50* goal has a relatively large effect.[62]

Furthermore, the bounding cases of the *act-early* and *act-late* scenarios provides a partial answer to the third fundamental question posited in Figure 1 (i.e., whether it matters what *path* is taken from the current transportation system to the system required in 2050 to meet the *80in50* goal). The areas under the emissions paths shown in Figure 32 are given in Table 18. Acting "late" rather than "early" produces 22% to 27% greater cumulative GHG emissions from LDV within each of the six *80in50* scenarios I modeled. Thus, even though all scenarios meet the 80% GHG reduction target for the transportation sector, the *path* taken to 2050 within each *80in50* scenario also matters for the reduction in cumulative GHG emissions that will mitigate atmospheric concentration increases and climate change.

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[62] At the moment, policy goals are based on emissions per year rather than cumulative emissions. The cumulative emissions are sometimes discussed via the proxy of "stabilization paths".

Cumulative GHG Emissions, 2010-2050 (MMTCe)	Actor-Based	Efficient Biofuels	Electric-Drive	Multi-Strategy Pessimistic	Multi-Strategy Middle	Multi-Strategy Optimistic
Main Scenario	1,079	1,518	1,503	1,288	1,332	1,413
Sensitivity Scenarios (Early/Late)	996 / 1,258	1,375 / 1,756	1,365 / 1,777	1,179 / 1,512	1,229 / 1,531	1,257 / 1,614
Change from Main Scenario	-8% / 17%	-9% / 16%	-9% / 18%	-7% / 17%	-8% / 15%	-11% / 14%

Table 18: Comparison of cumulative LDV GHG Emissions between three transition path scenarios for the period 2010 - 2050: the main PATH modeling scenario and the bounding *act-early* and *act-late* scenarios.

Since the *80in50* goal was based on stabilization of atmospheric GHG concentrations below levels at which damaging changes may occur (CalEPA, 2006), comparing the transition paths for GHG emissions from the California transportation sector to the atmospheric stabilization paths developed by the IPCC provides another useful basis for evaluating the difference between the six *80in50* scenarios I modeled (Figure 34).

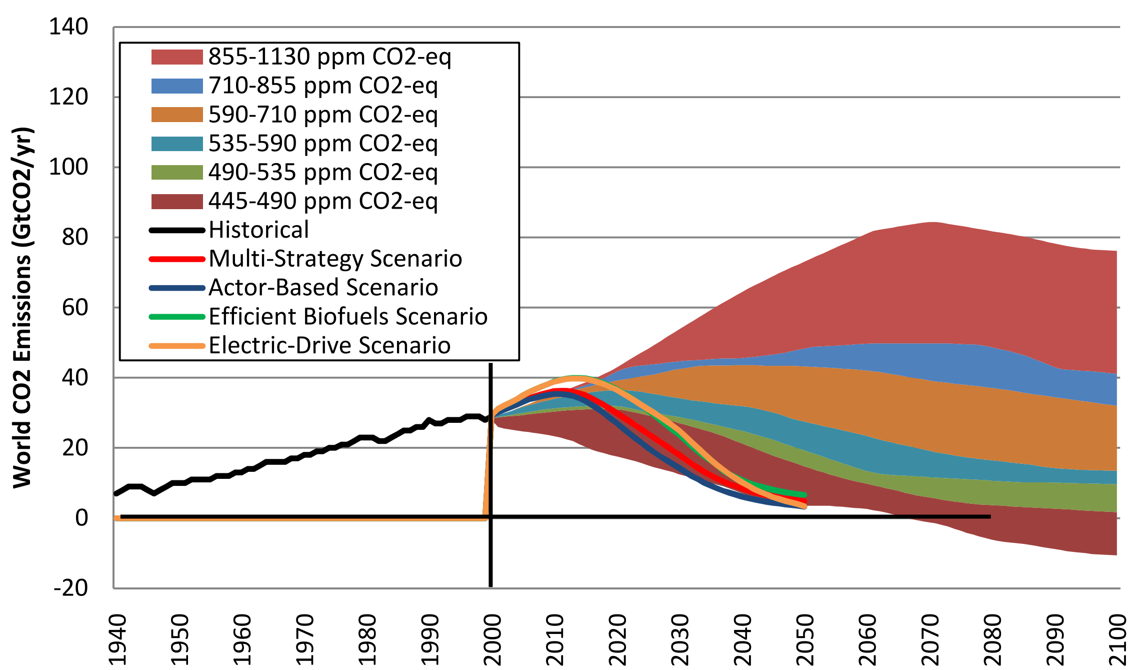


Figure 34: The *80in50 PATH* modeled GHG emissions from LDV in California are shown scaled to match World CO_2 emissions stabilization paths from the IPCC (IPCC,

2007). The modeled California LDV GHG emissions were multiplied by 180 to match the scale of world emissions. The comparison is meant to provide context for interpreting the shape of emission reduction paths for California LDV only, not to imply any similarity between California LDV emissions and global CO_2 emissions. The rate of emissions reduction in meeting the *80in50* goal for all six scenarios exceeds the range for stabilization of atmospheric GHG concentration below 450 ppm CO_2 in the near-term and is within the range in the long-term.

My focus in this report on GHG emission reductions in the LDV sub-sector of the transportation sector may not be representative of transition pathways for economy-wide GHG emission reductions. The shape of transition pathways is heavily influenced by the performance of new technologies, market penetration rates for these technologies, and the dynamics of turnover in the existing fleet/stock. Since other sectors of the economy like power generation, industrial, and residential and commercial buildings differ significantly from LDV in these dimensions, it is likely that each will follow different paths to achieving the *80in50* goal. This caveat is also true when considering other transportation sub-sectors. Since the GHG emission reduction goals established by the California Global Warming Solution Act (AB 32) and other policies are for economy-wide reductions, it is important consider the sum of sector-specific transition paths when evaluating success in meeting these goals.

There are likely to be interactions between sectors as well. For example, early action to decrease the carbon intensity of electricity will benefit the transportation sector as it diversifies in energy sources. But increasing electrification in the vehicle fleet will require greater supply of low-carbon electric generation capacity in order to meet carbon intensity and emission reduction goals for the power sector. A chicken-and-egg problem in developing new vehicle technologies and fuel supply infrastructure may also exist (e.g., for hydrogen and FCV). Consequently, actions to increase the availability of alternative fuel vehicles may stimulate development of low-carbon energy supply infrastructure and vice-versa. But lack of action in one sector is likely to inhibit action in the other. Thus, there is a need for future work in assessing interactions between transition paths across sectors of the economy.

It is also important to note that 2050 is a somewhat arbitrary date, and the differences between *80in50* scenarios in cumulative emissions from 2010-2050 is not meant to be an indication of the longer-term potential for cumulative emission reductions past 2050. It may be the case that a scenario with higher cumulative emissions for the period 2010-2050 would produce lower cumulative emissions over a longer time frame like 2010-2100 or beyond. For example, while the *Actor-Based* scenario produces the least cumulative emissions for the period 2010-2050 (1,079 MMTCe), the "upper bound" for emission reductions for all other scenarios is greater (90% below the 1990 level for *Electric Drive*, 92% for *Efficient Biofuels*, and 94-96% for *Multi-Strategy* scenarios; see section 1.5). Thus, while the specific strategies highlighted in the *Actor-Based* scenario may be better for reducing cumulative emissions over the next 40 years, the strategies highlighted in the *Multi-Strategy* scenarios may be better for reducing cumulative emissions over a longer time frame.[63] Whether one approach is favored over another may depend on whether there is a perceived crisis point in climate change that would motivate greater emphasis on emission reduction prior to that date. The likelihood that a given set of strategies will work as expected may also be an important consideration.

A third basis for comparison is provided by answering the question, "by how much could the California LDV sub-sector *miss* the *80in50* goal while still producing the same cumulative GHG emissions as the original *80in50* scenario if the *act-early* scenario

[63] Note, only the *Actor-Based* scenario meets the intermediate waypoint for GHG emission reduction by 2020.

is achieved?" The cumulative GHG emissions from the California LDV sector from 2010 to 2050 for each *80in50* scenario are given in Table 18. Depending on the scenario and parameter changed, an *act-early* scenario can produce the same cumulative emissions as the *80in50* path with as little as 60% reduction in transportation-sector GHG emissions from 1990 levels in 2050. In other words, acting "early" could enable "missing" the *80in50* target for LDV by up to 20 percentage points while maintaining the same level of cumulative emissions from 2010 to 2050 as the original *80in50* scenario (Figure 35).[64] But it is important to recognize that missing the *80in50* goal implies higher emission rates in 2051 and beyond, meaning cumulative emissions for any timeframe longer than 2010-2050 would be higher under an *act-early* scenario that misses the *80in50* goal than with an *80in50* scenario that meets the *80in50* goal.

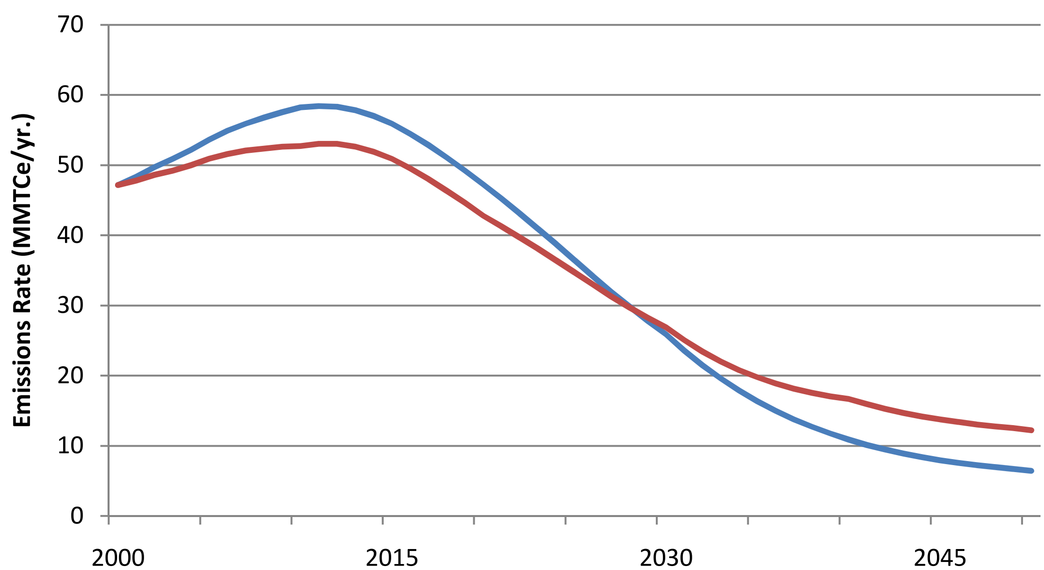


Figure 35: Hypothetical example of two GHG emission reduction transitions with equal cumulative emissions for the period 2000 to 2050 but different emissions rate in the year 2050.

[64] We compared cumulative emissions for the light-duty vehicle sub-sector while deviation from the 80in50 goal was evaluated for the whole transportation sector.

Changes to FCV and BEV performance cause more dramatic change in the GHG emission rate in 2050 than in cumulative emissions for period 2010-2050 because their impact in the fleet comes in later years. In contrast, changes to conventional gasoline vehicle performance have a larger impact on cumulative emissions than they do on achieving the *80in50* goal. For example, in the *Multi-Strategy*$_{Middle}$ scenario the fuel economy of FCV cars in 2050 could be as low as 30 mpgge[65] (less than 30% of the 104 mpgge for FCV cars in the main *Multi-Strategy*$_{Middle}$ scenario) and still produce the same cumulative emissions from 2010 to 2050 as the main *Multi-Strategy*$_{Middle}$ scenario *if* all other parameters (e.g., the rate of fuels decarbonization and efficiency improvement for other technologies) are consistent with the *act-early* case. Conversely, fuel economy for conventional gasoline vehicles in 2050 of only half what is needed in the main *Multi-Strategy*$_{Middle}$ scenario (i.e., 35 rather than 70 mpgge)[65] produces a 3% increase in cumulative emissions but just a 0.2 percentage point deviation from the *80in50* goal in the *act-early* case of this scenario.

These results suggest that acting early may increase the probability of success in mitigating climate change, if defined by cumulative emission reduction for the period 2010-2050, by allowing for the potential that some technologies or other factors do not perform as well as required for the *80in50* goal. Acting early can also allow flexibility in the market penetration rate of advanced vehicle technology. For example, under an *act-early* case, equivalent cumulative GHG emissions for the period 2010 to 2050 can be achieved with less than half of the FCV and BEV fleet shares in 2050 of the main *Multi-Strategy*$_{Middle}$ scenario (i.e., 21% and 9.8% respectively under the *act-early* case as opposed to 46% and 23% in the main scenario). But while cumulative emissions from

[65] Fuel economy is for new vehicles, on road, and is a weighted average of cars and trucks.

2010 to 2050 are equivalent, it is important to emphasize that the *80in50 goal* is not achieved with this *act-early* scenario and that equivalence in cumulative emissions for the period 2010 to 2050 does *not* imply equivalence in cumulative emissions over different time periods or equivalence in overall climate change mitigation.

2.4 Discussion

Meeting a proportionate share of California's 2020 *and* 2050 GHG emission reduction goals from the transportation sector is feasible under only one 80in50 scenario (the *Actor-Based* scenario, although the *Multi-Strategy* scenarios also come close) provided the following are accomplished:

1. Vehicle efficiency improves to 125 mpgge fleet average on-road fuel economy (82-90 mpgge in the *Multi-Strategy* scenarios) through application of all technology improvements to fuel economy (i.e., not to vehicle performance improvement) and a shift in fleet composition to 90% cars (62-65% in the *Multi-Strategy* scenarios);
2. Aggressive electrification of LDV that renders some technologies like HEV and biofuels "transitional" in the LDV sub-sector and allows supply-constrained low-carbon liquid fuels (especially biofuels) to be used in other sub-sectors;
3. Shift to lower-carbon fuels and aggressive decarbonization of all primary energy sources;
4. Decrease in LDV travel demand (VMT per capita) by approximately 50% from the business-as-usual *Reference* scenario (4,570 miles/year versus 9,220 miles/year) caused by a combination of 38% decrease in passenger miles per capita (from 15,310 in BAU) and 25% increase in average vehicle occupancy

(from 1.66 in BAU).[66] For the *Multi-Strategy* scenarios, these figures are 5-23% decrease in LDV travel demand from BAU caused by a combination of 5-15% decrease in passenger miles per capita and 0-10% increase in average vehicle occupancy from BAU.

5. Decrease in HDV truck miles per person by 35% from the business as usual *Reference* scenario (398 miles/person/year rather than 612 in BAU).[67] HDV truck miles are not reduced from BAU in any of the *Multi-Strategy* scenarios.

In other words, nearly all underlying parameters for the transportation system are pushed close to the bounds of feasibility defined in current literature in order to achieve both the 2020 *and* 2050 GHG emission reduction goals in these scenarios.

Two other scenarios, the *Efficient Biofuels* and *Electric-Drive* scenarios, meet the 2050 GHG emission reduction goal for the transportation sector but fail to meet the 2020 goal. The primary differences between these scenarios and those that do meet the 2020 goals are the following:

1. Less dramatic vehicle efficiency improvement, reaching 89 mpgge fleet average on-road for the *Electric-Drive* scenario and 59 mpgge for the *Efficient Biofuels* scenario, due to less efficient dominant vehicle technology in the *Efficient Biofuels* scenario (FFV ICE) and relatively high fleet share for light trucks/SUVs in both scenarios (40%) (Figure 29).
2. No decrease in LDV or HDV travel demand from the baseline business-as-usual case in Yang et al. (2009) (Figure 28). This is the most important reason the

[66] Some 15% (*Multi-Strategy*) to 40% (*Actor-Based*) of the decrease in LDV travel demand is accounted for in mode shift to buses and rail.

[67] Similar decreases in aviation and marine transport intensity become significant when considering overall GHG emissions, but in this paper we have focused on in-state emissions only.

Actor-Based (and *Multi-Strategy* if acting early) scenarios meet the 2020 goal while the other scenarios do not. Differences in LDV GHG emissions per mile in 2020 across the 80in50 scenarios (Figure 31) due to differences in vehicle efficiency improvement (Figure 29) and fuel decarbonization (Figure 30) are quite small. Consequently, VMT reduction is an additional action taken in the *Actor-Based* scenario that appears necessary for meeting the 2020 goal while on the path to the 2050 goal.

3. Very large quantity (16 billion gallons) of low-carbon (17.7 gCO_2e/MJ) biofuels in the *Efficient Biofuels* scenario ameliorates the need for aggressive electrification of LDV. Although a stark difference between the *Efficient Biofuels* and other scenarios, the biofuel supply does not cause a large difference in fuel carbon intensity in 2020 (Figure 30), which means it is a relatively unimportant reason the Efficient Biofuels scenario does not meet the 2020 goal, neither helping nor hurting relative to the other scenarios.

All six scenarios require aggressive decarbonization of the primary energy sources used for transportation, including through successful use of CCS across all carbon-based energy sources.

2.4.1 Timing for Transitions

Transitions in vehicle technology, energy supply, and transportation infrastructure must begin soon and progress rapidly in order to meet the *80in50* GHG emission reduction goal because fleet transition lags behind market transition and the intermediate 2010 and 2020 GHG emission reduction goals require early action.

The California Zero Emission Vehicle (ZEV) program provides one opportunity for vigorous incentives to push the transitions modeled in this dissertation. For development of this policy, it is important to recognize that some combination of FCV and BEV are required to meet the 2050 goal (although the relative shares are flexible due to approximate equivalence in emissions per mile), unless large quantities of low-carbon biofuels are available or consumer preferences for vehicle attributes change.

With sufficient quantity of sufficiently low-carbon biofuels, large numbers of FFV hybrid vehicles suffice for meeting the 80in50 goal, as portrayed in the Efficient Biofuels scenario. If consumers are willing to accept compromise in vehicle performance and size and make a dramatic shift away from light trucks and SUVs, as portrayed in the Actor-Based scenario, the need for BEV and FCV is ameliorated by lower VMT and higher fuel economy than possible through technology improvement alone. In this scenario, large numbers of PHEV suffice for meeting the 80in50 goal.

The six *80in50* scenarios modeled cover a range in future states of the transportation sector that meet the *80in50* goal, and thus a range in transition paths for meeting the goal as well. Assumptions taken from literature for feasible limits in T, E, and C factors and rates of change along with the aggressive *80in50* goal (and intermediate waypoints) constrain this range for alternative *80in50* scenarios, transition paths, and alternatives to my aggressive market competition decision rule of lower-carbon technologies displacing higher-emission alternatives at the maximum rate possible. But highly uncertain and influential parameters like low-carbon biofuel feedstock supply and processing technology, and land use planning and travel demand behavior prevent the use of a single scenario to characterize the pathway to meeting the

80in50 goal in the transportation sector. Thus, while future work should develop an objective function for optimization to identify "best" *80in50* scenarios and transition paths, the optimization will remain an approximation subject to these same highly uncertain swing factors. That is why I believe the scenario approach used in this dissertation is a valuable and necessary next step between the static modeling of 2050 by Yang et al. (2009) and an optimization model that may include economic considerations in the objective function and partial equilibrium in its dynamics.

2.4.2 The Effect of Relaxing Constraints

Relaxation of the *80in50* target or limits for underlying parameters could broaden the range of possible *80in50* scenarios quickly. For example, the range of possible scenarios for achieving 50% reduction in GHG emissions from 1990 levels by 2050 is much broader than for the *80in50* goal because there is a wider range for each parameter between the minimum level required and the maximum level feasible by 2050. Alternatively, slower than forecast population growth would reduce the rate of VMT increase, ceteris paribus, thereby reducing the need for highly efficient and low-carbon advanced vehicle technologies in the 2050 fleet and easing the required rates of penetration for these technologies in the marketplace. Or if vehicle efficiency improves more than feasible limits for 2050 (or if I made an incorrect assessment of those feasible limits), perhaps through some paradigm shift like Personal Rapid Transit that redefines the required performance characteristics for what constitutes a vehicle, then a wider range in fuel carbon intensity and travel behavior would be possible while still meeting the *80in50* goal. In other words, innovation and policy to expand the feasible limits for parameters in my modeling will improve the probability of success in achieving the *80in50* target by increasing the range of options. Further research to improve estimation of the shape of transition paths possible in related sectors (e.g., electric generation) will further narrow the range in the *act-early* and *act-late* bounds of the *80in50 PATH* modeling.[68]

2.4.3 The Effect of Fleet Turnover Rate and Vehicle Lifetime on the Scenarios

Changes in the parameters that influence stock turnover, left unmodified in my research, could relax the stringency of the *80in50* goal, thereby providing more room for alternative scenarios and transition paths. I did not modify the fleet turnover or use characteristics in the VISION model (i.e., the vehicle survivorship from year to year in the fleet and annual mileage profile by vehicle age). More rapid fleet turnover, perhaps from policy directed toward accelerated scrapping of old vehicles like the Cash for Clunkers program of 2009, would change the translation of market share into fleet share and could relax the need for the aggressive market penetration rates shown in Figure 21 - Figure 26. But the timing of such policy action is important to ensure the retired vehicles are replaced with the vehicle technology and efficiency characteristics needed to achieve the *80in50* goal. Conversely, improved vehicle quality, perhaps from more durable materials and components used in advanced vehicle designs, could increase vehicle life, reduce fleet turnover, and thereby require even more aggressive market penetration rates than shown in Figure 21 - Figure 26. The PATH model is based on historical rates of fleet turnover.

2.4.4 The Potential Effect of Paradigm Change in Personal Transportation

The feasibility limits that constrain parameters in the *80in50 LEVERS Model* assume no paradigm change in transportation. For example, I assume *all* technological

[68] In this paper, I have attempted to capture the range of such alternative transition paths in the *act-early* and *act-late* scenarios but more research is needed to accurately characterize limitations in the rate of infrastructure change in the fuel supply industries.

improvements are applied to vehicle efficiency rather than to performance as we have seen in the recent past (US EPA, 2006), but I also assume vehicle performance is maintained at current levels (except in the Actor-Based scenario). Aside from the shift in fleet composition to more cars and more aerodynamic and light weight designs, the streets of 2050 look much as they do today, with 5-seat four-wheeled vehicles of comparable size capable of accelerating 0-60mph in less than 10 seconds. Large deviations from this paradigm could allow movement of some parameters beyond the constraints I imposed.

2.4.5 Transitions in the Energy Supply System

The possible range for variation in transition paths in the energy supply mix is relatively large because we currently have less guidance for limitations on the rate of change in energy system transitions from prior research. The research from EPRI on decarbonization of electricity (EPRI, 2007a) and from the NRC on decarbonization of hydrogen (NRC, 2009) shown in Figure 20 generally consider the least-cost methods of generation and delivery during trends of buildout in these fuel supply chain infrastructures. These engineering economic approaches are the best two examples of research on the potential rate of change in energy systems and consequent supplies and carbon intensities of transportation fuels.

Furthermore, the mix in energy supply for the transportation sector is to some extent an accounting result dictated by carbon cap-and-trade policy and cost competition not included in this model. For example, consider the question of which sector gets credit for the low-carbon electrons charging PHEV and BEV, the electric generation sector or transportation sector? Also, by using life-cycle emission numbers in my modeling, I am assigning upstream emissions to the transportation sector that might otherwise be allocated to other sectors. Consequently, it is important to note that the energy source mix shown in Appendix A and fuel carbon intensity shown in Figure 20 are for the hydrogen, electricity, and biofuels *used in transportation* only. For example, the electric generation mix used in transportation is not necessarily reflective of the overall grid mix in 2050.

2.4.6 Interactions with the Electricity Sector

I assume 30% to 40% renewable-source electricity for transportation in 2050 in the six *80in50* scenarios despite the 33% RPS for California in 2020 (per Executive Orders S-14-08 and S-21-09; CPUC, 2009) because the electric generation sector is presumably using a large portion of available renewable generation to meet its own emission reduction requirements. Modeling of inter-sector competition for scarce resources is left to future partial equilibrium economic modeling and it is important to recognize that the modeling approach presented in this dissertation is not designed to perform such analysis. However, in the final chapter of this dissertation I will consider the development and investments that may be needed in the California wind industry in order to supply the level of renewable-source electricity for LDV in each 80in50 scenario.

Although I do not model the timing of PHEV and BEV charging or the source for marginal electrons, the point is simply that electrons *credited* to the transportation sector need 6.5 to 34 gCO_2e/MJ (depending on the *80in50* scenario) in order for the transportation sector to meet the *80in50* goal.

It is also important to recognize the importance of success with CCS in the energy mix I have assumed in order to achieve such low GHG intensities. Although kept within feasible bounds in my modeling (Johnson and Ogden, 2008; Johnson et al., 2008; MIT, 2007), failing to achieve 60% to 80% CCS efficacy across all carbon-based energy sources in 2050 would require further increase in the share of renewable-source energy in order to maintain fuel carbon intensity at approximately 35 gCO_2e/MJ or less across all fuels used. More work is needed to assess limitations in both CCS and renewable-source energy development in order to define transition paths in the energy sector more precisely.

As with competition for scarce resources, my scenario modeling is not designed to assess the marginal cost of additional CCS versus renewable-source energy to optimize the balance. My current modeling only allows us to say what the carbon intensity of electricity, hydrogen, and biofuels needs to be in order for the transportation sector to meet the *80in50* goal, with the specifics of how this is achieved subject to a relatively broad range of possibilities.

To the extent an alternative energy supply scenario produces different fuel carbon intensities, the vehicle mix would need to change in order to maintain compliance with the *80in50* goal. For example, lower carbon intensity for electricity and higher carbon intensity for hydrogen would imply more BEV and fewer FCV to meet the *80in50* goal.

2.4.7 Consistency in Underlying Technologies for Intermediate and Long-Term Goals

To ensure uninterrupted progress toward long-term GHG emission reduction goals, it is important to consider whether the changes in vehicle technologies used to meet intermediate goals like the 2020 emission reduction goal and LCFS are consistent with the changes in vehicle technologies for the transition paths to 2050 described in this dissertation. A smooth and uninterrupted transition path in annual GHG emissions through 2050 may obscure incompatibility in underlying technologies if, for example, a fleet comprised of hybrid FFV carries the emission reduction through 2030 with little progress in development and market penetration of the PHEV, BEV and FCV needed to meet the 2050 goal. Such discrepancy could pose a potential problem if left unresolved due to the inertia in the transportation fleet. Achieving goals for 2020 and 2030 with a fleet composition not suited for the deeper emission reductions required by 2050 may seriously inhibit the ability to achieve the 80in50 goal. Consequently, it is important for researchers and policymakers considering actions directed toward intermediate goals to consider compatibility of these actions with the long-term 80in50 goal.

In this dissertation, I have focused on the *80in50* goal and, taking it as a binding constraint, shown the implications for transition paths. Although I considered whether the paths pass through intermediate goals (e.g., 1990 level emissions by 2020, LCFS requirements) and used these waypoints as guides in some cases (e.g., RPS for electricity), my ultimate focus was always on achieving the *80in50* goal. I showed that the 2020 goal for GHG emissions is met under one *80in50* scenario but not under two others.

Similar work by Dr. Lutsey focused on meeting the 2020 GHG emission reduction and LCFS requirements is producing somewhat antithetical results to all but the *Efficient Biofuels* scenario, with fleet transition toward large numbers of biofueled HEV and low-carbon biofuels playing a much larger role in the LDV sector (Lutsey, 2009).

To meet the 2020 LCFS goal, large quantities of low-carbon biofuels are needed. But to meet the 2050 goal, especially if biofuel feedstock supply constrains the total quantity of low-carbon biofuels available in 2050, a rapid shift away from biofuels to BEV and FCV may be necessary (as in the *Multi-Strategy*$_{Pessimistic}$, *Actor-Based* and

Electric-Drive scenarios).[69] If this proves to be the case, a dilemma due to fleet inertia may emerge for reconciling a fleet in 2030 comprised of many biofueled ICE and HEV vehicles with a fleet in 2050 comprised mostly of FCV and BEV. Although the GHG emission reduction paths may match nicely, the underlying technologies in the LDV fleet may not.

2.4.8 Future Work

As discussed in the previous section, future work should consider the link between intermediate- and long-term emission reduction efforts in order to answer the question of whether the transition path to intermediate goals is on the path to the longer-term 2050 goals. Simply looking at whether transition paths in GHG emissions meet in the middle (i.e., the transition path for GHG emissions through 2020 or 2030 produced by near-term strategies matches the path for 2030 through 2050 produced by long-term strategies) is not sufficient to answer the question of whether underlying changes in vehicles and fuels are in accord. To the extent the vehicle fleet mix that meets the intermediate goals and the 2050 goal differ, transitions to the intermediate solution may actually *hinder* transitions to 2050 by introducing inertia for an "incorrect" fleet mix. The related policy question to consider is how performance-based standards (e.g., Pavley standards; CARB, 2004; CARB, 2008a) can bring about the jumps in fuel and vehicle pathways that are required to meet 2050 goals, rather than incremental changes in vehicle efficiency and fuel composition that may dead-end at maximum improvement that falls short of the *80in50* goal.

[69] Since much of the energy-dense low-carbon liquid fuels available in 2050 are needed in the aviation, marine and HDV sub-sectors in order for the whole transportation sector to meet the *80in50* goal, biofuels may play a relatively small role for LDV in 2050.

One key question for whether biofueled vehicles will be “transitional” with relatively short duration in the marketplace is whether these are distinct vehicles at all. If the goal of making gasoline-like, diesel-like and jet-like fuels that can be blended into the fuel mix is achieved, then biofuels become transitional fuels in existing conventional vehicles rather than making new cars, trucks and airplanes.

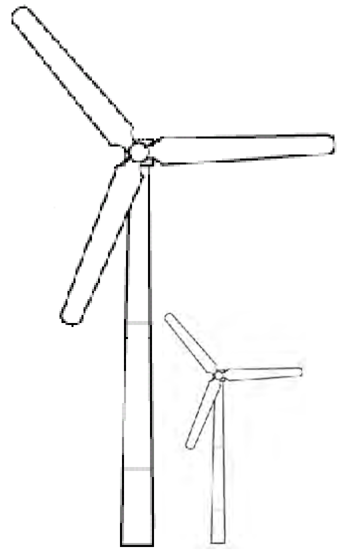
In this dissertation, I showed a range in possible *80in50* scenarios and transition paths to achieving the *80in50* goal in the transportation sector, and the implications of that range for cumulative GHG emissions between now and 2050. Since the *80in50* goal is motivated by climate change mitigation, which is a function of atmospheric GHG concentrations that result from cumulative emissions, differences in cumulative emissions may be useful for ranking *80in50* scenarios and transition path alternatives. A complete optimization may combine such rankings with other goals like minimizing transition costs into a complete objective function. Future work should endeavor to make such optimization.

I am aware of several useful extensions of this dissertation, some of which have already been mentioned in the context of relevant material. I focused on LDV because of information availability and policy interest in this sub-sector. But the modeling by Yang et al. demonstrated the importance of considering the entire transportation sector when evaluating the role that each sub-sector must plan in reducing GHG emissions. Furthermore, transition paths will likely differ between sub-sectors due to differences in market penetration rates for new technologies and turnover rate in existing equipment. Future work should consider transition path modeling for other sectors and transportation sub-sectors as well.

Since there are likely to be interactions between sectors seeking to meet economy-wide GHG emission reduction goals, future work should explicitly assess potential reinforcing and inhibiting interactions between transition paths across sectors of the economy. I have left modeling of inter-sector competition for scarce resources through partial equilibrium economic analysis to future work.

As vehicle technology diversifies, specialization of use may increase. If, for example, BEV are used for short trips in town while FCV are used for longer journeys, future work should consider developing additional vehicle categories based on the type of use in order to more accurately track the annual mileage for each vehicle technology.

Finally, since my research is entirely scenario based, I cannot comment on the likely costs associated with each 80in50 scenario transition path and have no basis for optimization to identify the "best" scenario(s) and transition path(s). Future work should develop an objective function for evaluation of alternative scenarios through such optimization. I have identified several potential factors for inclusion in the objective function that are likely to differ between 80in50 scenarios: cost, cumulative GHG emissions, and probability of success.



CHAPTER 3: REPOWERING CALIFORNIA WIND FOR ELECTRIC VEHICLES TO MEET THE 80IN50 GOAL: A SUMMARY OF POTENTIAL BENEFITS AND BARRIERS

3.1 Introduction

Having looked in the first two chapters at macro-level transitions for meeting the 80in50 goal in the transportation sector, and LDV fleet in particular, this last chapter of the dissertation is meant to be a deep dive into the micro-scale of activities and changes required to realize the aggregate transition paths. Specifically, this chapter contains an analysis of barriers and benefits to repowering and new development in the four primary resource areas of the California wind industry, which is one potential source of the low-carbon renewable source electricity needed for charging plug-in vehicles in the 80in50 scenarios.

Many approaches to the study of renewable energy potential have been undertaken by others, ranging from resource assessment (e.g., CEC, 2008) to economics (e.g., Wiser et al., 2008) to systems analysis and integration (e.g., McCarthy and Yang, 2009). These studies generally employ models to create simplified representations that offer opportunities for insight into underlying relationships. The prior research specifically on the use of wind-source electricity for plug-in vehicles has generally used aggregate-scale models to consider system impacts. Examples include a study at the National Renewable Energy Laboratory (NREL) on potential “synergisms between wind energy and plug-in hybrid electric vehicles” and a study in progress by McCarthy and Yang on integration of wind-source electricity into the California electric grid dispatch systems (Short and Denholm, 2006; see McCarthy and Yang, 2009 for modeling methods in use for the study in progress).

