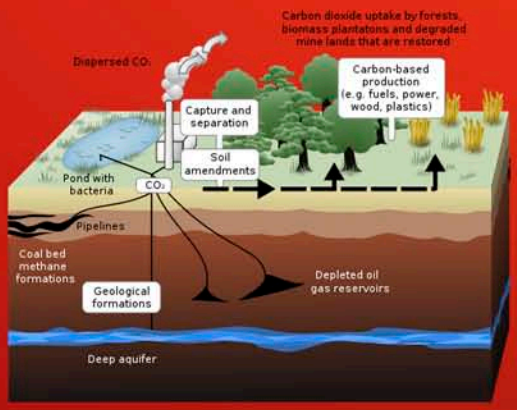

California's Energy Future - Portraits of Energy Systems for Meeting Greenhouse Gas Reduction Targets

California Council on Science and Technology

September 2012

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Jeffery Greenblatt and Jane Long

LEGAL NOTICE

ACKNOWLEDGEMENTS

We would like to thank the Stephen Bechtel Fund and the California Energy Commision for their contributions to the underwriting of this project. We would also like to thank the California Air Resources Board for their continued support and Lawrence Livermore National Laboratory for underwriting the leadership of this effort. In addition to thanking all of the California Energy Future committee members who provided input in the course of developing the set of portraits and technology evaluations presented here, the authors wish to thank the following individuals for their invaluable contributions: Ron Schoff (Electric Power Research Institute), who provided information on improving the efficacy of CO_2 capture and storage; Max Wei (Lawrence Berkeley National Laboratory), CEF committee member who contributed the literature review in the behavior change section; Andy Satchwell and Sila Kiliccote (Lawrence Berkeley National Laboratory), who provided background information on flexible load management and pointed toward helpful references on demand response; Robert Williams (Princeton University) who gave generously of his time to answer our questions about his biomass/CCS research; Chris Yang and Joan Ogden (UC Davis), CEF committee members who developed and helped review the hydrogen analysis, and Heather Youngs (UC Berkeley), CEF committee member who provided critical information for developing the net zero biomass and doubled biomass supply scenarios.

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 Library of Congress
Cataloging Number in Publications Data Main Entry Under Title:
California's Energy Future:
Porttraits of Energy Systems for Meeting Greenhouse Gas Reduction Target
September 2012
ISBN-13: 978-1-930117-69-3

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Message From CCST

CCST is pleased to present the results of an analysis of portraits of future energy systems for meeting California's 2050 greenhouse gas (GHG) reduction targets. The report documents two sets of portraits, detailed in the two main report sections: those that can reduce GHG emissions to 60% below the 1990 level by 2050, and those that can contribute toward reducing emissions all the way to the 80% reduction level, and beyond. This study is part of the California's Energy Future (CEF) project, which was undertaken to help inform California state and local governments of the scale and timing of decisions that must be made in order to achieve the state's goals of significantly reducing total GHG emissions over the next four decades.

California's Global Warming Solutions Act of 2006 (AB32) and Executive Order S-3-05 set strict standards for the state to meet. In order to comply, California needs to reduce its greenhouse gas emissions to 80% below 1990 levels by 2050 while accommodating projected growth in its economy and population. This will likely require maximizing efficiency in all economic sectors, electrification of much of the transportation sector and many stationary uses of heat, a doubling of electricity production with nearly zero emissions, and development of low-carbon fuels. Achieving these goals will require a combination of strategies; some are available now, while others will require substantial research and development to realize. This report is a summary of the realistic potentials of these technologies for California, and presents an analysis of potential GHG emissions savings, technological readiness, costs, reliability, resource constraints, policy assumptions, barriers, and potential synergies with other technologies.

We believe that the CEF energy system portraits report presents valuable insights into the possibilities and realities of meeting California's future energy needs and GHG emissions targets by 2050, and hope that you will find it useful.

Jane C.S. Long
California's Energy Future Committee
Co-chair

Miriam John
California's Energy Future Committee
Co-chair

I. Introduction

Energy policies in the state of California are very advanced compared to the rest of the nation and much of the world. A wide variety of policies have been put in place to meet the goal of the California AB32 law, which requires returning to 1990 greenhouse gas (GHG) emissions by 2020. Executive Order S-3-05 also requires that the state reduce emissions to 80% below the 1990 level by 2050 (see Figure 1). Although such radical emission cuts will be challenging, they are similar to those adopted by the European Union. If California grows in population and economy as projected, the 2050 goals will look like a 90% reduction relative to 1990 in emissions per capita, which is a very difficult goal in less than 40 years.

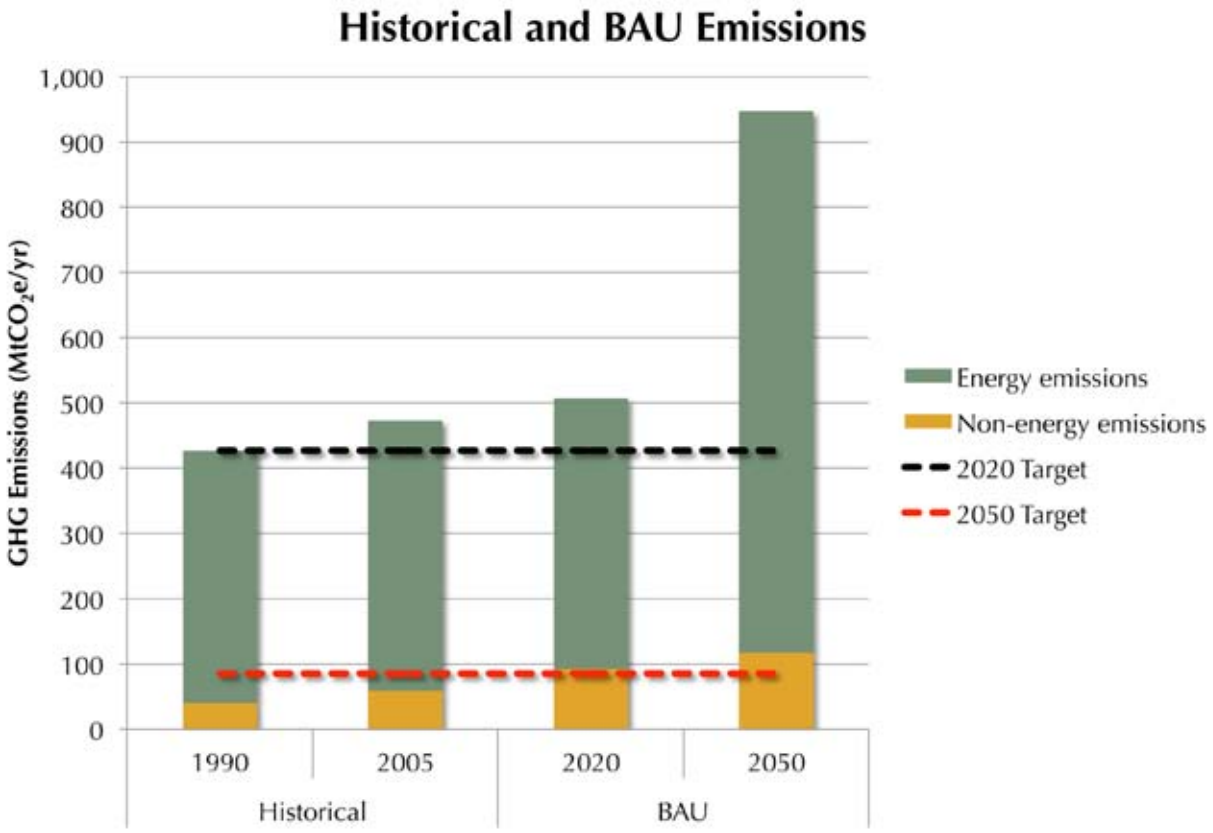

Figure 1. Historical and Projected Business-As-Usual California GHG Emissions. $MtCO_2e$=million metric tons CO_2-equivalent.

The California's Energy Future (CEF) Summary Report (CCST, 2011; see www.ccst.us) developed a simple model for identifying energy systems that would meet our energy needs in the future, while attempting to meet 80% emission reductions below the 1990 level. The model is a logical analysis that minimizes burning of fossil fuel (unless the emissions can be captured and sequestered). The model takes actions based on four simple questions that are illustrated in Table 1.

	Question	Response
Demand analysis	1. How much can we control demand through efficiency measures?	Decrease need for electricity and fuel
	2. How much do we electrify or convert to hydrogen fuel?	Increase the demand for electricity or hydrogen, decrease the demand for hydrocarbon fuel
Supply analysis	3. How do we de-carbonize enough electricity to meet resulting electricity demand?	Capacity from nuclear, fossil/CCS, or renewables
	How do we balance load?	Load balancing: natural gas (increases demand for fuel), energy storage, or demand management.
	4. How do we de-carbonize enough fuel (hydrocarbons or hydrogen) to meet remaining demand?	Biofuel, hydrogen with CCS, fuel from electricity

Table 1. Four Questions Leading Toward Action in Achieving Radical GHG Emissions Reductions in California by 2050

These actions are also summarized in schematic form in a set of GHG intensity-demand diagrams in Figure 2.

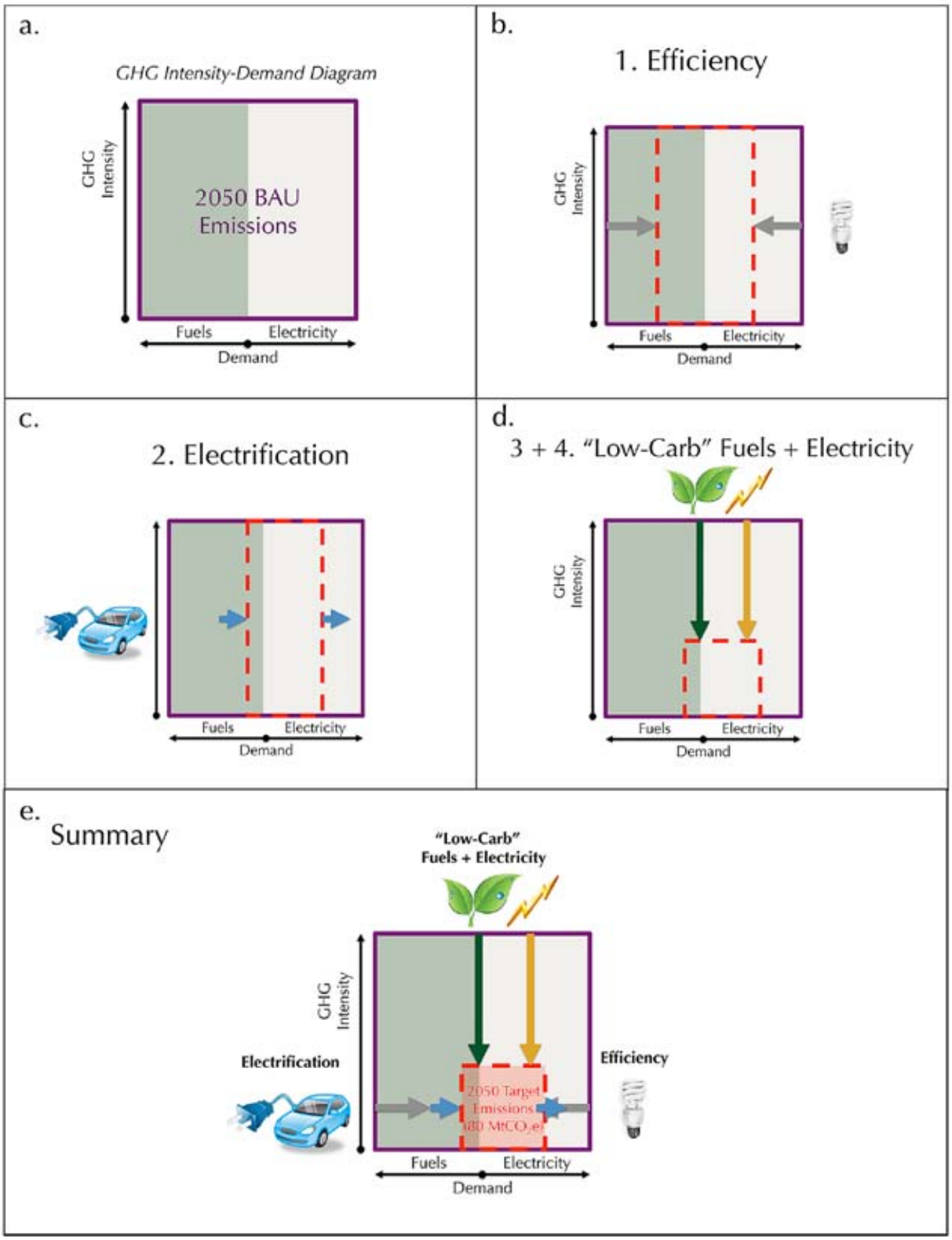

Figure 2. Four Actions to Reduce GHG Emissions in California by 2050

This study was conducted in two parts:

First, we estimated how far we could reduce emissions if we only invoked technology that was either commercially available (bin 1), or in demonstration (bin 2) at costs that were estimated to be "reasonable" and rates that were historically supportable (see Table 2). We were able to show that emissions could be cut by about 60% from the 1990 level this way. A number of energy system portraits that differ mainly in how they deliver electricity were possible for this level of emission reductions. The first part of this report provides the details of each energy system portrait that results from deploying the four actions outlined above efficiency, electrification, low-carbon electricity and low-carbon fuels.

Second, we began a search for more advanced technologies and approaches that would allow the state to reach its target of 80% emissions reductions. The latter part of this report explores several of these technologies in detail, and estimates the GHG reduction potentials that would result from their widespread implementation. These technologies were assumed to be either in development (bin 3) or research concepts (bin 4).

Technology Bin	Description
Bin 1	Deployed and available at scale now
Bin 2	Demonstrated, but not available at scale or not economical now
Bin 3	In development, not yet available
Bin 4	Research concepts

Table 2. Technology readiness bins.

II. Getting to 60%: How Far Can We Get with Technologies Available Today?

The first stage of the analysis was a bottom-up study that looked at how fast known technologies could be deployed to:

1. Make energy use more efficient in buildings, industry and transportation.
2. Electrify not only light-duty vehicles, but also trucks, buses, trains, building heat, and industrial process heating.

We found that all buildings would either have to be demolished, retrofitted, or built new to very high efficiency standards, that vehicles of all sorts would need to be made significantly more efficient, and that industrial processes would need to advance beyond technology available today. Moreover, widespread electrification wherever technically feasible would be required, through the use of hybrid or all-electric vehicle drivetrains, heat pumps for space and water heating, and specialized electric heating technology (microwave, electric arc, etc.) in industrial applications.

These two steps resulted in a modified demand scenario for electricity and fuel, summarized below in Table 3.[1]

Energy Carrier	Units	2005	2050 Business-As-Usual	2050 Efficiency + Electrification
Electricity	TWh/yr	270	470	510
Hydrocarbon fuels (gaseous + liquid)	bgge*/yr	35	64	23

Table 3. Summary of Historical and Projected Energy Demands in California
* Billion gallons of gasoline equivalent, equal to about 1.15 billion therms of natural gas.

This demand was then met by deploying supply technology to:

3. Meet the demand for electric generation capacity with combinations of low-GHG nuclear energy, fossil fuels with carbon capture and sequestration, and renewable energy. Emissions from balancing supply and demand at all temporal and spatial scales were also considered.
4. Meet as much of the demand for fuel as possible with sustainably-produced, low net lifecycle GHG biofuels.

We found that many combinations of low-GHG electricity generation technologies were technically possible, with each technology having its pros and cons. We found little data to support analysis of either the amount of load balancing required or the emissions associated with such. We therefore calculated the emissions that would result from the energy system for various electricity portfolios, assuming that load balancing was either somehow handled without emissions (the zero-emissions load balancing, or "ZELB," case), or was handled entirely with natural gas. As discussed below in

1 Note that some corrections in the analysis since publication of the Summary Report have resulted in minor changes to some of the reported numerical values.

Electricity Supply and Load Balancing Variants, load balancing can become an important source of emissions, and must be treated as an energy sector in itself for the purpose of emissions reductions.

For biofuels, we estimated that advanced technologies likely available by 2050 would be about 80% less carbon intensive than fossil fuels. However, we found that the amount of biomass likely to be available — including imports roughly equal to what would be available within the state — would only amount to about half of the required demand for fuel.