The study at NREL considered the potential impact of the dispatchable load and energy storage capacity in PHEV fleets on increased wind energy integration into electricity grid operations. As the authors note, “one possible solution to the problem of variable wind output is energy storage." But with expansion of pumped hydro storage beyond the 20 GW in place unlikely and other alternatives adding significantly to the cost of the electricity being stored, the "optimal solution for wind would be coupling it with a low-cost source of storage (or dispatchable load) that is perhaps already in existence for some other purpose" (Short and Denholm, 2006). A fleet of PHEV certainly fit this description. Using a framework in the WinDS model that competes wind and conventional alternatives like fossil fuels and nuclear to minimize system-wide costs of meeting electric loads, the authors assessed the impact of PHEVs on the market potential of wind power through contribution of both planning and operating-reserve capacity.[70]

The authors found that, compared to a base case model run through 2050 that did not include PHEVs (i.e., a "business as usual" scenario for the United States), the "deployment of PHEVs results in vastly increased use of wind." Specifically, cost-effective wind installations in the base case total 208 GW by 2050 while the total was

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[70] Typical planning reserves of 10-18% more than projected peak demand help ensure adequate capacity for continuous system reliability even when a generator or transmission fails or demand exceeds forecasts. Operating reserves, including generators that can be started or ramped up quickly, help respond to short-term demand fluctuations.

The WindDS model captures grid reliability requirements through constraints on planning reserves (aggregate installed capacity multiplied by a reliability factor must exceed peak demand multiplied by the peak reserve margin) and operating reserves (the system must have a certain amount of "quick-start" capacity like combustion turbines and hydroelectricity and "spinning" capacity like partly-loaded fossil or hydroelectric plants). Since the variability of wind generation precludes it from contributing fully to the reserve margins required by utilities, only a small fraction of a wind farm's nameplate capacity can usually be counted toward the planning reserve margin requirement. As more wind is integrated onto the electric grid, this "capacity credit" declines even further (especially with closely-grouped wind farms whose output is closely correlated). The variability of wind generation also tends to increase the operation reserve requirements as well.

Although provision of supply regulation reserve to the electric grid (i.e., an ancillary service to the grid in following second-by-second variations in load) can be the most valuable form of regulation service provided by PHEVs capable of vehicle-to-grid bi-directional power flows, the authors did not consider it in their modeling because they did not include the economics of PHEVs (taking a market penetration scenario as given) and because wind power does not significantly impact regulation reserve requirements.

Wind deployment in the WindDS model is constrained by a range of factors including, "environmental, land-use, and siting issues; transmission constraints; low conventional fuel costs; and the resource variability of wind." The addition of PHEVs to the model relaxed only the impact of wind-resource variability.

235 GW in their PHEV-20 case and 443 GW in their PHEV-60 case. The reserve capacity provided by the PHEV fleet allows an increase in wind development that satisfies the increased electricity demand of the PHEV fleet, with excess left over to displace coal or other electric generation sources.

The study by McCarthy and Yang uses an hourly dispatch model of the California electric grid to simulate its "response to added vehicle and fuel-related electricity demands in the near term." The authors were able to identify the mix of generation sources used to supply the incremental electricity demand from vehicles (i.e., the "marginal electricity mix") and calculate the associated greenhouse gas emissions. The authors conclude that, in the near-term, the "marginal electricity mix for vehicles… in California will come from natural gas-fired power plants, including a significant fraction (likely as much as 40%) from relatively inefficient steam- and combustion-turbine plants."[71] The study by Short and Denholm (2006) took the opposite approach of considering how much incremental wind development a fleet of PHEVs could enable (see discussion above).

Ongoing research at the University of California, Davis is using the dispatch model developed by McCarthy and Yang to look specifically at the use of renewables for plug-in electric and hydrogen fuel cell vehicles in California (personal communication, Alexander "Sandy" Allan).

My analysis in this chapter is more in line with the latter, considering the magnitude of incremental wind development necessary to supply the renewable-source electricity needs for plug-in LDV in each 80in50 scenario and the project-level benefits and barriers that might help or hinder such development. The intent for this chapter is to complement these model-based efforts with careful consideration of the *complicating*

[71] The timing of vehicle recharging can influence this result.

factors that have been assumed-away in most analyses to date. Although statistician George Box is often remembered as having proclaimed, "all models are wrong, but some are useful," the actual quote in one of his books is, "remember that all models are wrong; the practical question is how wrong do they have to be to not be useful" (Box and Draper, 1987). This chapter examines this proclamation for the case of transition dynamics in transportation energy systems.

Any model is, of necessity, a simplification of reality made with assumptions that smooth over complications. Chosen wisely, these simplifications enable insight that cannot be found by simply observing the world. These are the models that become useful. But there are also some models that are not useful, either because the model builder did not make assumptions and structure the model wisely or because the situation simply did not lend itself to modeling.

It is the latter case that I will consider for the question of future development in renewable-source electricity supply for plug-in vehicles. Are the complicating factors for wind power development that are omitted from system models – the potential benefits and barriers compiled in this chapter – influential enough for the outcome to render the model descriptions and forecasts hopelessly inaccurate? Does this situation simply not lend itself to modeling? Having modeled transitions in the transportation sector to achieve the 80in50 goal in the first two chapters of this dissertation, we now turn attention to some project-level details in one particular area of those transitions in an attempt to assess whether actual success with these transitions will depend more on local, idiosyncratic factors that defy modeling rather than the basic relationships easily coded into a model. My hope is that such analysis will add *richness* to our understanding of how the transition paths modeled in Chapter 2 may (or may not) proceed.

I begin this chapter by setting the stage with a history of the California wind industry, inventory of the existing stock of wind turbines in the four major wind resource areas that account for 99% of installed capacity (Table 19 in section 3.1.1), and discussion of modern turbine technology. The survey of the current state of knowledge regarding wind repowering in California that follows brings together individual pieces of the repowering dilemma that have been researched and documented in a new and valuable way. I am the first to compile the scattered pieces into a more complete picture of the potential barriers and benefits to repowering at the project level that are summarized in Figure 38 and Table 20 (in section 3.1.1). Doing so reveals the important insight that favorable economics are a necessary but insufficient condition for repowering and the many other factors involved are local, complex, and potentially influential to the ultimate outcome. The result of this survey is a richness of understanding at the project level for complications that could impede some of the transitions necessary in the energy sector to achieve the 80in50 goal for transportation.

I then shift the focus to consider what each of the 80in50 transition paths may imply for repowering in the California wind industry in terms of annual turbines installed, monetary investment and land area needed, and potential action needed to increase transmission capacity, decrease permitting time, and increase wind farm size and/or parcel size or decrease setback requirements in order to accomodate this growth. The chapter ends with discussion of several case studies that illustrate how the barriers and benefits have influenced individual repowering projects, and some general conclusions regarding common themes and suggestions for future research.

3.1.1 The Potential for Wind Repowering to Meet the Renewable-Source Electricity Requirements for 80in50 Scenarios

The total quantity of electricity required for LDV in the 80in50 scenarios ranges from 35,000 to 76,000 GWh/year (excluding the *Efficient Biofuels* scenario; Figure 36). The portion of this total electricity demand for transportation that is renewable-source electricity, with assumed carbon intensity of zero gCO_2e/MJ, ranges from 14,000 to 30,000 GWh/year.

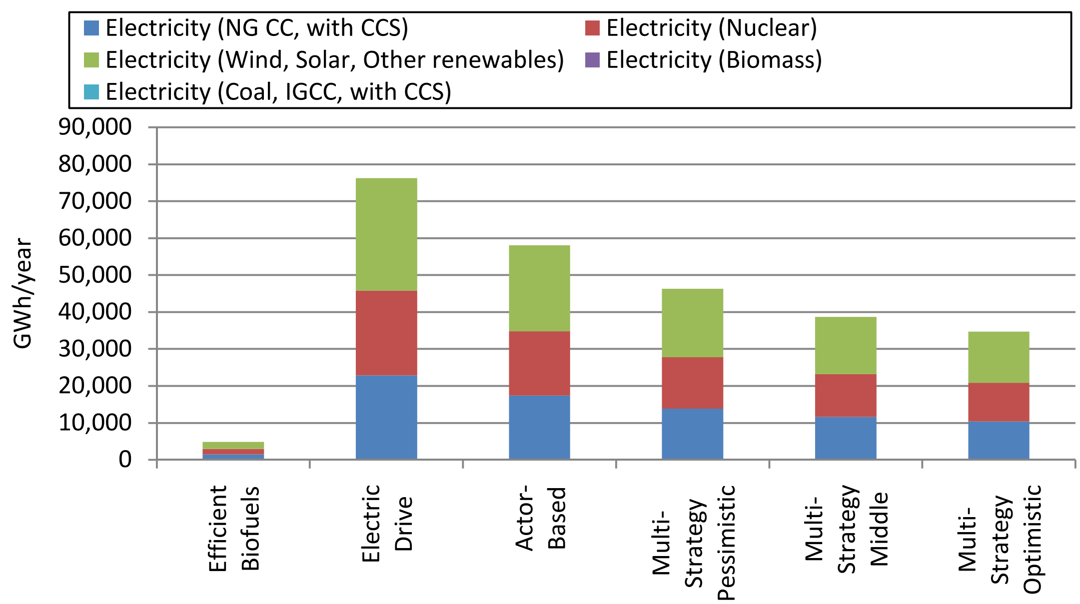

Figure 36: Electricity demand for LDV in 2050 by source for six 80in50 scenarios. The carbon intensity for each source is held constant across all scenarios: 20.2 gCO_2e/MJ for natural gas combined cycle with carbon capture and sequestration (NG CC, with CCS); 1.6 gCO_2e/MJ for nuclear; and 0.0 gCO_2e/MJ for renewable (wind, solar, other).

How will this renewable-source electricity be generated? One potential source is repowering and expansion of California's wind resource. Although there are big uncertainties for total electricity demand in California in 2050 (McCarthy et al., 2008), it is likely that more renewable-source electricity will be needed by the year 2050 to meet 33% (or higher) RPS requirements and GHG emission reduction requirements in the electric generation sector. However, it may also be a reasonable approximation to assume incremental wind-source electricity provides charging for plug-in electric vehicles while other renewables like solar, geothermal and tidal serve the electric generation sector. This is because the intermittency of wind and poor match with daily peak electricity demands (i.e., the wind blows more at night) make integration of large scale wind a challenge for electric grid operators.[72] The potential for off-peak charging and dispatchable load via energy storage afforded by plug-in LDV fleets therefore make them an attractive use of wind-source electricity (McCarthy and Yang, 2009; Short and Denholm, 2006). In contrast, incremental generation from other renewable resources like solar, hydroelectric, geothermal and tidal may be used to meet renewable portfolio standards and GHG emission reduction goals in the electric generation sector due to their better predictability and match to electricity demand profiles.

The term "repowering" in wind generation developments refers to the replacement of old, usually smaller wind turbines with new, usually larger ones.[73] There are several reasons why one might expect repowering to occur in the California wind industry.

1. California was one of the first locations for utility-scale wind development, meaning some existing equipment dates back to the early 1980s.[74] This means

[72] "Variability in wind output implies limited predictability; high natural ramp rates; and, often, limited coincidence with peak demand. These factors can restrict the ultimate penetration of wind power into traditional electric power systems" (Short and Denholm, 2006).

[73] The definition of repowering is important for contracting between power producers and utilities, where the utilities' perspective includes the additional element of maintaining existing nameplate capacity (i.e., any added capacity requires a new power purchase agreement).

[74] The California "wind rush" during which approximately half of the turbines in place today were installed (35% of current capacity) occurred in the early 1980s, a little over 20 years ago.

California is home to the first wind resources with a large inventory of aging equipment (35% of current capacity is more than 20 years old).

2. The initial development of “wind farms” in California in the 1980s was executed rapidly (i.e., a “wind rush”) due to high energy prices and government incentives.
3. This development occurred in the relatively few good wind resource areas in California located in mountain passes between the central valley and ocean (Figure 39), meaning opportunities for greenfield development are somewhat limited.[75] In fact, four primary wind resource areas account for 99% of total installed capacity and turbines in California (Table 21).
4. Wind turbine technology has also evolved over the last several decades to become larger in size and more sophisticated in technology (Appendix A). Taller towers that put the turbine in a better wind regime and variable speed turbine design and power electronics that enable capture of more of the wind resource make new turbines more productive with higher capacity factor.
5. Furthermore, wind turbines are generally designed for a useful life of approximately 20 years and, like any other machinery, experience increasing operation and maintenance cost as they age. This also contributes to better capacity factor for newer turbines.
6. Repowering may also afford the opportunity to increase nameplate capacity, if not constrained by transmission capacity or other limitations, which also increases energy production.

[75] Note, however, that one of the benefits of new, larger turbines is the ability to generate power at modest wind speeds, which mitigates the importance of these few prime locations and enables continued greenfield developments in lesser wind resource areas. Consequently, a large operator with many project sites may find it optimal to allocate a limited quantity of new turbines to greenfield developments in lesser wind resources since the higher wind speeds in prime wind resources are sufficient to keep older technology generating. A good wind resource, however, remains a fundamental pre-condition for wind development.

7. A renewable supply curve for California shows wind near the bottom as a low-cost option for meeting renewable portfolio standards (CPUC, 2008; Figure 43).

Yet much of California's valuable wind resource areas remain occupied by an aged fleet of relatively inefficient turbines. With relatively few good wind resource areas, successfully meeting state renewable portfolio standard (RPS) requirements may require repowering of existing wind developments as well as development of new windplants, solar, geothermal, and other renewable resources. Thus, it may be important to identify barriers to repowering and what changes could be made to encourage replacement of old equipment located in prime wind locations that is wearing out with new wind turbines.

Could repowering meet the needs for renewable-source electricity for use as transportation fuel in each of the 80in50 scenarios? The following three cases bound the possible answers to this question:

- If all of the approximately 1,700 MW of installed turbines from the 1980s were repowered such that nameplate capacity did *not* increase and only the capacity factor improved to 35 percent, we could expect approximately 2 GWh/year of *incremental* electricity production, or less than 0.02% of what is required in the 80in50 scenarios (Figure 37).
- The total potential increase in nameplate capacity with repowering is approximately 25 to 35 percent of the total installed capacity of 1980s turbines (SCE, 2007).[76] Data from the California Energy Commission's Wind Performance Report shows 644 MW of installed capacity that was built in the 1980s (Table 21), which would yield 691 GWh/year of incremental electricity production with

[76] Turbines installed in the 1980s are singled out because repowering of the oldest in the stock of existing turbines may be an early action on the transition path to supplying the renewable-source electricity required in order to meet the 80in50 goal in the transportation sector (see section 3.9).

35% capacity increase and 35% capacity factor. Others have estimated the total installed capacity of 1980s vintage turbines (and other turbines likely to be repowered) at 1,700 MW, which implies the potential for 425 to 595 MW of incremental capacity with repowering (SCE, 2007). In this case, up to 1,824 GWh/year of incremental electricity production could be realized.[77] This scenario for repowering with capacity increase could provide 6 to 13 percent of the incremental renewable-source electricity required for plug-in LDV charging in the 80in50 scenarios (Figure 37).

- If nameplate capacity is increased through repowering *and* expansion of wind development in the existing four primary wind resource areas (Altamont, Tehachapi, San Gorgonio and Solano), the incremental generation could be 24,700 GWh/year (RETI, 2010; Table 19). This amount of incremental generation requires a 5.75-times increase in installed capacity (from 1.86 GW to 10.70 GW) and is more than the total renewable-source electricity requirements for transportation in all but the Electric-Drive 80in50 scenarios.

Thus, in addition to investigating the conditions – both benefits and barriers – necessary for repowering to occur, an emphasis on understanding whether or not an increase in nameplate capacity (and project expansion) is likely to occur in the process is imperative for identifying actions needed to achieve the 80in50 goal.

[77] For example, if 1,700 MW of wind capacity is repowered with 35 percent increase in capacity, 595 MW of additional capacity would result. Assuming 35 percent capacity factor, this 595 MW of additional capacity would produce 1,824 GWhr per year (595 MW * 365 d/yr * 24 hr/d * 0.35 = 1,824 GWhr/yr).

	Altamont	Tehachapi	San Gorgonio	Solano
Installed Capacity in 2005 (MW)	450	750	440	220
Annual Generation in 2005 (GWh/y)	963	1,795	984	626
Potential Installed Capacity (MW)	2,624	4,394	2,790	894
Potential Annual Generation (w/o losses, GWh/y)	7,034	12,833	7,771	2,865
Potential Annual Generation (w/ losses, GWh/y)	6,683	12,192	7,382	2,721
Capital Cost ($/kW)	$ 2,451	$ 2,405	$ 2,472	$ 2,177
Incremental Generation Potential (GWh/y)	5,720	10,397	6,398	2,095
Total Incremental Generation Potential (GWh/y)				24,610

Table 19: Potential for increased capacity in the four primary wind resource areas of California. Installed capacity and annual generation in 2005 were calculated from the California Energy Commission Renewable Performance Report database; potential installed capacity and annual generation were calculated from the RETI database (RETI, 2010).

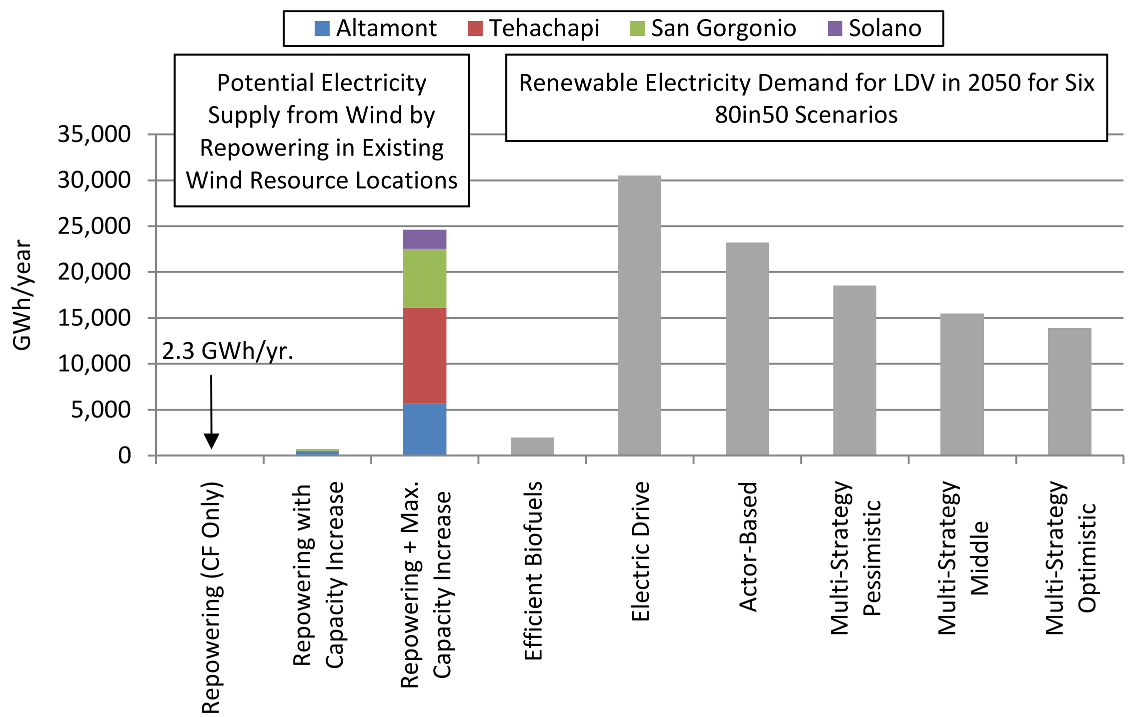

Figure 37: Renewable electricity demand for LDV in 2050 for six 80in50 scenarios (grey) and the potential incremental renewable electricity supply from wind. Three cases for incremental production are shown: with increase in capacity factor only; capacity increase with repowering of 1980s era turbines only; and with maximum capacity increase in the existing four primary wind resource areas (calculated based on data from RETI, 2010).

But investigating the questions posed above is complicated by the fact that repowering is a highly project-specific decision. *Possible* benefits from repowering and barriers to repowering are shown in Figure 38 and Table 20. Important factors include the economics of capital investment for increased energy production and capacity factor and decreased O&M costs, limitations in subsidies like the federal Production Tax Credit, stipulations in current power purchase agreements and opportunities for terms in new contracts, the availability of adequate turbine supply and transmission capacity, regulatory constraints ranging from setback requirements and zoning to concerns about aesthetics and avian mortality, and the impact of repowering on local economies through jobs and tax base. It is the balance of these considerations at the individual project level that determines whether repowering is implemented or not. Since these factors change over time, one might ask both *whether* repowering is likely to occur for a particular project now and *when* repowering is likely to occur for that project in the future.[78]

[78] The former has been addressed in a scoping-level study of the economics of repowering by Ryan Wiser of LBNL (Wiser, 2008); the latter is yet to be investigated in a rigorous way.

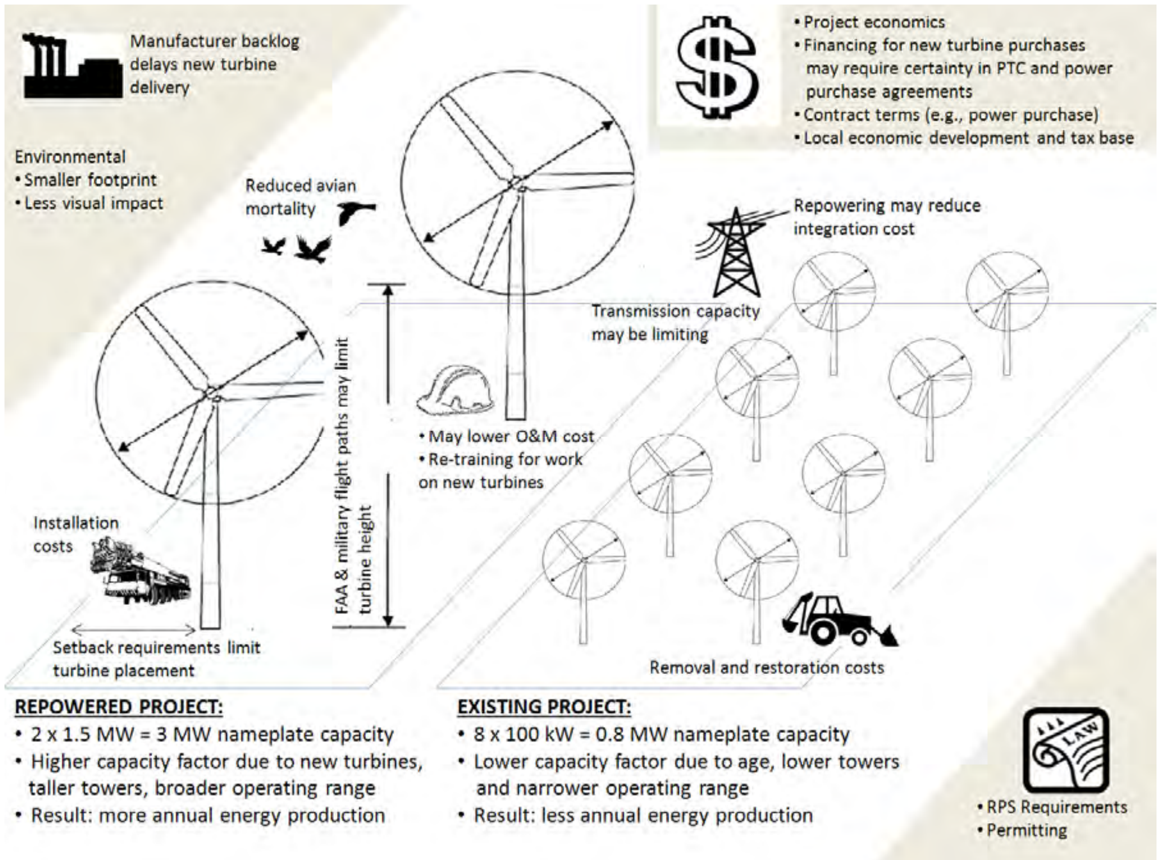

Figure 38: A hypothetical wind project is shown before (right) and after (left) repowering. Some of the potential benefits from and barriers to repowering that are discussed in this dissertation chapter are noted.

Effect	Benefit Explanation	Barrier Explanation
1. Economics (profit)	Increased power production (from effects 3 and 4) with lower operation and maintenance cost may increase profitability of wind projects if the initial capital expense of repowering is more than compensated.	Repowering requires major new capital investment while existing equipment may be fully depreciated, leading to decreased profitability if power production does not increase enough to compensate the capital investment.
2. Construction Jobs & Tax Base	Repowering requires removal of old turbines and installation of new turbines, which creates employment and increases the value of capital assets.	Retraining employees may be necessary when new equipment is installed and there may be a shortage of skilled labor.
3. Nameplate Capacity	New large turbines with higher turbines and larger swept area can collect more of the wind resource, meaning the total installed capacity on a particular site and annual energy production can increase with repowering.	The ability to increase nameplate capacity during repowering may be blunted by some combination of insufficient transmission capacity (effect 13), regulatory limits on tower height and spacing (effect 12), existing power purchase agreements that provide attractive pricing only for the current installed capacity (effect 5), limited eligibility for the PTC (effect 15), and local zoning constraints (e.g., overall MW cap in Altamont).
4. Capacity Factor	New turbines tend to have a larger rotor for a given rated power (i.e., lower specific power), thereby improving the capacity factor and annual energy production.	
5. Contract Terms	New power purchase agreements negotiated in the course of repowering may offer better contract terms, depending on the existing terms, the value placed on power quality and reliability, market conditions during contract negotiation, and other considerations.	Existing long-term power purchase agreements may provide attractive pricing only for the existing equipment or current installed capacity, blunting the benefit of reduced cost of generation with repowering by also reducing the purchase price, and blunting the potential benefit of increasing nameplate capacity with repowering. This barrier may crumble naturally over the next several years as the existing ISO4 contracts with attractive pricing terms begin to run out, forcing renegotiation.
6. Power Quality	Modern variable-speed turbines with power electronics are able to deliver dynamic VAR	Current renewable portfolio standards (RPS), power purchase agreements (PPA), and production tax credit (PTC) are on an

	support, low-voltage ride-through, and other ancillary services to help reduce line losses in the grid and improve its reliability.	energy basis (i.e., per MWh). Thus, the dominant incentive for utilities seeking to meet RPS requirements and power producers seeking PTC benefit and utility revenue is to maximize energy production.
7. Safety	New turbines may experience lower failure rate due to technical improvements and the relative youth of the equipment. The rotational speed is slower for large, modern turbines and tip speed is roughly unchanged, meaning the change in throw distance in the event of a failure is almost entirely due to change in tower height.	Although the throw distance in the event of a failure is likely not much greater for large, modern turbines, safety regulations based on ratios and multiples of turbine dimensions require much larger buffers and set-backs, which can restrict turbine placement during repowering (effect 12).
8. Avian Mortality and Environmental Impacts	Fewer new large turbines can produce the same energy as many more old small turbines, thereby reducing the probability of bird encounters. Repowering also presents for opportunity for revised turbine locations in the lee of hills where fewer raptors soar. These considerations are especially important in Altamont, where good habitat increases bird density.	Repowering does not eliminate avian mortality and continued bird deaths have become a barrier to repowering in sensitive areas, especially for projects increasing installed capacity. Furthermore, repowering projects require the preparation of environmental impact review (EIR) or environmental impact statement (EIS) studies, which can be complex and costly.
9. O&M Cost	New equipment in general will have lower maintenance cost than old equipment; new turbines have also been designed to minimize operation and maintenance costs.	New turbine technology has had less time in the field and, consequently, there is less information with which to assess expected performance and O&M costs. The typical response to this uncertainty is the purchase of manufacturer warranties. New equipment may also require investment in personnel training.
10. Aesthetic Concerns	Modern large turbines rotate more slowly and produce less noise, which may make them less aesthetically displeasing.	Modern large turbines are taller, which may make them more visible from some vantage points.
11. Lighting		Taller turbines require aviation safety lights making them more visible and , depending on the site, aesthetically less pleasing.
12. Use of Existing	Unlike greenfield development, repowering occurs on existing sites, where access roads and	Much existing infrastructure cannot be re-used due to changes in turbine locations (in the case of roads) and turbine requirements

Infra-structure	other infrastructure may be re-used, reducing the cost per kW of installed capacity.	(in the case of substation and transmission infrastructure), and permitting requirements.
13. Setbacks, Building Codes, Zoning		Turbine height may be constrained by Federal Aviation Administration restrictions and military flight patterns, which limits the ability to increase energy production by capturing the higher-quality wind resource found further from the ground. Local building codes and setback requirements can impose restrictions on tower location that lead to less installed capacity rather than more when repowering with large modern turbines. Finally, the length of time and cost required for obtaining permits necessary for repowering can be large.
14. Trans-mission Capacity	The improvement in capacity factor for modern turbines (effect 4) can improve the utilization of associated transmission infrastructure especially if loaded with high wind share.	Inadequate transmission capacity can constrain the ability to increase installed capacity during a repowering project, which severely constrains the potential benefit of increased energy production (effect 3).
15. Turbine Supply	Repowering increases sales for turbine manufacturers, thereby increasing employment and resources available for continued design improvement.	Global demand for modern wind turbines exceeds supply, with lag time between order and delivery on the order of two years. Reasons for this market disequilibrium include recent increases in the price of other energy sources, renewable portfolio standards and other demand pull, and instability in the turbine market caused by changing public policy incentives.
16. Federal Production Tax Credit (PTC)	The federal PTC helps defray the capital cost barrier to repowering (effect 1) by providing a tax credit of 1.9 cents per kWh.	The PTC was scheduled to expire in 1999, 2001, 2003, 2005, 2007, 2008, and 2009. Renewal of the PTC for relatively short periods has introduced uncertainty in future benefits that causes the wind industry to freeze development plans every few years until the PTC is renewed. Such fluctuation introduces inefficiency at every level of the industry.

Table 20: The possible benefits from and barriers to repowering that are discussed in this dissertation chapter (also shown in Figure 38). Many potential benefits can also be barriers to repowering, which illustrates the project-specific nature of repowering decisions.

3.2 The California Wind Resource

Four primary wind resource areas account for 99 percent of total installed capacity and turbines in California. These are the Altamont Pass (eastern Alameda and Contra Costa Counties), Tehachapi Pass (Kern County), San Gorgonio Pass (Riverside County), and Solano (Solano County) areas (Figure 39).

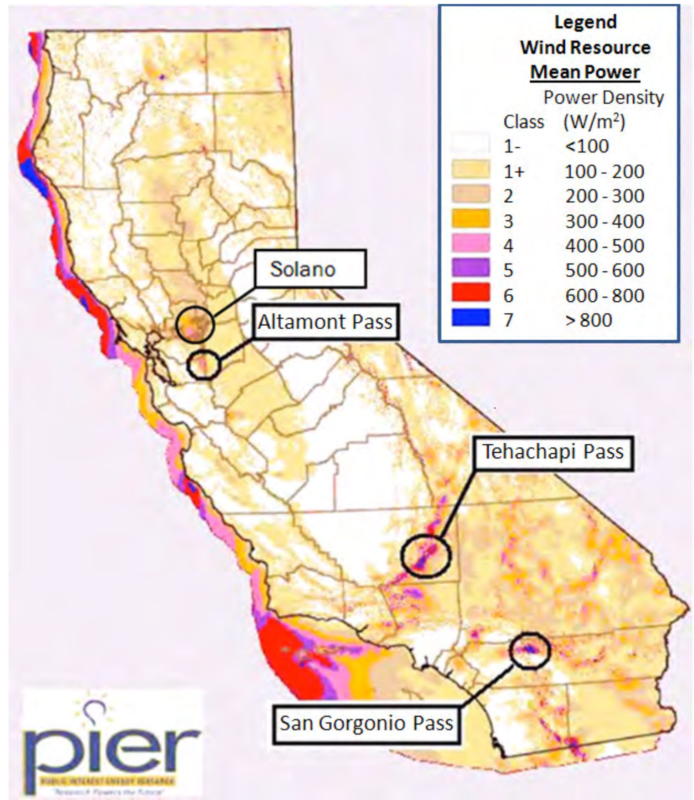

Figure 39: Major wind developments in California, distributed based on resource, demand, and transmission infrastructure (CEC, 2008)

3.3 The California Wind Industry

Nearly all of the wind capacity installed during the "wind rush" of the 1980s was located in Altamont, Tehachapi and San Gorgonio passes because of their high quality wind resources and proximity to load centers and extant under-utilized high voltage transmission lines (Behnke and Erdman, 2006).[79] Altamont hosts a lesser wind resource but its proximity to the PG&E substation for bulk power transmission minimized transmission

[79] "Additional wind projects, accounting for less than 1% of total state capacity, were installed in Pacheco Pass, southern Solano County and eastern San Diego County…" (Behnke and Erdman, 2006). We do not consider the Pacheco Pass, Cochella Valley, or Boulevard wind resource areas in this report since they are relatively recent developments and thus less relevant for current repowering decisions.

interconnection costs for wind developers; Tehachapi hosts some of the best winds but was initially hampered by its longer distance from market and weaker transmission infrastructure. Solano County was developed after the other three due to a lesser wind resource and relative distance from major load centers. Major extant under-utilized transmission capacity enabled delivery of power to market and Kennetech machines with variable-pitch blades enabled adequate power production from the lesser wind resource.

There are similarities and differences among the four major wind areas in California (Table 21). To illustrate the evolution of wind development and differences in conditions between these four areas, the following paragraphs describe snap-shots of what a "typical" wind development might look like.

	Altamont	Tehachapi	San Gorgonio	Solano
Projects	18	78	60	3
Turbines	4,490	3,700	2,700	630
Installed Capacity (MW)	450	750	440	220
Energy Production (MWh)	963,000	1,795,000	984,000	626,000
Avg. Turbine Size (kW)	100	200	160	350
Avg. Turbine Age (yrs. in 2005)	15	11	14	13
Avg. Capacity Age (yrs. in 2005)*	15	8	10	6
Avg. Capacity Factor	24.3%	27.2%	25.7%	32.1%
Percentages for turbines installed in the 1980s				
Turbines	85%	33%	54%	5%
Installed Capacity (MW)	84%	14%	34%	5%
Avg. Capacity Factor	19.6%	17.7%	22.7%	N/A

Table 21: Summary statistics for the four primary wind areas in California (approximate, year-end 2005, calculated from the California Energy Commission Wind Performance Report database). *Average capacity age is calculated as the turbine age weighted by nameplate capacity.

3.3.1 The Rush is On!

The California "wind rush" of the early 1980s is on, motivated by economic and regulatory incentives: fossil fuel prices have been high and are expected to stay high, federal and state investment and energy tax credits sum to nearly 50 percent, the Public Utility Regulatory Policy Act (PURPA, passed in 1978) requires regulated utilities to purchase electricity from Qualifying Facilities (QF) at avoided cost (interpreted as the high forecasted fossil fuel costs), and California has mandated Interim Standard Offer 4 (ISO4) contracts with 10 years of fixed above-market power purchase rates.[80,81] In response to mechanical and structural failures in megawatt-sized prototypes of the time, developers are installing projects using 50 to 300 kW turbines (Behnke and Erdman, 2006; Gipe, 1995). By the time the rush subsides, over 17,000 wind turbines with a total capacity of over 1,600 MW have been installed and the "wind farm" concept is widely accepted.[82]

The economic incentives provided by the confluence of global energy markets and national and state policies in the early 1980s succeed in causing a dramatic increase in wind development in California. But with the boom came some problems. The early tax credits were not based on energy production and, as such, were not subject to long-term equipment performance. They also provided greater than 100% cash-on-cash benefits in some cases. The result was little concern for actual power production and sometimes

[80] The information in this paragraph was adapted from Behnke and Erdman's (2006) wonderfully concise history of the California wind rush.

[81] There were four types of standard offer contracts, known as SO1, SO2, SO3, and ISO4. The SO1 and SO3 contracts paid for energy on an as-available basis at short run avoided cost and current shortage cost as-delivery avoided costs. The SO2 and ISO4 contracts paid fixed energy price for 10 years and forecasted firm and as-available capacity costs. For further discussion, see Redlinger et al. (2002).

[82] 1600 MW nameplate capacity from 17,000 turbines implies approximately 100 kW average size.

hasty design and installation of wind equipment.[83] Although repowering has since replaced some of the worst-performing initial wind-rush turbines, many remain despite dramatic improvements in technology over the intervening two decades (Table 23).

3.3.2 The Year 1988

It is six years after the first ISO4 contracts took effect and over 90 percent of the world's wind capacity is installed in California (Behnke and Erdman, 2005). Altamont, San Gorgonio, and Tehachapi passes are the centers of the universe for the wind industry. But the "phasing out of tax credits between 1984 and 1986 and the prohibition on new ISO4 contracts in 1988" has brought an end to the wind rush (ibid). Relatively little new wind project development is underway. Variable-speed turbines have not been invented yet and the variable-pitch Kenetech 56-100 (100 kW nameplate capacity, 56 foot rotor diameter) is the "typical" machine. The federal and state investment tax credits that started in the 1970s expired at the end of 1985, but were replaced in 1992 by the federal production tax credit (PTC) which provides a credit based on energy production (i.e., cents per kWh generated). There are no renewable portfolio standards but PURPA still requires utilities to purchase power from independent power producers.

3.3.3 The Turn of the Century

As the 20th century came to a close, the future of the PTC and, by extension the US wind industry, became uncertain. Beginning in 1999, the PTC expired three times and was extended five times, each time for relatively short periods (i.e., 1-2 years) (Table 22). This uncertainty led to volatility in the wind industry, with dramatic swings in turbine

[83] Consultant Bob Lynette estimated there were approximately 1,000 machines in California that were "so poorly designed or manufactured that they were unsalvageable." Paul Gipe estimated that in 1997 the number was more like 3,000 turbines comprising 230 MW (Gipe, 1997).

production and project installation caused by PTC extensions and impending lapses. The PTC law was also changed in 1999 to deny production tax credits to repowered wind facilities under existing contracts unless the power purchase agreement with the purchasing utility was changed to specify that the additional power from a repowered project would be priced at short-run avoided cost.[84] The provision, contained in Section 45.(d)(7)(B) of the Internal Revenue Code and known as the "California Fix," slowed repowering for several years because short-run avoided cost was significantly less than under existing contract terms and proved unattractive. The California Wind Energy Association (CWEA) has estimated that 245 MW was repowered prior to 1999 while only 23 MW were repowered between 1999 and 2003.

[84] In general, avoided cost is the marginal cost of energy acquired through alternative means. Short run avoided cost in this case refers to the avoided cost of energy acquisition and ongoing expenses for the electricity generation replaced by wind-source electricity; it does not include long-term capital costs for facilities and infrastructure upgrades. However, avoided cost in California is set through administrative rulemaking rather than by a market, where "total avoided cost" is defined as the "total cost avoided to society through reduction in energy demand, which can be either electricity or gas." (CPUC, 2005)

Legislation	Date Enacted	PTC Eligibility Window	Effective Duration*	Wind Capacity Built in PTC Window (MW)
Section 1914, Energy Policy Act of 1992 (P.L. 102-486)	10/24/92	1994 – 6/1999	80 months	894
Section 507, Ticket to Work and Work Incentives Improvement Act of 1999 (P.L. 106-170)	12/19/99	7/1999 - 2001	24 months	1,764
Section 603, Job Creation and Worker Assistance Act (P.L. 107-147)	03/09/02	2002 - 2003	22 months	2,078
Section 313, The Working Families Tax Relief Act (P.L. 108-311)	10/04/04	2004 - 2005	15 months	2,796
Section 1301, Energy Policy Act of 2005 (P.L. 109-58)	08/08/05	2006 - 2007	24 months	5,454**
Section 201, Tax Relief and Health Care Act of 2006 (P.L. 109-432)	12/20/06	2008	12 months	3,000***
Emergency Economic Stabilization Act of 2008 (P.L. 110-343)	10/3/08	2009	12 months	TBD

Table 22: History of the PTC and related development activity (Wiser, 2007). Caveats noted in the table include the following: *considering lapses; **5,454 MW based on 2,454 MW installed in 2006, and AWEA projection of 3,000 MW to be installed in 2007; ***Estimate assuming AWEA's 3,000 MW 2007 projection holds throughout 2008.

3.3.4 Present Day

The United States now has nearly 20,000 MW nameplate wind capacity installed, with 2,484 MW in California (approximately 600 MW in Altamont, 1,000 MW in Tehachapi, 590 MW in San Gorgonio, and 300 MW in Solano) (Figure 40). By the end of 2007, approximately 340-365 MW of California wind projects had been repowered (Wiser et al., 2008).[85] This amounts to 20 percent of the "market potential" of 1,640 MW

[85] Wiser et al. estimated 365 MW of repowered projects based on the California Energy Commission Wind Performance Report database, updated to include repowering contracts signed under the California RPS. The California Wind Energy Association estimated 340 MW.

of existing installed capacity (ibid).[86] The bulk of this chapter is devoted to investigating why repowering has not been more extensive.

The California wind industry is characterized by variable speed turbine technology with power electronics and large turbine sizes that enable production from lesser wind resources and offer additional benefits (e.g., in power quality). Uncertainty in the PTC has caused a periodicity to wind investments and instability and disequilibrium in the supply of turbines. Pressure from RPS requirements is continuing to motivate development and 20-year ISO4 contracts are beginning to expire. Rapid global wind development has rendered the California market just one piece of the puzzle for turbine manufacturers, project financers, and developers. The poorest performing of turbines from the original 1980s wind rush have been removed from the landscape, but other 20-year-old machines are still producing power, making the landscape a mixture of small and large turbines, grouped by project boundaries. Nearly 12,000 "first generation" turbines are still in place in the four primary wind areas in California (Table 23). This stock of old equipment implies an opportunity for repowering that, for some reason, has not yet been acted upon. The economics of repowering, however, suggests that project owners may find it more profitable to continue operating this equipment rather than repower (see section 3.5).[87]

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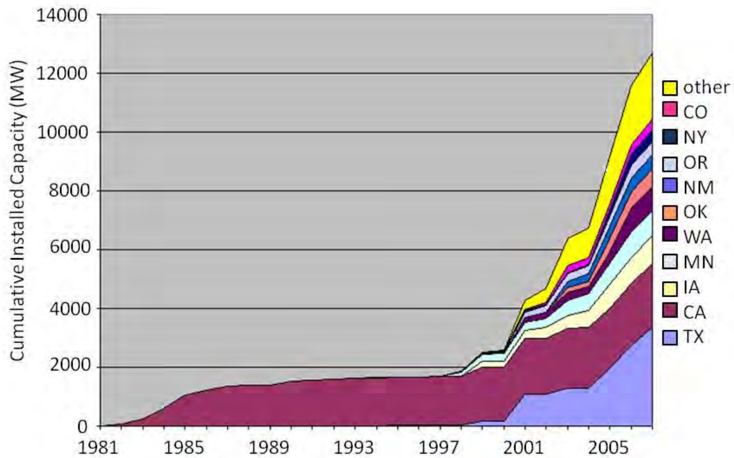
[86] Wiser et al. defined the repowering market potential as the total capacity of projects more than 13 years old (i.e., constructed prior to 1995).

[87] Turbine counts, however, can be misleading since modern machines tend to be much larger and, consequently, repowering projects tend to reduce the number of turbines even when increasing the installed capacity. Based on total power production, the share of "old" turbines in California wind energy is smaller (30 percent). Another way to quantify the ratio of "old" equipment to new in the California wind industry is to consider the relative wind resource occupied by each type of equipment. A crude measure of this (that inherently assumes parity in wind resource quality) is the land area occupied. Assuming standard spacing for each turbine type, one can estimate the total area occupied by multiplying the spacing by the turbine count, which yields an estimate of the percent of the available wind resource occupied by old turbines.



State	Capacity
Texas	5605
California	2484
Iowa	1375
Minnesota	1366
Washington	1289
Colorado	1067
Oregon	964
Illinois	736
New York	707
Oklahoma	689
New Mexico	496
Wyoming	349
Kansas	465
N. Dakota	345
Wisconsin	327
Pennsylvania	294

Figure 40: History of installed wind generation capacity in the United States (MW), cumulative and current (AWEA, 2008).

Model	Nat.	Orient.	No. Blades	Rotor Diam. (m)	Nameplate Capacity (kW)	Early First Generation Turbines Operating (few), Standing, or down			
						Est. No. Units		Est. Capacity (MW)	
						1997	2005*	1997	2005*
Bouma	NL	u, a, m	3	20	200	3	0	0.5	0
Carter	US	d, p	2	23	250-300	11	0	2.8	0
Carter	US	d, p	2	10	25	99	0	2.5	0
Century	US	u, a, tv	3	12	75-100	0	0	0	0
ESI 54	US	d, p	2	16	50-80	0	0	0	0
ESI 80	US	d, p	2	24	250-300	20	0	5.5	0
Fayette	US	d, p	3	10-11	75-95	400	0	25	0
Jacobs	US	u, a, tv	3	8-9	18-20	204	0	3.8	0
Polenko	NL	u, a, m	3	19.6	100	12	0	1.2	0
Storm Master	US	d, p	3	12	40	10	14	0.4	0.6
Wenco	CH	u, a, m	2		100	0	0	0	0
Windshark	US	d, p	2	16.4	80-90	200	0	12	0
Windtech	US	d, p	2	15.8	75-80	0	0	0	0
					Total:	959	14	53.6	0.6
						Later First Generation Turbines Operating or Still in Service			
						Est. No. Units		Est. Capacity (MW)	
						1994	2005*	1994	2005*
Aeroman	D	u, a, m	2	12.5	40	283	46	11	2
Enertech	US	d, p	3	13.5	40-60	469	144	19	6
Bonus	DK	u, a, m	3	15-16	65-100	838	403	82	32
Micon	DK	u, a, m	3	15-16	65-75	1494	166	134	16
Nordtank	DK	u, a, m	3	15-16	60-75	987	646	81	51
Oak Creek	DK	u, a, m	3	15-17	60-75	312	0	21	0
Vestas	DK	u, a, m	3	15-17	65-90	2628	1783	295	144
Wincon	DK	u, a, m	3	15-16	65	199	122	21	13
WindMaster	B	u, a, m	3	23-25	200-250	161	0	35	0
Windmatic	DK	u, a, m	3	14-17	65-95	176	139	14	11
USW 56-100	US	d, p	3	17.6	100	4236	0	424	0
					Total:	11,783	3,449	1,136	275

Table 23: Estimated number of “early first generation turbines” and “later first generation turbines” in 1994, 1997, and 2005 in California (sources: Paul Gipe, 1997 and CEC WPR Data). Orientation: u=upwind, d=downwind, p=passive, a=active, m=mechanical, tv=tailvane. *approximate, calculated from the California Energy Commission Wind Performance Report database.

3.4 Modern Turbine Technology

Machines capable of variable speed operation, with power electronics, have become the standard in modern turbine design (Christenson, 2006).[88] This ability confers several benefits (Figure 41). Dynamic VAR control (i.e., the ability to control voltage at the point of common interconnection) means wind turbines can keep voltage steady or even boost voltage on a weak grid.[89] The power electronics in variable speed turbines mean that even without wind, modern turbines can provide reactive power to the grid, and the level of reactive power stays constant as turbines come online. Thus, wind turbines now provide voltage support and regulation to the grid at all times, even without active power generation, and the adverse voltage impact caused by older turbines tripping offline is greatly reduced or eliminated (Christenson, 2006). Turbine power output can be automatically adjusted to compensate for frequency changes and avoid voltage effects.[90]

[88] Power electronics are used in modern wind turbine designs to adjust the load for the following reasons: 1) to maintain optimum slip in variable wind conditions; 2) to allow variable speed generator operation in order to maintain optimum tip speed ratio (i.e., the ratio of tip speed to wind speed), and thus maximize power production, in the presence of variable/gusty winds; 3) to enable low-voltage ride through (i.e., continued operation during transient drops in line voltage); 4) and for power factor compensation and harmonic content control (i.e., power quality in AC circuits). The result is more efficient conversion of wind energy to electricity. Slip is the difference between generator speed (rpm) and synchronous speed (e.g., 1800 rpm is necessary to make 60 Hz AC with a synchronous generator).

[89] The variable-speed architecture enables VAR support with any "arbitrary leading or lagging power factor as long as the current capacity of the inverter is not exceeded" (Behnke and Erdman, 2006).

[90] For example, a 2 percent frequency increase (Hz) is compensated by 50 percent reduction in wind farm power (kW). Conversely, a 4 percent frequency reduction (Hz) is compensated by a 10 percent power increase (kW). Duration of the frequency disruption might be up to one minute.

Modern turbines have also been designed with low-voltage ride through capability (approaching zero-voltage ride through), meaning the turbines no longer need to shut down to protect themselves during transient dips in grid voltage typically caused by unforeseen events (e.g., a tree knocks down power lines). This ability improves grid performance and reduces wear and tear on the turbine from grid-related emergency shut-downs.

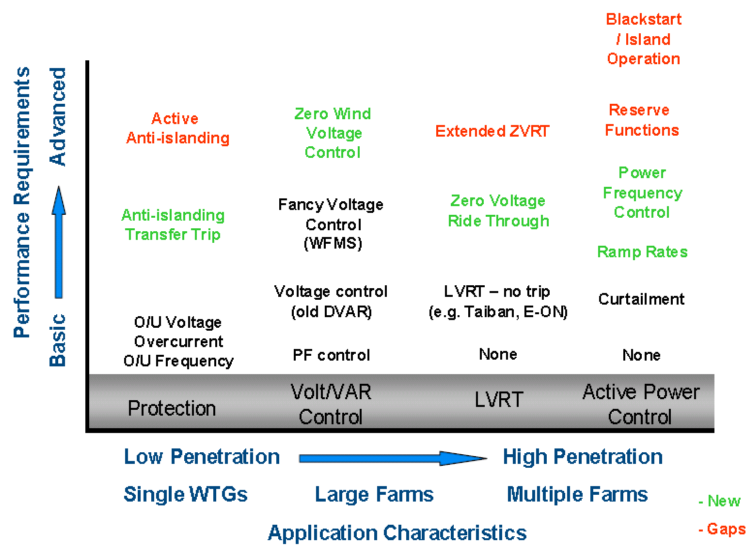


Figure 41: Performance characteristics of modern wind turbines (Christenson, 2006). Black text indicates turbines in operation, green text indicates turbines now being installed, and red text indicates challenges not yet addressed in turbine design.

For land-based turbines, 1.5 to 3.0 MW has become the industry standard, with 80 to 100 meter towers, 98 percent availability and capacity factor around 40 percent (Christenson, 2006). Some manufacturers are developing larger turbines, but logistical difficulties (e.g., bridge height constraints for the many oversize transport trucks required to deliver one turbine) confine these primarily to offshore applications.

New wind developments (less for repowered projects) are large and with 200 MW or more coming on line, “grid-friendly” wind technology must “do its part” to support the grid (Christenson, 2006).

Wind projects can be managed with power ramp rate control to behave more like conventional thermal power plants if the value to system operators of the ability to ramp power production is high enough.[91] To accomplish this power management, the wind plant is curtailed below nameplate capacity with a control system to ramp production up or down as needed by the system operator. The variability of wind power is reduced, meaning wind power can be predictable and planned, but this comes at a cost in capacity factor (i.e., total annual energy production is less than it would be without power ramp control) unless combined with on-site energy storage (e.g., battery, hydrogen, ammonia, pumped hydro, compressed air, desalinating water).[92] For wind plant startup and shutdown, power ramp rate control can regulate the rate at which power comes online or offline.[93]

Thus, modern wind turbine technology offers benefits for grid operation at all three relevant time scales. For spinning reserves, day-ahead scheduling accomplished with multi-day forecasting can enable planning for supplemental generation as needed. Load following at the five-minute dispatch scale can be accomplished with active power management, maybe combined with onsite storage. Frequency and tie-line regulation is accomplished with turbine level active and reactive power controls.

These features of modern wind turbine technology enable higher wind penetration without adverse effects on the grid, and also may increase the value proposition for wind power. If this value is *rewarded* in higher power purchase price for wind electricity generated

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[91] The ability to control power production from a portion of generation assets online, increasing and decreasing as necessary to match demand in near real-time, is important for grid operating stability.
[92] Although RPS PPAs include sale of ancillary services to the utility, the utilities do not currently envision a right to dispatch or physically control the units.
[93] Improving ability to forecast speed and turbine availability enables modeling future power production, which enhances the ability to plan for wind power production and supplemental generation if needed (e.g., with hydro, gas turbines) rather than simply taking variable production as it comes.

with modern turbine technology, it could add impetus for repowering. Alternatively, regulations making these features *requirements* might also encourage repowering.

Improving both reliability and serviceability to reduce operating and maintenance costs have also been primary objectives in new turbine development. Reliability is measured in failure rates and serviceability is measured in downtime (Figure 42). Together, these two factors interact to determine the weak links in turbine design. Turbine system engineering has produced a roughly inverse relationship between failure frequency and down time per failure (i.e., higher frequency failures tend to be more quickly and inexpensively fixed), although there is still room for improvement (Figure 42).[94]

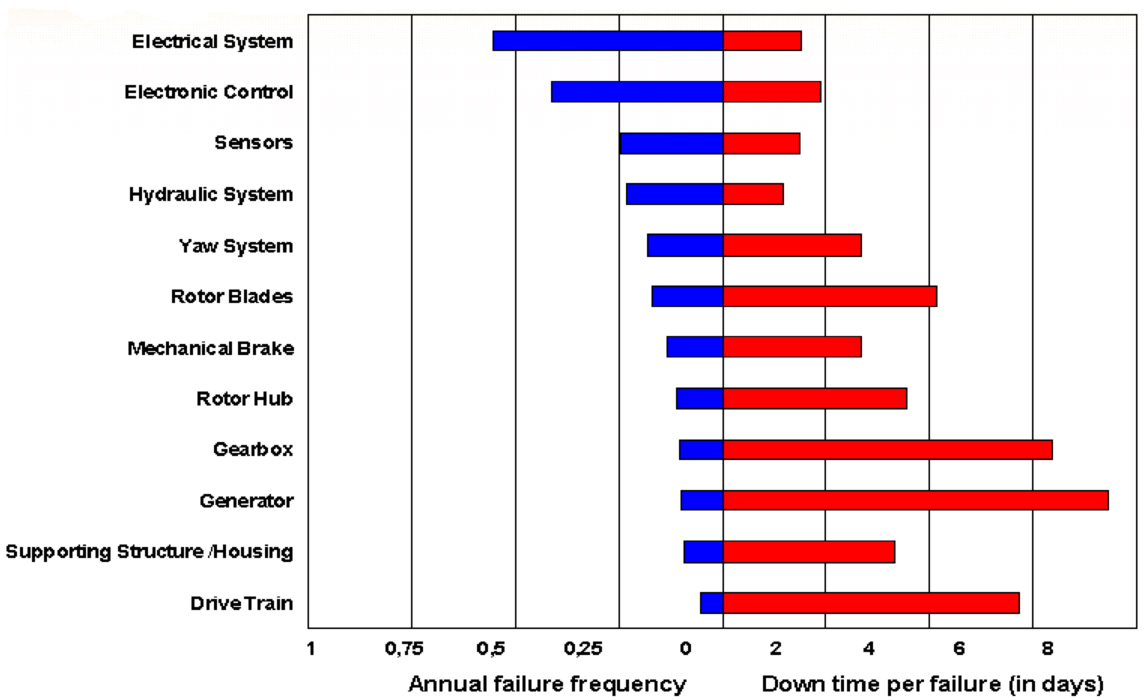

Figure 42: Failure rates and downtimes by turbine system component (Hill, 2006).

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[94] Gearboxes have historically been a weak point in turbine design and continue to be so as turbines have grown in size. One approach to this challenge designed by Clipper is to split the load from the turbine into four generators (the Clipper Liberty series), resulting in four high speed output shafts, a lighter and more efficient gearbox, load split by a factor of 16, and the ability to replace all high-speed stage components using an on-board gantry crane (Mikhail, 2006). A second approach is to eliminate the gearbox by applying a direct-drive design.

In general, turbine reliability has been improving as the wind industry matures. In analyzing detailed failure data, Larwood and van Dam (2006) found evidence of a three-fold decline in blade failure rate from the 1980s through 2001. Considering the Kenetech 56-100 machine, which was manufactured in the 1980s and has proven to be one of the more reliable of first-generation turbines, comparisons in failure rate are mixed. For the period 2000 to 2003, the Kenetech 56-100 rotor failure rate of 5.4×10^{-3} failures per turbine per year was 60% higher than the average for all wind turbines located in Denmark over the period 1993-2006 (3.4×10^{-3}) and 77% lower than the average for all wind turbines located in Germany for the period 1996-2006 (1.5×10^{-2}) (Larwood and van Dam, 2006). Similarly, the Kenetech tower failure rate of 6.9×10^{-4} for the period 2000 to 2003 was seven times higher than the average for all wind turbines located in Denmark (1.0×10^{-4} for 1993-2006) and two orders of magnitude less than the average for all wind turbines located in Germany (1.5×10^{-2} for 1996 to 2006) (ibid). But the salient question for repowering decisions pertaining to turbine failure probabilities in new turbine equipment is whether equipment owners *believe* the probability is less with new equipment.[95] Consequently, manufacturers' willingness to signal reliability with instruments like warranties and guarantees will also be important factors for the risk-reduction component of repowering decisions.

Challenges for turbine manufacturers include a changing policy and market context for wind, supply chain complexity and component shortages, demand shift from Europe to North American and Asia, large multi-national companies entering the market, fewer but larger customers, market expansion in areas of high political risk, and a global

[95] Of course, actual failures in existing installed equipment are salient for repowering decisions because they present the owner with an immediate decision to repair, repower or walk away.

marketplace (Soby, 2006). The North American market is growing due to increased energy demand, the federal PTC, price volatility of natural gas, state RPS standards and competitiveness of wind as a renewable resource, energy security and independence concerns, and increasing consumer and corporate environmental awareness, but has also been cyclical due to PTC uncertainty (Figure 48).

3.5 Project Economics

Although the benefits discussed in section 3.7 can encourage repowering and the barriers discussed in section 3.8 can derail a repowering project, profitable project economics are a necessary if not sufficient condition.

A summary of the levelized cost of generation provides some insight into the economic factors in repowering decisions. Wind power generated in a class 5 resource appears to be a low-cost option for electricity when 34% capacity factor is achieved (i.e., reliable new-technology turbines are used) and when tax credits are included (Appendix B). However, renewable power generation technologies benefit from low operating costs (e.g., the wind is free) and suffer from high capital costs and low capacity factor, relative to conventional fossil-fueled generation (Appendix C). Thus, the relative advantage in levelized cost of generation for wind power will suffer from decreases in capacity factor and/or increases in capital costs. Older wind turbine technology generally achieves lower capacity factor than new equipment because it operates in a narrower range of wind speed and is less reliable due to design and age. But this equipment has often been fully depreciated.[96] Thus, the essence of repowering decisions may be simplified as a tradeoff between improving capacity factor (and possibly reducing O&M cost) versus incurring additional

[96] Note, however, projects that have changed ownership recently may have older wind turbine equipment with positive book value and cash flow effects from the depreciation tax shield. In this circumstance, repowering would cause a writeoff of these assets.

capital cost. In a competitive marketplace, a poor result in this tradeoff that changes the relative advantage in wind generation costs can cause other renewable energy development (e.g., solar or greenfield wind) to be the low-cost option rather than wind repowering.

The economic analyses of repowering available suggest that many projects would produce higher-cost power if repowered now than if left in place for several years, to be repowered at a later date (Wiser et al., 2008). The balancing factor to this result, however, is the fact that the California rate payer shoulders less of the cost of repowering so long as the federal production tax credit is in effect. Thus, the question of whether more rapid repowering would be "good" from the perspective of providing consumers with low-cost renewable energy depends on the balance of cost for "forced" repowering (e.g., via incentives and subsidies to improve project economics) and the expectation for federal tax credit renewal. It is also important to place such analysis of wind in the context of the next-best renewable energy source that would be used to meet the binding constraint of RPS in the absence of wind.

The economic modeling of wind-project repowering decisions done by Wiser et al. (2008) found that a "general lack of economic incentive to repower all but the most poorly functioning of the wind turbine fleet" poses a "primary barrier to more-rapid wind repowering." The lack of economic incentive is because "aging wind facilities may often be more profitable, in the near term, in continued operations than they would be if they pursued repowering with new wind turbines." In other words, "owners of many existing, aging – but still well-performing – wind power projects are doing what is in their own best financial interest: continuing to reap significant cash flow from old, depreciated wind projects that receive qualifying facility (QF) prices. Such project owners may have little economic incentive to repower at this time, as repowering requires substantial new investment and potentially different and more onerous contract terms and pricing."

Existing Project Assumptions			Repowered Project Results	
Revenue	Annual O&M Cost and Capacity Factor	LCOE for Remaining Project Life	LCOE equal to Existing Project NPV	LCOE equal to $0 NPV (IRR=10%)
	Low ($40/kW, 30%)	$66.7 / MWh	$117.9 / MWh	
Low	**Mid** ($60/kW, 22%)	$67.2 / MWh	$90.5 / MWh	
	High ($90/kW, 16%)	$77.2 / MWh	$80.0 / MWh	
	Low ($40/kW, 30%)	$80.4 / MWh	$132.3 / MWh	
Mid	**Mid** ($60/kW, 22%)	$80.6 / MWh	$98.5 / MWh	$80.0 / MWh
	High ($90/kW, 16%)	$81.6 / MWh	$80.4 / MWh	
	Low ($40/kW, 30%)	$88.6 / MWh	$141.2 / MWh	
High	**Mid** ($60/kW, 22%)	$88.6 / MWh	$103.6 / MWh	
	High ($90/kW, 16%)	$87.0 / MWh	$80.9 / MWh	

Table 24: Economics of repowered wind projects (Wiser et al., 2008). The authors used a cash flow model to compare existing 25 MW wind facilities with repowered and new greenfield alternatives, also with 25 MW installed capacity.[97] They used low-, mid-, and high-cost scenarios for O&M costs and capacity factors since adequate data on these critical parameters were not available, and used low-, mid-, and high-revenue scenarios to account for potential power purchase contract structures. To compare existing and repowered projects, the authors interpreted the 20-year levelized cost of energy (LCOE) for repowered projects required to match the net present value (NPV) of continued operation of existing wind projects (calculated for each cost and revenue scenario) as the necessary contract price to induce the decision to repower.[98,99] In only two cases is the LCOE with

[97] Future analyses should consider the possibility that repowering results in an increase in installed capacity. Wiser et al. note that, "it may be useful to explore scenarios in which the repowered facility is larger than the existing facility that it replaces. In this instance, the NPV of the existing (non-repowered) facility would be allocated across a larger number of repowered project MWhs, leading to a potentially lower payment (in $ per MWh terms) needed to accelerate repowering." However, there may also be cases where repowering results in *less* installed capacity due to setback restrictions (see section 3.8.6).

[98] The authors also calculated the 20-year levelized cost of energy for repowered projects required to deliver a 10 percent internal rate of return (IRR), which is interpreted as the minimum nominal IRR for a wind project. Their comparison of alternatives also included the 20-year levelized price for greenfield projects to achieve 10 percent IRR, and the current 20-year market price referent (MPR). The comparison of repowered and greenfield projects is salient if one believes there is a shortage of wind turbines available such that project developers face a one-or-the-other decision between these types of projects. However, such a short-term disequilibrium should not form the basis for public policy.

[99] Using equal NPV as the criterion for repowering viability is an approximation because, as Wiser et al. note, the relative risk/uncertainty in existing versus repowered projects has bearing on the decision as well. The authors note that, "existing (non-repowered) facilities [may] shoulder greater O&M, project failure,

repowering lower than for the remaining life of the existing project: the mid-revenue/high O&M/low capacity factor case; and the high-revenue/high O&M/low capacity factor case. In other words, only the poor-performing existing projects see motivation to repower to reduce the levelized cost of energy. The sensitivity of LCOE to the input assumptions defined for each case demonstrates the highly project-specific nature of repowering decisions.

Wiser et al. concluded that, in 2008, "…project owners will only be motivated to pursue project repowering, in the near term, if levelized revenue over $98.5/MWh is available. For existing wind projects that are better-functioning than the 'mid-case' assumes, higher levels of payment may be necessary to accelerate the repowering process." Recent increases in the MPR may motivate more repowering, but it is the expectation of future MPR that really matters for repowering decisions.

One implication of economic modeling of repowering decisions is that repowering will proceed "naturally" as old equipment reaches the end of its useful life, suffering increasing O&M costs and declining capacity factor (Table 25).[100] Future economic analysis of repowering should model this likely path of future repowering to enable simulation of the potential effect of policy on repowering decisions. In the next section, I examine potential future paths of repowering to meet the 80in50 goal by assuming a 30-year average lifetime for wind plants.

Why, then, would public policy seek to accelerate repowering faster than this natural rate? Environmental, human health, and energy security externalities have motivated establishment of a RPS that forces increasing renewable generation capacity. Recognizing that renewable energy may be the lowest-cost alternative once these

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and revenue risks," in which case simple NPV analysis would "underestimate the economic potential for near-term repowering."

[100] Decreasing supply of attractive greenfield sites (i.e., close to demand and/or transmission with good wind resource) will also tend to increase repowering due to changes in the relative LCOE.

externalities are counted, the RPS seeks to artificially increase demand to compensate for the market imperfection. This is an efficient policy in the sense that it increases the value of renewable energy while allowing the free market to inform individual project development decisions (e.g., repowering wind versus greenfield development verses alternative renewable energy source). Additional policies to encourage repowering in particular will introduce economic inefficiency. For example, Wiser et al. (2008) conclude that, "to encourage *early* repowering, it may be necessary to consider a more proactive state policy, one that would offer an explicit incentive for the replacement of aging wind projects," but recognize that such a policy is "unlikely to be economically efficient…" (emphasis added). As described in section 3.8, however, there are many other barriers to repowering that introduce market failures and inefficiencies as well by making the execution of a repowering decision slow and difficult.

		O&M Cost and Capacity Factor Assumption		
		Low-Cost ($40/kW, CF=30%)	**Mid-Cost** ($60/kW, CF=22%)	**High-Cost** ($90/kW, CF=16%)
Revenue Assumption	**Low**	NPV: $12,687	NPV: $3,526	NPV: $22
		Life: 23	Life: 10	Life: 1
	Mid	NPV: $17,511	NPV: $6,186	NPV: $121
		Life: 26	Life: 14	Life: 2
	High	NPV: $20,477	NPV: $7,909	NPV: $302
		Life: 28	Life: 16	Life: 4
NPV is in $000, remaining project life is in years.				

Table 25: the economics of existing wind projects (Wiser et al., 2008). The low-, mid-, and high-cost scenarios vary O&M costs and capacity factors, with the low-cost case assuming the highest capacity factor. Projects in the low-cost case (i.e., with low O&M costs and high capacity factor) are not likely to be repowered unless the expected revenue generated from such repowering is very high. Conversely, projects in the high-cost case (i.e., with high O&M costs and low capacity factor) generally have only 1 to 4 years (from 2009) before they become uneconomic to maintain. These results imply that owners of high-cost facilities are likely already planning for repowering while owners of low-cost facilities are probably not. Thus, the repowering decision may hinge to a large degree on how the *existing* machinery is performing, perhaps even more so than on how the new machinery will perform. This implies that repowering is inevitable as existing machinery performance deteriorates with age and reduction/elimination of other barriers to repowering identified in this report may be necessary buy not sufficient conditions for near-term repowering decisions. It is also important to recognize that this analysis aggregates many project-specific factors, like project-specific power purchase agreement terms, that are likely important for each individual repowering decision.

Wiser et al. (2008) also concluded that, if the 2-cent per kWh 10-year federal PTC that is currently extended through 2009 is discontinued at some point in the future, there may be benefit to encouraging “early” repowering investments made while the federal government effectively covers a portion of the cost. Additional renewable power may be less expensive for *Californians* if additional investments are made while the federal government pays a portion of the cost. Thus, there may be a balancing decision between the economic inefficiency introduced by repowering incentives that distort the price signal for lowest-cost renewable energy investments and the economic benefit for Californians of investments made while the federal government effectively pays a portion of the cost. However, a rational wind operator with perfect foresight already incorporates the probability of PTC discontinuation in his or her repowering decisions, so the more economically efficient government policy for encouraging "early" repowering may be to make the threat of a PTC sunset credible rather than offering "explicit incentives for the replacement of aging wind projects" while the PTC is still in effect as Wiser et al. suggest.