The 2050 Median Case

After initial exploration of potential 2050 California energy systems, a reference "Median Case" portrait was developed to represent a plausible future as determined by the CEF committee. This portrait began with the 2050 demand projection that assumed realistic but aggressive levels of efficiency and electrification in all sectors, summarized in Table 4 below. Details are provided in Appendix A and in separate CEF reports (Yang et al., 2011; Greenblatt et al., 2012b).

Energy Carrier	Energy Supplied	Fraction of Energy Carrier Total
Electricity		
- Natural gas with CCS	161 TWh/yr	31%
- Nuclear	161 TWh/yr	31%
- Renewables (including biomass)	172 TWh/yr	33%
- Load balancing natural gas (without CCS)	25 TWh/yr	5%
- Subtotal	520 TWh/yr	100%
- Zero-emission load balancing[a]	25 TWh/yr	5%
Fuels[b]		
- Gaseous biofuel (biogas)	5.5 bgge/yr	22%
- Gaseous fossil fuel (natural gas)	5.1 bgge/yr	21%
- Liquid biofuels	7.5 bgge/yr	31%
- Liquid fossil fuels	6.4 bgge/yr	26%
- Biofuels subtotal	13.0 bgge/yr	53%
- Fossil fuels subtotal	11.5 bgge/yr	47%
- Subtotal (without CCS)	24.5 bgge/yr	100%
Natural gas with CCS	8.5 bgge/yr	N/A
Total fuels (including those with CCS)	33.0 bgge/yr	N/A

Table 4. Median Case 2050 Supply Portrait
[a] Does not count toward total generation because no new energy is created.
[b] Not including natural gas with CCS (because emissions are sequestered).

The electricity sector was composed of an approximately one-third blend of each the main low-GHG technologies: renewables, fossil/CCS and nuclear. The portrait was silent on how much electricity was generated in-state, but our assessments indicated that there were sufficient site locations, sources of cooling water,[2] underground CO_2 storage reservoirs and renewable resources to provide the required energy entirely within California, though perhaps not at the lowest cost (note, however, that we did not perform a detailed economic analysis to address this latter issue).

To this mix, half of the required load balancing was assumed to be provided from natural gas generation, and half from zero-emission load balancing technologies (flexible demand management, electricity storage, or other unspecified technologies; see discussions in load balancing section and in Greenblatt et al., 2012a). For the hydrocarbon fuel sectors, 13 bgge/yr of biofuel supply was assumed,[3] displacing approximately 50% of fossil fuel demand (not including natural gas used with CCS for electricity generation). See (Richter et al, 2011), (Greenblatt et al, 2012a) and Youngs et al, in prep.) for details.

Figure 3 shows the GHG reduction results of this first stage of analysis. By deploying all four actions to reduce the GHG footprint of the energy system, we were able to achieve an energy system that has 60% fewer total GHG emissions than in 1990. Table 5 provides a breakdown by sector of the Median Case 2050 GHG emissions.

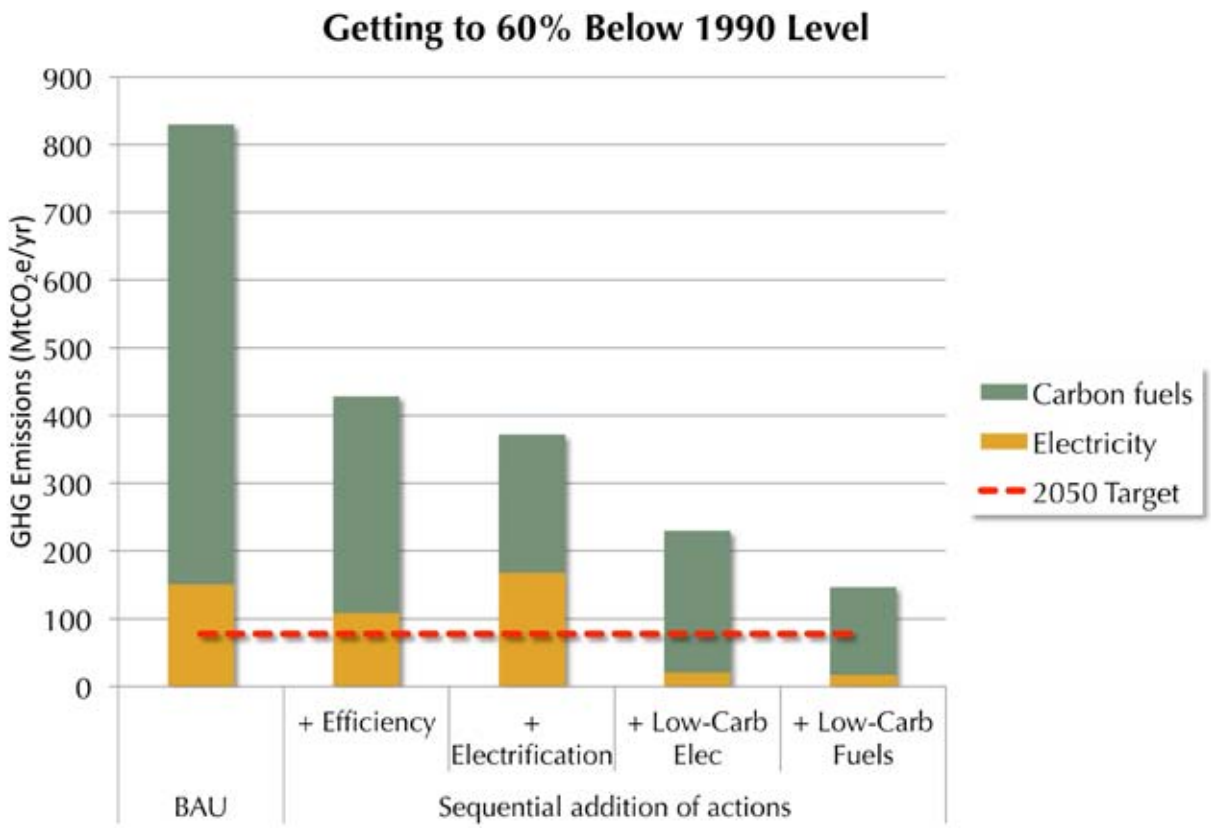

Figure 3. Strategies to Achieve 60% Emissions Reductions in California by 2050. BAU=Buiness-As-Usual

2 The nuclear and fossil/CCS teams determined that if cooling water were insufficient or too expensive, air-cooling was a feasible technology option with a tolerable impact (~10%) on efficiency (Richter et al. 2011; Greenblatt et al., 2012a).

3 An additional 2.0 bgge/yr was used in the electricity sector to make 25 TWh/yr, bringing the total assumed biomass resources to 15.0 bgge/yr (or 188 mdt/yr). Fifty percent of this resource was assumed to be produced within California, with the other half imported.

Energy Sector	GHG Emissions ($MtCO_2e/yr$)
Electricity	17.0
Building (plus ag/other) heating	10.8
Industrial heating	47.3
Transportation	71.3
Total	146.4

Table 5. Median Case 2050 GHG Emissions by Sector

Portrait Variants

In addition to the Median Case, a number of energy system portraits were explored, each of which emphasizes a different dominant type of supply technology. Below, we summarize all of the portrait "variants" that were presented in the Summary Report. Some of these variants resulted in emissions significantly above or below the 60% reduction level achieved by the Median Case. (In Section III. of this report, we use the Median Case as a starting point for examining which new technologies might be invoked to finish the job of reducing emissions all the way to 80% below the 1990 level).

The variant cases were helpful in characterizing the impact of some technology assumptions on overall GHG emissions:

- Electricity supply variants[4]:
  - High nuclear electricity case (~60% of annual electricity demand)
  - High fossil/CCS electricity case (~60% of annual electricity demand)
  - High renewable electricity case (~90% of annual electricity demand)
- Electricity load balancing[5] variants on Median Case and each of the above:
  - 100% natural gas case
  - 100% zero-emissions load balancing ("ZELB") case
- Biomass supply variants on Median Case:
  - Low biomass supply case [40 million dry tons (mdt)/yr]
  - High biomass supply case (376 mdt/yr)
- Biomass GHG intensity variants on Median Case and each of the above:
  - Low GHG intensity case (0% of fossil fuels)
  - High GHG intensity case (50% of fossil fuels)

<u>Electricity Supply and Load Balancing Variants</u>

Table 6 presents a matrix of variants in two dimensions, with the electricity supply choice (nuclear, coal/CCS, natural gas/CCS, renewables, or a mix) in one dimension, and the load balancing choice

4 All variants assume at least 33% renewable generation; see Table 3.
5 Load balancing is the ability to match electricity supply to demand at all times, which becomes especially important when supply is dominated by intermittent sources such as wind or solar energy.

(100% natural gas, 100% ZELB, or a 50% mix of each) in the other dimension. The Median Case is defined by the combination of a mix of electricity supply technologies and a mix of load balancing solutions.

For all mixed load balancing cases, emissions are approximately 60% below the 1990 level (variations from 137 to 163 $MtCO_2e/yr$). This is because electricity emissions from all cases are dominated by natural gas for load balancing, with smaller amounts from biomass and fossil/CCS (where present), and emissions from outside the electricity sector are virtually identical.[6]

However, differences in load balancing more strongly affect overall emissions: across all combinations shown in the Table, total emissions vary from 123 to 173 $MtCO_2e/yr$. The lowest emissions are found in the nuclear and renewables cases with 100% ZELB, while the highest emissions are found in the fossil/CCS and renewables cases with 100% natural gas for load balancing.

The largest difference in emissions for any electricity supply variant is found in the renewables case (123 to 173 $MtCO_2e/yr$). This is because the assumed amount of load balancing required is larger than in the other cases, amounting to 20% of total electricity-sector demand. When this load balancing demand is satisfied by ZELB technology, emissions are extremely low. However, when load balancing is provided by natural gas turbines, emissions increase by 50 $MtCO_2e/yr$; this difference alone is two-thirds of the overall state target (77 $MtCO_2e/yr$).

6 The reason emissions are not exactly identical is due to the impact of the electricity sector configuration on demand elsewhere in the energy system, which affects emissions. For instance, cases with natural gas/CCS require more refining capacity, which increases indirect emissions.

Load Balancing Variant	Electricity Supply Variant[a]				
	Nuclear	Natural Gas/CCS	Coal/CCS	Renewables[b]	Mix[c]
	Electricity sector				
100% ZELB[d]	6	16	34	6	11
100% Nat. Gas	19	29	42	36	24
Mix (50% of each)	12	22	37	20	17[f]
	Rest of energy system[e]				
100% ZELB[d]	118	128	118	118	123
100% Nat. Gas	131	136	131	137	134
Mix (50% of each)	125	133	125	131	129[f]
	Total				
100% ZELB[d]	123	144	151	123	133
100% Nat. Gas	150	165	173	173	158
Mix (50% of each)	137	155	163	150	146[f]

Table 6. 2050 Greenhouse Gas Emissions ($MtCO_2e/yr$) for Electricity Supply and Load Balancing Variants

[a] Exact supply proportions depend on amount of natural gas used for load balancing, but all cases contain at least 33% renewables per California law.

[b] The renewables variant assumes twice the required load balancing (20% of total annual electricity demand, versus 10% for other variants) due to greater frequency of supply-demand mismatch.

[c] Mix assumes 33% Renewables, 0-10% Natural Gas (without CCS) depending on the load balancing variant, and the remainder shared equally between Nuclear and Natural Gas/CCS.

[d] ZELB = zero-emission load balancing technology (electricity storage, flexible demand management, and possibly other strategies or technologies).

[e] Emissions from the rest of the energy system vary due to changes in refining needs, which affect overall carbon fuel and electricity demands.

[f] Median Case: 33% Renewables, 31% Nuclear, 31% Natural Gas/CCS, 5% Natural Gas and 5% ZELB (as electricity storage).

Figure 4. shows these same results graphically.

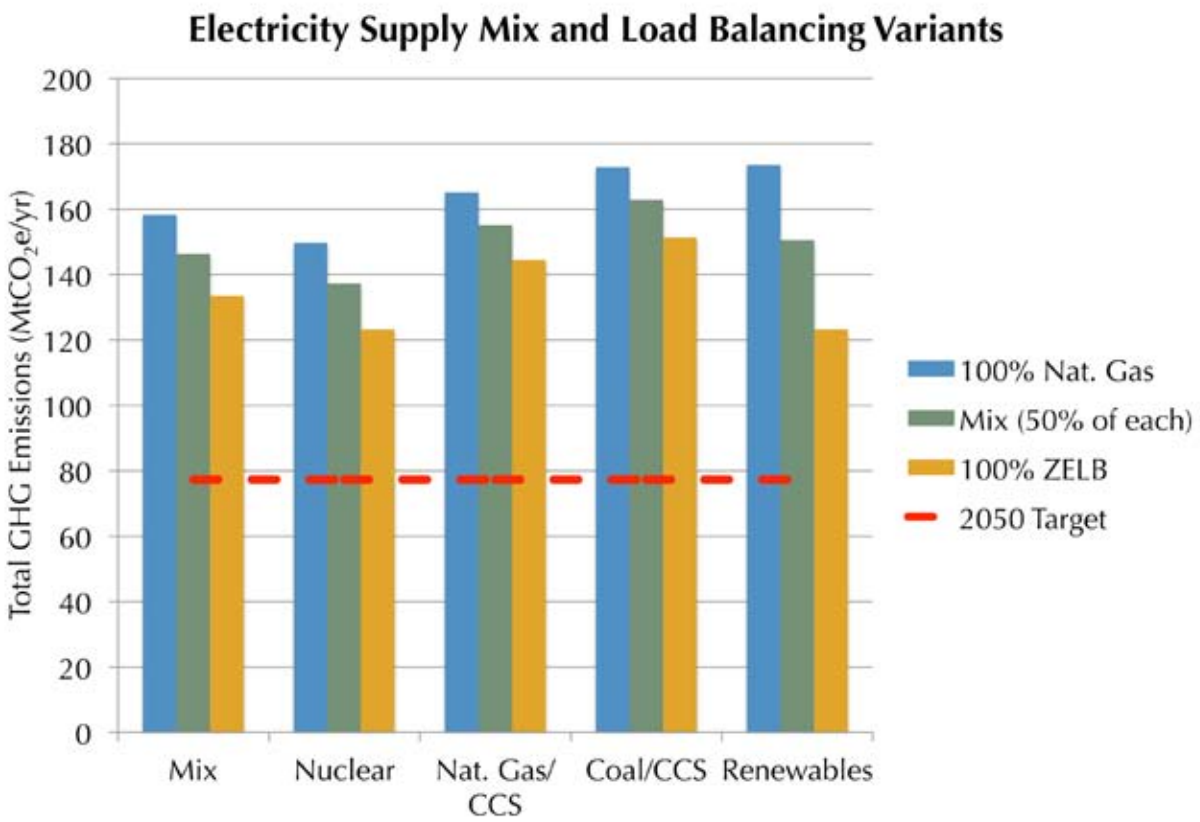

Figure 4. Greenhouse Gas Emissions ($MtCO_2e/yr$) for Electricity Supply and Load Balancing Variants

Biomass Variants

After all possible transportation and heat has been electrified, there remains a need for 23-26 bgge/yr of liquid and gaseous hydrocarbon fuels for mobile and stationary uses (depending on refining energy demand).[7] The Median Case demand is 24.5 bgge of fuel in 2050. This fuel use will not be amenable to CCS and thus the only possible way to eliminate emissions is to use low-carbon fuels. Here, we explore how much of this demand can be met from biomass-produced fuels, using various assumptions about their net GHG emissions.