Finally, "there is a concern that constrained supply and policy-driven demand are driving up the costs of RPS contracts… but a shifting resource mix is also responsible." (CPUC, 2008; see section 3.6). "While California has vast untapped renewable potential, many of the state's lowest cost resources – the low-hanging fruit – have already been developed." (ibid) Thus, as the RPS drives demand into higher-cost renewables, the opportunity for favorable contract prices will encourage wind repowering (Table 24, Table 25). Hence repowering is likely to accelerate, as old equipment continues to age, remaining renewable resources are developed leaving few attractive greenfield sites, and the market equilibrium power purchase price increases.

3.6 State Renewables Goals

Renewable Portfolio Standards (RPS) are becoming more popular as a policy tool at the state level to encourage development of renewable energy production. Currently 41 states have RPS standards (DSIRE, 2008). California's RPS was established in 2002 by Senate Bill 1078, which originally required investor-owned utilities (IOUs), energy service providers (ESPs), and community choice aggregators (CCAs) to increase the amount of renewable energy in their generation portfolios by one percentage point per year (reaching 20 percent by 2017), and established a system for selection of renewable energy projects based on a "least-cost, best-fit" process that includes consideration of "estimates of indirect costs associated with needed transmission investments and ongoing utility expenses resulting from integrating and operating eligible renewable energy resources" (Shiu, 2007). Wind projects typically fare well relative to other renewable energy alternatives in this selection process. This target was accelerated by the Energy Action Plan (EAP) and by Senate Bill 107 in 2006 to 20 percent by 2010. The California Public Utilities Commissions (CPUC) and California Energy Commission (CEC) are responsible for implementing the RPS program.

The fundamental mechanism of an RPS is to artificially increase demand for renewable energy production, which tends to increase the marginal cost the market will bear, thereby enabling profitable development of more generation capacity (Figure 44). The higher price paid for wind energy will support development of both greenfield and repowering projects, with higher marginal cost as the relatively low-cost projects are completed. This development corresponds to movement along the supply curve in Figure 44. However, if repowering shifts the wind power supply downward by reducing the cost of generation for existing projects, the supply of wind generation may increase while the cost of wind energy decreases. Since an RPS is for all renewables, not just wind, supply curves for energy alternatives are needed as well to develop a complete picture of conditions for development of new generation capacity.

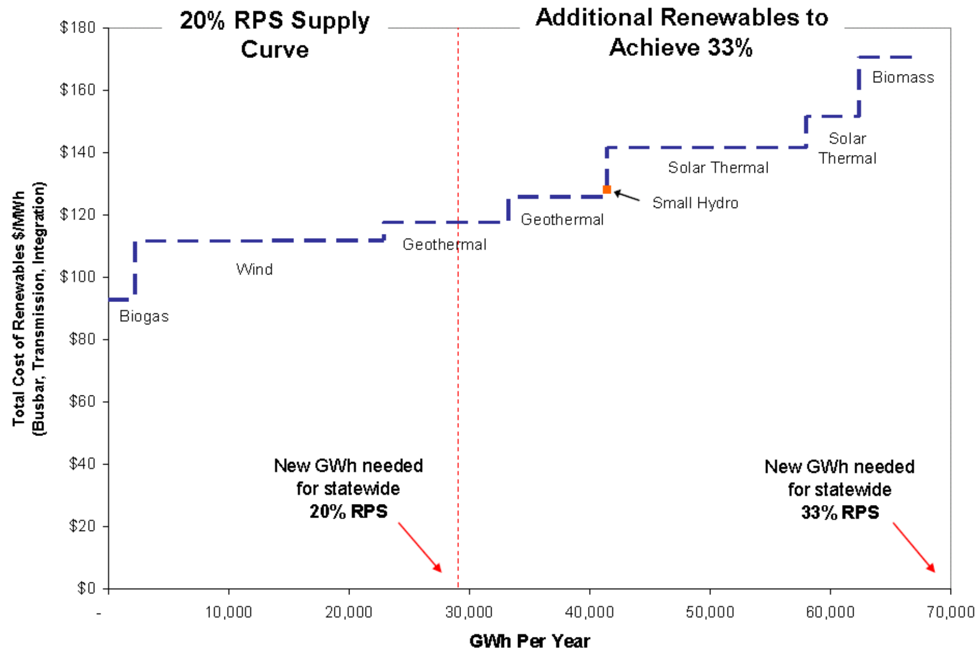

Figure 43: The California Public Utility Commission's estimated renewable energy supply curve (CPUC, 2008).

Figure 43 shows the California Public Utility Commission's estimate of the current renewable energy supply curve (CPUC, 2008). At present, it appears the major investor-owned utilities in California may be facing difficulty in meeting the current RPS targets, let alone possible future increases. California's three large IOUs collectively served 12.7% of their 2007 retail electricity sales with renewable energy; Pacific Gas and Electric (PG&E) had 11.4%, Southern California Edison (SCE) had 15.7%, and San Diego Gas & Electric (SDG&E) had 5.2%.[101] The breakdown of this renewable energy generation for IOUs, ESPs, and small and multi-jurisdictional utilities by resource type was as follows: 47.93% geothermal; 19.04% wind; 14.32% biomass; 11.12% small hydro; 4.73% biogas; and 2.86% solar (ibid).

[101] Current renewable procurement status as of Sept. 1, 2008 (CPUC website, http://www.cpuc.ca.gov/PUC/energy/electric/RenewableEnergy/). ESPs collectively served 4.7% and small and multi-jurisdictional utilities served 9% with renewable electricity.

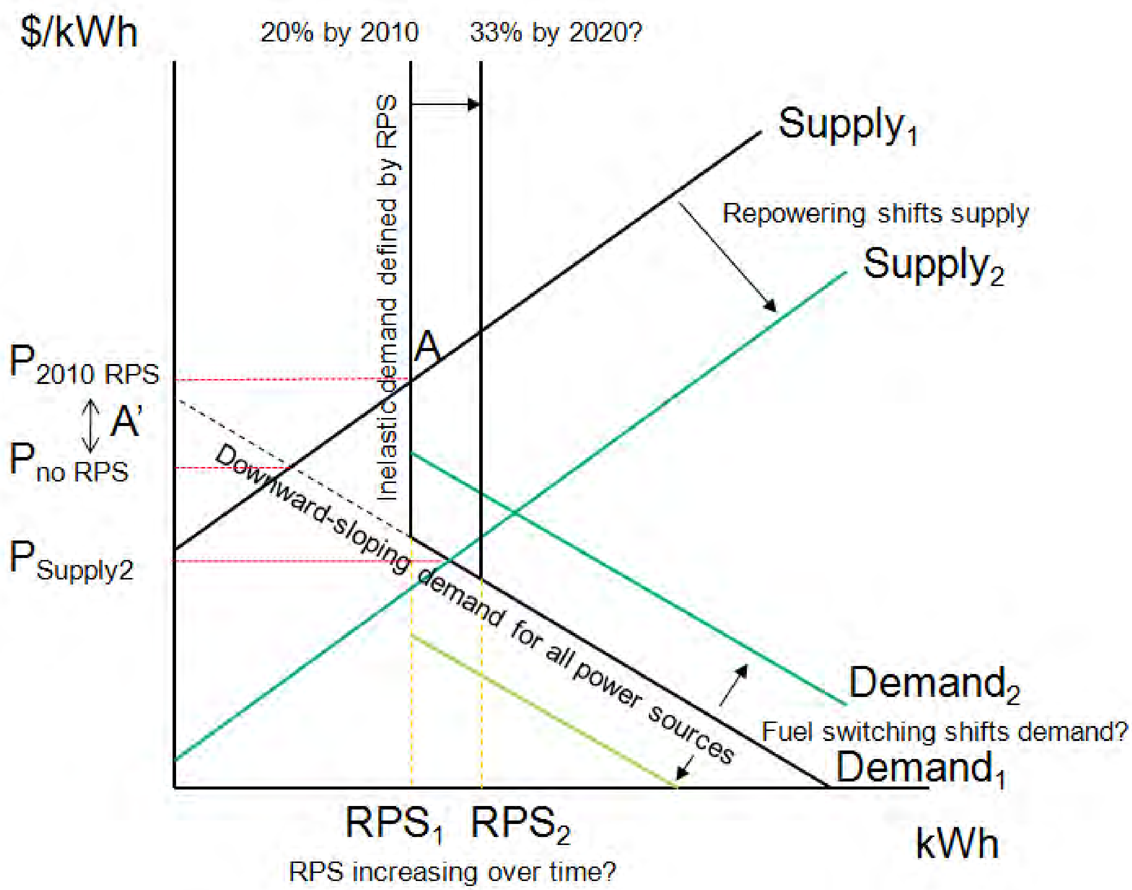

Figure 44: Hypothetical depiction of power production alternatives and the mechanics of a renewable portfolio standard. The RPS creates artificial demand inelasticity, meaning demand becomes vertical (perfectly inelastic) at the RPS-imposed energy quantity (kWh). In the hypothetical situation represented by point A, the RPS holds renewable generation at the quantity RPS_1, but imposes an increase in energy price of A'. If repowering and new turbine technology reduce the cost of wind generation, supply may shift to $Supply_2$ in which case the quantity of renewable power production is above the 2010 RPS and the RPS has no effect on market price ($P_{Supply2}$).[102] The diagram also shows the potential impact on market price and quantity of renewable energy if the RPS increases, if fuel switching shifts demand outward, or if energy efficiency shifts demand inward. Since the RPS requires a minimum *share* of total energy generation from renewables, decreased demand through energy efficiency that reduces the total quantity of energy sold would also reduce the quantity of renewable generation needed to meet the RPS.

[102] Since the RPS applies to all renewables, the supply curve depicts the marginal cost of generation over all renewable as the quantity of renewable power increases, meaning changes in the cost of wind power may cause kinks in the supply curve rather than shifts.

In their 2008 status report on RPS-eligible power procurement, the CPUC identified the primary "risk factors" for meeting RPS targets. Results were as follows (with percentage of new RPS generation at risk due to each factor in parentheses): uncertainty in the federal PTC and other relevant tax credits (72%), transmission capacity (48%), developer inexperience (14%), financing (11%), site control (10%), permitting (10%), price re-opener (8%), military radar (5%), technology (4%), fuel supply (4%), and equipment procurement (3%). The CPUC identified the potential expiration of the federal PTC and Investment Tax Credits (ITC) and transmission capacity as the two primary risk factors.

The IOUs have actively sought new contracts with generators to increase the level of RPS-eligible renewable generation to the RPS requirement of 20% by 2010. In 2008, for example, 32 percent of PG&E electricity came from "renewable energy sources," but only 12% qualified under California's renewable portfolio standard program. An RFO issued by PG&E on March 7, 2008 requested bids by May 12, 2008 for execution of final agreements and submission to the CPUC for approval by the end of the year (www.pge.com/renewablesrfo).

Since 2002, the CPUC has approved 95 contracts for 5,900 MW of new (61 projects for 4,480 MW) and existing (34 projects for 1,420 MW) RPS-eligible capacity.[103] These contracts are more than sufficient to meet the 20 percent goal *if* all the capacity is online by 2010. Therefore, "it appears…that the RPS procurement process is working" based on the capacity in approved contracts (ibid). However, the progress in the *delivered* energy on which RPS progress is measured "has been slow" (ibid). Since 2002, only 14 contracts for approximately 400 MW have come online, meaning California's IOUs need approximately 3,000 MW additional capacity to come online in the next two years.

[103] As of July, 2008 (CPUC, 2008)

Furthermore, "RPS generation has not kept pace with overall load growth," meaning renewable generation as a percentage of total power sales has actually been *declining* since 2002 rather than increasing by at least one percentage point annually as required in the RPS (Table 26).[104]

		2003	2004	2005	2006	2007
PG&E	RPS Eligible GWh	8,828	8,575	8,543	9,114	9,047
	RPS GWh as % of bundled sales	12.4%	11.6%	11.7%	11.9%	11.4%
SCE	RPS Eligible GWh	12,613	13,248	12,930	12,706	12,465
	RPS GWh as % of bundled sales	17.9%	18.2%	17.2%	16.1%	15.7%
SDG&E	RPS Eligible GWh	550	678	825	900	881
	RPS GWh as % of bundled sales	3.7%	4.3%	5.2%	5.3%	5.2%
TOTAL	RPS Eligible GWh	21,991	22,500	22,298	22,719	22,393
	RPS GWh as % of bundled sales	14.0%	13.9%	13.6%	13.2%	12.7%

Table 26: RPS-eligible power generation by IOU and as percentage of total bundled sales, annually since creation of the RPS (CPUC, 2008).

The CPUC 2008 status report on RPS-eligible procurement concludes that, "if the state successfully removes barriers to project development, California IOUs would be on target to hit 20% in the 2012-2013 timeframe," but not by 2010 as specified in the RPS (CPUC, 2008).[105] In other words, project development barriers are more important than contracting and procurement processes. The remainder of this report is focused on investigating barriers to repowering projects in California's extant wind projects in more detail.

[104] Annual variation in the renewable energy resource base (e.g., rainfall, wind) can also impact annual variation in RPS-eligible energy production.

[105] The CPUC also noted that, *if* the 20% goal is achieved by 2013, it leaves "only 7 years to achieve the 60% increase in RPS generation needed to reach a 33% target in 2020." They also argued that the overarching policy goal in such an increase in RPS standard should be clearly articulated (e.g., GHG emission reduction, energy independence, economic development) since this goal is likely to impact the program design.

3.7 Reasons to Repower (Benefits)

The potential motivations for repowering depend on perspective. Although the repowering decision ultimately rests with project owners, I use this section to summarize the reasons for repowering from a variety of stakeholder perspectives.

3.7.1 Increased and More Reliable Power Production with Lower O&M Cost

Utility-scale turbines have grown from 50 kilowatt (kW) machines approximately 25 meters (m) in overall height to 3.0 megawatt (MW) machines over 125 m tall (Larwood and van Dam, 2006). The increase in turbine diameter means larger swept area, which translates to increased power production from each turbine. Taller turbines also generally intersect higher wind speeds, which also translates into increased power production. The result is that one large modern turbine can produce the energy of dozens of small old turbines and, depending on turbine spacing considerations or limits, repowering can maximize the power production from a given lease area (i.e., maximize use of the available wind resource).[106]

As discussed in section 3.4, modern turbine technology also delivers more efficient conversion of wind energy to electricity and more reliable, controllable, and higher quality power, which may deliver several benefits for the power producer.[107] Variable speed turbines can increase power production 10-15 percent by maintaining optimal aerodynamic performance (with optimum tip speed ratio) and continued power production over a wide range of wind speeds (Behnke and Erdman, 2006). Improved

[106] The larger rotors and taller towers also enable power generation at lower wind speeds, which can increase energy production with repowering but is most important for greenfield developments in lesser wind resource areas.
[107] Note, however, that payment for these ancillary services is unlikely without merchant generation rather than long term power purchase agreements.

reliability, both from better designs and young equipment, will increase the capacity factor, which translates into increased energy generation and improved project economics (e.g., shorter payback on initial turbine investment) (Figure 45). Higher quality power may increase the value to system operators and thus the price paid to power producers.[108] Improved reliability may also translate into reduced operation and maintenance cost.

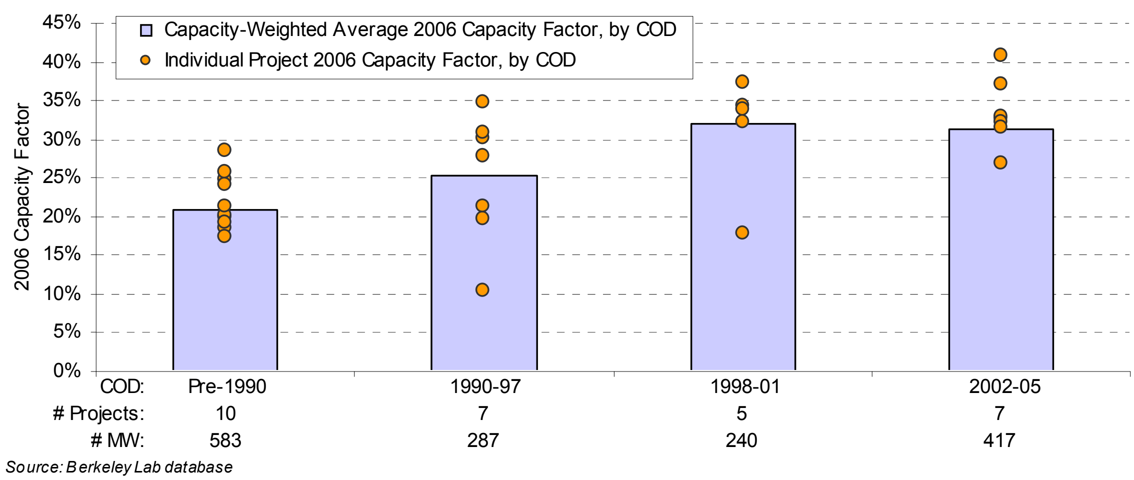

Figure 45: Average 2006 capacity factor for a sample of California wind projects representing 64 percent of total installed capacity (Wiser et al., 2008). Grouped by date of installation, the figure shows the average capacity factor is higher for new machines, which means more energy generation over the course of a year.[109] From the equipment owner's perspective, this means more revenue from more power production for a given installed nameplate capacity and wind resource. From the government's perspective, this means more total renewable energy generation from the state's wind resources. From the IOU's and ISO's perspectives, this means more progress toward the RPS without need of additional transmission capacity. From the ratepayer's perspective, this may mean lower cost of energy.

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[108] Capturing revenue from provision of ancillary services may require a merchant generator business model wherein energy, capacity, ancillary services, PTC benefits, and green attributes are all sold separately.

[109] If new wind projects achieve 34 percent average capacity factor and old projects are achieving approximately 22 percent capacity factor, then repowering 1,000 MW of old wind projects *without* any increase in nameplate capacity would increase renewable electricity production more than 1,000 GWh per year, which is equivalent to 350 MW of new wind power capacity (Wiser et al., 2008).

Operations and Maintenance costs have been estimated at approximately $0.005 per kWh for new equipment, increasing (approximately linearly) over time to around $0.02 per kWh by year 20 (Figure 46; Hill, 2006).[110] Operation and maintenance costs for old turbines are likely higher both because of equipment age and differences in turbine design. The old, constant-speed turbine designs suffer overloads in turbulent winds that cause fatigue loads on the equipment and require over-sizing of structures to ensure acceptable life expectancy (Behnke and Erdman, 2006). Modern variable speed wind turbine systems provide the ability to limit and control torque, reducing fatiguing loads and structure over-sizing while also allowing continued operation over a wider range of wind conditions. Larger turbines may also have lower O&M costs simply because the cost of each incident is spread over a larger quantity of energy production. This result is accentuated if the frequency of incidents is lower with new technology, but mitigated if the cost per incident increases (e.g., for the high cost of very large cranes needed for some modern turbines).[111] Both the American Wind Energy Association and Utility Wind Interest Group have had operations and maintenance working groups to investigate ways to improve reliability and reduce O&M costs.

[110] Monetary figures given are real dollars, not constant dollars.
[111] There is some question as to whether O&M costs are actually increasing for some modern turbines. The supply of cranes for installation and some maintenance on very large turbines is a limiting factor commanding economic rent. Some believe that O&M costs for the industry have historically been understated and that current projects are facing around $0.02 per kWh for *average* O&M costs over the lifetime of the project. For comparison, coal baseload plants have O&M cost of approximately $0.001 to $0.002 per kWh, primarily because the costs are spread over very large quantities of energy production. The Sandia National Laboratories, Albuquerque has been working on compiling a database of O&M costs to investigate this question and identify target areas for improve reliability to reduce these costs.

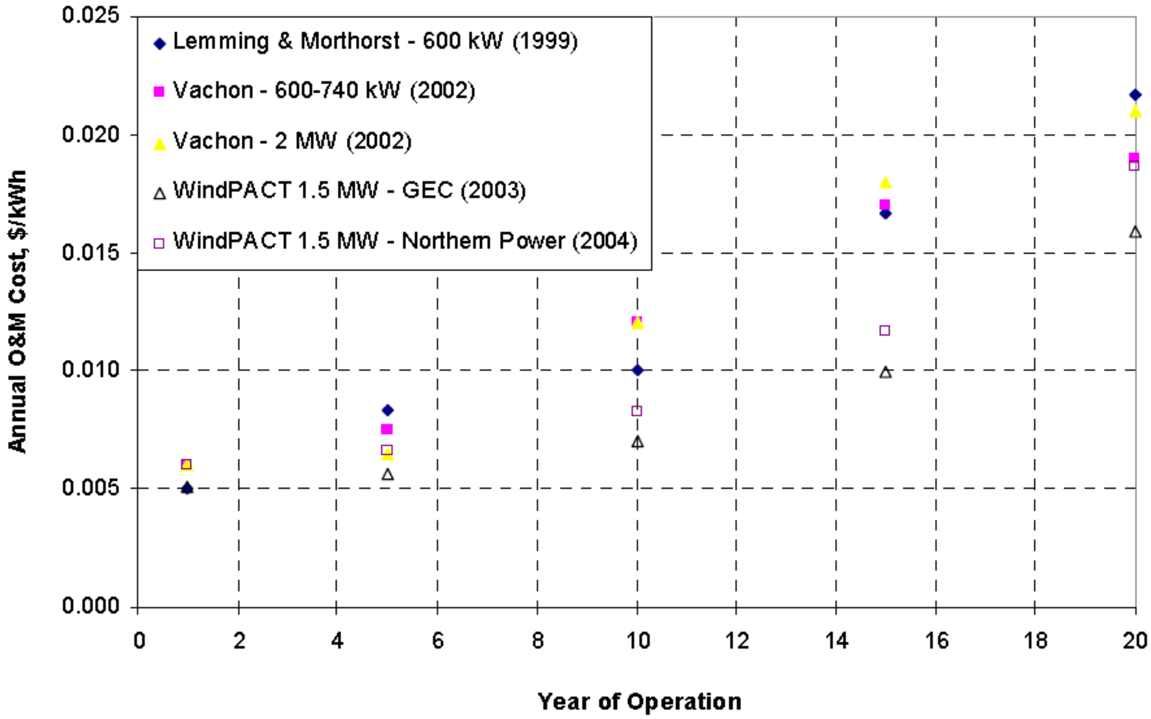

Figure 46: Estimated increase in operating and maintenance costs over time for five modern wind turbines (Hill, 2006).

3.7.2 Increased Turbine Sales

Replacing old equipment with new represents additional sales for turbine manufacturers. In some cases, turbine manufacturers have partnered with project owners and operators (and others) to finance repowering projects. For example, General Electric approached Babcock and Brown about a stake in the Buena Vista repowering project.

3.7.3 Reduced Avian Mortality and Project Footprint with Fewer Turbines

Repowering may reduce avian mortality by replacing many rapidly-spinning small machines located on hill crests where raptors soar on updrafts with fewer slower-spinning large machines located just on the lee side of hills (Kerlinger et al., 2006; Smallwood, 2006). Ongoing studies are refining the understanding of how to execute repowering to optimize reduction in avian mortality without compromising power production. Especially in the Altamont Pass area, concern about the number of birds killed by wind turbines has limited wind development (see section 3.8.3).

Reducing the number of turbines for a given nameplate capacity can also reduce a wind project's physical footprint on the land by reducing the number of roads and tower foundations and by moving some transmission lines underground.

For example, the Diablo Wind Energy Project in Altamont pass replaced 169 vertical axis wind turbines with 31 larger horizontal axis turbines. Studies suggest this repowering project reduced bird fatality by 70% overall, with 62% reduction for raptors, and 85% reduction for burrowing owl, but nearly 300% *increase* for red-tailed hawk (see sections 3.10.1.2 and 3.8.3; WEST, Inc., 2006; Smallwood, 2006). These studies concluded that changes in mortality were likely due to the reduced number of wind turbines, turbine locations, and the increased height above the ground of the turbines.

- Fewer larger turbines reduce the chances of encounter
- Larger, more visible blades rotate more slowly (tip speed is approximately the same).
- Higher turbines avoid flight zones for some raptors (but not others)
- Fewer perching opportunities on tubular towers without guy wires
- Power lines buried
- Turbine location to minimize encounters (e.g., lee side of hill).

Table 27: How repowering may reduce avian mortality.

3.7.4 RPS Progress from Existing Wind Development Areas & Infrastructure

If repowering increases the nameplate capacity of wind projects and/or improves capacity factor, then more renewable energy production can occur from existing wind development areas. For utilities, this means progress toward renewable portfolio standards. As discussed in section 3.6, some utilities may be facing difficulty in meeting the current RPS targets, let alone possible future increases. Furthermore, since existing wind areas were developed due to synergy between high quality wind resource, proximity to market and/or ample transmission capacity, and since increases in capacity factor may not require additional transmission capacity, the incremental renewable energy production from repowering may be relatively low cost.

But the amount of additional energy production available by repowering is not a panacea for helping the state meet RPS goals. Even if all of the approximately 1,700 MW of installed capacity of old wind turbines were to be repowered, with 25-35 percent increase in capacity realized during the repower, the result would be about 1,100 GWh per year of increased wind energy generation.[112] One utility called such an increase "helpful" but said it would represent "less than two thirds of one annual procurement target for the three largest utilities for a single year… [it] simply isn't that large… [and is] not so significant that it warrants special attention," especially considering transmission constraints (SCE, 2007). The total potential *increase* in nameplate capacity with repowering – approximately 460 MW – represents a small but helpful contribution toward the RPS target.

3.7.5 Reduced Cost of Integration

Although a relatively minor component of the overall cost of wind energy, the integration cost for intermittent renewables may increase as their share of total generation increases due to the RPS (Shiu, 2006).[113] Integration cost is defined by California statute

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[112] For example, approximately 1,320 MW of wind capacity was installed in the 1980s. If all these projects were repowered with 35 percent increase in capacity, 462 MW of additional capacity would result. Assuming 30 percent capacity factor, this 462 MW of additional capacity would produce 1,214 GWh per year (365 d/yr * 24 hr/d * 0.3 = 1,214 GWh/yr).

[113] The calculation of integration cost is performed on the margin, for each addition of generation capacity. The regulation and load following impacts that result from fluctuations in aggregate load and/or

as the "indirect costs associated with ongoing utility expenses from integrating and operating eligible renewable energy resources" (Shiu, 2007). Other potential indirect costs include transmission investments and remarketing costs. The total cost is the sum of direct cost (also called bid price, or the price paid to the power producer) and indirect costs (Figure 47).

As explained by Shiu (2007), "electricity is a unique commodity because it has two different units of value. Electric generation facilities provide energy value, but they also deliver capacity value." The capacity value derives from the need for the power grid to have enough generating capacity at any given moment to supply load demand. Although the system "ultimately delivers energy to consumers, …without sufficient generating power the grid can become unstable and collapse into blackout" (ibid). Thus, "a generator's ability to deliver power when needed provides capacity value that is separate and distinct from the energy it delivers" (ibid). If repowering increases generating capacity with modern turbines that continue to operate over a wider range of wind speeds than the old turbines they replace, it will provide value to the grid beyond the energy delivered because it will increase system reliability during peak demand periods. A metric for this value, the "capacity credit," has been defined to quantify the "value of a generator's contribution to the reliability of the overall electrical supply system… [compared to a] combined cycle natural gas reference unit as the benchmark" (Shiu, 2007).[114]

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uncontrolled generation are determined; these impacts must be compensated. The cost of integration is the cost of this compensation in terms of "greater amounts of purchased regulating capacity and greater use of the short-term energy markets" (Shiu, 2007). If the intermittency of renewable-source generation exceeds the capacity of online generating units equipped with automatic generation control (AGC) to modify production quickly (i.e., minute-to-minute regulation), then additional increments of renewable-source generation capacity may decrease system realiability and impose higher integration costs.

[114] One way to determine capacity credit is through system reliability analysis. As Shiu (2007) explains, "Any generation resource that contributes to system reliability is providing capacity value and the preferred method for determining the capacity value is to calculate the *effective load carrying capability* (ELCC).

However, the capacity value varies depending on system load, with the highest value occurring only when the grid is in danger of insufficient generating power (e.g., when demand nears peak levels (Shiu, 2007). Relative to the benchmark of a medium gas unit, wind in California generally has poor capacity credit (24% to 39% from 2002 through 2004) due to the variability of generation (Shiu, 2006). Consequently, the regulation cost of integrating such intermittent generation into the electric grid ranged from \$0.0024 to \$0.007 per kWh for the period 2002 through 2004, which is approximately 3 to 8 percent of the estimated levelized cost of energy for new merchant wind projects in 2007 (\$0.0842 per kWh) (Shiu, 2007; Klein and Rednam, 2007).

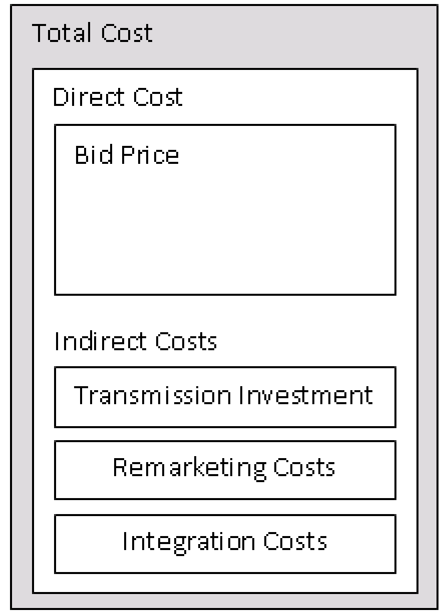

Figure 47: Integration costs are one part of total costs in the least-cost, best-fit process.

The cost of integration for renewables may also increase in the future if a higher percentage of total generation comes from intermittent renewables, leaving less ramping capacity from thermal generation available for load following. Current levels of renewable generation do not have "significant effect on the total energy requirements for the short term load following market, … ample depth is available in the short term generator stack to handle incremental energy requirements, [and] the ramping capability

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This requires a reliability model that can calculate *loss of load probability* (LOLP), loss of load expectation (LOLE), or *expected unserved energy* (EUE). ELCC is a way to measure a power plant's capacity contributions based on its impact to system reliability… all power plants with a non-zero forced outage rate have an ELCC that is less than rated capacity (barring unusual plants with artificially low-rated capacity with respect to actual achieved capacity)."

of thermal generators responding in the load following time frame appears to [be] very large and capable of supporting a large amount of renewables" (Shiu, 2007). However, as the percentage of total generation from renewables increases, the ramping capacity for load following will decrease unless the renewable power generation is designed with ramping capability (see section 3.4).

Repowering may mitigate the cost of integration in several ways. As already mentioned, a capacity increase associated with repowering will tend to increase the capacity value, which is further augmented if turbine operation is coordinated to include some ramping capability. Taller turbines that intersect more consistent wind and variable-speed turbine technology that enables continued operation over a wider range of wind speeds also reduce the regulation cost of grid intergration (i.e., improve the capacity value as measured by the Effective Load Carrying Capability, ELCC) due to more reliable operation.[115] Consequently, improvement in reliability from repowering may reduce integration costs for system operators, which could translate into modest increases in power purchase prices *if* passed on to power producers in power purchase contracts.

3.7.6 Local Economic Development and Increased Tax Base

A report by the National Renewable Energy Laboratory summarizing available studies of the economic impact of wind farms in rural communities in the United States found that, "wind installations create a large direct impact on the economies of rural communities, especially those with few supporting industries" (NREL, 2006). In general,

[115] Note, the ELCC is different than capacity factor (defined as actual generation (MWh) divided by nameplate capacity for generation (MWh)) since ELCC depends on the timing of generation to coincide with peak demand moments such that grid reliability is ensured. Wind has higher ELCC (24% to 39%) than capacity factor because peak wind generally coincides with peak demand in summer months. Thus, the ELCC is, "a way to measure a power plant's capacity contributions based on its impact to system reliability" (Shiu, 2007).

a seven-fold multiplier on primary direct wind energy payroll can be used to calculate total local economic impact that includes the effects of indirect jobs, landowner royalties, changes in taxable property values, and wind energy project property taxes (NAWS, 2008). However, the realized economic impacts vary according to local conditions.

Repowering can increase the tax base for local government. For example, implementation of the Tehachapi development plan (section 3.10.2) could increase the wind industry tax base ten-fold, from $400 million to $4 billion, which would make the wind industry larger than any other single company in the Kern County tax base (Romanowitz, 2006).[116] The Shiloh II project, a $300 million 150 MW investment in Solano County, is anticipated to involve 26 landowners with 6,800 acres, require 95-160 construction workers and 12 ongoing O&M jobs, and generate over $1 million in property taxes and hundreds of thousands of dollars in lease payments annually (PPM Energy, 2009).

3.8 Reasons to Not Repower (Barriers)

The potential benefits of repowering were summarized, by stakeholder perspective, in section 3.7. In this section I consider reasons to continue operating old equipment (i.e., barriers to repowering). I focus on the project owner's perspective since other stakeholders generally do not object to repowering (as long as the terms and execution of the repowering are acceptable to them).[117]

[116] Current eastern Kern County major industries include the wind industry ($400 M), US Borax ($350 M), and Cement Manufacturing ($230 M). Top companies for the entire Kern County include Chevron ($3,600 M), AREA ($2,600 M), Elk Hills Occidental ($2,600 M), and new Tehachapi RPS Wind ($4,000 M with implementation of the development plan). Note, however, that most of the development in this plan is new greenfield development rather than repowering.

[117] For example, some environmental groups oppose capacity increases with repowering, especially in the Altamont Pass area, due to concern for avian mortality. Utilities purchasing power will seek to negotiate favorable terms in new power purchase agreements. Landowners and government regulators may stipulate requirements for removal of old equipment, site remediation, and limitations on new construction.

Only about 0.3 percent of the nation's wind generation potential has been developed. Although this statistic makes it seem like plentiful greenfield opportunities would diminish the incentives for repowering existing sites, it is potentially misleading since the majority of the nation's wind potential is stranded far from markets in sparsely-populated great plains states without adequate transmission infrastructure. Repowered projects may also face difficulty with adequate transmission capacity constraining the ability to increase installed capacity.