Our estimate of in-state biomass resources from waste products, crop residues, and marginal lands not usable for agriculture was between 40 and 121 mdt/yr. This represents a range of between 3 and 10 bgge/yr of liquid and gaseous biofuels. It is possible that our "fair share" of likely worldwide production could make up the difference between the state's needs and in-state supplies. As this is uncertain, we chose a median estimate of 7.5 bgge/yr in-state production, of which we assumed 2.0 bgge/yr would be burned directly as biomass for electricity, leaving 5.5 bgge/yr available for

7 This range is expanded somewhat when one considers the effect of load balancing on total fuel demand. In the Median Case, about 2 bgge/yr of natural gas is assumed to be used to supply half the load balancing or 5% of electricity demand (roughly 25 TWh/yr). This demand could be zero or as much as 8 bgge/yr (in the high-renewables case with all natural gas load balancing). Assumptions about available biomass supply could further increase or decrease total demand by several bgge/yr, due to changes in refining energy needs.

fuel production. A similar amount of 7.5 bgge/yr as California's "fair share" of imported biofuel was included, for a total of 13.0 bgge/yr available biofuel.[8]

Currently, biofuel is produced from food crops such as corn, sugarcane and soybean with a process that results in about 40% to 50% of the emissions of fossil fuel. Future technologies are expected to reduce this to 20% (80% reduction over current fossil) by 2050 for both liquid and gaseous biofuels. Because the state Renewable Fuel Standard (RFS2) has set caps on the production of corn ethanol and conventional biodiesel, production of 85% ethanol/15% gasoline blends (E85) and biodiesel were not analyzed in the CEF scenarios, whereas "drop-in" fuel technologies, such as renewable gasoline and diesel replacement fuels (bin 2 and 3 technology), which can be made by several routes from biomass, were included.

It is important to recognize that the amount of biomass that might be available to California could be much smaller or much larger than the median assumption of 13 bgge/yr. The low biomass supply variant was based on the low end of the estimated range of available California supply (40 mdt/yr) (Youngs et al., 2011). The high estimate was simply a doubling of the Median Case supply to 376 mdt/yr. The proportion of fuels and electricity in the low supply case was assumed to be the same as in the Median Case, while in the high supply case, sufficient biomass was assigned to fuels to completely satisfy demand for liquid and gaseous fuels (23 bgge/yr), with the balance used for electricity (88 TWh/yr, or 17% of electricity demand).

Moreover, the net GHG emissions from biofuel production is currently very uncertain; thus we explored a range of biomass GHG intensity, using the low and high estimates from Youngs et al. (in prep.) of 0% and 50% that of lifecycle fossil fuels, respectively.

These above two sets of variants were combined together with the Median Case to make a total of 9 variant cases, shown in Table 7 and Figure 5.

Biomass GHG intensity (Fraction of lifecycle fossil emissions)		Biomass Supply (mdt/yr)		
		40	**188**	**376**
	Biomass product			
	Fuels (gge/yr)	2.8	13.0	23.0
	Electricity (TWh/yr)	5	25	88
0%		213	114	5
20%		220	146*	75
50%		230	195	180

Table 7. 2050 Total State Greenhouse Gas Emissions ($MtCO_2e$/yr) for Biomass Variants
* Median Case

8 Including the 2.0 bgge/yr used for electricity, total biomass supply is thus assumed to be 15 bgge/yr, or 188 mdt/yr (using a future conversion efficiency of 80 gge/dt).

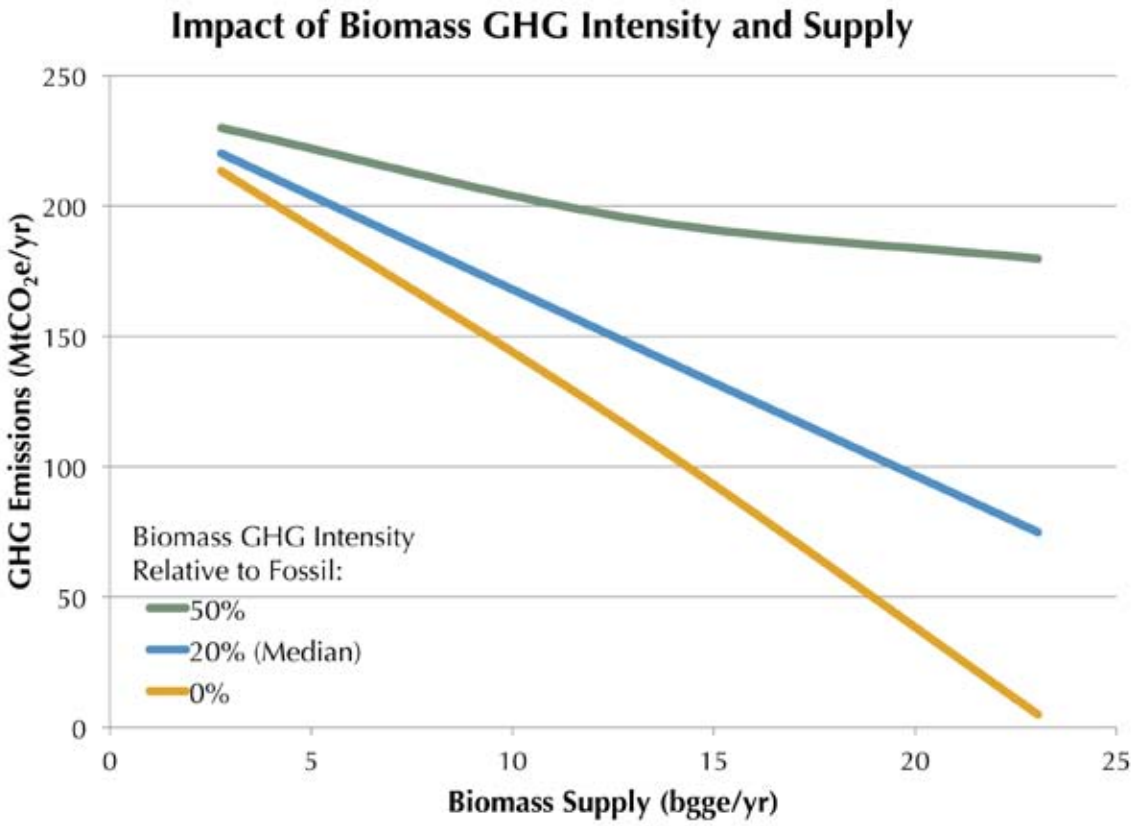

Figure 5. Greenhouse Gas Emissions ($MtCO_2e/yr$) for Biomass Variants. Biomass supply is the sum of both fuel and electricity products.

Spreadsheet Tool

The basic organization and operation of the spreadsheet tool that keeps track of all technology choices, insures supply matches demand and calculates the resulting emissions of the energy system is also discussed. A summary of the CEF spreadsheet tool is provided in Appendix B.

III. Getting to 80% (and Beyond): Opportunities for Technology Innovation

By limiting the analysis of new energy systems to technology that is largely available or in demonstration today, we were able to identify energy systems that produced total emissions that were approximately 60% lower than the 1990 level. Below, we examine more radical measures that would reduce California's emissions in 2050 from 60% to 80% below the 1990 level, thus achieving the ambitious target of Executive Order S-3-05. We examine ten strategies not considered in the 60% scenarios, but conclude that only three of them have the potential to reduce emissions to the 80% level on their own. Therefore, while it may be possible to reach the target emission level with a single strategy, a combination of two or more strategies will probably be required.

As shown in Figure 6, we need to cut about 50% of the emissions in the median portrait in order to attain the carbon footprint of the 2050 goal. Nearly all these emissions are coming from remaining fossil fuel use for transportation, heat and load balancing.

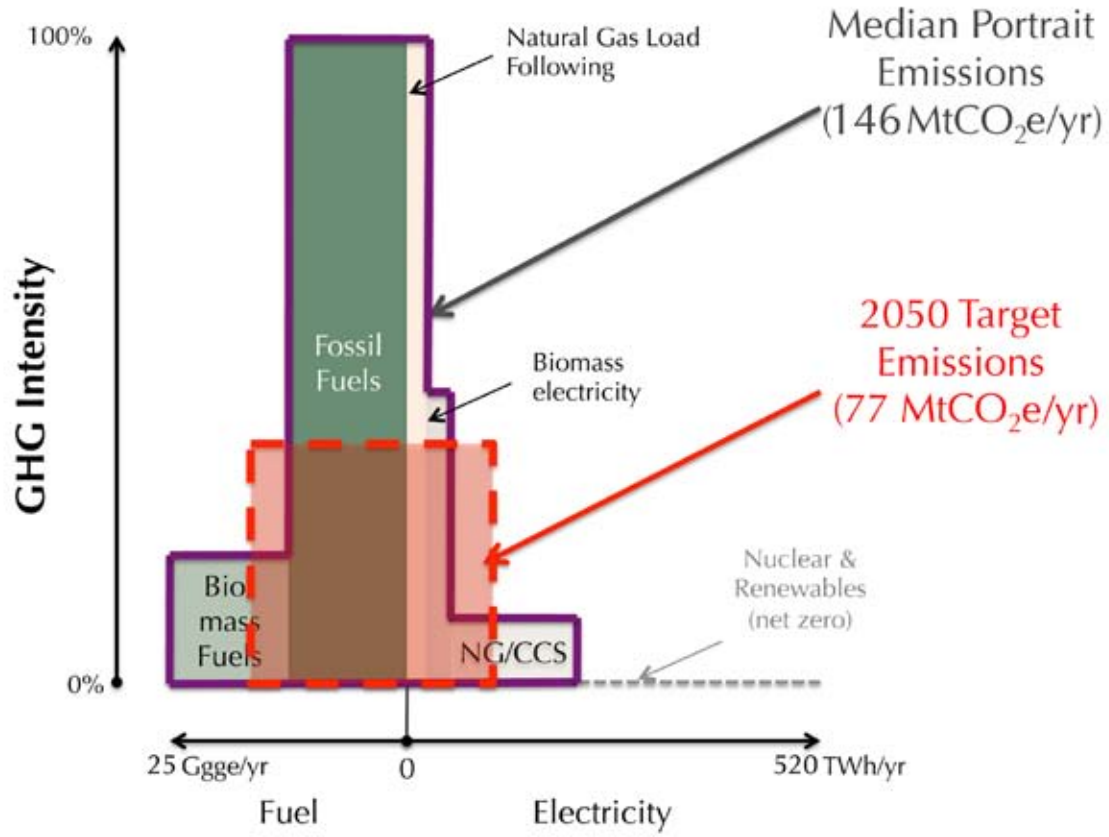

Figure 6. Difference Between Carbon Footprints of the Median Case and 2050 Target
Note: Remaining fossil fuel use is primarily for heavy-duty transportation and heat. The horizontal axis represents demand for energy, divided into electricity and fuels, and the vertical axis represents the relative carbon intensity of that energy, so the areas of each component indicate their GHG emission contributions. The area surrounded by purple indicates median portrait emissions, while the area of the red box represents 2050 target emissions, though the shape of the 80% reduction box could be quite different from this depending on assumptions.

In order to concentrate on the remaining problem of emissions from fuels, we assumed one electricity portfolio (the Median Case) that has roughly equal amounts of nuclear power, fossil with CCS and renewables, and we assumed that by 2050 half the load balancing[9] was accomplished with zero-emission load balancing technology without emissions. The actual technology is unspecified, but this latter assumption is simply an "unbiased" convenience. We did not analyze the likelihood of achieving any particular technology for accomplishing ZELB, and this issue clearly deserves further study. So, the ZELB variable has been set to "half way" as a means of roughly leveling the playing field for various methods of producing electricity, and to allow us to explore the fuel problem. It should not be interpreted as a prediction or a currently known capability. From the discussion of energy supply variants explored in the section, *Portrait Variants*, we know that this choice of load balancing technology assumption has a strong effect on the resulting statewide emissions. Compared to the Median Case with 146 $MtCO_2e$/yr, emissions could be as low as 123 $MtCO_2e$/yr or as high as 173 $MtCO_2e$/yr — representing a range that is nearly as large as the 2050 target itself (77 $MtCO_2e$/yr).

Surprisingly, the renewables-dominant case is where the variation in emissions is the largest, because for an intermittent, renewables-dominant system, the amount of natural gas ramping that was required was about 20% of annual electricity generation, as opposed to 10% for a baseload-dominated system (using either nuclear or fossil/CCS technology). For more information, see Greenblatt et al., 2012a. Thus, the difference in emissions between accomplishing load balancing with 100% natural gas versus 100% ZELB is about twice as large (50 $MtCO_2e$/yr) in the renewables case as in the other cases.

While all cases were assumed to meet the same high level of reliability,[10] the challenge for a renewables-dominated system is greater than in the other cases, because of the "gigawatt-day" problem that we describe in detail in Greenblatt et al. (2012a). Briefly, there exists a potential scenario that, despite a geographic diversity of renewable wind, solar and other resources, there will be extended periods of time — multiple days or even weeks — where renewable supply is insufficient to meet demand even after all available load flexibility, short-term storage and imported resources have been deployed.[11] We estimate that the required energy shortfall could amount to many gigawatt-days. However, the size and nature of the gigawatt-day problem under various future scenarios is not well understood at present, and thus research to better characterize it appears to be important for long-term electricity policy planning.

Section Organization

The remaining GHG emission challenges for the California energy system fall into two main categories: hydrocarbon fuels and load balancing.

For hydrocarbon fuels, the problem is an insufficient quantity of low GHG fuel to substitute for fossil fuels. Biomass quantities are limited in California, and probably nationwide; it is unclear whether sufficient quantities of low-GHG biofuels will be available for purchase internationally, and there are currently few alternatives to biofuels.

9 Defined as electricity strategies that facilitate balancing of demand with supply at various timescales, e.g., seconds to days. Strategies include dispatchable fossil (mostly natural gas) generation technologies, dispatchable renewable technologies including hydro, biomass and geothermal, energy storage technologies (pumped hydro, compressed air, batteries, etc.), electric vehicle charging, and other demand management approaches.

10 Average bulk power system reliability in the U.S. is between 99.9% and 99.99%, which translates into an annual outage rate of between ~9 hours and ~50 minutes, respectively (Gellings et al., 2004, cited in FERC, 2007, p. 2-5).

11 Such a situation is not unlike the involuntary shut-down of a nuclear reactor, but plant designs are supposed to take low-probability events into account, such as the earthquake plus tsunami which struck the Fukishima nuclear plant in Japan last year, in order to maintain the average system reliability levels cited above.

Solutions to the "fuel problem" can be broken into four categories:

1. Further reducing demand: behavior change and/or more aggressive energy efficiency
2. Further shifting away from fuels: hydrogen substitution and/or more aggressive electrification
3. Further lowering the GHG intensity of fuels: zero-emission biofuels, and biomass with CCS for fuels and/or electricity production
4. Increasing the low-GHG fuel supply: doubled biomass supply, biomass and coal with CCS, and fuel from sunlight

Many of these solutions will be discussed in more detail in the section, *Solving the Fuel Problem*.

For load balancing, the problem is that emissions from natural gas turbines—currently the lowest-cost technology for matching supply with demand—are significant, and almost as great as the entire 2050 target if a high-renewables future is pursued. Alternatives fall into four categories, and are either at a very early stage of development or currently too expensive:

1. Flexible load management
2. Energy storage
3. Natural gas turbines with CCS
4. Production of fuels or other bulk commodities (such as desalinated water)

Solving the fuel problem would also solve the load balancing problem, so in a sense it is the more important of the two problems. Each of these above solutions is explored in the section, *Solving the Load-Balancing Problem*.

Finally, there are solutions that were considered which could help lower overall state GHG emissions but did not fall into either of the above categories:

1. Develop net zero-emission CCS
2. Eliminate CCS from the electricity mix
3. Reductions of non-energy GHG emissions

These approaches are discussed in the section, *Other GHG Reduction Strategies*.

There are undoubtedly other technologies to consider as well that the CEF committee did not identify.

Solving the Fuel Problem

Behavior Change

We estimate that, based on a survey of existing literature and our own calculations, behavioral changes could reduce energy demand by 7-11% and lower emissions by 24 $MtCO_2e$/yr. Studies by others indicate that even larger reductions in use (up to 20%) are possible in the residential sector. Below, we review some of the existing literature on behavior change, summarize our technical assumptions, and then follow with brief discussions of the technical maturity, reliability, resource constraints, policy assumptions, barriers, and potential synergies.

Literature Review

Existing reports tend to be focused on the short term (less than 10 years) and to include a wide variety of actions, including both adoption of more energy efficient end-use appliances and vehicles, as well as ongoing behavior changes such as dietary habits and driving patterns. Varying assumptions are made for the penetration (or adoption) rate of a given action or behavior in the overall population. The majority of reports tend to focus on residential actions, perhaps because the commercial and industrial sectors are more heterogeneous and more difficult to treat. Indeed, for some analysts, "industry behavior change" is an oxymoron, since, in principle, industry has strong bottom-line incentives to save money and energy. In practice, however, energy savings may not be a foremost priority in many industries and/or may not be recognized as an area for significant bottom-line savings.