The cost of energy generation with repowering may be higher than the cost of continued energy generation with existing equipment for several reasons. Existing machinery may be fully depreciated, meaning operating and maintenance are the only costs of generation (i.e., not debt service). "Because the wind spins a turbine for free, wind farms are virtual cash machines once they are up and running. Repowering a site may more thoroughly tap the available wind resource, but it also requires a major upfront capital investment" (Wagman, 2008). Consequently, some have argued that, "from a public policy perspective, the best thing to do is wait for these [old] machines to die."[118] I discuss the economics of repowering in more depth in section 3.5.

Although the cost of repowering is generally thought to be less than greenfield development due to existing infrastructure from the previous equipment, much of the existing infrastructure will need replacement to accommodate the new turbines or removal and restoration to comply with regulations. New machines often need new foundations and access roads both to accommodate the larger towers and turbines and to accommodate changes in spacing and location. Old foundations usually must be buried or

[118] Rick O'Connell, renewable energy consultant with Black and Veatch, quoted in Wagman, 2008.

completely removed.[119] Repowering may also require new pad-mounted transformers for each turbine to accommodate the increased power production with a 34.5 kV (or higher) collection system rather than old 12 or 13.4 kV medium-voltage collection systems (with each transformer serving several turbines) (Behnke and Erdman, 2006).

Although it was once thought that the scrap value of wind equipment would offset removal and restoration costs, the experience in many cases has been otherwise, with the end result sensitive to fluctuating prices for both restoration work and old equipment (Gipe, 1997). The cost to remove the 1,200 MW of first-generation turbines standing in California in 1997 was estimated to be more than $100 million in 1997 (ibid). The removal and restoration experience in the United States in the late 1990s is summarized in Table 28. The lowest-cost method for equipment removal – cutting the tower with a torch to fell the turbine like a tree – can be as little as $20 to $40 per kW (ibid).[120]

Source	Location	Brand	Units	MW	Cost	$/kW
USDA[1]	Bushland, TX	Sandia	1	0.5	$325,000	650
USDA	Hahuku Pt., HI	Mod 5b	1	3.2	$500,000	156
GMP[2]	Mt. Equinox, VT	USW 56-100	2	0.2	$20,000	100
SeaWest[3]	Palm Springs, CA	Enertech E44	85	3.36	$290,000	86
NAE[4]	Sibley, IA	WindMatic	5	0.325	$19,000	58
Herling	Palm Springs, CA	Various	300			50
Finova[5]	Altamont, CA	WEG MS2	20	4	$150,000	38

Table 28: removal and restoration costs for projects implemented in the United States in the late 1990s (Gipe, 1997). 1) $120,000 for removal, with disassembly and site restoration accounting for the rest. This is on the high end because was experimental turbine, removing only one, and to higher standard (completely remove foundation). 2) GMP is Green

[119] In 1997, the Bureau of Land Management required partial removal of the foundation (Kern County did not), Alameda and Riverside counties and the BLM required removal of non-operating wind turbines (Kern County did not), and all jurisdictions required proper disposal of turbines and components that are removed (Gipe, 1997).

[120] In the late 1990s, Ahmed Mohsen from the Bureau of Land Management Ridgecrest office estimated $2,000 to $10,000 per acre for removal and restoration cost. This compares to $4,500 per acre spent by the average Maryland coal mine for site reclamation. Contractor Jerry Herling had removed 400 to 500 machines in California by the late 1990s and generally found that it "takes longer to remove the turbines than to reclaim the sites" (Gipe, 1997)

Mountain Power. Removal costs alone were $75 to $100 per kWh; foundations were left in place. 3) 55% of the $290,000 was the cost to remove the turbines. 4) NAE is Northern Alternative Energy. These costs include complete removal and restoration. 5) Restoration only. Cost does not include removal. Most of cost was burying foundations one meter below grade (cost would have been higher if had been required to remove foundations).

Finally, continued operation of existing turbines may also be less risky than repowering. Although the frequency of equipment failure may be higher due to age, the operating and maintenance costs may be more certain for existing turbines. Furthermore, the contractual relationships and permitting for continued energy production with existing equipment are in place (unless near the end of a contract term) whereas repowering typically requires complicated and sometimes lengthy permitting processes and contract re-negotiations. In the following sections, I elaborate on several barriers to repowering in more depth.

3.8.1 Permitting

The cost in time and resources required for permitting of wind projects in California is generally higher than in other wind resource areas. Referring to difficulty with siting projects and the lengthy permitting process, Hunter Armistead, head of North American Renewables at Babcock and Brown said in 2008, "[California is] one of those markets where if you plan on building in California you better have a backup" (Scanlon, 2008). Environmental review and permitting has been especially challenging in the Altamont Pass wind resource area, in part due to greater avian populations and migrations. For the Buena Vista (completed in December, 2006) and Tres Vaqueros (currently underway) repowering projects (see section 3.10.1), George Hardie started the permitting process 4+ years earlier in 2002. At a minimum, permitting introduces a delay between the decision to repower and completion of the project, often of several years.

The cost of such a delay, in project risk and financing as well as distraction from other business activities may also prevent some otherwise profitable repowering projects from moving forward.

The legal and permitting requirements for wind projects is also a shifting landscape, which presents additional difficulty for projects with long development schedules. For example, the history of regulation in the San Gorgonio wind resource area (Riverside County) is shown in Table 29.

1980: SCE test site established, a few private developments as well
1982: San Gorgonio Wind Resource Study, a joint planning effort motivated by the sudden influx of development, was completed and a general plan and zoning regulations were first adopted.
1983: a site-specific Environmental Impact Report (EIR) was completed by the County and a site-specific Environmental Impact Statement (EIS) was completed by the Bureau of Land Management (BLM).
1983-1990: the first commercial Wind Energy Conversion System (WECS) permits were issued and early ordinance amendments were passed.
1990: the peak in total number of installed turbines in San Gorgonio pass (4,254)
1993: permits issued for re-powering existing commercial WECS permits, which started a trend toward fewer, taller turbines.
Late 1990s: a set of 200- to 330-foot WECS projects were proposed and implemented.
2003: the total number of wind turbines installed in San Gorgonio had declined to 2,789.
Today: the noise standard has declined from 65 db(A) originally to 55db(A) now (measured 10 feet away from a residence).

Table 29: The history of regulation in the San Gorgonio wind resource area (Clark, 2004).

3.8.2 Contractual Obligations and Legal Limitations

Negotiation of new contractual arrangements or re-negotiation of existing contracts is generally required for repowering projects. For example, project owners may need to renegotiate leases with landowners for repowering since new roads and foundations are needed and transmission may be moved underground. New power purchase agreements with utilities are also likely. Existing leases may also be expiring.

Finalizing contracts is generally a necessary pre-condition for project financing since the threat of litigation and associated uncertainty has made it difficult to get project financing in the past.

Dispute over the treatment of power purchase agreements between project owners and utilities can often be a sticking point in repowering. The project developers contend that they have the right under existing ISO4 power purchase agreements to sell the output of repowered projects at the original (favorable) ISO4 pricing. Utilities, on the other hand, contend that repowering triggers contract renegotiation, from which less favorable pricing is likely to emerge. The compromise most often reached is for continuation of ISO4 pricing for the originally contracted output and pricing at short-run-avoided-cost for capacity and energy produced above this amount.

The "California Fix" in federal Production Tax Credit legislation adds an interesting wrinkle to power purchase agreements and project financing for repowering.[121] The Public Utilities Regulatory Policies Act requires utilities to purchase energy from Qualifying Facilities at a rate which does not exceed the utility's avoided cost. Avoided costs are the "incremental costs to an electric utility of electric energy or capacity or both, which but for the purchase from the QF, such utility would generate itself or purchase from another source" (18 C.F.R. SS 292.101(b)(6)). The practical result of this language for repowering projects is that incremental deliveries above existing contracts due to an increase in nameplate capacity and/or improved capacity factor must be purchased at avoided cost only (rather than potentially higher rates under existing contract terms) in order for the repowered facilities to qualify for the federal PTC for the incremental

[121] Section 45.(d)(7)(B) of the Internal Revenue Code

generation.[122,123,124] Thus, independent power producers wanting to repower must negotiate new contracts with the utility stipulating this treatment before going ahead with the repowering in order to get project financing supported by the PTC. Consequently, signing new contracts with utilities is a necessary enabling step for repowering in order to get project financing.[125]

> "In order to finance new, environmentally friendly power projects, developers need long-term contracts with creditworthy buyers."
> ~ Pedro Pizarry, Southern California Edison's senior vice president of power procurement (Edison International, 2006).

New and renegotiated contracts may include additional requirements like collateral, performance requirements, and scheduling constraints that project owners may consider onerous (Wiser et al., 2008). However, these contracting tools also serve a purpose in aligning incentives to guarantee delivery of contracted services.

Negotiation of new contracts also offers the potential for changes in structure that could encourage repowering as well. For example, differentiation in power purchase

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[122] Wiser et al. (2008) wrote that the California fix "effectively excludes from PTC eligibility any repowered wind project that remains on an existing qualifying facility (QF) contract (entered into before January 1, 1987). The repowered facility will be eligible for the PTC only if the existing standard offer contract is 'amended' such that any wind generation in excess of historical norms is sold to the utility at short-run avoided cost, or if this excess generation is sold to a separate entity, or if the repowered project receives an entirely new contract from the purchasing utility (in lieu of the existing standard offer contract)."

[123] The renegotiated rate has typically been less than the existing contract. For example, the Diablo windplant (section 3.10.1.2) was selling under a power purchase agreement set to expire in 2016 at 6.8 cents per kWh; the renegotiated contract price is 4.3 cents per kWh, rising up to 5 cents per kWh in 2016 with inflation (windenergynews.blogspot.com, 2005). Consequently, the power producer needs a benefit in power production (e.g., poorly performing Flowind vertical axis turbines) to make such a price decrease (along with the capital investment) worth it. Currently, however, new wind projects are bidding higher than existing QF projects (personal communication, Hugh Merriam, April 6, 2009).

[124] An increase in nameplate capacity is not allowed pursuant to CPUC decisions absent commensurate ratepayer benefit.

[125] In 2005, for example, Southern California Edison applied for approval of four contract amendments to allow repowering of four facilities (CTV Power, Windland, and Coram Energy in Tehachapi, and Karen Windfarm in San Gorgonio). According to application documents, "the wind facilities are each parties to existing Interim Standard Offer 4 (ISO4) contracts with SCE. The amendments limit the amount of incremental energy and capacity that SCE is obligated to purchase, after repower, to prices at avoided cost, thus allowing the repowered facilities to qualify for the federal Production Tax Credit (PTC) for incremental generation" (CPUC, 2005).

price based on factors relevant for integration cost (see section 3.7.5) would establish incentive compatibility for repowering that improves reliability and quality of power generation with modern turbine designs (see section 3.4). The discrepancy between actual generation and nameplate capacity in the wind industry is partly due to older turbine technology; modern and future technology will be more reliable and will minimize this capacity discrepancy.

Finally, legal limitations may constrain project design such that it is no longer a viable business decision. For example, total generating capacity of wind farms in Altamont Pass has been capped at 583 MW until operators can prove they can reduce bird deaths (windenergynews.blogspot.com, 2005). Such a constraint eliminates the potential repowering benefit of increased nameplate capacity. Conflict with other wind operators due to wake effects that reduce power generation for downwind turbines may limit the allowable configurations of a repowering project.

3.8.3 Environment (avian, roads)

Concern for bird deaths caused by wind turbines is especially strong in the Altamont Pass area due to better habitat attracting larger avian populations. As mentioned previously, this concern has motivated policy restrictions on the number, size, and placement of turbines for new and repowering projects.

The federal Migratory Bird Treaty Act prohibits killing raptors and other migratory birds. Disagreement about avian mortality can lead to litigation that slows or even blocks repowering projects. For example, the Center for Biological Diversity, Golden Gate Audubon Society and Californians for Renewable Energy twice appealed the eastern Alameda County zoning board’s renewal of permits for nearly all the 4,000

Altamont turbines in the county in 2003 and 2004 (with some renewals into perpetuity at the request of the companies; Kay, 2004). In 2004, the Center for Biological Diversity sued FPL Group Inc. (the parent company of FPL Energy) and Danish wind-power company NEG Micon for killing protected species in Altamont. The settlement in 2007 included mitigation measures to reduce bird deaths and seasonal shutdown of some turbines.

Repowering has, however, been used pro-actively to avoid such litigation. Babcock and Brown's repowering of Buena Vista (see section 3.10.1.3) is an example of such an approach (Scanlon, 2008). Babcock and Brown approached Attorney General Bill Lockyer and reached an agreement (in May, 2006) that assured B&B no legal action would be taken against it as long as it met certain conditions in the repowering projects (e.g., independent and impartial monitoring of Buena Vista for bird carcassas). The settlement was justified based on the idea that these data would help future repowering projects be done in a manner to best reduce bird kill. The agreement also stipulated that if Buena Vista did not reduce avian deaths 50 percent from the base level of 54 per year, Babcock and Brown would be obligated to start decommissioning the existing turbines at Tres Vaqueros beginning in September, 2012. Babcock and Brown also paid $350,000 each for Buena Vista and Tres Vaqueros repowering into a conservation fund run by the California Fish and Game Department, and paid $1,000 per MW-year in mitigation fees to the Contra Costa avian mitigation fund. The settlement provided security against lawsuits that allowed Babcock and Brown to get the $65 to $70 million of funding needed per project for turbines, associated infrastructure, labor, and legal costs).[126] Facing the incentive of mandatory decommissioning of the Tres Vaqueros project for insufficient reduction in avian mortality, Babcock and Brown also chose to work with Shawn Smallwood (an avian mortality expert) on placement of new turbines. The unique set of circumstances faced by Babcock and Brown, and the creative settlement agreement they were able to negotiate, is one reason why they were able to repower some of their facilities in Altamont while others did not.

Although research has improved our understanding of turbine-caused avian mortality, the implication for reducing such mortality in the course of repowering is somewhat uncertain. On one hand, Thelander and Smallwood (2004) estimated mortality rate of 0.19 birds per turbine per year in the Altamont Pass area, of which approximately one-half were raptors (mostly red-tailed hawks).[127] They also suggested that repowering would not reduce the number of birds killed because “the number of bird fatalities per turbine string increases in relation to the total rotor swept area” and more birds were killed on tubular than lattice towers, suggesting that “it is reasonable to infer that reducing the number of turbines in a particular area will not result in a reduction in bird fatalities unless the total rotor swept area is also reduced [and] it is reasonable to expect that the number of bird fatalities at fewer post-repowering turbines should remain nearly equal to the number of kills reported at the more numerous pre-repowering turbines.”

Others, however, have suggested that Thelander and Smallwood’s estimate of avian mortality was too high (EcoStat, 2007). A subsequent study by Smallwood (2006)

[126] Note, another source (Jane Kay, Chronicle, “Taming the deadly wind farm,” Dec. 19, 2004) said the Buena Vista repowering would cost $40 million at $1 million per MW for new turbines (total repowering was 38 MW).
[127] Of 5,000 deaths annually, 24 were golden eagles (a protected species).

specifically on the Diablo Winds repowering project (see section 3.10.1.2) found the following:

> "Mortality estimates caused by the new and replaced wind turbines indicated overall bird mortality was reduced 70% by the Diablo Winds Energy Project, and raptor mortality was reduced 62%. Burrowing owl mortality was reduced 85%, and most of the total bird mortality reduction appeared to be among song birds. On the other hand, red-tailed hawk mortality increased nearly three-fold, and some species were killed by Diablo Winds that were not reported killed by the replaced turbines during Smallwood and Thelander's study, including golden eagle and bats. Differences in mortality were likely due to the reduced number of wind turbines, turbine siting, and the increased height above the ground of the turbines… Also, the repowering did not change the risk of collision for all raptors or all birds, perhaps because avian utilization of the Diablo Winds project site declined along with mortality between studies…"

A CEC consultant report concluded in 2004 that research findings that "repowering with larger turbines at safer locations may be key to reducing bird deaths at Altamont" were "sufficiently robust" for the wind industry to begin repowering with larger turbines in safer locations, or implementing measures to avoid or reduce bird deaths (CEC, 2004).

Decisions for turbine locations made in the course of repowering may be important for avian mortality. A study by Smallwood and Neher (2004) found that red-tailed hawk, American kestrel and golden eagle tend to fly over the windward rather than leeward side of hills. The implication is that locating turbines on the "prevailing leeward aspects of ridges and hills should result in reduced encounter frequencies between flying raptors and wind turbines" (Smallwood and Neher, 2004). Subsequent research is investigating power production differentials by turbine location to evaluate whether an "economically viable wind farm design" could be developed that also "minimizes bird mortality." Since energy production from a wind turbine varies with the cube of wind speed, turbine location in ideal wind conditions is important to long-term power production and project economics.

The issue of avian mortality with wind repowering is complicated, with the results for reduced avian mortality likely depending on the details of execution for each project. Avian mortality has dissuaded and blocked repowering as well as motivated it in the past.

3.8.4 Turbine Supply and Human Resources

The turbine manufacturing industry has been subjected to boom and bust cycles in the United States due to uncertainty in renewal of the federal production tax credit (Figure 48) and lack of sustained demand. The result is insufficient supply of the variable-speed megawatt-size turbines that have become the industry standard, and lag times of two years or more between placing an order and equipment delivery.[128] However, it may now be the case that renewable portfolio standards and regulatory responses to global warming concerns will create sustained demand for wind turbines even absent the PTC (personal communication, Hugh Merriam, April 6, 2009).

Extensions in project timeline that delay the start of revenue-generating power production put strain on project financing. Project owners considering repowering (or greenfield developments) are thus faced with the difficult task of placing turbine orders years in advance, when project uncertainties may be yet to resolve, or developing project plans over a longer period of time, which entails additional cost. In such a shortage environment, it may be easier to obtain new turbines for large greenfield developments than for repowering projects that tend to be relatively small (Wiser et al., 2008). In any

[128] An industry that expands and contracts frequently may also exist in permanent disequilibrium, meaning production costs have not been driven down by a competitively efficient marketplace and turbine prices are therefore higher than they would otherwise be.

case, the difficulty that delays in turbine supply cause for assembling the pieces of a repowering project may be enough to prevent some projects from implementation.

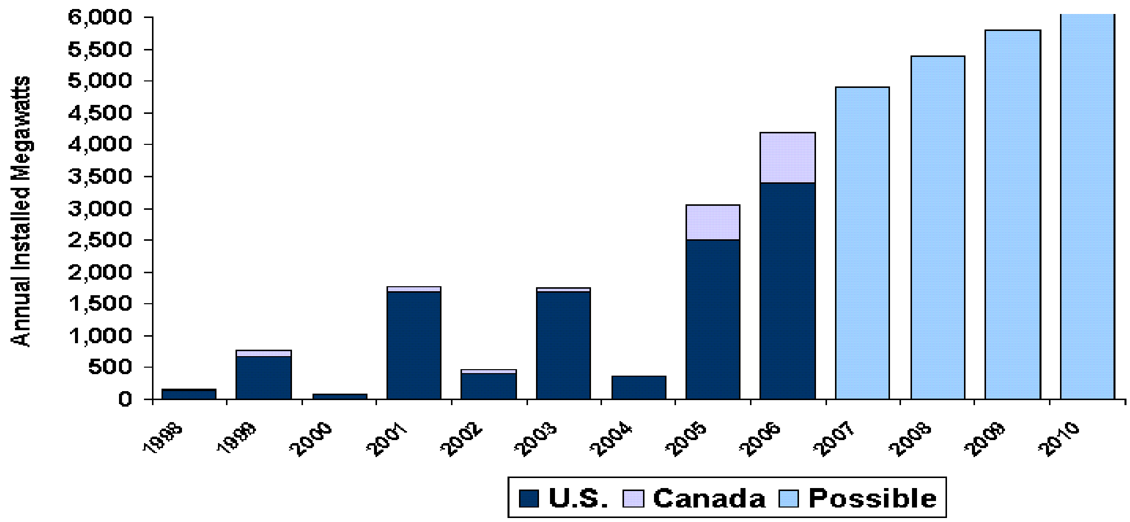

Figure 48: The impact of uncertainty in federal Production Tax Credit renewal on turbine manufacturers has been an unstable, cyclical market for turbine installations (Soby, 2006). The result in today's market, where high prices for alternative energy sources and renewable portfolio standards are pushing demand, is disequilibrium with insufficient supply. Market shares (global, 1.5 MW segment) for turbine manufacturers in 2005 were Vestas (28%, 42%), GE Wind (18%, small), Enercon (14%, 23%), Gamesa (13%, 14%), Suzlon (6%, small), Siemens (6%, 9%), others (15%, 12%).

The pool of skilled workers for the wind industry has been impacted similarly by the boom-bust cycle caused by PTC renewal uncertainty, compounded by rapidly evolving turbine technology. In some cases, "lack of human resources to work on repowering opportunities, when demand for new greenfield projects is at an all-time high," can force the repowering project to a back burner (Wiser et al., 2008).

3.8.5 Tower Heights (FAA, military regulations)

The optimum height for modern wind turbines is generally between 350 and 550 feet (Romanowitz, 2006). Power is proportional to wind velocity cubed and the exponent

$^1/_7$ is a rule of thumb for wind shear, so there is strong incentive to build towers taller to increase power production. But these turbine heights are tall enough to cause conflict with aircraft if located in flight paths. For example, the Tehachapi wind resource area is close to Edwards Airforce Base, which has some low-level planes flying *below* the wind turbines.[129] The Federal Aviation Administration (FAA) considers wind turbines obstructions to air navigation due to their height (Patterson, 2005). Wind project owners are reluctant to reduce tower heights, however, due to the aforementioned wind speed and power production increases with height.

In San Gorgonio Pass, a wind project (called a Wind Energy Conversion System, or WECS) may request heights up to 500 feet. In Tehachapi, an agreement between the county, military bases and wind producers was reached that "caps the height of turbines at 400 feet in some places and 600 feet in others" (Schuster, 2007). A precedent-setting map of zoning has been developed delineating differential tower height zones that protects critical military flight paths while allowing taller turbines in non-critical areas. Having this zoning in place has enabled moving forward on wind projects with certainty.

[129] Military aircraft are allowed to fly at 200 feet above the ground.

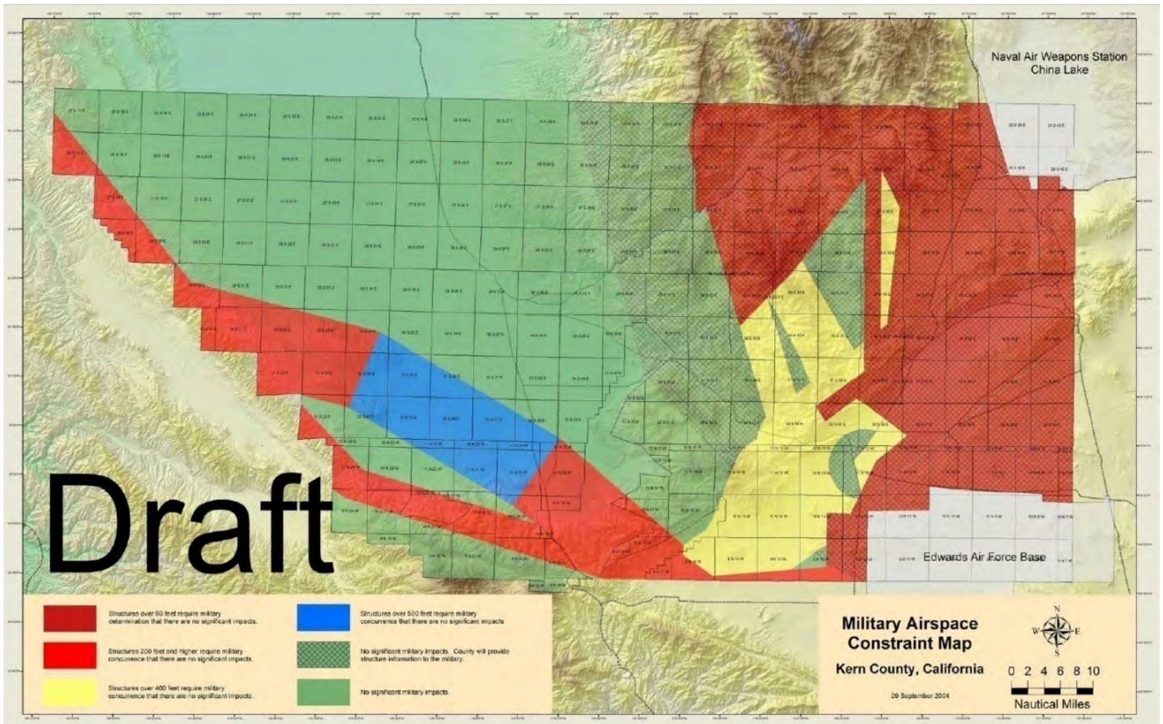

Figure 49: Wind turbine height zoning map for military airspace in the Tehachapi pass area. Turbine height is unlimited in green areas, limited to 500 feet or less in blue areas, to 400 feet or less in yellow areas, and to 200 feet or less in red areas (critical military flight paths).

3.8.6 Setbacks and Building Codes

Setback requirements for wind turbines have been implemented at the county level primarily to "reduce the risk of damage or injury from fragments resulting from wind turbine rotor failures" (Larwood and van Dam, 2006).[130] Since the distance such fragments travel is a function of the release velocity and height, setback requirements have generally been based on "overall turbine height," which is the tower height plus blade radius (Figure 50).

[130] Other reasons for setbacks include scenic protection, consideration of acoustic impacts, and other property-specific conditions.

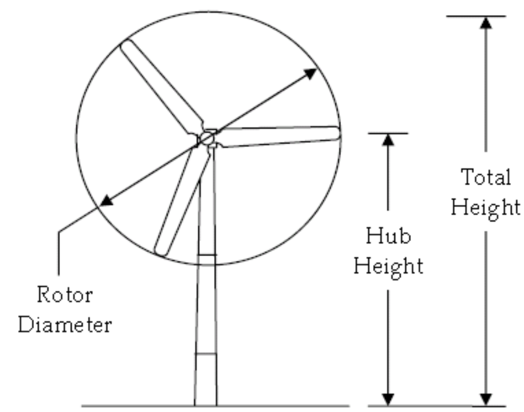

Figure 50: Wind turbine dimensions (Larwood and van Dam, 2006)

The transition to taller machines with longer blades that generally characterizes wind project repowering (Appendix A) can be precluded by setback requirements if land parcels are too small. In any case, setback requirements can reduce the number of larger modern machines that can be placed on an existing project site, thereby "reducing the economic viability" of the decision to repower (Larwood and van Dam, 2006). In fact, setbacks can cause total energy production to be less with larger, modern turbines than with smaller, older machines (Figure 51).

Current setbacks vary by county but generally use a fixed distance and/or "multiple of overall turbine height." Three times overall turbine height from the property line is a common setback, with the typical range being 1.25 to 3 times overall turbine height (larger for special areas; Table 30).[131] The minimum setback is for adjacent wind energy zoning in Riverside County. Alameda County adjusts its setbacks for sloping terrain. All counties except Riverside County allow for reduction of the setback distance with special consideration.[132] Merced County (Pacheco Pass area) and San Joaquin County (Altamont Pass area) use standard building setbacks for wind turbines in

[131] Although the technical basis for setbacks is obscure at best, the setback distance of three times the total turbine height may have come out of the context of intense development in Riverside County, where the expectation of in-row spacing at six diameters for wake effects led to the conclusion that, "adjacent parcels would require spacing of at least half this distance" (Larwood and van Dam, 2006).
[132] "The Altamont Repowering EIR (Alameda County 1998) is an example of a reduced setback, which resulted from a developer submitting a rotor fragment risk analysis as substantiation for the reduction" (Larwood and van Dam, 2006).

agricultural districts. In San Gorgonio Pass (Riverside County), scenic setbacks require ¼ mile from all scenic highways, 500 to 1,000 feet from I-10 east of highway 111, and 2/3 mile from highway 111 south of I-10 and north of Palm Springs. Safety setbacks in San Gorgonio Pass also require five rotor diameters from lot lines perpendicularly (or within 45 degrees of perpendicular) downwind of the predominant with direction, and 1.25 times turbine height for above-ground transmission. For Tehachapi pass, Kern County wind energy ordinance regulates lot size, height limits, roads, and distance between structures.

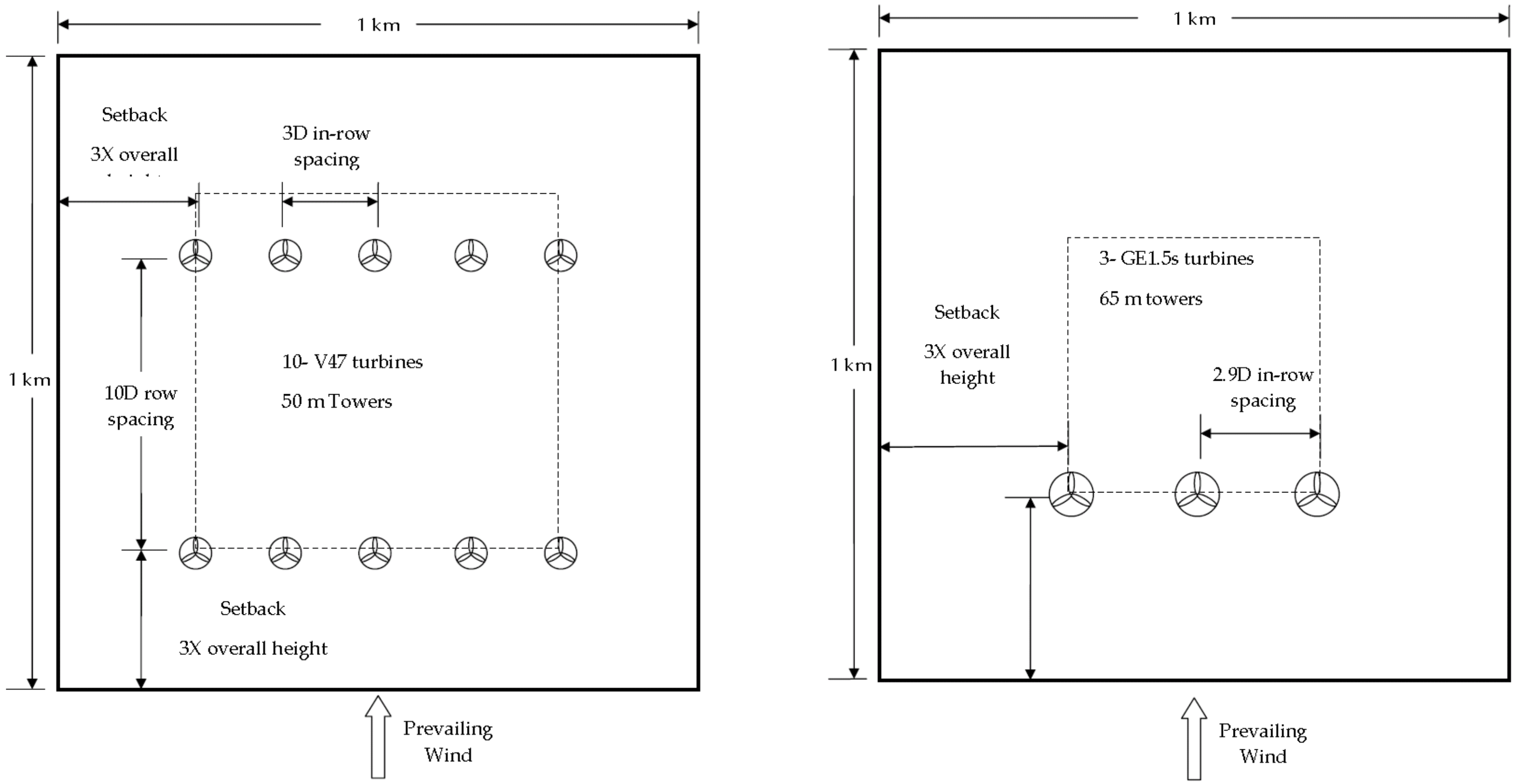

Figure 51: Turbine layouts based on setback requirement of three times total turbine height for Vestas V-47 660 kW turbines on 50-meter towers (left panel) and GE 1.5 MW turbines on 65-meter towers (Larwood and van Dam, 2006). Total nameplate capacity is larger for the older, smaller Vestas machines (6.6 MW) than for the newer, larger GE machines (4.5 MW) due to setback and turbine spacing requirements.[133]

[133] Note, turbine row spacing perpendicular to the prevailing wind is largely determined to optimize power production subject to array loss, or the shading effect of each turbine reducing the wind speed and introducing turbulence for downwind turbines. Variation in prevailing wind direction, topography, and interaction with neighboring wind developments can all add complication to the simplified picture of turbine location presented in this figure.

County	Property Line	Dwelling	Roads	Reductions in Setbacks
Alameda	3x / 300 ft (91 m), more on a slope	3x / 500 ft (152 m) more on a slope	3x / 500 ft (152 m), 6x / 500 ft from I-580, more on sloped terrain	maximum 50% reduction from building site or dwelling unit but minimum 1.25x, road setback to no less than 300 ft (91 m)
Contra Costa	3x / 500 ft (152 m)	1000 ft (305 m)	None	Exceptions not specified in ordinance can be filed with county
Kern	4x / 500 ft (152 m) <40 acres or not wind energy zone 1.5x for >40 acres	4x / 1000 ft (305 m) off-site	1.5x	With agreement from adjacent owners to no less than 1.5x
Riverside	1.1x to adjacent wind energy zones	3x / 500 ft (152 m) to lot line with dwelling	1.25x for lightly traveled, 1.5x / 500 ft (152 m) for highly traveled.	None
Solano	3x / 1,000 ft (304 m) adjacent to residential zoning 3x from other zonings	3x / 1,000 ft (304 m)	3x	Setback waived with agreement from owners of adjacent parcels with wind turbines

Table 30: Safety setbacks by county (Larwood and van Dam, 2006; for reference purposes only, check counties for current zoning requirements). When a fixed distance is included with the multiple of overall turbine height, the maximum of the two values is used for the setback.