The references surveyed here suggest that household actions can cut residential energy demand by up to 22%, with an overall sector-wide GHG reduction of up to 15% in the near term (less than 10-year time frame). These reductions include a wide range of behavior actions that span purchase and investment in more energy-efficient equipment and vehicles, to "no-cost" actions such as recycling or carpooling.

The Natural Resources Defense Council (NRDC) (2010) reported a 15% cut in overall carbon emissions through "simple inexpensive personal actions" such as more efficient hot water use, upgrading of appliances less frequently,[12] and recycling whenever possible. This study assumed that 100% of the population adopts all included actions, which are mostly habitual behaviors but also included purchasing actions such as programmable thermostats and compact fluorescent lamps (CFLs).

Dietz et al. (2009) reported the potential for a 7.4% overall emission reductions in the near term (equivalent to 20% of household direct emissions) with "little or no reduction in household well-being." The authors included adoption of more energy efficient technologies such as energy efficient appliances and automobiles, and utilized adoption rates either based on uptake rates from historical pilot programs in energy efficiency or from historical behaviors in other fields such as health care and safety. Similarly, Laitner et al. (2009) reported the potential for 22% reduction in household energy use in the next 5-8 years, with 57% of the savings from low- to no-cost actions, and the remainder from savings based on investment decisions. The authors described a "2x2" behavior continuum with cost on one axis and duration on the other (one-time purchase decisions vs. ongoing behavior). Behaviors from across this continuum were included in their study.

BC Hydro (2007) utilized a customer survey framework to assess energy savings potential in the 2007-2026 timeframe. They made a distinction between "lifestyle change" behaviors (reduced energy service) and "non-lifestyle" behaviors (preserved levels of energy service) and included only the latter in their estimates. Actions included hot water settings and usage patterns and thermostat setting as well as weather stripping, storm window installation and low-wattage lighting. The study found a 6.2% electricity savings potential in the residential sector and 2.8% electricity savings potential in the commercial sector.

In the area of transportation, several studies have cited the potential for 6-20% fuel savings from eco-driving (IEE, 2008; Boriboonsomsin et al., 2010; GeSI, 2010). Lower savings estimates included only modified driving habits such as acceleration, idling time and maximum speed, while higher

12 While this action reduces the energy consumed during product manufacture, it is not clear that this always results in full lifecycle energy savings, since new appliances are often more efficient.

savings estimates included tactical decisions such as route selection and vehicle maintenance. An upper limit to the impact of all non-vehicle purchase actions appeared in Sivak and Schoettle (2011), where "worst-case" eco-driving conditions (tactical decisions, driving habits, and vehicle condition) were estimated to degrade official listed fuel economy by 45%.

A not-yet released study involving some of the authors of this report (Wei et al., in press) focused on long-term habitual behavior change, since habitual behavior changes are expected to take a long time (decades) to be adopted in significant numbers. Other measures, such as weather-stripping, CFLs, and more fuel-efficient vehicles, were assumed to be covered by other regulatory frameworks that could be developed in the future. For example mandates for residential/commercial energy upgrades or tightened appliance and vehicle standards would effectively require societal changes in "purchasing behavior." The study also considers behavior impacts as a function of the future energy system, since carbon emissions savings will depend on the makeup of the electricity supply and fuel supply.

Using a bottom-up approach of estimating adoption rates based on historical adoption rates in recycling, diet, and health and safety, the study found a potential for 8-17% carbon savings from long-term habitual behavior corresponding to nominal and high adoption rates. Larger savings are projected if out-of-state emissions are included. For example, a large component of emissions reduction from increased recycling and reduced consumption is from outside the state, since much industrial production of consumer goods has migrated out of California (and the U.S.). Wei et al. found that, similar to the CEF report, liquid fossil fuel is a large component of remaining carbon emissions even after deep energy efficiency measures, transition to clean electricity, electrification of vehicles and heat, and ramping up of low-carbon biofuel production. The report thus finds that actions in transportation that reduce vehicle miles travelled (VMT) have the largest impact, followed by increased recycling and reduced consumption.

Wei et al. also calculated behavior savings in two different ways. Using transportation VMT reduction as an example, the first method assumed that demand reduction from behavior actions translated proportionately to "clean" (low-carbon, biomass-based) and "dirty" (high-carbon, fossil-based) fuel demand reduction. In other words, a 10% lower demand in fuel translated to 10% lower biofuel and 10% lower fossil fuel demands. The second method posited a regime in which all demand reduction translated to a reduction in fossil fuel first. In this case, the carbon savings increased from 8-17% to 11-40%. This regime could emerge if, for example, fossil fuels become sharply more expensive through supply shocks, high carbon taxes, or other strong policy incentives to adopt biofuels over fossil fuels. In the current (CEF) analysis that follows, the second method was assumed.

This is a rich and under-studied area, and deserves further exploration that is unfortunately beyond the current scope of this study. In the following sections, we outline the assumptions made in the behavior change case, their impacts and challenges.

Technical Assumptions

Most assumptions for this case were not technical, but the availability of sensors and other automated equipment to facilitate behavior change were assumed; most of these are available today, though perhaps at a cost that is too high for widespread adoption (see cost discussion below). We have assumed that the majority of demand reductions arise from personal choice, though probably amplified by vigorous publicly- and privately-sponsored campaigns.

Table 8 summarizes the assumed changes in demand for all sectors, which were applied equally to all energy carriers since the behaviors target end-use consumption broadly, rather than technologies associated with specific fuels. However, because of feedbacks in the energy system (the reduction in fossil fuel production and its subsequent impacts on energy demand, counterbalanced by increases in electricity demand from increased bus and rail transport), reductions by energy carrier were not uniform. Table 9 summarizes the resulting changes by energy carrier, and overall GHG emissions.

Sector	Change in demand relative to Median Case
Residential	-10%
Commercial	-10%
Industrial	-10%
Agricultural/Other	0%
Transportation:	
- Light-Duty Vehicles	-10%
- Heavy-Duty Vehicles	-10%
- Airplanes	-10%
- Buses	+200%*
- Passenger Rail	+200%*
- Freight Rail	-10%
- Marine Transport	-10%

Table 8. Demand by Sector for Behavior Change Case
* Increases partially offset reductions in light-duty vehicles.

Energy Carrier	Units	Median Case	Behavior Change Case	Difference
Electricity	TWh/yr	520	482	-7%
Gaseous fuel	Bgge/yr	10.6	9.5	-11%
Liquid fuel	Bgge/yr	13.9	12.5	-10%
GHG emissions	$MtCO_2e/yr$	146	122	-16%

Table 9. Changes in Demand by Energy Carrier and Overall GHG Emissions for Behavior Change Case. Emissions decrease more strongly than energy use due to the assumption that fuel use reductions preferentially target fossil fuels, rather than the mix of fossil- and biomass-based fuels assumed in the Median Case.

Technological Maturity

As behaviors do not depend very strongly on technology, there are no solutions that are not technologically mature. That said, however, there are a few areas where technical innovation can improve behavior change adoption:

- Buildings: Occupancy sensors and feedback controls to optimize conservation behavior
- Industry: Product design emphasizing longer-lasting products, and products made with less material and energy inputs
- Transportation: Feedback indicators to enable "hypermiling";[13] information systems to allow for optimal route planning car-sharing and public transit systems.

Costs

For most behaviors examined, little to no cost barrier was identified. While purchasing longer-lasting or better-designed products may cost more initially, it is assumed that the lifetime cost will probably be lower. Other technological options discussed above would have negligible cost on a societal level.

Reliability

No change in reliability could be identified.

Resource Constraints

Physical resources would likely become less constrained with widespread adoption of behavior change practices.

Policy Assumptions

By their very nature, behavior changes are difficult to legislate. However, there are many historical examples of policy-induced behavior change when the public need was deemed sufficiently high, for instance, seat-belt use, reducing drunk driving, decreased smoking, and bans on dangerous foods or substances. Indeed, some of these resulting trends were used to project potential future behavior change in Wei et al. (in press), reasoning that similarly-crafted public policies could be instituted to emphasize promising energy-related behavior changes.

Barriers

The greatest barrier to behavior change is reaching millions of individuals, which is generally considered to be very difficult. Behavior change within industrial design is probably somewhat easier to implement, but requires a strong societal signal that such changes will be profitable to industry; therefore, they rely on social behavior change as well, and remain quite difficult to achieve.

Potential Synergies

Some synergies exist, for instance, consumer demand for longer-lasting electronics coupled with a cultural shift within industry to design such products. Other synergies, such as the cost-savings

13 The act of driving using techniques that maximize fuel economy (Wikipedia, 2012).

associated with conserving energy, could be amplified through consumer awareness, particularly electronic tools to make these savings more visible and/or engaging, e.g., community competitions, etc.

Hydrogen

Hydrogen is already used industrially on a large scale, with California consuming about 1,400 GgH_2/yr, or approximately 1,400 bgge/yr (Ogden, 2011). Most hydrogen applications are currently in petroleum refining. The hydrogen case assumes the large-scale introduction of hydrogen as an energy carrier, with about half of the demand going to light-duty vehicles, and smaller amounts consumed by industrial heat applications, buses and short-range heavy-duty trucks. Hydrogen used in transportation can be considered a form of electrification because it is converted by a fuel cell to electricity that subsequently powers electric traction motors, just as in an electric vehicle.

If hydrogen were widely available, where would it make sense to augment or replace the fuel-switching changes suggested by the Median Case? By examining each sector individually and determining the realistic level of hydrogen adoption, if any, in conjunction with the efficiency and electrification already assumed in the Median Case, we determined that a demand of 8,000 GgH_2/yr (about 8 bgge/yr) would materialize in 2050. This would displace about 7 bgge/yr of liquid and gaseous hydrocarbon fuels and 50 TWh/yr of electricity, and save more than 40 $MtCO_2e$/yr.

However, implementing hydrogen on this scale is challenging both from an infrastructure as well as a technology perspective, particularly for mobile uses that will consume the majority of the hydrogen in the portrait. While high-density, on-board hydrogen storage and fuel cell technology have taken great strides in recent years, including the production of hundreds of demonstration vehicles, they are still very expensive compared to conventional vehicles. Yang et al. (2011) estimate that the price premium for hydrogen vehicles could drop to $10,000 by 2020 and possibly as little as $3,600 by 2030 with full-scale commercialization. Deployment of sufficient density of hydrogen refueling stations will also be initially costly, though production of hydrogen (discussed below) may eventually become less expensive than conventional gasoline on a per-mile basis.

Hydrogen Demand

We examined each energy sector for where hydrogen could play an important role in further reducing direct fuel combustion, or in competing with electrification. Starting from the base demand case, the major sectors for hydrogen were identified as transportation (specifically, light-duty vehicles, short-range heavy-duty vehicles, and intracity buses) and industrial heating. The residential and commercial sectors are already largely electrified in the Median Case, and the use of hydrogen as a low-temperature heat source appeared unnecessary and probably cost-prohibitive to build a hydrogen pipeline that reaches every building just as natural gas does now.

The use of hydrogen for long-distance transportation (heavy-duty vehicles, buses, rail and airplanes) is less certain. Jacobson and Delucchi (2011) recently concluded that hydrogen is a feasible option

for aviation using liquid hydrogen. While such aircraft would require about four times more volume to store their fuel, the fuel would have three times less mass, since hydrogen is one-twelfth the density of jet fuel, resulting in greater payload and range. Since aircraft are arguably the most difficult transportation mode to convert to either electricity or hydrogen, they argued that all other energy needs not met by electricity could be satisfied by hydrogen.

Though attractive in some respects, such a solution has a number of barriers, including the complete redesign and replacement of conventional aircraft, the significant energy penalty for liquefaction (approximately 1/3 of the lower heating value of hydrogen), and the currently high cost of hydrogen production (see discussion further below). However, it may not make sense to burn hydrogen directly in applications where it does not provide efficiency benefits and where a low-carbon conventional fuel could be produced more cheaply. Therefore, in our scenario, the use of hydrogen for long-distance transportation is excluded, but it remains an important option to explore in more detail in future studies.

The fraction of hydrogen assumed for each sector, the assumed efficiency, and the resulting demand, are summarized in Table 10, while Table 11 provides a fuel-by-fuel demand case comparison for each sector.

Sector*	Fraction of 2050 demand			Hydrogen efficiency	Hydrogen demand (GgH_2/yr)
	Carbon fuels	Electricity	Hydrogen		
Industry	51%	27%	21%	20% better than HC fuels	3,160
Light-duty vehicles	22%	22%	56%	79 mpgge	4,230
Heavy-duty vehicles	82%	9%	9%	25 mpgge	170
Buses	0%	0%	100%	70 seat-mpgge	420
TOTAL					**7,980**

Table 10. Technical Assumptions for Hydrogen
*Omitted sectors were assumed to have no or very little hydrogen demand potential.

Sector	Energy Carrier	Units	Demand in 2050			Change from Base to Hydrogen Case	Change from BAU to Hydrogen Case
			BAU Case	Base Case*	Hydrogen Case		
Industry	Electricity	GWh/yr	53,866	108,707	108,707	0%	-2%
	Gaseous fuel	TBtu/yr	679	592	345	-42%	-78%
	Liquid fuel	Mgge/yr	2,340	2,487	2,487	0%	-47%
	Hydrogen	GgH_2/yr	0	0	3,162	N/A	N/A
Transport	Electricity	GWh/yr	0	88,936	43,380	-51%	N/A
	Liquid fuel	Mgge/yr	20,155	10,811	7,347	-32%	-79%
	Hydrogen	GgH_2/yr	0	0	4,816	N/A	N/A
Others	Electricity	GWh/yr	217,398	305,607	305,607	0%	-14%
	Gaseous fuel	TBtu/yr	745	210	210	0%	-82%
TOTAL	Electricity	GWh/yr	271,264	503,249	457,693	-9%	-2%
	Gaseous fuel	TBtu/yr	1,423	802	555	-31%	-80%
	Liquid fuel	Mgge/yr	22,495	13,298	9,834	-26%	-76%
	Hydrogen	GgH_2/yr	0	0	7,979	N/A	N/A

Table 11. Demand Comparisons by Sector and Fuel Type for Hydrogen Case. * Similar to Median Case, but without corrections due to refining or energy storage.

For the industrial sector, the assumption that hydrogen can substitute for 21% of demand is based on CEF's assessment of the demand for high-temperature heat that is supplied by natural gas in the Median Case. Applications include boilers, and production of steel, glass and cement, which we estimate constitute 25% of high-temperature industrial demand.

For light-duty vehicles, we assumed that hydrogen, by offering longer range and faster refueling time than all-electric vehicles, could displace a larger fraction of conventional-fuel vehicles than in the Median Case, with 56% of 2050 vehicle miles served by hydrogen and 22% by electricity, as opposed to 40% electricity in the Median Case.

For heavy-duty vehicles, it was assumed that half the short-range fraction (estimated at 18% of total vehicle-miles travelled) could be substituted with hydrogen, which would offer significantly longer range and similar performance as an electric-drive vehicle.

For buses, it was assumed that virtually all applications would be short-range intra-city trips. Because buses do not travel long distances before refueling, and can accommodate large hydrogen storage tanks, they are more easily converted to run on hydrogen than light-duty vehicles, so it was assumed that 100% of buses would run on hydrogen.

Hydrogen Production

Hydrogen is an important energy carrier because it contains no carbon atoms, unlike all other directly combusted fuels considered in the CEF study. However, its success as a GHG mitigation strategy depends on producing that hydrogen without emitting (much) CO_2.

The following cases were considered as the main options for producing hydrogen with no or modest CO_2 emissions:

1. Hydrogen produced from fossil fuels (coal or natural gas) with CCS.
2. Hydrogen produced from biomass. (If CCS is used, this would give net negative lifecycle GHG emissions).
3. Hydrogen produced from low-carbon electricity via water electrolysis.
4. Hydrogen produced from high-temperature water electrolysis via nuclear or fossil thermal sources.

Regardless of the source chosen above, about 10% of hydrogen would probably need to be produced on-site from natural gas reforming *without* CCS, to provide service in remote regions where it is cost-prohibitive either to build H_2 pipelines or capture CO_2 and pipe it to a central storage facility.

Producing 90% of hydrogen from fossil fuels with CCS would require 16 large (440 GgH_2/yr each, approximately 440 Mgge/yr) coal/CCS hydrogen plants in 2050. The technology would have 90% capture efficiency, resulting in total emissions of approximately 14 $MtCO_2e$/yr. An additional CO_2 storage requirement of 72 $MtCO_2e$/yr in 2050 would also be necessary. If natural gas were used as the fuel, emissions would be approximately 7 $MtCO_2e$/yr, with approximately half the storage requirement, but natural gas is generally more expensive.

Hydrogen from biomass is feasible, with or without CCS, and Parker et al. (2008) estimate that up to 1,500 GgH_2/yr could be produced from their estimates of available California biomass (34 mdt/yr) at an H_2 selling price of just above $4/kg (equivalent to about $4/gge). However, this would only supply ~20% of the required demand. If biomass resources were increased to the CEF median estimate (94 mdt/yr), about 4,000 GgH_2/yr could be produced, equivalent to half of the required demand. Producing 90% of hydrogen demand would require 170 mdt/yr, nearly double the estimated in-state resource, so massive amounts of imported raw biomass or biomass-derived hydrogen would be required. Any of these levels of biomass utilization for hydrogen would, however, divert these limited resources away from biofuel production and increase the GHG emissions of the remaining carbon-based fuels, largely offsetting any savings. For both these reasons, therefore, biomass was not considered to be a viable, large-scale option for producing hydrogen.

Hydrogen produced from electricity via water electrolysis would require an additional 350 TWh/yr of electricity production in 2050 to deliver 90% of hydrogen demand. This places heavy demands on the electricity system, which would increase 69% relative to the Median Case.

High-temperature water electrolysis to produce hydrogen, while technically possible from nuclear or fossil thermal sources, is currently still at the R&D stage. For nuclear, it would require very high-temperature (800-900°C) gas reactors that, while very efficient (~50%), would require an additional 31 GW of nuclear capacity to deliver 90% of the hydrogen required in 2050. This is about 70% more than the capacity needed to produce 67% of electricity from nuclear energy in the Median Case (see Richter et al., (2011) for more details).

Producing 10% of the required hydrogen (0.8 bgge/yr) from on-site natural gas reforming without CCS would require 1,600 small natural gas reforming plants producing 0.5 GgH_2/yr (0.5 Mgge/yr) each. This natural gas-based hydrogen contributes approximately 5 $MtCO_2e$/yr to total emissions.

Hypothetical build-out scenarios for hydrogen are outlined in Table 12 below.

	2015	2020	2030	2040	2050
Total demand (GgH_2/yr)*	5	90	1,050	4,640	7,980
Onsite natural gas capacity (GgH_2/yr)	5	90	800	800	800
Number of onsite reformers (each 0.5 GgH_2/yr)	11	180	1,600	1,600	1,600
Residual capacity required (GgH_2/yr)	0	0	250	3,840	7,180
Options for meeting residual demand:					
Conventional Electrolysis					
Electricity capacity (TWh/yr)	0	0	12	189	353
Increase in electric capacity from Median Case	0%	0%	3%	42%	69%
Fossil/CCS					
Number of coal/CCS H_2 plants (each 440 GgH_2/yr)	0	0	0.6	8.7	16.3
CO_2 stored ($MtCO_2$/yr)	0	0	2.5	38.4	71.8
Increase in CO_2 storage requirement from coal/CCS scenario	0%	0%	10%	38%	29%
High-Temperature Electrolysis					
High-temperature nuclear capacity required (GW)	0	0	1.1	16.6	31.0
Increase in nuclear capacity from 67% nuclear case	0%	0%	8%	64%	71%

Table 12. Build-Out Scenario for Hydrogen

* 1 GgH_2 = 1000 metric tons H_2, or approximately 1 Mgge/yr. Total does not include current hydrogen capacity of approximately 1.4 GgH_2/yr that is used in petroleum refining, as this is assumed to not be transferrable to other uses and will largely vanish along with petroleum refining by 2050.

California law currently requires that 33% of hydrogen production come from renewable resources. While it is possible for biomass to be gasified to produce hydrogen, as stated above, it is expected that biomass will be better used in producing liquid biofuels. Therefore, renewable hydrogen is likely to come from electrolysis from renewable electricity generation.

Technical Maturity

The maturity of hydrogen technology is outlined in Table 13 below.

Bin	Demand technologies	Supply technologies
1	H_2 fuel cell vehicles, compressed H_2 storage	Natural gas reforming, H_2 electrolysis, CO_2 pipeline network, H_2 pipeline network
2	H_2 internal combustion engines, H_2-fired burners, liquefied H_2-powered aircraft	CO_2 storage in depleted oil/gas fields, H_2 refueling stations
3		Gasification of coal with CO_2 capture for H_2 production, CO_2 storage in saline aquifers
4	Advanced hydrogen storage	High-temperature (800-900°C) H_2 electrolysis using gas-cooled nuclear reactors

Table 13. Technical Maturity Bin Assignments

Cost Estimates

The initial cost of a hydrogen fuel cell vehicle at low volume production is estimated to be quite expensive (around $50,000 more than a conventional gasoline engine) (Bloomberg, 2010), but studies have shown that with high volume production and some technology advances, this cost gap could fall to $3,000 to $5,000. Such improvements would be applicable for heavy-duty trucks and buses as well.

The cost of hydrogen-fired burners for industrial heating, while currently not widely available, has been used in industry, and hydrogen-rich syngas has been burned in residential and commercial settings (Ogden, 2011). Therefore, in principle a hydrogen burner is no different from a natural gas burner, so the high-volume cost is assumed to be the same.

Currently available (bin 1 and 2) technologies for making hydrogen include reforming from natural gas and electrolysis. Estimated costs for large-scale production of hydrogen from natural gas are relatively inexpensive (around $2/gge), while electrolysis is fairly expensive (up to $8/gge). The cost of transport and refueling stations can add additional costs to the selling price of hydrogen, though onsite production is less expensive when demand is low and unable to support a large-scale production and distribution network (NRC, 2008).

Gasification of coal with CCS promises to bring this cost down considerably, by some estimates to \$1-1.3/kg H_2 (De Lorenzo et al. 2004; Kreutz and Williams, 2004; DOE, 2008). The cost of deploying a H_2 pipeline network to distribute H_2 around the state would add another \$1.5/kg H_2 (Yang and Ogden, 2007), bringing the total cost to \$2.5-2.8/kg H_2. Such a network is more expensive than a natural gas network because of the need for special materials to prevent metal embrittlement and H_2 leakage, as well as higher working pressures. The U.S. Department of Energy's hydrogen production cost goal is \$5-7/kg H_2 in 2015 (DOE, 2011).

No cost estimates were available for high-temperature gas-cooled nuclear reactor technology.

Reliability

It is expected that a hydrogen economy would be as, if not more, reliable than today's petroleum and natural-gas based system, because of the domestic feedstocks for H_2 and multiple modes of H_2 production.

Resource Constraints

Platinum is a concern for fuel cells, but it is expected that with future development the amount of platinum required would be similar to or even below what is found in a catalytic converter (Yang et al., 2011).

Current demonstration fuel-cell vehicles (FCVs) have been able to lower platinum loading to approximately 30 g in their latest FCV demonstration model (Bloomberg, 2010). At \$35-40/g Pt per fuel cell, this still amounts over \$1,000 of platinum per vehicle, and in 2008 the price for platinum has spiked much higher (nearly \$80/g) and could again move higher in the future. There is a significant research effort to try to lower platinum loadings without sacrificing cell durability, power density and efficiency and promising laboratory-scale test results have been presented using loadings that are greater than a factor of 10 lower than current levels (Sun et al., 2011). Alternative electro-catalysts for fuel cell electrodes that do not rely on expensive precious metals are being explored to help lower fuel cell costs as well.

To build a hydrogen pipeline distribution system will potentially require new land acquisitions for rights-of-way. For conventional electrolysis, the significant increase in electricity demand may place constraints on resources if generated with renewables, though it may help with load balancing of intermittent renewables. For fossil/CCS production, the increase in CO_2 storage requirements places an additional burden on underground storage capacity, but presumably this technology pathway would only be undertaken if substantial storage capacity were already available (e.g., from saline aquifers) and so would not create a significant additional challenge. Nuclear fuel capacity would be adequate to accommodate the increased capacity for high-temperature electrolysis (see general discussion on fuel availability in the Nuclear report; see Richter et al., 2011 and Ogden and Yang, 2009).

Barriers

Unlike gasoline or electricity, there is no widespread network for hydrogen distribution in place. To serve early FCV owners, hydrogen could be provided by truck delivery or via onsite production from

natural gas or electricity. With strategic placement of the first hundreds to thousands of vehicles in "lighthouse" cities, good fuel accessibility could be provided with a sparse network (Ogden and Yang, 2009, Ogden and Nicholas, 2011). Once demand reached a large enough density, e.g., when 10-25% of vehicles in a city ran on hydrogen, pipelines might be built to bring hydrogen to stations (Ogden and Yang, 2009; NRC, 2008). Large-scale central facilities like bus depots and industrial facilities may also be candidates for early hydrogen markets. The key to successful introduction of hydrogen is building supply in concert with growing demand. It is not necessary to build a full pipeline system to get started with hydrogen. However, a widespread production and pipeline distribution network would be very capital-intensive, and require special materials and higher-quality workmanship (to prevent leakage) than conventional pipelines. Table 14 enumerates these and other barriers, while Table 15 compares fuel cell stack technical and cost targets relative to estimated current values assuming mass production.

Barrier	Examples	Ways to overcome	Difficulty
Total vehicle system	Vehicle design and integration. Hundreds of demonstration FCVs are now being tested in California, Europe, Japan and Korea. These vehicles have logged over 1 million miles in California alone. These vehicles have 280-400 mile range and refuel in 5 minutes.	Problems largely solved	Low
Fuel cell stack	Improve membrane durability, freeze tolerance and material costs	Additional R&D	DOE Goals within reach by 2015
Hydrogen onboard storage	Reduce cost, weight and volume of storage tanks	Additional R&D	See table below
Refueling infrastructure	Permitting, siting of stations. Codes and standards. Coordinated deployment of hydrogen stations in metropolitan areas.	Partnerships to encourage coordination between energy companies, auto companies and local officials. Infrastructure subsidies.	Moderate
Vehicle adoption and stock turnover	Higher initial purchase cost and limited model availability. Slow turnover of vehicle fleet.	Purchase incentives (subsidies, feebates)	Hard

Resource constraints	Platinum for fuel cell electrodes (but see Sun et al., 2011), some rare earth elements for motors	Substitute materials available with additional R&D	Medium
Policies and behavior	Purchase incentives and refueling infrastructure, high level of coordination between vehicle manufacturers and station deployment		Medium to hard
Costs	H_2 FCVs at scale will be $3,000-$5,000 more expensive than conventional vehicles. Fuel costs per mile should be lower once infrastructure reaches scale.	Feebate, direct subsidy or financing. FCVs should compete on a lifecycle cost basis once they are mass produced and H_2 infrastructure scales up.	Medium

Table 14. Barriers to Hydrogen Fuel Cell Vehicle Implementation

	Today	2015 Goals
In-use durability	2000	5000
Vehicle range (miles/tank)	280-400	300
Fuel Economy (mi/kg H_2)	72	60
Fuel Cell Efficiency	53-58%	60%
Fuel Cell System Cost ($/kW)	51	30
H_2 Storage Cost ($/kWh)	15-23	10-15 (NRC)
		2-4 (USDOE)

Table 15. Fuel cell stack technical and cost targets relative to estimated current values assuming mass production
Source: Yang et al. (2011)

Potential Synergies

Hydrogen offers the potential for moving a greater fraction of the light-duty vehicle fleet away from petroleum than using battery-powered vehicles. Hydrogen FCVs are refueled like conventional gasoline vehicles and are not subject to limitations on the availability of home-based charging

infrastructure in cities and for multi-family dwellings, which is expected to make up the vast majority of electric-vehicle charging. Hydrogen could be used by those who do not have dedicated off-street parking and enable switching more vehicles off of hydrocarbon fuels.

For fuel production, each pathway has certain built-in advantages:

1. The use of fossil/CCS hydrogen can take advantage of the existing CO_2 capture technology and CO_2 distribution network that would presumably be in place for other parts of the energy economy (electricity and possibly hydrocarbon fuel production).
2. The use of electrolysis would, of course, take advantage of an existing electricity distribution network, though the increase in total generation would hardly constitute a small increment of that system, but would represent a major expansion.
3. The use of high-temperature fossil or nuclear electrolytic hydrogen production would take advantage of a technology that is also highly efficient for electricity production, and enable the collocation of production plants, fuel delivery infrastructure and fuel waste management on the same site as used for electricity production.
4. Finally, the use of natural gas reforming without CCS would leverage an existing gas pipeline infrastructure and, presumably, the network of vehicle filling stations.

(The fifth option, hydrogen from biomass, was not considered to be a viable alternative because of its competition with biofuel production, and the inadequate biomass supply to meet the required demand.)

Net Zero-Emission Biofuels

The largest unknowns in estimating the emissions from biofuels are not the viability of specific technologies, but rather the way in which total lifecycle GHG emissions are estimated, as approaches by different researchers yield substantially different results at present. For instance, the California Air Resources Board calculates that production and use of cellulosic ethanol from lignocellulosic (woody) sources could produce 70-80% fewer greenhouse gases than fossil fuels (Youngs and Somerville, 2009); while the EPA, 2009, projects even more substantial reductions for cellulosic ethanol (80-110%),[14] with the possibility of net carbon sequestration using sustainably-managed perennial crops over a long time period (Anderson-Teixeira et al., 2009).

Moreover, there is a lack of adequate information on the net GHG emissions of many advanced-technology pathways. Emissions for renewable diesel production from jatropha or algae are largely unknown [though in order to gain approval under the Energy Independence and Security Act (EISA), 2007, advanced biodiesel will have to yield at least a 50% CO_2 reduction over diesel from fossil sources]. Emissions from the production of advanced hydrocarbons from biomass via catalysis or biotechnologically-enhanced fermentation are also not known. Thermochemical routes to advanced hydrocarbon fuels from biomass indicate approximately 88-94% lifecycle GHG reduction compared with petroleum-based fuels (Larson et al., 2006; Liu et al., 2011).

Based on the above uncertainty, for the assumed adoption of advanced "drop-in" hydrocarbon fuels derived from lignocellulosic biomass, the CEF analysis adopted a range of lifecycle emissions reduction relative to fossil fuels from 50-110%, with the Median Case assuming an 80% reduction.

14 EPA estimates include direct life-cycle and land-use emissions for CO_2, N_2O and CH_4.Possible additional emissions caused by indirect or consequential effects (such as international market-induced land-use change when agricultural production is displaced) are also considered.

The same percentage reduction was used for all hydrocarbon fuels. Depending on the details of how the biomass is grown, transported, and converted into fuel, the net GHG emissions could fall anywhere in the above-quoted range, or even outside of it. For more information, see the CEF report on biofuels (Youngs et al., in preparation).

Assuming biofuels could be produced with net-zero GHG emissions, rather than the 80% reduction below fossil fuels as in the Median Case, statewide emissions would be 32 $MtCO_2e$/yr lower. However, much lower GHG emissions can be achieved by increasing biomass supply, or by combining biomass strategies with CCS; these are discussed in the sections *Strategies Using Biomass with CCS* through *Artificial Photosynthesis*.

Strategies Using Biomass with CCS

Because biomass represents nearly a net-zero carbon resource, it is usually not considered in conjunction with CCS because it already has relatively low GHG emissions. However, combining it with CCS (to make either fuels or electricity) can result in a net-negative GHG process that facilitates the displacement of fossil fuel emissions elsewhere in the economy. An example is the use of biomass electricity with CCS to displace petroleum-based gasoline used in transportation. Depending on the details of the process, such an arrangement may result in lower GHG emissions for the economy as a whole.

The idea of combining biomass with CCS has only recently received attention in the international community, with the First International Workshop on Biomass and Carbon Dioxide Capture and Storage held in October 2010 (BCCS, 2010), and the publication of *Potential for Biomass and Carbon Dioxide Capture and Storage* in July 2011 (IEAGHG, 2011).