However, since tip speed generally does not increase with machine size due to fewer revolutions per minute, the salient factor for setbacks with larger turbines may only be the increase in release height (Figure 52). Consequently, careful review of setbacks to establish acceptable hazard probability based on "formal analysis of the rotor fragment hazard" may result in smaller setbacks that reduce this barrier to repowering. The end result would be "risk-based setback standards" (ibid).[134]

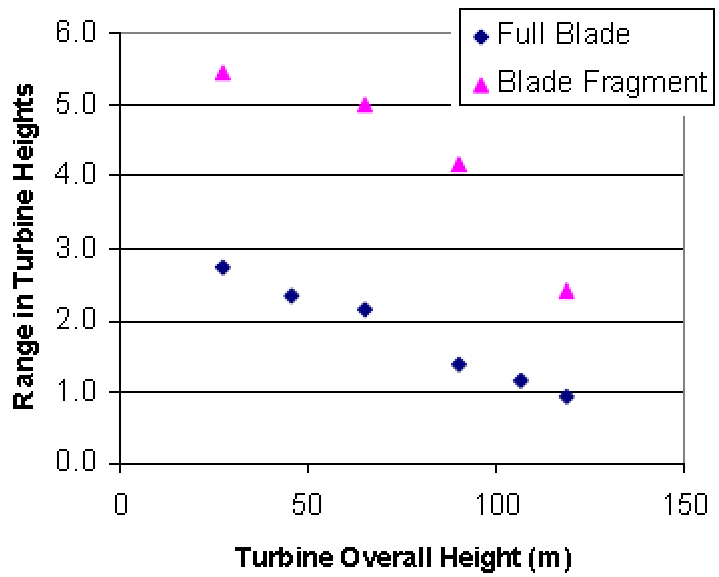

Figure 52: Rotor fragment analyses documenting maximum lateral throw range for failure under nominal operating conditions for a variety of turbine heights (Larwood and van Dam, 2006). As overall turbine height increases, the normalized maximum throw distance decreases because tip speed remains constant. Such results suggest that "setbacks based on overall turbine height may be reduced for larger turbines," which would reduce the barrier of setbacks for repowering decisions (ibid). Higher initial velocity causes blade fragments to fly farther than full blades.

[134] Larwood and van Dam (2006) found the probability of rotor failure to be "in the 1-in-1000 per turbine per year range." They also concluded that, "modern wind turbines might offer higher reliability, thus lowering the risk of rotor failure," and that since the "hazard area is governed by the blade tip speed" and "tip speed tends to remain constant with turbine size… more appropriate setbacks might be a fixed distance, and not a function of the turbine size." Such a change would reduce the barrier setbacks based on multiples of overall turbine height pose to repowering decisions.

3.8.7 Transmission Capacity

Since the major wind areas in California are located some distance from electricity demand centers, adequate transmission capacity is necessary to bring wind power to market. The relatively low capacity factor for wind generation, however, poses a challenge for investment in dedicated transmission infrastructure since it too would suffer from low capacity factor. Consequently, insufficient transmission capacity is a frequent constraint for wind power development and is particularly limiting for connecting the Tehachapi area (wind) and the Imperial Valley (geothermal) to heavily populated areas.

> "The state's renewable resource potential is more than sufficient to achieve the RPS goal of 20% renewable energy generation, although transmission capability constrains our ability to tap renewable energy in several key resource areas."
> ~ (Shiu, 2007).

Repowering with modern variable-speed turbines can mitigate transmission constraints by reducing reactive power (see section 3.4), but any associated increase in nameplate capacity will require additional transmission capacity.[135] Thus, one of the primary benefits of repowering – increasing power production from a given wind resource – is often constrained by transmission capacity.

Approval of additional transmission capacity has been a necessary condition for repowering in some cases. For example, in 2005 Southern California Edison issued a solicitation for renewable energy and subsequently signed the largest wind energy contract in US renewable industry history. But the 1,500 MW of wind power from Alta Windpower Development LLC to be provided by 50 square miles of turbines in the Tehachapi region required new transmission capacity. "The success of the large wind

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[135] Likewise for improvement in capacity factor if the available transmission capacity is consistently utilized by a combination of power sources.

project announced today depends on SCE receiving authorization from the CPUC and other regulatory agencies to construct a series of new and upgraded high-voltage transmission lines that would deliver electricity from potential new wind farms in the Tehachapi area" (Edison International, 2006).

Current transmission planning evolved logically as engineers identified needs (i.e., problems with system reliability), identified solutions, studied the solutions identified, and identified a preferred alternative (Shirmohammadi, 2006). Planning of the electricity grid was the result of an internal utility decision-making process. Now, however, regulators, utilities, generation owners, and system operators work together to develop the most "reasonable and cost effective" transmission plan. This more complicated process involves a kind of regional (horizontal) planning with many entities involved (vertical planning) that has led to more transmission projects due to valuation of previously unrecognized benefits (ibid). For example, these projects may deliver economic benefits from enhanced competition, from improved supplier access to markets and improved consumer access to more resources and generation. Incorporation of policy considerations and economic externalities in the planning process can promote environmental benefits.

After a drought in major transmission upgrades since the early 1980s, twenty-six transmission projects totaling $3.2 billion were approved between mid-2005 and the end of 2006 (Shirmohammadi, 2006). The largest of these projects, including Palo Verde – Devers 2 ($700 million), TransBay ($350 million), and Sunrise/Greenpath ($1.1 billion) are shown in Appendix D. Transmission projects are presented to the CAISO and FERC as integrating resources in a "least-cost best-fit" solution with "heavy reference to economic and reliability benefits of the infrastructure" (ibid).

Large transmission projects are normally justified on an economic basis, but may also address major regional reliability issues for many users. Environmentally-driven transmission projects can also provide reliability and economic benefits *if* planned. For example, the Sunrise and Tehachapi projects are intended to provide access to renewable resources but also provide reliability and economic benefits.

The primary purpose of the Sunrise Powerlink (also known as the GreenPath or SunPath project) is to provide access to renewable resources in the Salton Sea area. However, the project also provides significant economic benefit to rate payers (an estimated 1.5 benefit/cost ratio) and solves a reliability problem for the San Diego area caused by current energy import limitations (Shirmohammadi, 2006).

The Tehachapi Transmission Project will establish a network backbone system in the Tehachapi area capable of supporting 6,000 MW of renewable generation capacity in the area, enabling approximately 4,500 MW of new generation capacity to come onto the grid (Appendix E). But the project also provides positive economic value for ratepayers, addresses reliability needs of the CAISO grid, provides for future low-cost expansion capability for Path 26, and provides for the potential to integrate planned renewable resources in Inyo and northern San Bernardino counties (Shirmohammadi, 2006).

Use of existing right of way can facilitate transmission projects (Appendix E), but timely permitting from the CPUC and County government are necessary as well as availability of key components like transformers, breakers, power steel, and contractors.

Especially for the larger capacity expansions, project management to coordinate parallel work is essential.

Ongoing activities suggest new transmission infrastructure may enable additional wind generation capacity to come online in some areas. Allowance by FERC of additional profit incentives for transmission owners may also encourage greater investment (Wiser and Bolinger, 2007). The Western Governor's Association has set a goal for 30 GW of clean energy generating capacity that includes recommendations for transmission expansion and more efficient use of existing transmission. Several states are also proactively developing transmission infrastructure for wind, like the CREZ project in Texas, Tehachapi project in California, and CapX 2020 project for MidWest states. The US DOE has developed draft designations of two National Interest Electric Transmission Corridors, and the FERC has approved in principal a proposal from the California ISO for a new category of transmission to better serve wind.

3.8.7.1 Technical considerations for interconnection and transmission of wind

Although the following technical problems with interconnection and transmission of wind power were adequately resolved during the initial wind rush of the early 1980s, higher wind penetration motivated by RPS requirements and energy economics may require revisiting some with new solutions (Behnke and Erdman, 2006; Putnam, 1996). Some new wind technologies offer unique abilities to mitigate these technical considerations. Consequently, while adequate transmission capacity (and associated capital cost) may form a barrier to repowering with more installed capacity, the technical considerations for grid interconnection and transmission that re-emerge as wind penetration increases may serve to motivate repowering with new technology *if* the services these technologies can provide are rewarded in power purchase contracts.[136]

Reactive power control and voltage regulation – early turbine designs based on constant speed induction generators presented large reactive loads to the grid, which "created unnecessary loading and losses in the transmission system" and "created a voltage drop which violated planning and operational voltage regulation criteria" (Behnke and Erdman, 2006).

Reactive power refers to phase error in current and voltage (Figure 53). In alternating-current circuits, inductive reactance is common because the current flow lags the voltage pushing it due to time lag in the magnetic field. The result is that a circuit with many generators (e.g., power from a wind farm) will provide real or active power that is in-phase with voltage and reactive power that is out of phase with voltage. The reactive power uses transmission capacity but does not do any work. Consequently, power purchase agreements often stipulate a penalty for excessive reactive power and regulatory limits have emerged in Europe and the United States (Behnke and Erdman, 2006).

Power correction capacitors, installed by wind plant operators in response to financial penalties imposed by utilities for excessive reactive power consumption, fixed the problem in Altamont (Behnke and Erdman, 2006). In Tehachapi, where higher winds produce higher peak power generation (especially with repowering with new technology that can continue to generate in high winds) and where the distance from market makes for high source impedance, the severe problems with voltage regulation were solved until 2000 more crudely by simply curtailing wind production (with the utility paying for the undelivered power).

[136] see section 0 for discussion of the indirect cost of integration for intermittent wind power.

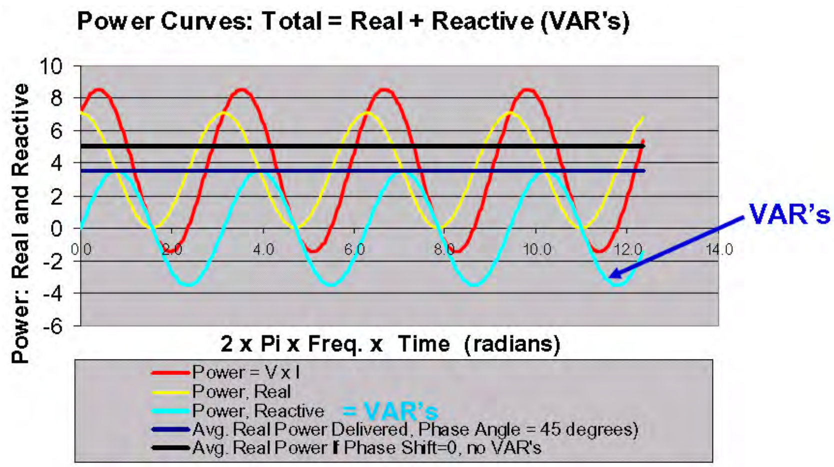

Figure 53: The impact of reactive power (blue) on real power (yellow). Average power (real) is *reduced* when phase shift is not zero. Reactive power (VAR) has average value of zero and thus transmits *zero* power to loads while still "consuming" space in wires and producing losses. Reducing VAR increases the amount of real energy that can be sold to customers.

"Wind plants are required to have some level of reactive power management capability. This can range from a requirement to provide sufficient reactive power compensation to provide for the plant's own reactive power consumption (within some bandwidth) to providing fast dynamic voltage control at the wind plant's point of interconnection with the transmission system operator" (Behnke and Erdman, 2006). In the United States, "wind plant[s] [are] required to have the capability to operate over a range of power factors from 0.95 over-excited (sourcing reactive power) to 0.95 under-excited (absorbing reactive power), but only if this is determined to be required for reliability reasons in the interconnection system impact study" (ibid). The ability to provide leading reactance (also called capacitive reactance) with modern power electronics can provide value to transmission system operators by offsetting reactive power. If this value is incorporated in power purchase contracts, it could provide additional financial reward for repowering.[137] And since modern wind plants can "source or sink reactive power even

[137] Many interconnection agreements have included a VAr or power factor requirement since about 1990, but few if any include payment for VAr support (a.k.a. leading reactive power).

during periods of time when the wind turbines themselves are not producing any active power…they are available to provide voltage regulation support regardless of wind condition," although no current contracts provide "financial incentives to capitalize on this capability" (Behnke and Erdman, 2006).

Harmonics, or periodic distortions of the supply voltage, "result from the flow of harmonic currents generated by nonlinear loads or generators through the source impedance at the location of the nonlinear device" (Behnke and Erdman, 2006). Although power electronic devices (rectifiers, inverters, converters) can be the source of current distortion, the variable-speed wind turbines with power electronic converters installed in the mid-1990s incorporated high frequency switching to mitigate the power quality problems of older converter technology (Behnke and Erdman, 2006).

Frequency control and operating reserves – at modest levels of wind penetration, the variation in wind generation was small relative to variations in load, so frequency control was not a problem and utilities did not have to alter their spinning or non-spinning reserve requirements (Behnke and Erdman, 2006). However, as wind penetration increases to fill a large share of the 20% level for renewables required by the RPS, the issue of frequency control and operating reserves may become salient.[136]

Stability has not been a documented problem, perhaps due to turbine rotors' large moments of inertia but more likely because of low wind penetration with sufficient spinning reserves (both of which may change in the future). But transient stability (i.e., the ability to return to stable operation after a major disturbance like transmission short circuits or large generating unit trips offline) is one of the major drivers behind recent low-voltage ride-through requirements for wind turbines (Behnke and Erdman, 2006).

Wind plants are now required to “ride through, or stay connected to the network and able to deliver power, during low voltage transients of a given magnitude and time duration” (Behnke and Erdman, 2006). This new requirement may contribute to the motivation to repower since older equipment will need retrofit to meet the ride through requirement.

Voltage Flicker, or momentary sags in line voltage that are perceptible in flickering lights, results from time-varying voltage sources. For wind turbines, such voltage fluctuations can come from power fluctuation in turbulent winds, from the magnetizing inrush current that occurs when generators are first re-connected to the grid after shutting down, and from pulsation in power production as turbine blades pass into the wind shadow created by the turbine tower. The first and third causes of flicker are mitigated when aggregated over a large wind plant with spatial diversity. The second effect is mitigated by control systems that bring turbines back online gradually and sequentially, thereby avoiding abrupt connection of many machines simultaneously. “Constant and dual speed machines offered in the current market are equipped with ‘soft starters’, power electronic devices that slowly ramp the excitation to the induction generator, which significantly reduces the inrush current, and, hence, the flicker associated with startup. “Variable speed machines, with their power electronics interfaces, have inherent current limitation capabilities which virtually eliminate inrush” (Behnke and Erdman, 2006). Here, then, is an example of service provided to the electric transmission system by modern wind technology that could provide incentive to repower if monetized.

SCADA Systems and TSO management of wind plants. The FERC requires wind plants to have *SCADA systems* (Supervisory Control and Data Acquisition) that provide real-time data to transmission system operators. The details of these data and their communication are left to the contracting parties (Behnke and Erdman, 2006). This is another example of technology-forcing regulation that could help motivate earlier repowering if current equipment will need retrofit to comply.

Furthermore, allowing the Transmission System Operator (TSO) to reduce wind plant power output directly through the SCADA system to manage deliverability and reliability in high-wind/low-load system conditions could also add value, if incorporated into operating systems and power purchase agreements (Behnke and Erdman, 2006). In the Danish market, where wind penetration is close to 100 percent in high-wind/low-load conditions, this "controllable power" is required at the turbine level for 20% to 100% of rated capacity. "This requirement has effectively eliminated stall regulated turbines from the Danish market, as they are unable to shed power in high winds to meet this new requirement" (Behnke and Erdman, 2006). With enough control over power output, wind plants could contribute to spinning reserve and frequency regulation through average operation below the power level available from prevailing wind conditions at each moment in time (ibid). However, the value of spinning reserve would need to outweigh the value of foregone energy production.

A related concept is *ramp rate control.* As wind plant power production varies over longer periods of time with variations in wind speed, other power plants on the grid must balance wind power output relative to load. Since many thermal power plants have significant inertia that limit their ramp rate up or down, the longer-term variability in wind production presents a problem as penetration rates increase. "While ramp rate control is in direct conflict with current wind turbine design goals of optimizing energy production, it is technically possible through a combination of wind plant and wind turbine control strategies, and is under consideration as part of RPS implementation in other states" (Behnke and Erdman, 2006). However, negative ramp rate control (i.e., limiting the rate at which power production falls as the wind drops off) may be difficult/expensive relative to positive ramp rate control (i.e., limiting the rate at which power production increases as the wind comes up) since the former requires some form of energy storage while the latter is easily accomplished with blade pitch control to shed aerodynamic lift (Behnke and Erdman, 2006).

3.9 Repowering for the 80in50 Transition Paths

In this section, I calculate the annual quantity of incremental wind capacity through repowering and expansion of wind power developments required to achieve the electricity decarbonization path for each 80in50 scenario shown in Chapter 2 (Figure 20). The incremental wind capacity is measured in the number of 2-MW turbines and capital investment required, with evaluation of implications for potential actions needed to address and remove some barriers identified in this chapter (i.e., setback requirements and parcel size, time required for permitting and environmental review, transmission capacity).

I assume the wind-source electricity used for transportation in charging plug-in LDV must be *incremental* because electricity production from existing wind turbines is already spoken for in the marketplace and by utilities in meeting their RPS and GHG emission reduction targets.

Although there are big uncertainties in projecting total electricity demand in California in 2050 (McCarthy et al., 2008), it is likely that a large amount of renewable-source electricity will be needed in the electric generation sector to meet 33% (or higher) RPS requirements and GHG emission reduction targets. Consequently, some analyses suggest that massive expansion of all renewable-source electric generation capacity, including wind, may be needed for the electric generation sector, meaning incremental wind-source electricity may not be available for use in transportation (RETI, 2010; personal communication, Alexander "Sandy" Allan).

However, for the analysis presented in this section I further assume that *all* incremental wind generation is used for transportation, specifically for charging plug-in LDV, and that *no other* renewable-source generation is used for charging these vehicles. In other words, the fraction of total electricity for plug-in LDV that must be renewable-source electricity in each 80in50 scenario is generated entirely with incremental wind production.

This assumption may be a reasonable approximation given the intermittency of wind and poor match with daily peak electricity demands (i.e., the wind blows more at night), which makes integration of large scale wind a challenge for electric grid operators.[138] The off-peak charging and energy storage potential of plug-in LDV fleets therefore make them an attractive use of wind-source electricity (McCarthy and Yang, 2009; Short and Denholm, 2006). In contrast, incremental generation from other renewable resources like solar, hydroelectric, geothermal and tidal may be used to meet renewable portfolio standards and GHG emission reduction goals in the electric generation sector due to the better predictability and match to electricity demand profiles of these resources. However, to the extent other renewable resources are used to supply electricity for plug-in LDV, the amount of annual incremental wind capacity will be less than shown in this section.

[138] "Variability in wind output implies limited predictability; high natural ramp rates; and, often, limited coincidence with peak demand. These factors can restrict the ultimate penetration of wind power into traditional electric power systems" (Short and Denholm, 2006).

3.9.1 Annual Wind Capacity Increase for Plug-In LDV

The paths of increasing electricity demand for charging plug-in LDV in each 80in50 scenario are shown in Chapter 2 (Figure 20). In particular, the total quantity of renewable-source electricity required in 2050 ranges from approximately 14,000 to 30,000 GWh/year in all but the *Efficient Biofuels* scenario. To meet this level of demand from incremental wind generation in California will require large increases in generation capacity.

There are two types of capacity increase that may occur. First, new turbines will eventually be needed to repower existing capacity when the old turbines cease to operate. An increase in capacity of 25 to 35 percent may occur in the process of repowering, as discussed in the introduction to this chapter. For the analysis presented in this section, I abstract from the detailed inventory of potential barriers and benefits presented in the rest of the chapter by making the simple assumption of a 30-year average lifespan for all turbines. Under this assumption, a turbine will be replaced once it reaches 30 years of service. Since this assumption contradicts the notion that project-specific conditions are salient for repowering decisions, the analysis presented herein should be interpreted as a scenario approach, consistent with the rest of the 80in50 modeling, that enables evaluation of what repowering and capacity increase may *need* to happen in order to meet the 80in50 goal for transportation.

Second, additional new turbines may be needed in order to increase capacity and electricity generation to the levels required for plug-in LDV charging in some 80in50 scenarios. These new turbines may be located in existing wind developments through more efficient use of land area and available wind resource or may occur on greenfield sites through expansion of the wind development.

The annual requirements for incremental wind-source electricity generation specified by the transition path modeling for each 80in50 scenario in Chapter 2 determine the total capacity of wind turbines needed in each year from 2010 through 2050. The number of *new* turbines that must be built each year to deliver this capacity is the sum of capacity increase and capacity lost due to retirement of 30-year-old turbines divided by the average size of new turbines. Based on recent trends in sizing for land-based turbines, I assume an average new turbine size of 2 MW with 35% average capacity factor (Wiser and Bolinger, 2008; Table 31).

Turbine Size Range	1998-99	2000-01	2002-03	2004-05	2006	2007
Total Capacity (MW)	1018	1758	2125	2776	2454	5329
Total Number	1425	1987	1757	1960	1532	3230
0.05-0.5 MW	1%	0%	1%	2%	1%	0%
0.51-1.0 MW	99%	74%	43%	19%	11%	11%
1.01-1.5 MW	0%	25%	44%	56%	54%	49%
1.51-2.0 MW	0%	0%	13%	24%	18%	24%
2.01-2.5 MW	0%	0%	0%	0%	16%	15%
2.51-3.0 MW	0%	0%	0%	0%	1%	1%

Table 31: Size distribution of new turbines installed in the United States from 1998 – 2007 (Wiser and Bolinger, 2008).

Actual project-level data from the California Energy Commission Wind Performance Report database were used to quantify the existing stock of wind turbines in the four major wind resource areas of California (Altamont, Tehachapi, San Gorgonio and Solano) in terms of age and size (Table 32). Annual repowering was then calculated according to a three-year smoothing of cohorts reaching 30 years of service (i.e., repowering of the total number of turbines reaching age 30 in a given year is spread evenly over the next three years).

Year Turbines Installed	Altamont Number	Altamont Avg. Size (kW)	Tehachapi Number	Tehachapi Avg. Size (kW)	San Gorgonio Number	San Gorgonio Avg. Size (kW)	Solano Number	Solano Avg. Size (kW)
1980	0	0	0	0	0	0	0	0
1981	0	0	0	0	0	0	0	0
1982	0	0	0	0	0	0	0	0
1983	0	0	0	0	0	0	0	0
1984	0	0	0	0	0	0	0	0
1985	486	117	77	64	694	71	0	0
1986	311	65	316	92	348	83	0	0
1987	0	0	2	200	83	101	0	0
1988	0	0	55	77	0	0	0	0
1989	2868	103	686	90	345	197	34	300
1990	0	0	98	225	128	176	503	100
1991	0	0	401	214	155	97	0	0
1992	0	0	31	225	32	174	0	0
1993	0	0	28	450	0	0	0	0
1994	0	0	0	0	25	100	0	0
1995	0	0	0	0	0	0	0	0
1996	26	65	0	0	0	0	0	0
1997	0	0	220	82	47	255	0	0
1998	325	128	905	257	64	236	0	0
1999	214	78	112	458	351	225	0	0
2000	15	60	153	448	35	65	0	0
2001	0	0	0	0	125	535	0	0
2002	26	60	39	573	0	0	0	0
2003	0	0	51	309	123	351	90	1800
2004	74	152	443	236	2	660	0	0
2005	0	0	7	1500	80	300	0	0
2006	0	0	0	0	0	0	0	0
2007	0	0	0	0	0	0	0	0
2008	0	0	0	0	0	0	0	0
2009	0	0	0	0	0	0	0	0
Total Number		4,345		3,624		2,637		627
Total Capacity (kW)		445,680		751,361		443,723		222,575

Table 32: Existing stock of wind turbines in four California wind resource areas as of 2005 (calculated from the California Energy Commission Wind Performance Report database).

The results of this modeling of stock turnover and increase in the installed wind generation capacity in California are shown in Table 34 and Figure 55. In the Efficient Biofuels scenario, very little electrification in the LDV fleet occurs, which means demand for renewable-source electricity is small relative to the other 80in50 scenarios and relatively little wind capacity increase is needed. As a result, the 1,351 total new 2-MW turbines installed during the period 2010-2050 are mostly for repowering of old turbines as they reach the end of their useful life. Based on an estimated total installed project cost in California of $1,565 per kW (in 2007 dollars; Wiser and Bolinger, 2008), the total investment in new turbine equipment over this period is also relatively low at $4.2 billion (Figure 54; Table 33).

In contrast, installation of new turbines for capacity increase to meet the demand for renewable source electricity to charge plug-in LDV in the *Multi-Strategy$_{Pessimistic}$*, *Multi-Strategy$_{Middle}$*, *Multi-Strategy$_{Optimistic}$*, *Actor-Based* and *Electric-Drive* scenarios far exceeds the number of new turbines needed for repowering. The total number of new 2-MW turbines installed during the period 2010-2050 in these scenarios is 4,415, 3,848, 3,533, 5,146 and 6,579 respectively, with total investment of approximately $11.1 to $20.6 billion needed. The maximum rate of new turbine installations in these scenarios reaches approximately 150 to 300 per year around the year 2028 (Table 34). This is the result of coincident peaks in new turbines for repowering and capacity increase (Figure 55). This annual installation rate of 300 to 600 MW is approximately 8 - 17% of the total for the United States in 2006 (Figure 48) and would be a 16 - 32% increase in the 2005 installed capacity of the four primary wind areas in California.

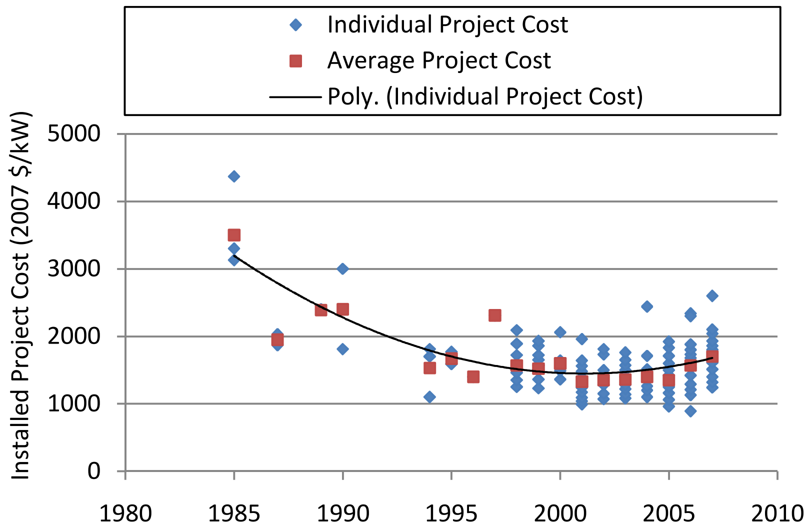

Figure 54: Installed wind project costs over time for the United States showing a reversal of the downward trend in recent years (Wiser and Bolinger, 2008).

Installed Project Cost (2007 $/kW)
$2,410
$1,690
$1,500
$1,370
$1,280
$1,140

Average: $1,565

Table 33: Installed project costs for six projects built in California from 2004 to 2007 (Wiser and Bolinger, 2008).

	Actor-Based		Efficient Biofuels		Electric Drive		Multi-Strat. Pess.		Multi-Strat. Mid.		Multi-Strat. Opt.	
Year	New Turbines	Installed Cost	New Turbines	Installed Cost	New Turbines	Installed Cost	New Turbines	Installed Cost	New Turbines	Installed Cost	New Turbine	Installed Cost
2010	2	8	2	5	14	45	6	20	6	19	7	23
2011	4	12	2	7	19	61	9	28	9	27	10	32
2012	6	20	4	11	27	83	13	40	13	40	14	45
2013	11	33	5	17	37	115	19	60	19	58	20	62
2014	18	57	8	24	49	153	28	88	27	83	27	84
2015	45	142	25	78	80	250	56	177	53	165	51	158
2016	64	202	37	115	97	302	74	231	68	213	65	203
2017	79	248	41	127	109	340	86	268	77	241	72	227
2018	83	259	30	94	107	335	84	264	71	224	66	206
2019	149	468	78	246	165	517	142	446	125	391	118	370
2020	185	580	93	290	190	595	166	521	144	451	136	424
2021	214	671	106	330	212	663	185	579	159	499	146	457
2022	179	560	52	164	171	535	138	431	110	344	103	323
2023	185	579	41	129	174	543	132	414	103	321	96	301
2024	188	589	28	88	176	552	125	391	94	294	88	275
2025	197	615	25	77	187	586	125	392	94	294	88	275
2026	200	627	21	65	197	617	124	390	93	292	87	273
2027	208	650	21	67	213	667	129	404	98	307	91	286
2028	245	767	55	172	262	820	167	522	136	425	129	402
2029	257	806	70	218	287	897	183	571	153	478	145	453
2030	263	822	72	225	307	961	180	564	160	502	151	474
2031	222	694	40	124	282	883	144	450	129	404	120	376
2032	188	589	21	64	224	701	124	387	113	355	104	324
2033	194	607	37	114	219	685	139	434	128	400	122	381
2034	188	587	40	126	201	630	141	441	131	410	107	334

2035	176	550	39	123	178	556	138	432	129	404	127	398
2036	134	419	32	102	160	500	104	327	96	302	97	303
2037	107	334	4	14	139	434	85	267	78	243	59	183
2038	92	287	0	0	129	405	77	241	70	219	74	231
2039	81	254	0	0	124	387	73	229	67	208	49	153
2040	74	232	2	5	133	415	76	238	69	217	77	242
2041	63	198	2	7	130	407	72	226	67	209	52	162
2042	56	176	4	11	131	409	72	226	67	209	54	169
2043	52	164	5	17	134	420	74	232	69	216	57	178
2044	52	162	8	24	140	438	79	248	73	230	61	192
2045	72	226	25	78	165	516	104	325	96	301	82	258
2046	85	265	37	115	176	550	118	368	108	338	94	294
2047	94	293	41	127	182	571	126	395	114	356	99	311
2048	92	289	30	94	176	550	122	380	105	329	91	284
2049	154	483	78	246	229	717	177	553	156	487	141	442
2050	186	582	93	290	250	782	198	620	172	538	157	490
TOTAL	5,146	$16,106	1,351	$4,227	6,579	$20,592	4,415	$13,820	3,848	$12,044	3,533	$11,059
TOTALS for the year 2050												
GWh/yr. for LDV		23,219		1,937		30,504		18,521		15,488		13,886
GWh/yr. Total		27,587		6,305		34,872		22,889		19,856		18,254
Turbines for LDV		3,787		316		4,975		3,020		2,526		2,265
Total All Turbines		4,499		1,028		5,687		3,733		3,238		2,977
Percent for LDV		84%		31%		87%		81%		78%		76%

Table 34: Total annual number of new 2-MW turbines and investment (2007 $ millions) required for repowering to maintain current annual electricity production plus supply the required renewable-source electricity for plug-in LDV in each 80in50 scenario from incremental wind generation. The total number of turbines and wind-source electricity generation in the year 2050 along with the share used to charge plug-in LDV are given for reference.

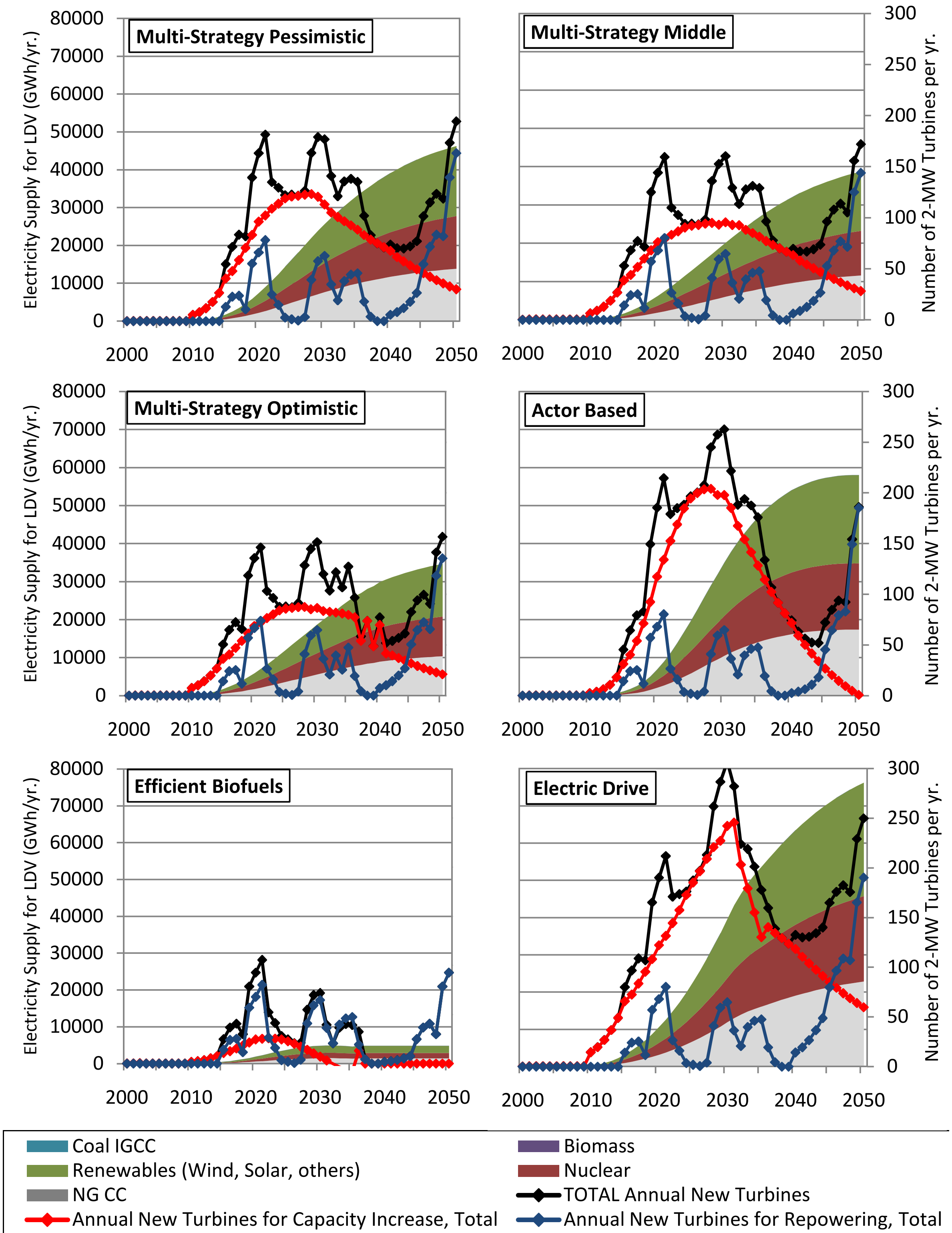

Figure 55: Annual new wind turbine installations for the repowering to maintain current annual electricity production plus capacity expansion needed to generate all renewable-source electricity for plug-in LDV in each of the 80in50 scenarios. The total quantity of electricity supply needed for charging plug-in LDV is shown, by source, for reference.