In this section, we examine three major strategies involving biomass and CCS:

1. Biomass with CCS for electricity production
2. Biomass with CCS for fuel production
3. Biomass and coal (or other fossil fuels) with CCS for production of fuels, electricity or both

All strategies are capable of significant emissions reductions below the Median Case. The major considerations that will determine which strategies would be most favored include:

1. *Cost of transporting biomass to centralized plants*. The diffuse nature of biomass resources, particularly waste biomass, limits how much biomass can be cost-effectively transported to a plant site and hence the plant's overall size. The high cost of transport, both fixed- and distance-based, precludes shipping from being an economical mode of transport for many agricultural residues (Searcy et al., 2007), though (Larson et al., 2010) estimated that increased scale economies of plants that can use biomass harvested over a larger area may offset increased transportation costs. Unless plants are located in areas of especially abundant biomass resources or such resources can be cheaply transported there,[15] biomass-only plants typically need to be smaller than an equivalent fossil fuel-

15 For instance, barge or rail transport could be significantly cheaper than truck transport in areas where it is available, increasing affordable transportation distances. Barge transport of biomass is potentially important for plants in coal-rich Ohio River Valley and in Mississippi River Valley. Rail transport will be important for Wyoming and Montana. Although biomass supplies are scarce in these coal-rich western states, biomass for synfuel plants built there are likely to be hauled to such coal-exporting states by coal trains that would otherwise return empty. In the case of Powder River Basin (PRB) coal, the biomass might be brought in via trains that could pick up biomass supplies on the way back to the PRB from biomass-rich southeastern and midwestern states. Likewise trains hauling coal to the West Coast from Wyoming and eastern Montana could pick up biomass supplies in Washington, Oregon, Idaho, and western Montana

based plant, which increases the overall production cost because scale economies are less. On the contrary, by co-feeding biomass and fossil fuels (such as coal) in a single gasification system, the size limitation is largely eliminated, facilitating lower cost of production through greater scale economies. However, in areas of scarce fossil resources (typically outside the U.S. such as many tropical countries), biomass-only fuel production plants with CCS could also be viable.

2. *Value of electricity co-generation in gasification-based plants*. Considerable waste heat is generated in the Fischer-Tropsch fuel synthesis process, and more high-quality waste heat is generated if the system is not optimized to maximize fuel production. Utilizing this waste heat for electricity production therefore increases the overall efficiency of the plant and generates a potentially important second revenue stream, creating a hedge against volatile fuel prices and lowering overall fuel production costs. The economic advantages of coproduction under a strong carbon mitigation policy appear to be compelling; however, the complexity of marketing two disparate products and local electricity market conditions may present significant challenges.
3. *Value of CCS relative to other GHG reduction strategies*. Capturing CO_2 from biomass may be less cost-effective than reducing GHG emissions in other parts of the energy economy, though CO_2 capture costs for fuel production plants will be lower than that of electricity-only plants (Williams, 2012). But our analysis indicates that almost all available strategies for GHG reduction may be necessary to meet the 2050 target, so the market for CO_2 reductions will probably support such strategies, and a well-developed CO_2 pipeline and storage infrastructure will lower the cost of CCS for all users of the technology.
4. *Value of energy supply security*. While it may be economically less disruptive to continue to rely on imported petroleum based, or even biomass based fuels, there are potentially large energy supply security advantages to meeting most fuel demand domestically. This can be accomplished by devoting biomass resources primarily to fuel production rather than electricity, as well as synthesizing fuels from domestically available fossil resources (such as coal), in combination with CCS.

Each strategy is discussed separately in the sections that follow.

Biomass Electricity with CCS

This strategy assumes that biomass is used for producing electricity, rather than fuels, in conjunction with CCS. Such an arrangement would yield negative net CO_2 emissions in the electricity sector and offset much of the emissions from fossil fuel combustion in other sectors, primarily transportation. Using all of the 94 mdt/yr in-state biomass in the Median Case assumption would meet about 18% of electricity demand (95 TWh/yr) and save approximately 50 $MtCO_2e$/yr compared with the median scenario. (Out-of-state biomass resources were still assumed to be converted into biofuels). This is possible because nearly all of the carbon in the biomass can be used to offset fossil fuel emissions, whereas biofuels (without CCS) can only offset the carbon in the fossil fuel actually displaced, roughly 50% of biomass carbon content. However, the success of biomass/CCS hinges critically on this assumption (as well as on overall economics), so additional research is needed to thoroughly validate these conclusions.

We assume that all domestically-produced biomass is used for electricity production, with remaining carbon fuel demands (both gaseous and liquid) met by fossil fuels. Two electricity cases were examined: one containing 33% renewables (18% biomass/CCS and 15% other renewables) and 31% natural gas/CCS, and another containing 64% renewables (18% biomass/CCS and 46% other renewables); both cases contained 31% nuclear and 5% natural gas without CCS for load balancing. The amount of imported biofuel (7.5 bgge/yr) supplies about half of the liquid fuel demand, but none

before returning (Williams, 2012).

of the gaseous fuel demand, resulting in an overall supply of about 30% of the total hydrocarbon fuel demand (not including natural gas used for CCS). Table 16 summarizes these two cases.

Parameter	Biomass/CCS Case		Median Case (for comparison)
	Case 1: No Fossil/CCS	Case 2: With Fossil/ CCS	
Electricity demand (TWh/yr)	519	523	520
Electricity Supply (% of Total)			
Biomass/CCS	18%	18%	0%
Fossil/CCS	0%	31%	31%
Natural gas without CCS (load balancing)	5%	5%	5%
Nuclear	31%	31%	31%
Other renewables	46%	15%	33%
Biomass Supply (mdt/yr)			
Electricity	94	94	25
Fuels	94	94	163
Total	188	188	188
Fuel Demand and Supply (bgge/yr)			
Total demand (excluding natural gas for CCS)	24.1	25.3	24.5
Biofuel supply	7.5	7.5	13.0
Fraction of total demand met by biofuels	31%	30%	53%
GHG Emissions ($MtCO_2e$/yr)			
Electricity sector	-63	-58	17
Fuel sector	156	157	129
Total	93	99	146
Difference from Median Case	-53	-47	N/A
CO_2 Storage ($MtCO_2$/yr)			
Biomass/CCS	73	73	0
Natural gas/CCS	0	44	44
Total	73	117	44

Table 16. Biomass/CCS and Median Case Assumptions for 2050

Biomass in conjunction with CCS can produce negative net CO_2 emissions, provided that the input biomass is sufficiently low in net GHG emissions when burned normally. A biomass/CCS plant operates similarly to a fossil/CCS (coal or natural gas) plant, with a CO_2 capture rate near 90%. The best estimate from the literature that includes full lifecycle emissions comes from (Larson et al., 2006)[16] at -768 gCO_2/kWh. This can be compared with the (positive) emissions rate from a 2050 IGCC coal plant without CCS of about 800 gCO_2/kWh (EPRI, 2009).

Successful deployment of biomass/CCS depends on successful deployment of CO_2 storage technology, with the same limitations and challenges as for fossil/CCS (see Greenblatt et al., 2012a). We calculate that a CO_2 storage rate of 73 $MtCO_2$/yr is required in 2050 to sequester 90% of the CO_2 in the input biomass; with natural gas/CCS deployed in tandem (the more likely situation if CCS is widely available), total CO_2 storage requirements increase to 117 $MtCO_2$/yr. See Table 17 for further assumptions about the two cases, and Table 17 for a build-out scenario for Case 2 (biomass/CCS with natural gas/CCS).

Parameter	Units	2010	2015	2020	2030	2040	2050
Number of plants*		0	1	3	8	15	27
Total capacity	GW	0	0.5	1.5	4.0	7.5	13.6
Annual output**	TWh/yr	0	3.5	10.5	28.0	52.6	95.1
Fraction of demand met		0	1.1%	3.1%	7.1%	11.6%	18.1%
Net CO_2 emissions from biomass/CCS	$MtCO_2e$/yr	0	-3.5	-10.4	-27.7	-51.9	-106.1
CO_2 storage requirements	$MtCO_2$/yr	0	2.7	8.1	21.5	40.4	73.1

Table 17. Build-out scenario for biomass/CCS with natural gas/CCS (Case 2)
* Assuming 500 MW net output per plant
** Assuming 80% average capacity factor

Biofuel Production with CCS

At least 50% of the CO_2 in biomass is lost during the conversion process to biofuels. By adding CCS to the biofuel production process, a great deal of CO_2 can be captured and sequestered, making this a potentially net GHG-negative process as for biomass electricity with CCS. This is done by efficiently converting the biomass to "syngas" (a mixture of hydrogen and carbon monoxide) in a gasifier, making as much hydrocarbon fuel as required via Fischer-Tropsch synthesis, burning the extra syngas in a turbine to make electricity, and converting the remaining carbon monoxide to CO_2 that is captured and sequestered. The technical challenges are similar to those encountered for biomass or fossil fuel electricity with CCS; the process for making fuels from syngas, known as Fischer-Tropsch, is well understood.

16 A more recent estimate from (Williams 2012) based on switchgrass is virtually the same (–776 gCO2e/kWh). Another estimate, from (S&T)2 (Consultants, 2005), gives a higher value of -824 gCO_2/kWh, but their estimate for a biomass electricity system without CCS also has net negative GHG emissions (-61 gCO_2/kWh), inconsistent with our assumption that net lifecycle GHG emissions from biomass is approximately 20% that from fossil fuels. Therefore, we have ignored this result, which also assumes a much lower net efficiency (26%) than in Larson et al. (39%).

Studies indicate that net GHG reduction can be almost 100% below that of direct fossil fuel emissions;[17] therefore, the GHG-reduction potential of biofuels with CCS is roughly double that of biofuels produced without CCS, allowing biofuels to offset the continued use of fossil fuels elsewhere in the economy, much as is done for biomass electricity with CCS described above. However, the approach of making biofuels with CCS is slightly more effective at removing CO_2 than for biomass electricity with CCS, due to a higher overall conversion efficiency (~50%) than for biomass electricity (~40%).[18]

We developed a case similar to the Median Case, with 7.5 bgge/yr of imported, conventionally-produced biofuels, 4.7 bgge/yr of domestic, Fischer-Tropsch (FT)-produced biofuels with CCS,[19] and 27 TWh/yr of electricity (including both co-product electricity and some biomass burned directly, equal to 5% of demand). The electricity sector was otherwise identical to the Median Case.

Net lifecycle GHG emissions from biofuels with CCS were assumed to be -14.0 $kgCO_2e$/gge, [20] compared to about +11.5 $kgCO_2e$/gge for petroleum-based gasoline. The overall resulting biofuel supply (including imported biofuels with 20% lifecycle emissions of fossil fuels) had a net lifecycle GHG emissions of -48% relative to fossil fuels, sufficient to lower economy-wide GHG emissions to 65 $MtCO_2e$/yr, below the 80% reduction target. The number of plants and the build-out rate are similar to conventional biofuels, but with the added requirement of CCS infrastructure sufficient to store 40 $MtCO_2$/yr from biofuel production, plus 44 $MtCO_2$/yr from natural gas/CCS electricity generation. Table 18 summarizes the details of the case in comparison to the Median Case.

Parameter	Median Case	Biofuel/CCS Case	Difference
Number of plants*	N/A	85	N/A
GHG emissions ($MtCO_2e$/yr)			
Electricity sector	17	13	-4
Fuel sector	129	51	-78
Total	146	65	-82
CO_2 storage ($MtCO_2$/yr)			
Biofuel/CCS	0	40	+40
Natural gas/CCS	44	44	0
Total	44	83	+40

Table 18. Median and Biofuel/CCS Case Assumptions for 2050
* Assuming 62 Mgge/yr and 31 net MW per plant.

17 For Fischer-Tropsch synfuels plants; see Liu et al. (2011); (S&T)2 Consultant (2006); and IEAGHG (2011). For cellulosic ethanol plants, net GHG reduction is less because only about 15% of the carbon in the starting biomass can be captured and sequestered, with ~50% remaining in the lignin and ~35% in the finished ethanol. See Liu et al. (2011), Online Supporting Material, Appendix E and Larson (2011).

18 Specifically, Liu et al. (2011) calculate a LHV conversion efficiency of 39.4% for pure electricity generation from biomass, but a net energy conversion efficiency of 47.5% for fuels plus 5.2% for co-product electricity from biomass, bringing total conversion efficiency to 52.7%.

19 The lower fuel yield relative to the Median Case is due to an assumed conversion efficiency of 62 gge/dt, based on Liu et al. (2011); this is lower than the 80 gge/dt assumed for conventional (advanced) biofuels.

20 Based on Liu et al. (2011) for Fischer-Tropsch biofuels, where we have apportioned emissions among fuel (90%) and electricity (10%) products. Another study by (S&T)2 Consultants (2006) considered this fuel production route, and obtained similar lifecycle GHG emissions rates once the land-use change sequestration rate was adjusted to zero to maintain consistency with our treatment of biomass in this study. The recently-released IEA study also estimated similar net GHG emissions rates (IEAGHG, 2011).

Coal/Biomass/CCS

Combining biomass with fossil fuels in conjunction with CCS can roughly double low-carbon fuel supplies over those produced from biomass alone. Depending on the biomass-to-fossil fuel input ratio, such an approach can result in net GHG emissions ranging from approximately half of conventional fossil fuels to slightly negative, e.g., lower than biofuels without CCS. While more complex than producing fuels or electricity from biomass alone, there are several economic advantages of this approach that will be discussed in the cost section below.

Liu et al. (2011) examined a number of hypothetical plants that produce both liquid fuels and electricity. The approach is similar to biofuels with CCS as described above, but potentially using separate gasifiers for the biomass and coal,[21] each optimized for the input feedstock. Several technical variants explored included the "recycling" of the unconverted syngas back into the gasifier to increase fuel yield at the expense of less electricity generation, variations in the biomass-to-coal input ratio, and an enhanced CO_2 capture process.[22]

Liu et al. (2011) examined configurations ranging from 100% coal to 100% biomass inputs, both with and without CCS. Four of the cases using both biomass and coal with CCS are summarized in Table 19. They found that three of the four biomass/coal cases (2-4) were able to achieve significant CO_2 savings relative to petroleum-based fuels. In addition, these three cases produced approximately as much output fuel on an energy basis as the input biomass,[23] a feat that cannot be achieved using biomass alone because the conversion efficiency limits the resulting fuel output to ~50% of the input biomass.

21 Separate gasifiers would be required for fluidized bed gasifiers (FBG) at biomass fractions of 30% or more, according to (Williams, 2011a). Torrefaction, a form of pyrolysis converting biomass to a coal-like material that is easier to grind; see (Wikipedia, 2011b) would be required for entrained-flow gasifiers to lower the energy penalty of grinding, and might be considered for FBG systems to reduce transport costs when hauling biomass long distances (Williams, 2012).

22 Achieved via autothermal reforming of C_1-C_4 gases + water gas shift + additional CO_2 removal equipment downstream of synthesis (Williams, 2011b).

23 The first biomass/coal case (1) has approximately the same net CO_2 emissions as petroleum-based gasoline, because only a small amount of biomass (12%) is used.

Case no.	Case identifier	Biomass input share		Output products (Percent of total input HHV energy)		Fuel output per unit biomass input (HHV)	Captured CO_2[a] (Percent of total inputs)	Lifecycle GHG emissions relative to fossil inputs	Lifecycle GHG emissions[b] relative to petroleum-based
		By energy (HHV)	By carbon	Biofuel	Electricity				
1	CBTL1-OT-CCS	12%	13%	32%	13%	2.63	57%	50%	112%
2	CBTL-OTA-CCS	29%	30%	32%	13%	1.12	69%	9%	20%
3	CBTL-OT-CCS	40%	41%	33%	15%	0.83	58%	9%	22%
4[d]	CBTL-RC-CCS	45%	47%	46%	4%	1.01	57%	3%	4%

Table 19. Selected Biomass/Coal Cases
Data from Liu et al. (2011). Note that quantities shown in the rightmost column were not reported directly in the paper but were derived from reported values by the CEF authors.
[a] CO_2 includes that captured by the plant plus that removed as char (~4%).
[b] CO_2 includes that vented from the plant plus that emitted when biofuel is burned.
[d] Case used in CEF calculations.

In the above table, two lifecycle GHG emissions indices are presented. Liu et al. (2011) calculated emissions relative to today's fossil energy system, which assumed coal-fired electricity ("GHGI" column); our calculation instead assigns all GHG emissions to the produced fuel, reflecting a future electricity system that has nearly net-zero GHG emissions.[24]

One important advantage of combining biomass and coal together in a single system is that it is able to produce about twice as much fuel output or more per unit biomass input as a pure biomass conversion process can, while maintaining very low net CO_2 emissions. There are also a number of economic advantages, discussed in the next section below.

Using data from Liu et al., the biomass conversion efficiency for Case 4 is 136 gge/dt, almost twice as large as we assumed for advanced-technology conversion of biomass (80 gge/dt). Other technical parameters from Case 4 are summarized in Table 20.

Parameter	Value	Units
Conversion efficiency	136	gge fuel per dt biomass
Electricity production	395	kWh electricity per dt biomass
Net CO_2 emissions rate	0.0553	tCO_2 per dt biomass
CO_2 storage rate	2.202	tCO_2 per dt biomass

Table 20. Technical parameters from Case 4 from (Liu et al., 2011)

24 We also made a small adjustment to the lifecycle GHG associated with the displaced fuel, to maintain consistency with our fuel assumptions elsewhere in the report.

Assuming 90% of the 94 mdt/yr domestic biomass is used for coal/biomass/CCS, this results in 11.5 bgge/yr of biofuel,[25] nearly as much as in the CEF Median Case without imports. Together with a small portion of biomass (9 mdt/yr) burned directly for electricity, 26 TWh/yr of electricity is generated as a co-product, equal to 5% of demand (as in the Median Case). Including 7.5 bgge/yr of imports brings total low-carbon fuels to 19.0 bgge/yr, about 80% of total hydrocarbon fuel demand. Thus the approach, while still insufficient to displace all fuel demands, would result in a significant increase in low-carbon fuels and hence GHG reductions. We estimate total, economy-wide net GHG emissions of 65 $MtCO_2e$/yr; about 140 $MtCO_2$/yr would also be sequestered. See the next section. With further technical improvements in yield, (e.g., double the biomass-only conversion efficiency or 160 gge/dt) fuel yields would boost by several more bgge/yr, edging closer to closing the demand gap entirely.

Comparison of GHG Reductions Among Biomass/CCS Cases

The three biomass/CCS strategies, plus the Median Case that includes biofuel production without CCS, are compared together in Table 21. As mentioned previously, all four cases assume the same availability of raw biomass resources (188 mdt/yr total), with half imported as conventional liquid biofuels without CCS.

	Units	Median Case	Cases with CCS		
			Biomass Electricity	Biomass Fuels*	Biomass/Coal Fuels*
Biomass Supply					
Domestic	Mdt/yr	94	94	94	94
Imported	Mdt/yr	94	94	94	94
Total	Mdt/yr	188	188	188	188
Fossil Fuel Supply					
Coal	Mtons/yr	0	0	0	67
Natural gas**	Bgge/yr	5.1	11.2	8.8	4.6
Petroleum	Bgge/yr	6.4	6.6	3.6	0.0
Total (excluding coal)	Bgge/yr	11.5	17.8	12.4	4.6
Biomass-based Outputs					
Fuels	Bgge/yr	13.0	7.5	12.2	19.0†
Electricity	TWh/yr	25	95	27	26†
Fuel demand met**	%	53%	30%	49%	80%
Fuel GHG intensity	$kgCO_2e$/gge	2.19	2.37	-3.77††	1.12††

25 Plus 17 TWh/yr electricity, about 3% of total demand.

Electricity GHG intensity	$kgCO_2e/MWh$	224	-768	-410††	13††
Net GHG Emissions by Carrier					
Electricity	$MtCO_2e/yr$	17	-58	13	13
Fuels	$MtCO_2e/yr$	129	157	51	52
Total	$MtCO_2e/yr$	146	99	65	65
Difference from median	$MtCO_2e/yr$	N/A	-47	-82	-82
CO_2 Storage Requirements					
Biomass/CCS	$MtCO_2/yr$	0	73	40	93
Other CCS	$MtCO_2/yr$	44	44	44	43
Total	$MtCO_2/yr$	44	117	83	137

Table 21. Comparison of GHG Reduction Strategies Involving Biomass and CCS
* Plus some co-product electricity.
** Excluding natural gas for electricity generation with CCS.
† Including outputs produced with coal, because net GHG emissions are close to zero.
†† GHG emissions are apportioned according to shares of total energy outputs as fuel and electricity.

The demand met by biomass-based fuels ranges from 30% for the biomass/CCS electricity case to 80% for the biomass/coal/CCS fuel case, with the other two cases at approximately 50%. Net electricity GHG emissions are ~15 $MtCO_2e/yr$ in all but the biomass/CCS electricity case, where it is strongly negative (-58 $MtCO_2e/yr$). Net fuel GHG emissions range from 157 $MtCO_2e/yr$ in the biomass/CCS electricity case to ~50 $MtCO_2e/yr$ in the biomass/CCS and biomass/coal/CCS fuel cases, while the Median Case emits 129 $MtCO_2e/yr$.

Total net GHG emissions for the energy system as a whole were approximately the same for the biomass/CCS and biomass/coal/CCS fuel cases at 65 $MtCO_2e/yr$. The biomass/CCS electricity case is significantly higher at 99 $MtCO_2e/yr$, owing mostly to the assumption of less efficient conversion of biomass to electricity (~40%) than to fuels (~50%). All biomass/CCS cases offer impressive GHG reductions from the Median Case, however.

Technological Maturity

Table 22 lists technology bins for biomass conversion processes with CCS. Existing technologies (bins 1-2) can be used for the cases discussed here, though with higher current costs.

Bin	Example Technology
1	Biomass co-firing, biomass combustion
2	High-efficiency biomass gasification, post-combustion CO_2 capture technologies, integrated gasification systems with CCS
3	New capture methods with >90% effectiveness, lower cost CO_2 capture technologies of all kinds, pretreatment technologies (torrefaction, etc.)
4	System designs with near-100% capture (e.g. solid-oxide fuel cell)

Table 22. Technology Bins for Biomass/CCS Technologies

Costs

Biomass Electricity with CCS
According to (Larson et al., 2006), overnight construction cost of a large, commercially mature 350 MW biomass/CCS plant is $1,431/kW (2003 $), including the cost of CO_2 capture and compression, but not transport or storage, which adds up to 10% of the lifecycle cost of the plant, depending on the storage location (depleted fossil reservoir or aquifer) and whether CO_2 credit is awarded (since net CO_2 emissions are negative). Assuming $3/GJ for biomass and $27/t$CO_2$ for CO_2 stored, estimated annualized generation costs range from $46/MWh (when CO_2 is stored in a depleted fossil reservoir for enhanced oil recovery) to $59/MWh (aquifer storage). Without a CO_2 price, the cost is higher by about $20/MWh.

It is expected that the cost of biomass/CCS electricity may rise in the future, due to increasing biomass and storage costs, though this could be offset by higher CO_2 prices. In the near term, e.g., before 2020, it is expected that the cost of biomass/CCS would be considerably higher than estimated here, since the technology is not yet mature and the biomass supply chain needs to be developed.

Biofuels with CCS
Liu et al. (2011) estimate that the overnight construction cost of a 62 Mgge/yr plant with 77 gross MW (31 net MW) electricity output, and consuming 1 mdt/yr of biomass, would cost $737M (2007$). This estimate assumes some technical progress to lower the plant cost below first-of-a-kind costs that would be encountered today. The levelized, 20-year fuel production cost is estimated to be $3.4/gge, assuming zero CO_2 price and electricity revenue price of $60/MWh. This corresponds to a breakeven crude oil price of more than $140/barrel. However, at a CO_2 price of $60/t$CO_2$, this cost drops to about $2.5/gge, corresponding to a breakeven oil price of approximately $70/barrel.

Coal/Biomass/CCS
Liu et al. (2011) estimate that the overnight construction cost of a 136 Mgge/yr plant with 157 gross MW (53 net MW) electricity output, consuming 1 mdt/yr of biomass and 0.71 million t/yr of coal, would cost $1,369M (2007$). As for biofuel/CCS, the estimated 20-year levelized cost of production in the absence of a CO_2 price is $2.3-2.7/gge or $90-110/barrel of crude oil (depending on the case), but at a CO_2 price of $60/t$CO_2$, the cost becomes much more competitive, with case 4 achieving

a break-even production cost below $75/barrel, and the most cost-competitive case 3 below $60/barrel.

Liu et al. (2011) put forth several arguments for why combining coal and biomass together have favorable economics over using biomass alone. The main advantage addresses a perennial problem with biomass: its high transport cost. Because biomass tends to be spread out diffusely over a large area, it is increasingly costly to collect and transport it to a central facility for conversion into fuels or electricity.[26] As a result, plant sizes tend to be smaller than a comparable fossil fuel plant, which increases the overall production cost because scale economies are less. However, by co-feeding biomass and coal in a single gasification system, plants can be built about 2-3 times larger with a similar amount of biomass, assuming coal is plentiful and cheap to transport to the facility, resulting in greater scale economies and hence lower cost of production. The increased complexity of a two-feedstock system is also largely offset by cost savings in many expensive shared components, such as the air separation unit, synthesis reactor, power generation island, and CCS technology.

By co-producing fuels along with electricity, a coal/biomass system also offers less costly fuel than petroleum when the price of CO_2 is high (e.g., $20-60/t$CO_2$). Also, co-production systems evaluated as electric generators offer much lower capture costs than any power-only system with CCS, a lower average cost of electricity than any power-only system in a world of high oil prices, and ultra-low electricity dispatch costs, enabling these systems to compete against other baseload generation technologies (Williams, 2012).

In addition to these cost considerations, by switching from imported petroleum to domestic coal to meet demand not met by limited biofuel supplies, a significant advantage in increased energy supply security is obtained.

Reliability

For biomass/CCS electricity, having a ~20% biomass fraction in the electricity generation mix will increase system reliability because it is baseload, making the system more like nuclear or fossil/CCS, and higher fractions of biomass than are used today are probably acceptable. For lower estimates of biomass availability, its contribution to grid reliability would be minimal. However, by continuing to rely on largely imported petroleum for the transportation system, energy reliability will be decreased, as these supplies will likely become increasingly costly to produce, with volatile price spikes as have been experienced several times in recent U.S. history. But we also assume that the overall transportation system will be much more electrified, decreasing, but not eliminating, California's petroleum dependence relative to today.

Producing domestic fuels with CCS from biomass would not affect fuel supply or electricity system reliability compared with the Median Case, and the biomass/coal case would increase fuel supply reliability since more of the total fuel demand would come from domestic sources.

In all cases, the additional reliance on CCS would put increased pressure on development of sufficient storage capacity, but would also accelerate the adoption and cost decrease of such technology, presumably increasing reliability.

26 See important caveats at the beginning of Section *Strategies Using Biomass with CCS*, however.

Resource Constraints

Biomass resources are limited, and the cases described above represent our best estimate of sustainable resource extraction rates. Coal supplies are plentiful in the U.S., so increased utilization as implied in the biomass/coal case would not place any appreciable constraints on that resource.

Biomass gasification for electricity or fuel production requires water, both for gasification and for cooling, unless air cooling is used, resulting in an efficiency decrease of approximately 10%). However, with evaporative cooling, water requirements per unit of primary energy consumed are much less for fuels production than for electricity production.

The major resource constraint might be the availability of underground CO_2 storage reservoirs, rather than biomass, though in the short-term, plentiful sequestration sites may exist, particularly in depleted oil or gas fields that also lower the cost of storage.

Policy Requirements

Four rather disparate biomass utilization pathways — biomass electricity with CCS, biofuels with CCS, biomass- and coal-based fuels with CCS, or biofuels without CCS — lie before California for consideration. Determining which pathway is the most economically viable in mitigating GHG emissions will require further research, development and demonstration. Any decision regarding the large-scale use of biomass in combination with CCS also presupposes the viability of CCS technology, so a determination also needs to be made rapidly as to whether — and when — CCS can become a major technology option for California.

A decision to emphasize biomass electricity with CCS over biofuel production would reverse the current policy direction, with large implications on private investment in biofuel technology, so it must be made carefully. A policy would also probably require explicit linkages between the GHG emissions credits generated in the electricity sector and the increased emissions in other sectors which continue to burn fossil fuels directly (primarily transportation, industry and, to a more limited extent, residential and commercial buildings). Without such linkages, the electricity sector would have little incentive to reduce net emissions of individual plants below zero. A carbon-trading market may provide such financial incentives, but further economic analysis is required to determine if such a mechanism would be sufficient to encourage large investment in biomass/CCS electricity over biofuel production.

As most technologies involving CCS would be unlikely to begin deployment before 2020, it is also important to examine whether the State could become locked into a sub-optimal biomass strategy in the near-term, as might be created by policy aimed at greatly expanding domestic biofuel production without CCS.

Potential Synergies

Two important synergies are the development of CCS technology with fossil fuels presumably initially with post-combustion capture from electricity plants), and gasification technology with fossil fuels for electricity production (fossil/CCS). The former would pave the way for more extensive use of CCS in other areas, such as CO_2 capture with biofuel production, while the latter would improve the gasification technology that can also be used with biomass, and is a central component of Fischer-Tropsch fuel synthesis.

A major challenge for CCS is its significantly higher current cost over technologies without CO_2 capture, so that without an appreciable price on carbon (~\$30/tCO_2), CCS may be economically uncompetitive. While subsidies or other financial mechanisms could provide the necessary correction for CCS to compete while accumulating experience to lower production costs, a promising near-term opportunity is Enhanced Oil Recovery (EOR). This process involves injecting CO_2 into mature oil production fields to extend their useful life. Current operations in the U.S. pay between \$25 to \$40/tCO_2 for pressurized CO_2, a price that may not be realized in a CO_2 trading scheme for many years. The potential for CO_2 EOR in the U.S. is large, producing 3.4 million barrels per day by 2030, and more than 100 billion barrels overall (ARI, 2011; Williams, 2011b). It is a near- to medium-term strategy to ease CCS into the marketplace, and would not increase the total consumption of oil, because it merely increases the production of domestic oil at the expense of imports, with important energy security benefits. EOR remains economically competitive even at CO_2 transport distances of up to 2000 km (Williams, 2011b). It is ideally suited to California and other western states that can join large pipeline networks bringing CO_2 to production fields in the Gulf of Mexico and elsewhere.

Doubled Biomass Supply

Our analysis indicates that in-state biomass supply is limited, possibly severely so, and out-of-state domestic, and particularly, international, biomass supplies are highly uncertain. The Median Case assumed an in-state biomass supply of 94 mdt/yr (7.5 bgge/yr), near the high end of the identified range of 40-121 mdt/yr, and achieving even this level of biomass production assumes significant increases in both gross productivity and recovery, utilization of virtually all available in-state waste biomass sources, and technical advances in biofuel production to produce low-carbon finished fuels (Youngs et al., in preparation). Potentials for drought-tolerant species such as agave, which would not displace productive agricultural land, have already been included in the above totals. Biomass "factory" approaches using highly-productive species such as algae still require large amounts of land and water, and might be favored over less efficient species, but would not expand the size of the overall resource. It is highly unlikely, therefore, that domestic biomass resources could be further expanded by 2050.

Similarly, across the U.S., biomass supplies are limited, with the highest estimate currently at 1,374-1,633 mdt/yr, by 2030, that assumes significant breakthroughs in production yield (DOE, 2011). Assuming that this yield is achievable in 2050, and that California takes no more that its "fair share" of the national resource, it could claim a maximum of approximately 12% of this biomass (based on projected populations of the state and nation in 2050), producing a maximum conceivable supply of 165-196 mdt/yr, approximately twice the Median Case estimate. However, this represents an absolute maximum potential; the DOE (2011) baseline estimate is 1,094 mdt/yr in 2030, which would allow 131 mdt/yr for California, approximately the same as CEF's own maximum estimate of 121 mdt/yr.

More promising are potential biomass yields internationally. While highly uncertain and therefore difficult to estimate quantitatively, biomass ambitions in tropical nations offer tantalizing levels of future output. The country of Brazil alone aims to increase its total production to more than 100 bgge/yr by 2030 (Youngs et al., in prep.); though Brazil's current domestic demand for sugar cane-based ethanol is approximately 4 bgge/yr (Youngs et al., 2011). It has the requisite land resources and is expected to grow its production capacity significantly. Therefore, it may be possible that an additional 7.5-15 bgge/yr of imported biomass (as finished biofuels) will be available in 2050, but as assumed throughout our analysis, the rest of the world would presumably also be moving toward a strongly biofuel-based fuel economy, making the cost of this imported fuel high if sufficient quantities are not available.

Doubling the total biofuel supply (by 188 mdt/yr, or 15 bgge/yr) achieves a very large reduction in GHG emissions: 75 $MtCO_2e$/yr, approximately equal to the statewide 2050 target. However, while technically possible, the impacts on food, water and mineral nutrients must be considered. Given the strong dependence of total State emissions on the demand for hydrocarbon fuels, efforts to expand biomass supplies as much as possible but with appropriate caution seem warranted.