3.9.2 Implications for Actions Needed to Remove Barriers for Repowering

3.9.2.1 Decrease Setback Requirements, Increase Parcel Size or Expand Area Zoned for Wind

Turbine spacing for minimal wind interference is generally thought to be three rotor diameters when aligned perpendicular to the wind and 10 rotor diameters when parallel to the wind (Larwood and van Dam, 2006; Figure 51). Thus, the minimum area required around each turbine in an array where the wind is generally from one direction would be 10d x 3d (where d is the rotor diameter). For example, a GE 1.5-MW turbine with 70.5 meter rotor span requires at least 37 acres per tower in an array set in a location with consistent wind direction (25 acres per MW). Similarly, the Vestas V90 1.8-MW turbine with 90 meter rotor requires at least 60 acres per tower (33 acres per MW). For an array in a location with variable wind direction, the minimum area around each turbine could increase to as much as 10d x 10d.

In addition, the setback requirements for property boundaries can require additional land area in wind resource areas where parcel size is small. In Altamont, the setback requirement is generally the greater of three times overall turbine height (tower plus ½ turbine diameter) or 152 meters; in Tehachapi it is 4 times overall turbine height or 152 meters; in San Gorgonio it is 1.1 times overall turbine height; and in Solano it is three times overall turbine height or 304 meters (Table 30).

These land area requirements raise three questions pertaining to the area associated with incremental wind production from repowering and expansion with new, large turbines to supply plug-in LDV. First, by how much would the area of the existing four primary "wind farm" developments need to increase in order to accomplish each 80in50 scenario if all renewable-source electricity for vehicle charging is generated from incremental wind capacity, assuming the entire development is one homogenous parcel? Second, recognizing that each wind farm development is an amalgamation of individual parcels, what is the minimum lot size (i.e., least "wasted" land) needed in order to accommodate the increased number of turbines within the existing wind development area, given current setback requirements? The difference between the answers to these two questions will give an outer bound to the potential impact of reducing setback requirements, for the case of reducing the requirements all the way down to the tower spacing guidelines to minimize wind interference (i.e., three times rotor diameter for parcel sides perpendicular to the wind and 10 times rotor diameter for parcel sides parallel to the wind).

To investigate these questions, I sorted the existing stock of wind turbines recorded in WPR data into nine cohorts of similar size class: 65 kW, 90 kW, 250 kW, 315 kW, 400 kW, 650 kW, 1 MW, 1.5 MW, and 2 MW. I then used a stock turnover model to track the annual replacement of old turbines with new plus additional new turbines necessary to provide the incremental renewable-source electricity required in each 80in50 scenario. I assume the average size for new turbines is 2 MW, with 75-meter rotor diameter and 60-meter tower height (based on the MWT-S2000 used in Buena Vista repowering). The total area required for turbines in each year is then calculated based on the evolving stock of turbines and the area required for each turbine type (based on representative dimensions) when placed in an array. The resulting evolution over time of the total area required in each of the four primary wind resource areas in California is shown in Figure 56.

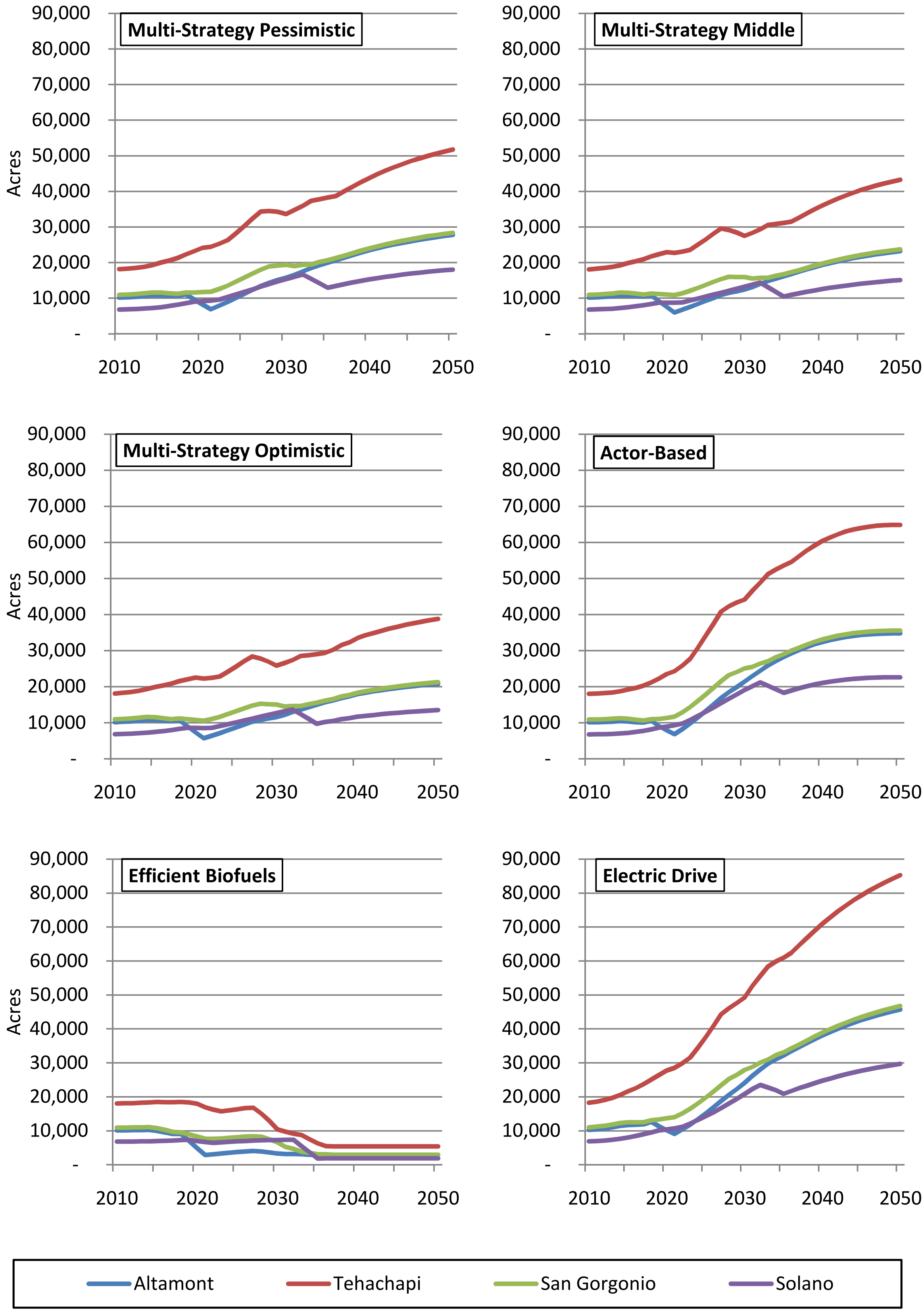
Multi-Strategy Pessimistic
Multi-Strategy Middle
Multi-Strategy Optimistic
Actor-Based
Efficient Biofuels
Electric Drive
Acres
90,000
80,000
70,000
60,000
50,000
40,000
30,000
20,000
10,000
-
2010
2020
2030
2040
2050
Altamont
Tehachapi
San Gorgonio
Solano

Figure 56: Total area required in each of the four primary wind resource areas in California in order to accommodate repowering to maintain current annual electricity production plus the required expansion in renewable-source electricity for plug-in vehicles under six 80in50 scenarios. The area required is calculated from the evolving turbine stock based on the area needed for each turbine type when placed in an array. No allowance for setback requirements is made (i.e. assume one homogeneous parcel covers the whole wind resource area). The current total area of these wind resource areas are the following: 50,000 acres for Altamont, 44,444 acreas for Tehachapi, 31,205 acres for San Gorgonio and 8,311 acres from Solano (adapted from www.aweo.org/windarea.html). Scenarios in which these areas are exceeded (e.g., Electric-Drive) imply a need for expansion in these areas or development in new areas.

I then estimated the maximum number of parcels that each wind resource area could accommodate, given the area required for turbine arrays and representative setback requirements. Assuming an average setback requirement of three times turbine height (tower plus rotor radius), the border area of each parcel unavailable for turbine installation is equal to $4SX - 4S^2$ where S is the setback distance (97.5 meters for the average new turbine described above) and X is the length of each parcel side (assuming uniformly sized square parcels). Trends in the resulting maximum number of parcels are shown in Table 35. This analysis shows that parcel consolidation and/or reduction in setback requirements are needed for the existing four primary wind resource areas in California to accommodate the increase in generation capacity needed to supply renewable-source electricity for plug-in vehicles in all but the *Efficient Biofuels* 80in50 scenario.

		2010	2020	2030	2040	2050
Actor-Based	Altamont	179	215	71	22	16
	Tehachapi	69	39	<1	<1	<1
	San Gorgonio	61	58	4	<1	<1
	Solano	1	<1	<1	<1	<1
Electric Drive	Altamont	177	179	55	10	1
	Tehachapi	68	23	<1	<1	<1
	San Gorgonio	61	42	1	<1	<1
	Solano	1	<1	<1	<1	<1
Efficient Biofuels	Altamont	179	279	327	341	341
	Tehachapi	69	69	140	223	223
	San Gorgonio	62	86	108	176	176
	Solano	1	1	<1	27	27
Multi-Strategy Pessimistic	Altamont	178	209	114	58	38
	Tehachapi	69	36	9	<1	<1
	San Gorgonio	61	55	17	6	1
	Solano	1	<1	<1	<1	<1
Multi-Strategy Middle	Altamont	178	221	148	84	60
	Tehachapi	69	42	24	5	<1
	San Gorgonio	61	61	30	15	6
	Solano	1	<1	<1	<1	<1
Multi-Strategy Optimistic	Altamont	178	225	159	95	74
	Tehachapi	68	44	30	9	2
	San Gorgonio	61	62	34	20	11
	Solano	1	<1	<1	<1	<1

Table 35: Maximum number of parcels in each of the four primary wind resource areas in California allowable to accommodate repowering to maintaining current annual electricity production plus the required expansion in renewable-source electricity for plug-in vehicles under six 80in50 scenarios. Numbers less than one indicate a need for expansion in the area.

3.9.2.2 Potential Effects of Permitting and Environmental Reviews

As mentioned previously, the CPUC had approved 95 contracts for 5,900 MW of new (61 projects for 4,480 MW) and existing (34 projects for 1,420 MW) RPS-eligible capacity since 2002 as of July, 2008 (CPUC, 2008). Assuming a lag of five years between contract approval and commissioning for operation, these contracts are sufficient to the demands for incremental renewable-source electricity for plug-in LDV charging in the 80in50 scenarios through about the year 2030 to 2050 (depending on the scenario). However, it is important to note that the CPUC and electric utilities contracting for this increased wind capacity are considering it as part of the means to meet the 20 *percent* renewable portfolio standard in 2010 (and potential 33% RPS in 2020), *without* appreciable increase in electricity sales due to plug-in vehicles (ibid). Furthermore, progress in *delivered* energy from these contracts has been slow, with only 14 contracts for approximately 400 MW coming online since 2002.

Consequently, it is reasonable to ask when project planning must begin in order to achieve the number of new turbines coming online in each year shown in Figure 55. This can be visualized by simply shifting the graphs in Figure 55 forward by the estimated lag time to create graphs of project initiation. Obviously, the longer permitting, environmental assessment and other things take (i.e., the potential barriers to repowering), the earlier project planning must begin. If such delays are long enough, it will mean we are already behind in the energy sector transitions needed to achieve the 80in50 goal for the transportation sector. For example, if the total delay between project planning and coming online exceeds 10 years, we may have insufficient projects in the works today to meet the needs for new turbines in 10 to 15 years. This is a clear example of how one of the potential barriers to repowering described in this report could prove influential in our ability to meet the 80in50 goal for transportation. In addition to the ongoing policy action at the statewide level, commensurate action at the regional and local levels may be needed as well. If action is not taken to reduce the lag time between project initiation and commissioning, a larger number of projects must begin now (or very soon) in order to meet the 80in50 goal (depending on the scenario strategies employed).

3.10 Case Studies

In this section, I discuss several examples of recent and planned repowering projects in California. The nameplate capacity of these projects is summarized in Table 36 and the timing is depicted in Figure 57. The projects are grouped by location in one of the four major wind areas in California. The case studies provide a feel for project-specific nature of repowering decisions.

Project Name	Location	Contract Nameplate (MW)	Estimated Incremental Annual Deliveries due to Repowering (GWh)
CTV Power	Tehachapi	14	4.7
Boxcar II	Tehachapi	8	0[139]
Karen Windfarm	San Gorgonio	11.66	13.6
Coram Energy	Tehachapi	3	6.41
		36.66	**24.71**

Table 36: Some repowering projects have increased nameplate capacity. The total increase for the four projects listed in this table is 2.8 MW (CPUC, 2005)

[139] This facility has historically delivered at levels significantly below the annual estimate in its Contract and does not presently anticipate exceeding this estimate even after the repowering. A contract amendment establishing a cap on deliveries to be paid for at above-the-avoided cost rates is required in order for the facility to obtain PTC for the repowering.

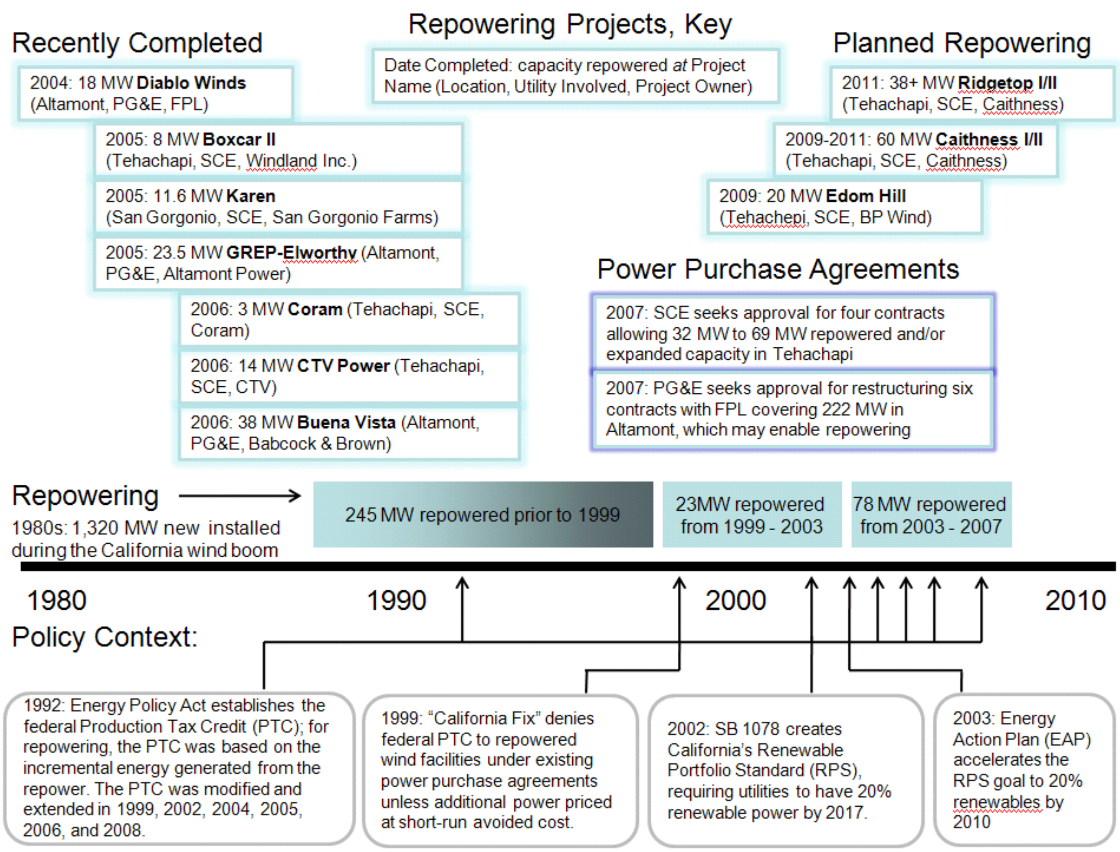

Figure 57: A timeline of California repowering. Since the enactment of the California RPS in 2002, investor-owned utilities (IOU) have signed 10 wind repowering contracts, for 124 MW to 161 MW of total capacity (Wiser et al., 2008, based on CEC tracking of RPS renewable energy contracts, available at http://www.energy.ca.gov/portfolio/contracts_database.html). Approximately 100 MW of these projects had been completed by the end of 2007 (ibid). The early stages for future repowering have been set by CPUC approval of restructuring contracts by both PG&E (32-69 MW in Tehachapi) and SCE (222 MW in Altamont).

3.10.1 Altamont Pass

The similarities between three repowering projects completed in the Altamont Pass area illustrate some of the barriers and benefits of repowering discussed in this report. The installed nameplate capacity in Altamont began declining around 1995 as first-generation turbines began to fail (Buckley, 2005). In particular, the Flowind vertical-axis turbines were some of the poorest-performing turbines in Altamont, with average capacity factor of 10% in the 1980s and 5% in the 1990s.

When original conditional use permits (CUP) in Altamont began expiring in 2001, renewal applications saw some consolidation occurred in land ownership and operator (Buckley, 2005).[140] However, no repowering was proposed by operators despite “intense” interest in repowering by government agencies (e.g., CEC, CBD) and environmental groups (e.g., Sierra Club, CaRE).

Recognizing the difficulty that environmental review and permitting posed in the Atlamont area in particular, a review was conducted of existing regulations and a general EIR was prepared in an attempt to ease this burden.[141] In a compromise between wind proponents and those concerned about avian mortality, a “Repowering Program” was established that stipulated no net increase in rated capacity, which was believed would result in reduced avian mortality as repowering replaced many old turbines with a few new, larger ones. The repowering program also stipulated turbine design standards, including larger, taller tubular towers, lower RPM, wider spacing, no guy wires, underground power lines, fewer access roads, FAA lighting, and a biological resources management plan (BRMP).[142] The intent was to provide adequate certainty about the future of wind development in Altamont to enable project owners to renegotiate power purchase agreements and get project financing for repowering.

[140] The original permits were for 20 years and were signed in 1981-1985.
[141] A 1998 environmental impact report prepared by Alameda and Contra Costa counties was meant to be used by companies wanting to repower. Although the Diablo repowering project did proceed under the auspices of this 1998 EIR, in most cases an individual EIR is needed for each project. Thus, the government’s effort to reduce the EIR cost barrier was largely ineffective.
[142] The BRMP was a plan for “avian impact avoidance” and management of “special status species” and biological communities.

Finally, a *requirement* for repowering was also built into the renewal conditions of permits for existing turbines. Based on a priority system established in CEC Tiers, the targets for this phased repowering mandate were 10% in 3 years, 35% in 6 years, 50% in 8 years, 85% in 10 years, and 100% in 13 years.

Despite these efforts, by 2008 only Altamont Power, FPL Energy, and Babcock and Brown had done repowering projects, two of which were remarkably similar (see descriptions below). These projects presented the most economically attractive conditions for repowering (see section 3.5), with replacement of turbines that were poor-performers (the vertical-axis Flowind), easy to take down (Flowind turbines were relatively short with generator and gearboxes on the ground), and had significant scrap value.[143]

Project economics, driven in part by the legal landscape, and the continued adequate performance of existing turbines may explain why other Altamont projects have not repowered. Compared to the 10 percent average capacity factor of the repowered Flowind turbines, the current average capacity factor for other 1980s vintage turbines in Altamont is approximately 19 percent. Existing ISO4 power purchase agreements also may make continued operation of existing equipment relatively lucrative. Lawsuits over avian mortality (especially protected species), introduce uncertainty in wind project repowering that makes project financing difficult (e.g., litigation may prevent replacement of old turbines after they have been taken down). Finally, despite the provision of the 1998 EIR, individual projects are likely to still need their own project-specific EIR before installing new turbines.[141]

[143] The scrap value for the Flowind turbines was unusually high. The aluminum blades were worth $0.30 per pound and the torque tube was worth $185/ton as straight pipe. Altogether, a Flowind machine might have had scrap value of $3,000 (Gipe, 1997). Compare that to $75/ton for scrap steel around the same time period (1997) and 2.5 tons in a 40 kW Storm Master, meaning $200 in scrap value, or $5 per kW.

Project Name	Turbines Replaced	Turbines Installed	Start Date	Date Completed
Elworthy	Flowind (169, 23.5 MW)	Vestas V47 (45, 29.7 MW)	2003 (permits)	2005
Diablo	Flowind (169, 21 MW)	Vestas V47 (31, 20.5 MW)	2004	Feb. 2005
Buena Vista	Windmaster 211 (179, 38 MW)	Mitsubishi 1-MW (38, 38 MW)	Dec. 2005 (Construction)	Dec. 2006

Table 37: Repowering Projects Completed in Altamont Pass

3.10.1.1 GREP-Elworthy by Altamont Power

The GREP-Elworthy project by Altamont Power was the first repowering project in Altamont actually implemented. A new conditional use permit was issued in 2003, which was tiered from the 1998 EIR (i.e., the project was able to use the 1998 EIR because no substantial changes had occurred in the meantime) and was fully compliant with the Repowering Program/BRMP.

The project replaced 169 vertical-axis Flowing turbines (23.5 MW nameplate capacity) with 45 Vestas V-47 turbines (660 kW nameplate capacity for 29.7 MW total). Thus, this is an example of increasing both nameplate capacity and capacity factor with repowering, resulting in more energy generation, while reducing the number of turbines, total acreage with turbines, and visual impact on the I-580 corridor (Appendix F). The project also included site reclamation for turbine foundation pads (covered with 3 feet of soil), access roads, electrical components, and underground transmission lines where feasible. Turbine locations were guided by habitat studies and avoidance guidelines, and avian monitoring was implemented.[144]

[144] The opportunity for comparative study of avian mortality was one factor in regulatory approval of this project.

3.10.1.2 Diablo Wind Energy Project by FPL

Figure 58: Flowind vertical-axis turbine

The Diablo repowering project on Altamont Pass Road also replaced 169 vertical-axis Flowind turbines (models F-17 and F-19; 21 MW), with 31 Vestas V47 turbines (20.46 MW nameplate capacity) (Smallwood, 2006). This project was constrained to existing nameplate capacity by the Altamont repowering program and existing power purchase agreements (although improved capacity factor did increase energy production). The project represented a relatively small portion of the 2,200 turbines owned by FPL in the Altamont area.[145]

For size comparison, the Flowind machines were 29.5 and 32.3 m in total height and 17.2 and 19.1 m in diameter. The Vestas V47 machine is 50 m to 55 m tall at the hub with rotor diameter of 47 m.

One study monitoring avian mortality at the Diablo site concluded that mortality declined after the Diablo Winds repowering despite increased utilization of the area by raptors (WEST, Inc., 2006). A second study that corrected for discrepancy in the height surveyed (800m rather than 300m) found that raptor use of the area actually declined and that, “adjusted mortality estimates caused by the new and replaced wind turbines indicated overall bird mortality was reduced 70% by the Diablo Winds Energy Project, and raptor mortality was reduced 62%. Burrowing owl mortality was reduced 85%, and

[145] FPL is a subsidiary of the Florida Power and Light utility, which was the largest wind-farm owner in the Altamont region and largest wind-power provider in the country. The Diablo project was jointly owned with Global Renewable Energy Partners, a subsidiary of Danish wind-turbine manufacturer Vestas.

most of the total bird mortality reduction appeared to be among song birds. On the other hand, red-tailed hawk mortality increased nearly three-fold, and some species were killed by Diablo Winds that were not reported killed by the replaced turbines during Smallwood and Thelander's study, including golden eagle and bats. Differences in mortality were likely due to the reduced number of wind turbines, turbine siting, and the increased height above the ground of the turbines… Also, the repowering did not change the risk of collision for all raptors or all birds, perhaps because avian utilization of the Diablo Winds project site declined along with mortality between studies…" (Smallwood, 2006). In contrast to Babcock and Brown's repowering of Buena Vista (see section 3.10.1.3), FPL did not adhere to new CEC recommendations for locating turbines on the lee side of hills.

3.10.1.3 Buena Vista Wind Farm by Babcock & Brown

Repowering of the Buena Vista wind project near Byron replaced 179 Windmaster 211 turbines with 38 1-MW Mitsubishi 1000A turbines for no change in nameplate capacity (38 MW). The project reduced the site footprint from 2,400 acres to 400 acres, moved overhead powerlines underground, and cost an estimated $40 million.[146] For size comparison, the Windmaster machines had 23 m towers while the Mitsubishi machines had 55 to 60 m toweres, with 36 m blades. The project is now owned by B&B subsidiary

Figure 59: Mitsubishi 1000A wind turbine

[146] power-technology.com, www.power-technology.com/projects/buenavistawind/

Babcock & Brown Wind Partners and passive investors GE Energy Financial Services and Wachovia Corporation,[147] and is operating under a 10-year contract with PG&E.

3.10.1.4 Tres Vaqueros (in planning) by Babcock & Brown

As of 2008, preliminary planning has begun for repowering of the Tres Vaqueros wind project, which currently has 85 turbines with a total installed capacity of 28 MW. The project is located in the Altamont hills between Tracy and Livermore.

3.10.2 Tehachapi

In Tehachapi, anticipation of new transmission capacity is fueling both greenfield and repowering developments that will increase installed generating capacity (see section 3.8.7).[148] In an area of proven high-quality wind resource that is only a few miles from the main transmission grid, the primary constraint on generating capacity for 20 years has been the connecting transmission lines. Now, the RPS is providing motivation to make the necessary infrastructure investment to enable expansion.

Where the Mojave Desert meets the mountains, the Tehachapi pass provides a low passage for wind that may contain 40% of the California onshore wind resource (Romanowitz, 2006). The primary wind resource area is 30 miles long by 6 miles wide, meaning a limited area some of which is already occupied by old wind turbine equipment. In fact, the pass is comprised of three major wind areas, two of which have been stranded without adequate transmission capacity.

[147] Babcock & Brown Wind Partners is the fifth largest wind-farm owner and operator in the world, with 1,585 MW installed capacity in the USA. The company enXco sold its 25% interest in Buena Vista to B&B in May, 2006.

[148] A plan for 4,500 MW of new transmission capacity may enable development that increases total capacity up to 6,000 MW in the Tehachapi area.

The existing wind developments in Tehachapi total 720 MW of installed capacity, split into 310 MW peak production from 350 MW installed on a Southern California Edison 66 kV transmission grid and 380 MW installed on the private 230 kV Sagebrush transmission line. The California Independent System Operator (CAISO) has plans to build a 4,500 MW transmission system upgrade and LADWP is planning 500 MW of transmission (see section 3.8.7; Romanowitz, 2006). However, these increases in transmission capacity are already oversubscribed, with more than 3,400 MW of projects planned in the spring of 2006 and 4,800 MW signed up by the end of that year (ibid). It appears an additional 2,000 MW of transmission capacity may be needed in the future. Finally, it is also important to recognize the lag time between deciding to do a wind project and bringing the power online. Since the 4,500 MW of transmission capacity is planned for completion in 2013, wind developers may face five years or more before additional capacity can come online.

The transmission constraint in Tehachapi forces an explicit one-or-the-other decision between greenfield development and repowering because developers clearly face a decision of whether to put repowered or greenfield projects on whatever limited transmission is available. For example, the Alta Wind Energy Center is a greenfield planned to have 600 to 800 turbines with 1,500 MW nameplate capacity that is contingent on new transmission capacity (Schuster, 2007). A project of this magnitude would likely cost $3 billion, provide 500 construction jobs and 300 long-term jobs, and require 50 square miles of area (ibid). The project has signed a 20-year contract with SCE, received approval from the CAISO board of governors in January 2007 and approval for the first segment from the California Public Utilities Commission on March

1, 2007, but still needs permission from US Forest Service to allow lines to run through part of the Angeles National Forest.

Unlike Altamont, the legal and regulatory context with wind development and repowering in Tehachapi is well organized and established. An excellent zoning and permitting process in Kern County is complemented by ordinance that has resolved military interactions and generally good public acceptance of wind projects in the area (Romanowitz, 2006).

> "Tehachapi has old equipment, but may be expanding rather than repowering."
>
> ~ Case van Dam

3.10.2.1 Edom Hill's wind project

Southern California Edison signed an amendment to an existing ISO4 contract with the Edom Hill wind project that will allow nearly a doubling in capacity from 10.9 to 20 MW by repowering (Edison International, 2006). The Edom Hills wind farm was acquired by Aequitas Capital Management in 2006.[149] The Bureau of Land Management released a draft environmental assessment for the project for public review in October, 2007.[150] These documents describe the plans by BP Wind Energy North America for replacement of 139 turbines with nameplate capacity of 10.9 MW with eight 2.5 MW turbines.

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[149] BNET Business Network, Business Wire, March 7, 2007 (http://findarticles.com/p/articles/mi_m0EIN/is_/ai_n27289984)
[150] http://www.blm.gov/ca/st/en/info/newsroom/2007/october/CDDNews0803_wind_EA.html

3.10.3 Solano County

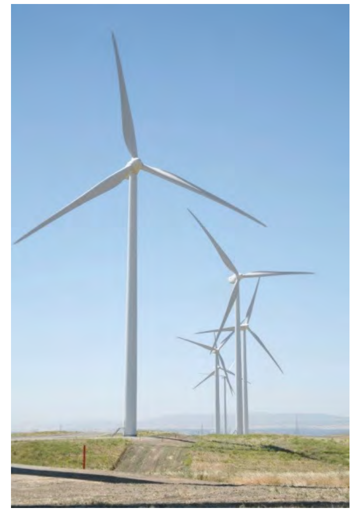

Figure 60: SMUD's eight 3-MW turbines in Solano County

The 400 MW wind capacity in Solano County is divided into five major projects that are currently owned by five different companies. Four of the five are recent developments that use modern wind turbine technology. The High Winds project owned by FPL was built in 2002 and has approximately 80 Vestas V80 turbines (1.8 MW machines with 80 m diameter rotor) for 160 MW total capacity. The SMUD project owned by the Sacramento Municipal Utility District (SMUD) currently uses 23 Vestas V47 (660 kW) and 29 Vestas V90 (3 MW) turbines for total installed capacity of 102.2 MW.[151] The Shiloh I project owned by IberDrola uses GE 1.5 MW turbines, with total installed capacity of 150 MW; the Shiloh II project now underway will add 75 2-MW machines to the area. In addition, enXco, has begun repowering some of its Kenetech 100 kW turbines with GE 1.5 MW machines.

Along with existing transmission capacity, the Kenetech 100 machines enabled initial development of the lesser wind resource in Solano County because they were the only turbines with pitchable blades that continued power production in low winds. This is interesting because one of the benefits of modern variable-speed turbine technology is continued power production over a wide range of wind speeds. In fact, the GE 1.5 turbines are often still running and producing power when the Kenetech 100s have shut

[151] SMUD Solicitation 080546.CBJ, https://usage.smud.org/EBSSExt/Solicitations/Solicitation.aspx?solnum=80546

down in low wind speeds. This is one reason for the recent greenfield and repowering development in Solano.[152]

3.10.3.1 enXco5

EnXco began repowering a portion of their enXco5 wind project in Solano County in 2005.[153] Ninety Kenetech 100s were replaced with six GE 1.5 MW turbines, a 15:1 replacement ratio with no change in nameplate capacity. The decision to maintain the existing installed capacity was due to the existing power purchase agreement capped at 60 MW. When this contract runs out in five years, it is likely that more Kenetech 100s will be repowered, with an increase in nameplate capacity (ibid).[154]

The choice of replacement turbine technology was influenced by the long track record of the GE turbine with good data on performance that reduced uncertainty about expected performance and O&M costs.[155] Interestingly, a similar level of understanding of the equipment was viewed as one reason to continue using the Kenetech 100 machines.[156] Expected turbine performance is especially important from an operations perspective when repowering because the larger modern turbines require very large cranes for major maintenance on the rotor and nacelle components, which can cost $75,000 just to deliver to the site (plus time and materials cost while operating). Although manufacturer warranty policies cover these costs in some cases, like the recent gearbox failures at

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[152] In addition to repowering the enXco5 site, enXco is developing the new Shiloh II project with 70 2-MW turbines from German manufacturer Re-Power (owned by Suzlon). Roads have been cut and transmission and substation infrastructure is under development. Towers and turbine parts will arrive at the Port of Sacramento.

[153] John Opris, personal communication, August 6, 2008; http://www.enxco.com/press_110905.php.

[154] Note, it is now relatively easy to negotiate power contracts with the RPS forcing more capacity.

[155] The GE turbine is also known for good power electronics that help maximize power production from a given wind resource.

[156] Although the Kenetech 56-100 machines operating in Alameda County, which were manufactured in the 1980s, have experienced higher rotor and tower failure rate than newer equipment, the cost of repair is generally less for the smaller Kenetech machines (see section 3.4).

enXco5, the cost will ultimately be reflected in turbine purchase price. The typical expectation for new turbine technology is a seven year simple payback period.

The proximity of Travis Airforce Base to the enXco5 project limited tower height below what would have been optimal.

3.11 Conclusions

The benefits of and barriers to repowering shown in Figure 38 and Table 20 are highly project-specific, with each context invoking some but not others. Despite this heterogeneity, the following common themes emerge.

Wind operators are generally rational economic actors. The cases where repowering has been implemented appear to have been wise business decisions from the operator’s perspective (i.e., increased profits) while immediate repowering of other projects would likely reduce profitability. Thus, economics is a common barrier to more rapid repowering. The fact is, most projects with old turbines are still operating well enough despite the aging and relatively small equipment that incurring the cost of new equipment would reduce rather than improve profitability.

However, economic profitability is a necessary but not sufficient condition for repowering. Other barriers like uncertainty in the federal production tax credit, costs associated with environmental permitting, delays in turbine procurement from a manufacturing industry buffeted by an unstable marketplace (Figure 48), contractual obligations and costs associated with new contract requirements, setback requirements, and transmission infrastructure constraints can all block repowering even when project economics are good.

Thus, there may be a role for government in promoting repowering by reducing or removing these other barriers to allow unfettered market selection of projects "ready" for repowering.[157] But the highly project-specific nature of repowering makes crafting such policy complex since what is effective for one project may cause unintended consequences for another. There may also be a role for government in promoting *early* repowering through an explicit incentive that improves project economics. Such a policy, however, is likely to be economically inefficient.

One of the primary incentives to repower – the ability to produce more MWh electricity per acre per year - is often blunted by some combination of insufficient transmission capacity, regulatory limits on tower height and spacing, existing power purchase agreements that provide attractive pricing only for the current installed capacity, and eligibility for the federal production tax credit only if the additional capacity is paid short-term avoided cost.

While modern wind turbine technologies are also capable of providing a variety of ancillary services to the electric grid, operators are concentrated on producing the highest quantity of electricity at the lowest cost possible because utilities are not exercising their option to purchase any other service. Wind turbine manufacturers and developers are focused on producing the lowest cost energy possible because energy production is the only thing for which they are paid (Behnke and Erdman, 2006). Most power purchase agreements give the purchasing utility exclusive rights to purchase all ancillary services, but none are doing so. The reason is a combination of the cost effectiveness of these services and a lack of developed market mechanisms to link

[157] For example, projects whose extant equipment is unreliable or outdated enough to make repowering profitable.

utilities, ISO, and power producers. However, the value of these ancillary services for grid regulation and reliability will increase as the share of power production from intermittent renewable-source generation increases. With sufficient valuation translated through power purchase agreements, we may see wind plant owners broaden their activities away from the current simple focus on maximizing energy production (Behnke and Erdman, 2006).

The objective of this study was to identify barriers to repowering. The time and budget allotted for this task was appropriately small. But in the process of my research, I identified three possible directions for future work that would help improve our understanding of repowering decisions and could improve policy planning in the California wind industry.

First, although the potential benefits and barriers for repowering have been well documented, very little work has been done to *quantify* their relative magnitudes in such a way that would enable a cost-benefit analysis of possible policies to encourage more rapid repowering. I stop short of such quantification as well. Quantifying the barriers and benefits for repowering will enable cost-benefit analysis of policy proposals intended to hasten repowering decisions.

Second, future work to extend existing economic models to forecast the *path* of future repowering decisions will enable policy simulation to examine how policy proposals might affect that path.

Third, in this study I focused on case studies of repowering projects that have been implemented. These examples illustrated some common elements of successful repowering. Future work to consider case studies of repowering projects that were *not* implemented may offer new insight into common elements of *unsuccessful* repowering an how to overcome these barriers.

Finally, in doing this research I found that most of the prior research on this topic has been done in California with the support of CEC / PIER. These entities and the California government should be commended for their foresight in data collection and research support that now enables informed policymaking regarding the next phases in California wind energy and renewable energy development, for the benefit of all Californians.

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Appendix A: 80in50 Scenario Parameters

		Petroleum	Biofuels	Hydrogen	Electricity	Transport Intensity (1990=100%)	Energy Intensity (1990=100%)	Carbon Intensity (1990=100%)
Efficient Biofuels 80in50	LDV	0%	83%	0%	17%	121%	33%	18%
	HDV	0%	95%	0%	5%	109%	60%	15%
	Aviation	25%	75%	0%	0%	238%	50%	40%
	Rail	0%	93%	0%	7%	146%	69%	18%
	Marine/Ag/Off-road	23%	77%	0%	0%	143%	45%	36%
	All subsectors combined	1%	83%	0%	15%	123%	42%	20%
	Fuel Demand (Billion gge)	0.5	16.2	0.0	1.3			
	Carbon Intensity (gCO_2e/MJ)	95-96	17.7	-	6.5			
	Total # of miles	*1,083.8*	*billion*					
Electric-drive 80in50	LDV	8%	0%	50%	42%	121%	21%	9%
	HDV	0%	0%	74%	26%	109%	47%	47%
	Aviation	50%	50%	0%	0%	238%	50%	63%
	Rail	0%	0%	0%	100%	146%	42%	7%
	Marine/Ag/Off-road	4%	32%	37%	27%	143%	45%	26%
	All subsectors combined	8%	2%	48%	41%	123%	31%	26%
	Fuel Demand (Billion gge)	1.2	1.0	7.1	3.7			
	Carbon Intensity (gCO_2e/MJ)	95-96	23.7	24.3	6.5			
	Total # of miles	*1,082.9*	*billion*					
Actor-based 80in50	LDV	20%	5%	10%	64%	75%	10%	32%
	HDV	25%	10%	10%	55%	222%	48%	56%
	Aviation	30%	70%	0%	0%	189%	42%	46%
	Rail	12%	3%	0%	85%	510%	44%	17%
	Marine/Ag/Off-road	44%	20%	9%	27%	113%	36%	59%
	All subsectors combined	21%	8%	9%	62%	96%	24%	45%
	Fuel Demand (Billion gge)	2.7	1.3	0.6	3.2			
	Carbon Intensity (gCO_2e/MJ)	95-96	17.7	48.4	6.5			
	Total # of miles	*843.4*	*billion*					

Multi-strategy *pessimistic* **80in50**	LDV	2%	7%	50%	42%	103%	19%	22%
	HDV	0%	43%	43%	14%	100%	51%	32%
	Aviation	0%	100%	0%	0%	99%	50%	42%
	Rail	0%	0%	0%	100%	146%	42%	7%
	Marine/Ag/Off-road	13%	46%	32%	10%	142%	45%	46%
	All subsectors combined	2%	13%	46%	39%	105%	32%	30%
	Fuel Demand (Billion gge)	0.3	4.4	4.6	2.4			
	Carbon Intensity (gCO_2e/MJ)	95-96	38.1	24.3	23.5			
	Total # of miles	*932.6*	*billion*					
Multi-strategy middle **80in50**	LDV	2%	12%	45%	42%	109%	21%	22%
	HDV	0%	49%	38%	13%	100%	52%	30%
	Aviation	0%	100%	0%	0%	99%	50%	37%
	Rail	0%	0%	0%	100%	146%	42%	7%
	Marine/Ag/Off-road	13%	56%	27%	5%	142%	45%	45%
	All subsectors combined	2%	18%	41%	39%	110%	33%	28%
	Fuel Demand (Billion gge)	0.3	5.2	4.4	2.7			
	Carbon Intensity (gCO_2e/MJ)	95-96	32.9	24.3	23.5			
	Total # of miles	*978.4*	*billion*					
Multi-strategy *optimistic* **80in50**	LDV	2%	25%	30%	43%	115%	24%	19%
	HDV	9%	50%	33%	8%	100%	54%	29%
	Aviation	0%	100%	0%	0%	99%	50%	21%
	Rail	0%	0%	0%	100%	146%	42%	7%
	Marine/Ag/Off-road	23%	56%	21%	0%	142%	45%	44%
	All subsectors combined	3%	29%	28%	40%	115%	35%	25%
	Fuel Demand (Billion gge)	1.0	6.6	3.4	2.9			
	Carbon Intensity (gCO_2e/MJ)	95-96	19.0	24.3	23.5			
	Total # of miles	*1,023.9*	*billion*					

Table 38: Scenario parameters for six scenarios describing the transportation system in California in 2050 that meets the 80in50 goal.

Appendix B: Number of Electric-Drive Vehicles in the Fleet

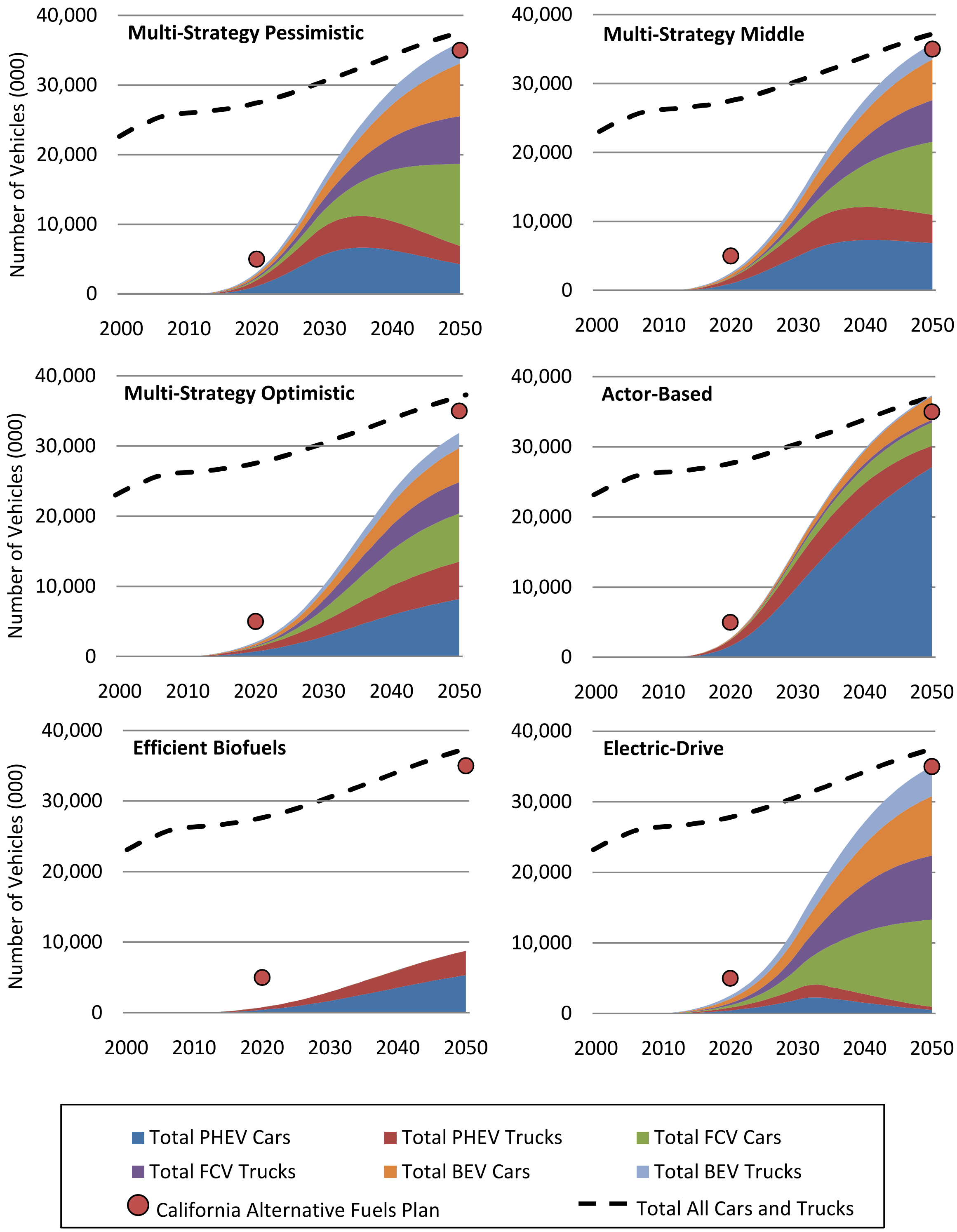
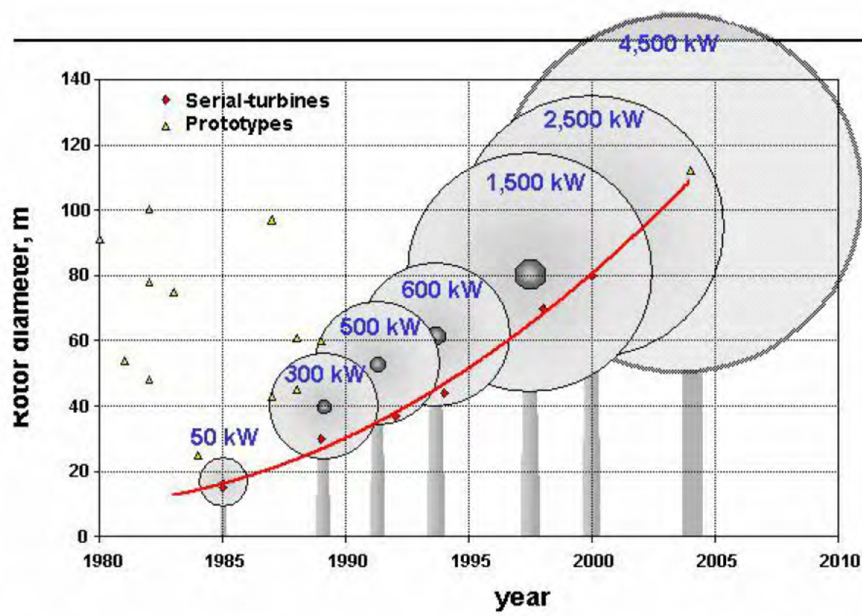
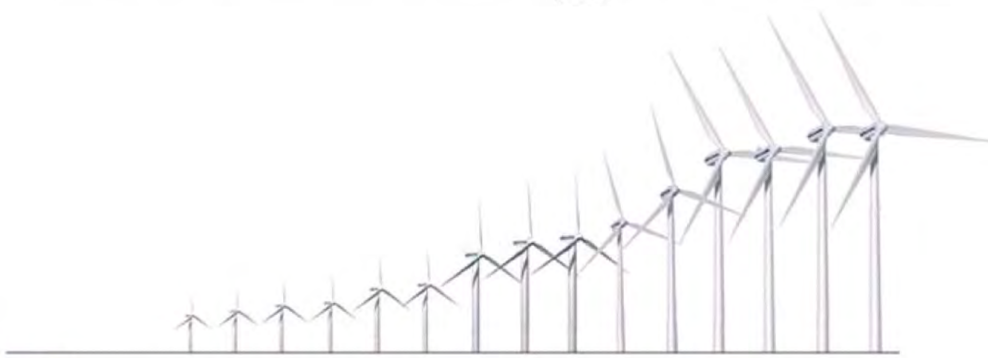


Figure 61: The number of electric-drive vehicles (PHEV, FCV and BEV) in the fleet under six *80in50* scenarios and the California Alternative Fuels Plan (CARB, 2007). The total fleet of LDV is shown for reference.

Appendix C: Evolution of Wind Turbine Size





Product/ Rotor diameter (m)	V15	V17	V19	V20	V25	V27	V39	V44	V47	V52	V66	V80	V82	V90	V90
Year of installation	1981	1984	1986	1987	1988	1989	1991	1995	1997	2000	1999	2001	2003	2004	2002
Capacity (kW)	55	75	90	100	200	225	500	600	660	850	1,750	1,800 2,000	1,650	1,800 2,000	3,000
MWh/year	217	265	301	346	481	647	1,304	1,581	1,947	2,530	4,705	6,320 6,668	6,414	7,498 7,295	9,154

Figure 62: Evolution of wind turbines toward larger, taller, more productive machines (Romanowitz, 2006; Soby, 2006). A modern turbine produces "100 times more electricity at half the cost than turbines 20 years ago" (Soby, 2006).

Appendix D: Levelized Cost of Energy for Merchant Plants

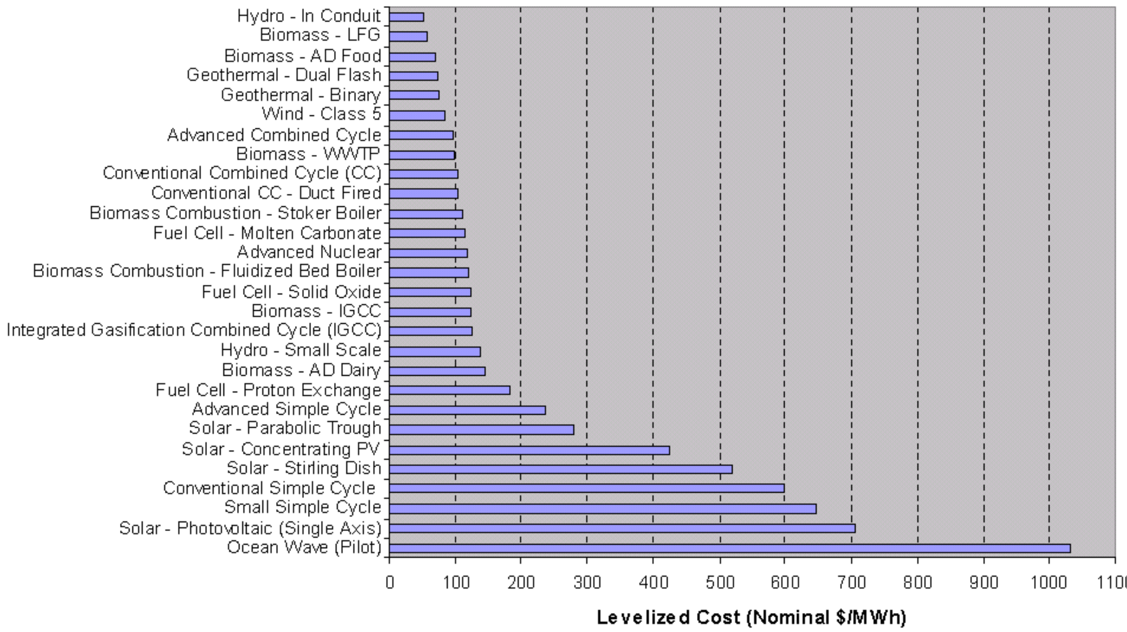


Figure 63: Total levelized cost of generation for merchant power plants (Klein and Rednam, 2007). Levelized costs include tax credits and other benefits attributable to each technology and are given in nominal 2007 dollars for generation units that begin operation in 2007.

Appendix E: Common Assumptions for LCOE Components

Technology (All costs in Nominal 2007$)	Gross Capacity (MW)	Capacity Factor (%)	Instant Cost ($/kW)	Installed Cost ($/kW)			Fixed O&M ($/kW-Yr)	Variable O&M ($/MWh)
				Merchant	IOU	Muni		
Conventional Combined Cycle (CC)	500	60%	781	844	849	779	9.86	4.42
Conventional CC - Duct Fired	550	60%	798	863	868	798	9.53	4.28
Advanced Combined Cycle	800	60%	766	828	834	763	8.42	3.83
Conventional Simple Cycle	100	5%	925	1000	1000	793	11.00	25.72
Small Simple Cycle	50	5%	974	1053	1053	846	17.65	26.10
Advanced Simple Cycle	200	5%	756	817	817	610	7.13	25.57
Integrated Gasification Combined Cycle (IGCC)	575	60%	2,198	3,007	2,941	2,569	36.27	3.11
Advanced Nuclear	1000	85%	2,950	3,754	3,662	3,177	140.00	5.00
Biomass - AD Dairy	0.25	75%	5,800	5,923	5,911	5,837	51.81	15.77
Biomass - AD Food	2	75%	5,803	5,925	5,913	5,840	155.44	-62.18
Biomass Combustion - Fluidized Bed Boiler	25	85%	3,156	3,223	3,217	3,177	150.26	3.11
Biomass Combustion - Stoker Boiler	25	85%	2,899	2,960	2,954	2,917	134.72	3.11
Biomass – IGCC	21.25	85%	3,121	3,320	3,301	3,181	155.44	3.11
Biomass – LFG	2	85%	2,254	2,302	2,296	2,263	20.73	15.54
Biomass – WWTP	0.5	75%	2,743	2,801	2,794	2,748	20.73	15.54
Fuel Cell - Molten Carbonate	2	90%	4,488	4,678	4,659	4,546	2.18	36.27
Fuel Cell - Proton Exchange	0.03	90%	7,239	7,545	7,515	7,332	18.65	36.27
Fuel Cell - Solid Oxide	0.25	90%	4,908	5,116	5,096	4,972	10.36	24.87
Geothermal – Binary	50	95%	3,093	3,548	3,501	3,227	72.54	4.66
Geothermal - Dual Flash	50	93%	2,866	3,287	3,244	2,988	82.90	4.58
Hydro - In Conduit	1	51 %	1,547	1,612	1,606	1,567	0.00	13.47
Hydro - Small Scale	10	52%	4,125	4,299	4,282	4,178	13.47	3.11
Ocean Wave (Pilot)	0.75	15%	7,203	7,662	7,617	7,342	31.09	25.91
Solar - Concentrating PV	15	23%	5,156	5,372	5,352	5,222	46.63	0.00
Solar - Parabolic Trough	63.5	27%	4,021	4,190	4,175	4,073	62.18	0.00
Solar - Photovoltaic (Single Axis)	1	22%	9,611	9,678	9,672	9,632	24.87	0.00
Solar - Stirling Dish	15	24%	6,187	6,446	6,423	6,266	168.92	0.00
Wind - Class 5	50	34%	1,959	2,000	1,997	1,972	31.09	0.00

Table 39: Common assumptions for components of the levelized cost of generation for a variety of power generation technologies (Klein and Rednam, 2007).

Appendix F: Recent & Future Transmission Projects in California

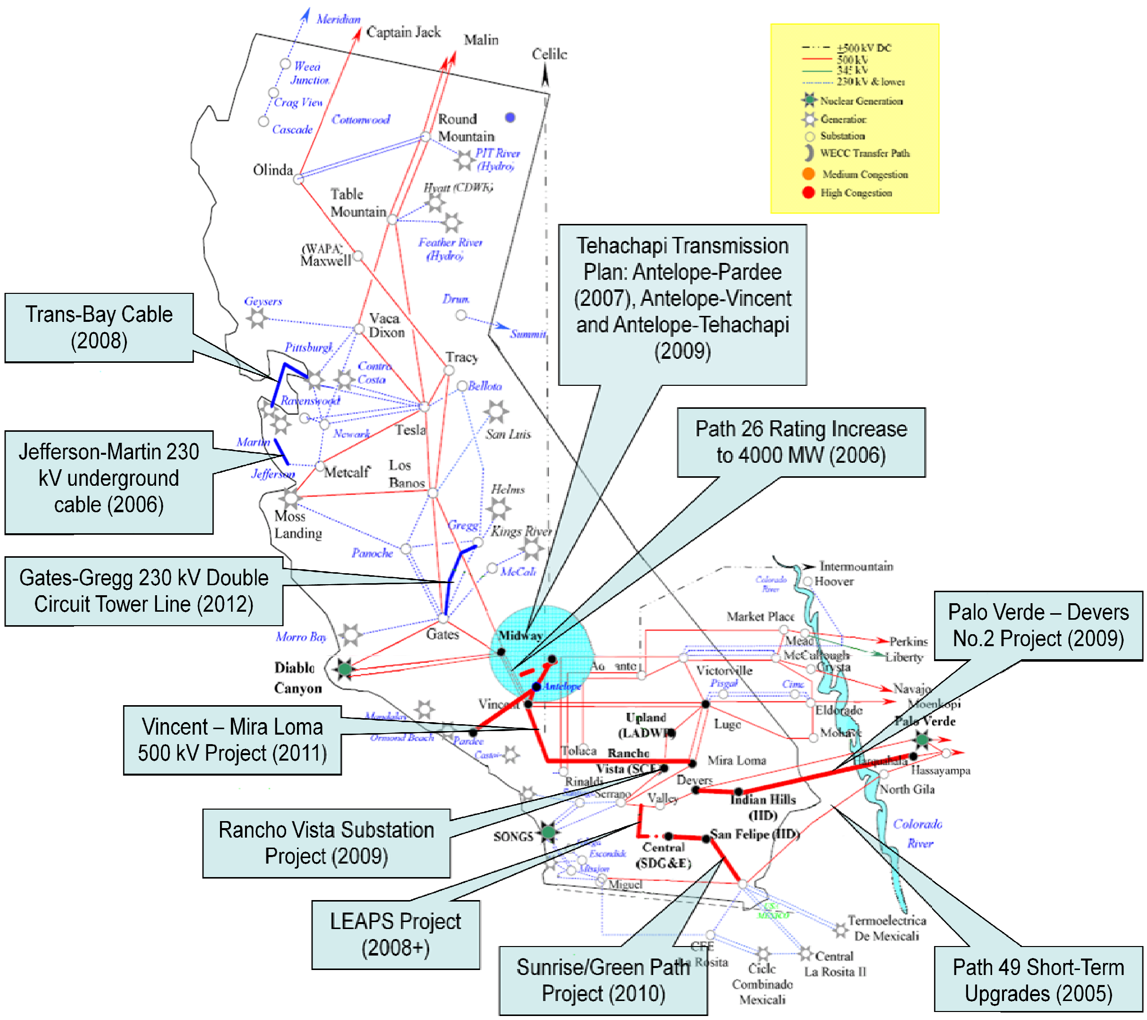


Figure 64: Major recent and upcoming transmission projects in California (Shirmohammadi, 2006). The complete Tehachapi plan of service calls for 350 miles of mostly 500 kV transmission lines, two large substations (230 to 500 kV) and rebuilding of two existing substations, with completion in 2013 at an estimated cost of $1.8 billion (Tarpley, 2006).[158] The Green Path project includes 100 miles of transmission and two new substations, for an estimated total cost of $1.1 billion (ibid).

[158] The cost estimate was based on conceptual level engineering, with a +/- 40% margin of error.

Appendix G: Tehachapi Plan of Service

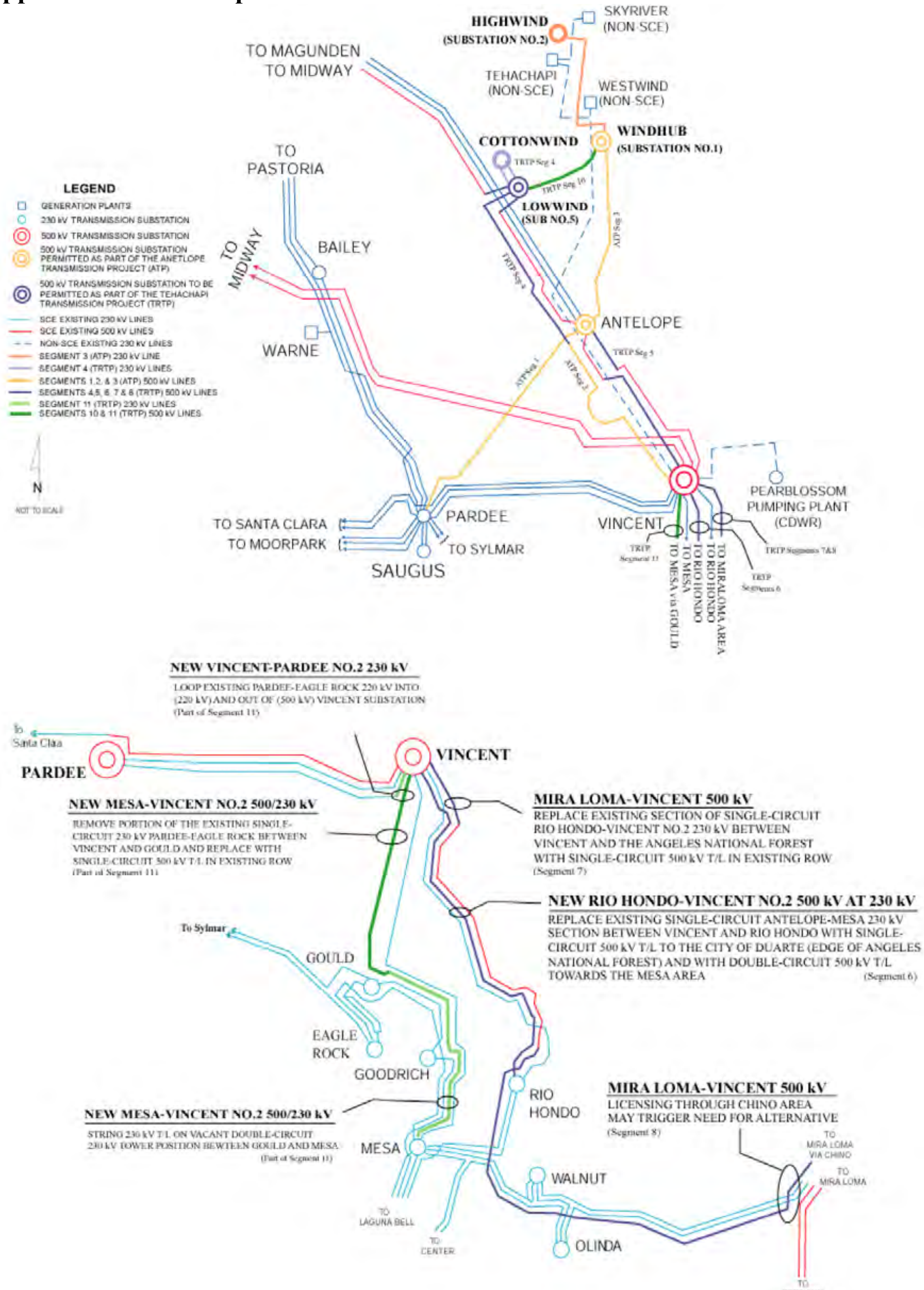


Figure 65: The complete Tehachapi plan of service (Tarpley, 2006). Red lines are existing 500 kV lines, blue lines are existing 230 kV lines, and new lines are labeled as segments (a total of 11). The 230 kV Antelope substation is also existing. All new segments will be built as 500 kV but operated initially at 230 kV until additional capacity is needed. The project timeline included PUC and Kern County permitting from January 2007 to January 2009, segments 1-3 (700 MW) completed in 2009, segments 4-8 (1,500 MW) in 2012, and segments 9-11 (2,300 MW) completed in 2013.

Appendix H: Elworthy Repowering Project Map

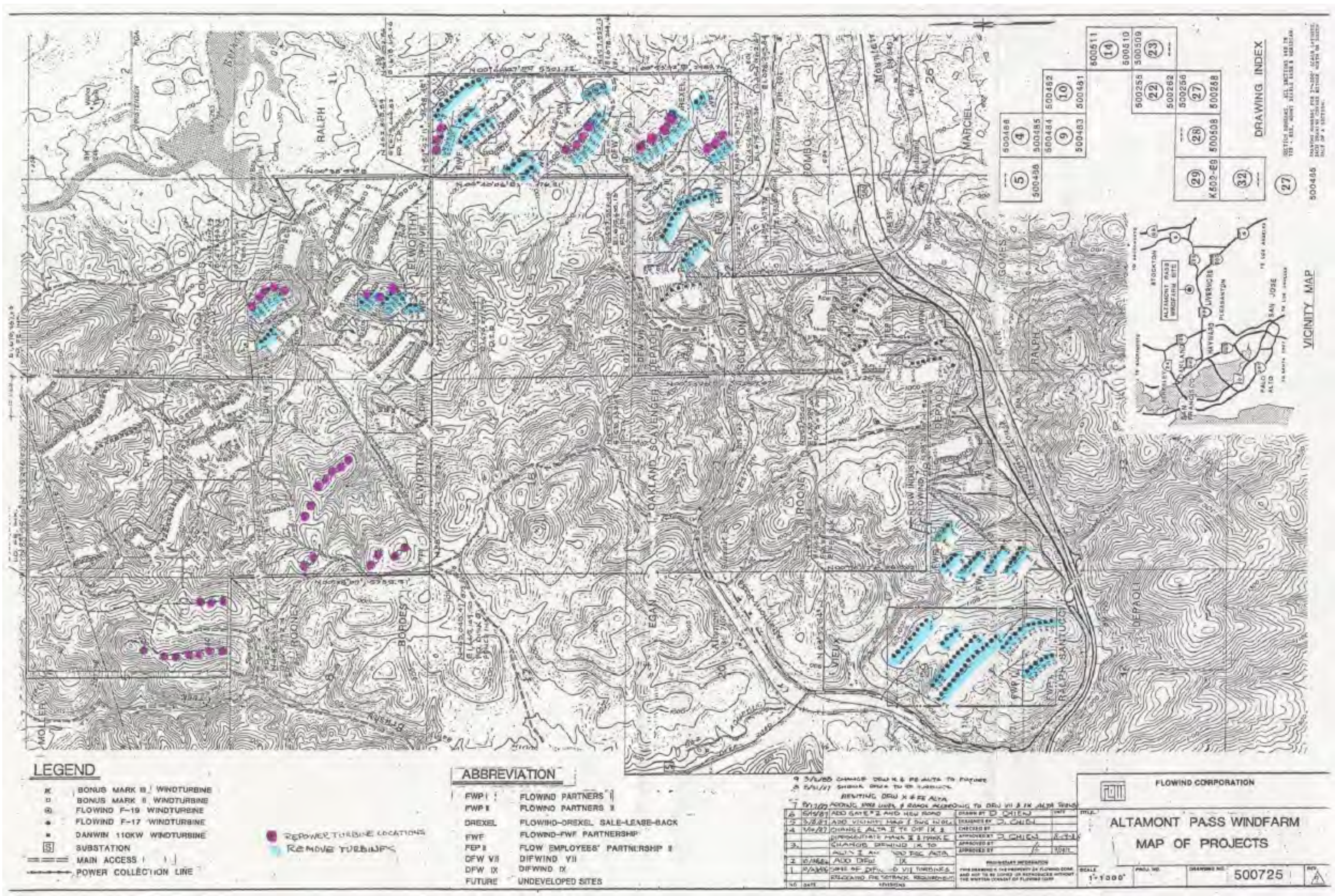


Figure 66: The Elworthy repowering project (Buckley, 2005). Old turbines removed are shown in blue; new turbines installed are shown in red. The total area is approximately 1,800 acres.