No matter how cost-effective, efficient or low-carbon a future biomass technology may be, the major limitation in supplying hydrocarbon fuels to California is the size of the raw resource. Our most optimistic estimate of the in-state potential (121 mdt/yr) would supply less than 10 bgge/yr, assuming very high conversion efficiency (80 gge per dry ton). This would amount to 40% of the Median Case fuel requirement. Imports from outside the state — and probably outside the U.S. — appear necessary to close this gap, absent a breakthrough in artificial photosynthesis (see Section *Artificial Photosynthesis* below), or a successful application of CCS technology to provide such a net-negative GHG benefit that fossil inputs could continue to be used without impact on GHG emissions (see Section *Strategies Using Biomass with CCS* above).

Artificial Photosynthesis

The final solution to be discussed here is using carbon-neutral fuels from sunlight, also known as "artificial photosynthesis" (JCAP, 2011). While the technology for making such fuel is currently in bin 4 (research stage), this approach if successful at low cost is capable of producing virtually unlimited quantities of hydrocarbon fuels for transport, building heat and industrial needs, as well as load balancing, with net zero CO_2 emissions. If production is achieved but not at a particularly low cost, then relative economics would determine the best use of this precious fuel commodity.

Discussion

We have outlined a number of possible solutions to the low-carbon fuel problem for California. Some of them (behavior change and hydrogen) focus on further reducing the demand for hydrocarbon fuels, while others (net zero-emission biofuels, strategies using biomass with CCS) reduce the GHG intensity of the fuels, and still others (doubled biomass supply, artificial photosynthesis) focus on expanding supplies. All provide important GHG reduction potentials, but those that reduce demand are more incremental than strategies that expand supply.

Strategies using CCS actually encompass three approaches: biomass electricity with CCS, biofuel production with CCS, and the combination of biomass and fossil fuels with CCS for (primarily) fuel production. All fundamentally provide a means of bringing the GHG intensity of the resulting bio-based products below zero, providing an "offset" to allow fossil fuels to continue to be used. Biomass electricity with CCS appears to provide a smaller GHG benefit than the other two strategies, which are on par with doubling the biomass supply (see Figure 7 further below in the report), and could, if fully implemented, bring emissions below the 2050 target by themselves. The combination of biomass and fossil fuels with CCS provides an especially interesting case where petroleum supplies are replaced with a domestic fossil energy source (coal or natural gas) and used, along with biomass, to produce hydrocarbon fuels with net zero emissions.

As noted above in Section *Doubled Biomass Supply*, the most important limitation in reducing the GHG emissions from hydrocarbon fuels is supply, so strategies that aim to significantly expand the amount of raw biomass should take highest priority, though all strategies should be investigated and, if promising, supported through state policy. However, strategies that can provide a strongly negative GHG offset offer an important complementary capability, and should also be vigorously pursued.

Ultimately, a combination of approaches must be found to make the net GHG emissions of the entire hydrocarbon fuel supply as close to zero as possible.

Solving the Load Balancing Problem

As discussed in the Summary Report (CCST, 2011), zero-emission load balancing (ZELB) technology is required to keep electricity-sector emissions low, and this is particularly important for a renewables-dominant solution because emissions from natural gas turbines (without CCS) would nearly exceed the emissions target on their own. See (Greenblatt et al., 2012a) for a discussion of how the load balancing capacity requirements were estimated.

In our Median Case, we assumed that half of the load balancing capacity would be provided by ZELB, through some combination of zero-emission electricity storage and flexible demand management. All of these strategies are difficult with today's technologies. Achieving 100% ZELB would save 13 $MtCO_2e$/yr compared with this scenario. In this section, we explore the details of these and other technologies in more detail. We should note, however, that our assumption of needing to provide new technology to handle only half the load balancing is simply an "unbiased" guess. It would have been equally possible to assume that we would use natural gas for all load balancing unless either storage or flexible load (smart grid) solutions were available.

Electricity Storage Technologies

As is discussed in (Greenblatt et al., 2012a), while there are some bin 1 and 2 storage technologies — specifically, pumped hydro and compressed air energy storage (CAES) — most are at the research (bin 4) or development (bin 3) stage, including most promising battery technologies, and advanced types of CAES. The U.S. Advanced Research Projects Agency for Energy (ARPA-e) is currently funding a number of projects aimed to improve performance and lower costs for both electric vehicle batteries and grid-scale energy storage (ARPA-e, 2011).

Electricity storage spans a wide range of operating timescales, from microsecond to several days (or longer), using different technologies. Two promising near-term technologies are flow batteries, which occupy a middle ground of fast (sub-second) response time and large (multi-hour) capacity, and compressed air energy storage (CAES), which offers inexpensive incremental storage capacity, but whose reliance on underground reservoirs limits where it can be deployed. Other interesting technologies discussed in (Greenblatt et al., 2012a) include concentrating solar power (CSP) with integrated thermal storage, allowing generation output to be shifted by a few hours to coincide with peak loads, and the liquid-metal battery, which may provide an inexpensive route to large storage capacity at low incremental cost without the siting limitations of CAES.. Numerous other types of battery technologies, as well as flywheels, ultracapacitors and superconducting magnetic energy storage, are also discussed as possibilities.

Flexible Demand Management

There are a number of existing and contemplated strategies for shifting or reducing end-use loads in response to electricity supply constraints, including dynamic pricing (with and without enabling technology, such as devices which automatically reduce consumption of specific devices), direct load control programs, interruptible tariffs, capacity bidding, demand bidding, and other offerings from the utility or aggregator. In its first national assessment of demand response potential, the Federal Energy Regulatory Commission (FERC) determined that current (2009) demand response capacity in the U.S. is about 38 GW, or 5% of peak load. In California, where a number of residential, commercial and industrial programs exist, that capacity is 4.3 GW, more than 7% of peak load (FERC, 2009).

Existing and projected demand response capacities in California are summarized in Table 23 below. Maximum 2019 capacities ("Full Participation" case) consist of about 6 GW of residential, 2 GW of medium commercial/industrial, and 4 GW of large commercial/industrial, totaling 12 GW, or 17% of peak load. Of these, most of the residential and medium commercial/industrial capacity is anticipated to be pricing-based, while the majority of large commercial/industrial capacity would come from interruptible loads and a handful of other programs. Across the U.S., FERC found that the maximum 2019 achievable potential for reducing peak demand through demand response strategies is 188 GW, or 20% of projected U.S. peak load.

Type of Intervention	Residential	Commercial & Industrial			Total
		Small	Medium	Large	
	Capacities in GW				
Current (2009) Capacities					
Pricing with Technology	0.00	0.00	0.00	0.00	0.00
Pricing without Technology	0.39	0.02	0.11	0.01	0.53
Automated/Direct Load Control	0.97	0.04	0.05	0.00	1.05
Interruptible/Curtailable Tariffs	0.00	0.00	0.03	1.63	1.65
Other Programs	0.00	0.03	0.00	1.01	1.04
Total (percentage of total peak load* shown in parentheses)	1.36 (2.3%)	0.09 (0.1%)	0.18 (0.3%)	2.65 (4.6%)	4.28 (7.4%)
Estimated Maximum ("Full Participation") Capacities in 2019					
Pricing with Technology	4.52	0.0	1.46	0.60	6.58
Pricing without Technology	0.76	0.04	0.24	0.48	1.52
Automated/Direct Load Control	0.97	0.04	0.05	0.00	1.05
Interruptible/Curtailable Tariffs	0.00	0.00	0.23	1.63	1.86
Other Programs	0.00	0.03	0.0	1.01	1.04
Total (percentage of total peak load shown in parentheses)	6.25 (9.0%)	0.11 (0.2%)	1.98 (2.8%)	3.72 (5.3%	12.05 (17.3%)

Table 23. Current (2009) and Estimated Maximum 2019 Demand Response Capacities in California
Source: (FERC, 2009), Appendix A, p. 92.
* Estimated 2009 peak load was 58,000 GW.

According to (Kiliccote, 2011), most demand response resources are currently called only a few times per year in California, during critical peak periods (less than 100 hours per year, or ~1% of total). Therefore, total energy shifted is quite small — approximately 0.4 TWh/yr in 2009 and 1.1 TWh/yr in 2019.[27] However, the potential for flexible demand management is much larger, if loads are shifted more regularly, e.g., daily or hourly. The main barriers are costs and policies.

27 Assuming the total capacities listed in Table 23 are deployed 1% of the year (87.6 hours), a total of 0.375 TWh would be shifted in 2009, and 1.056 TWh in 2019.

The cost to the electric utility for invoking demand response is currently quite high, often $0.50/kWh or more, equal to several times the average price of electricity. This reflects its current value in reducing critical peak loads, which are very expensive to meet otherwise because even the most costly generators must be utilized, but also the currently high cost of equipment and infrastructure to manage the capacity. As costs fall, lower-cost capacities will become available, though it will continue to be more advantageous to target larger facilities, because transaction costs remain high. Policies that encourage the use of dynamic pricing are few and far between, though mechanisms such as these that address short-term (< 1 day) variability — particularly for residential and small commercial customers — could have a larger potential capacity than most existing programs that provide day-ahead capacity from large commercial or industrial entities (Cappers et al., 2011). In most parts of the state, there is little correspondence between marginal cost and charged prices for electricity, so there is still little incentive for customers to actively manage their loads on a continual basis. Part of the reason for this is the complexity of dynamic pricing, and the reluctance to adopt policies that may hurt consumers, but these barriers can be overcome with increased familiarity and successful demonstrations of technology in actual use.

One study attempted to simulate a future residential flexible demand market with daily response capability (Roe et al., 2011). It assumed the use of a "premise energy management system" in a large U.S. home that included a plug-in electric vehicle, and assumed a daily 3-hour demand response (DR) period in the late afternoon. The study found that peak load was reduced by 6.4 kW (57%) during the DR period, and the amount of energy shifted was 6.3 kWh/day, equal to 44% of DR-period energy use, or 10% of annual energy use. While the scale of this type of load-shifting system is much higher than the statewide assessment discussed in (FERC, 2009), caution must be exercised in extrapolating to large numbers of homes, because the effect is large enough to dramatically change the shape of the daily demand curve, resulting in a saturation of the needed DR capacity. Put another way, if every home in California (about 12 million) were to reduce its peak load by this amount, the reduction would exceed current generating capacity! However, the estimate is a helpful demonstration of the size of reduction possible in the residential sector (considered to be the most difficult sector in which to implement demand response) using a simple control scheme.

Another example of a technology capable of dramatically shifting peak demand is Thermal Energy Storage (TES), which has had a long history in California. First embraced enthusiastically in the 1980s, it was subsequently defeated by tariffs that did not favor shifting to off-peak consumption (Schiess, 2011). Types of TES include conventional chilled water systems, chilled systems with a eutectic salt (which undergoes a phase change at 47°F), and chilled ice systems. In moving from chilled water to eutectic salt to ice as the cold storage medium, the capacity volume required falls dramatically, with eutectic salt requiring 30 to 50% of the chilled water storage volume, and ice requiring only 10 to 20% of the chilled water storage volume. Additional advantages of moving toward ice storage are that smaller fans and ducts in the air distribution systems can be used, and natural dehumidification is accomplished at the same time. Both provide energy and cost savings (CEC 1995, pp. 12-13).

An example of a recent company investing in TES technology is (ICE Energy, 2011), which specializes in ice-based energy storage for commercial air conditioning. Their "Ice Bear" system stores energy at night, by freezing 450 gallons of water, and then delivers that energy during the peak of the day by passing the hot refrigerant through the ice, rather than through a compressor, to provide cooling

to the building. Daytime energy demand from air conditioning (typically 40-50% of a building's electricity use during peak daytime hours) can be reduced significantly. The systems are designed to shift 32 kWh of on-peak energy to off-peak hours over a 6-hour, or longer, period. When aggregated and deployed at scale, a typical utility deployment would be able to shift the operation of most commercial air conditioning units from on-peak periods to off-peak periods, or allow dispatched operation in response to load balancing requirement. Ice Bear units are typically owned by utilities and installed at distributed locations behind the customer meter on commercial and industrial sites.

According to a 1995 CEC report on the technology, "TES is an energy technology offering compelling energy, environmental, diversity, and economical development benefits to California" (CEC 1995, p. 51). It identified statewide savings of over $500 million annually and increased property values of $5 billion arising from a 20% commercial market penetration of TES in 2005. Total savings at 20% penetration were estimated at about 1.3 TWh/yr, or 3.6% of the total projected air conditioning demand of 36 TWh/yr in 2005. An estimate of the annual air conditioning energy demand that can be shifted ranged from 40 to 80% (CEC 1995, p. 3-5).

Load-Following Fossil Generation with CCS

One possibility not included in the Median Case is that of using variable-output natural gas-fired generation in conjunction with CCS to produce a very low-carbon load-following solution. Both conventional simple-cycle turbines as well as fuel cells in combination with CCS are possibilities. While no cost estimates are available for either of these technologies, it is reasonable to assume a capture efficiency of 90% (or greater for fuel cells), thereby achieving most of the CO_2 reductions calculated for a 100% ZELB solution. Using conventional gas turbines has the advantage of well-proven technology, but it would be coupled to a more expensive separation process due to the diluted CO_2 stream in the exhaust gases (see discussion on CCS technologies in Section *100% Effective CCS*). By contrast, the natural gas fuel cell approach currently uses a more expensive power plant, but the exhaust is nearly pure CO_2, making capture less difficult. Both face challenges of being of a smaller scale than conventional baseload plants, so that capture technology would likely be more expensive per unit output. However, the low utilization factors of load-following generation would make the incremental cost of adding CCS technology far higher than in a baseload plant. Also, integration into the CCS reservoir process may be challenging technically; optimal injection flows into the reservoir are not likely to be well-matched with the CO_2 flows that will be produced by load balancing systems, further increasing the complexity, and likely the cost, of CCS when used for this application.

Other Load-balancing Solutions

Still other possibilities include using electricity during periods of excess generation (from baseload plants at off-peak times, or from variable renewable electricity) to make fuels such as hydrogen, or bulk commodities such as desalinated water. Another possibility, production of heat for later use, was discussed above under flexible demand management.

These approaches narrow the gap between supply and demand, but they do not necessarily utilize the most cost-effective means of producing the desired products. For instance, for hydrogen, the approach suffers from the currently high cost of producing hydrogen fuel this way; as discussed in the section on hydrogen, the lowest-cost way to produce the fuel is thermochemically from syngas, which is a process not readily amenable to large swings in output, e.g., for load balancing.

Processes also tend to be capital-intensive, which requires them to run virtually all the time to

recover their costs. When operated in an intermittent fashion as required for load balancing, the cost of production may become too high, even with the lower cost of the "excess" electricity taken into account, because most of the cost lies in capital recovery rather than operation.

One unique advantage of producing hydrogen is that it could subsequently be used to generate electricity during periods of excess demand, either in a fuel cell or conventional turbine; thus in this sense it is an energy storage technology. However, one must consider the round-trip efficiency and cost of this approach versus other energy storage methods. A recent study by the National Renewable Energy Laboratory found that large-scale production of hydrogen was cost-competitive with some battery storage technologies, but that pumped hydro and CAES were economically more attractive (see Figure ES-1 in Steward et al., 2009). However, the flexibility in siting offered by hydrogen may make it feasible in areas where pumped hydro or CAES is infeasible.

The final solution to be discussed here is the widespread availability of low-GHG hydrocarbon fuels, of which several methods of production are discussed in earlier sections. If available at sufficiently low cost, they would presumably be used in a conventional gas turbine as a natural gas (or oil) substitute. However, the challenges of producing a sufficient quantity of fuel are formidable.

Discussion

The institutional changes required to maximize flexible demand management ("smart grid") solutions are very large. While progress is being made toward increasing the amount of load balancing capacity available through these strategies, driven primarily by lower cost compared with inefficient peak generation and/or combustion-based ancillary services), it is unknown how much of the ZELB problem these approaches can solve, given the many individual actors and the amount of convenience or reliability that they are willing to sacrifice in exchange for lower electricity prices.

However, if energy storage technologies were available at sufficient scale and cost, we know that it could solve the whole problem. But such technologies are not available today: they are, with few exceptions, in bin 2 (available, but more expensive than conventional generation), bin 3 (still in development), or bin 4 (research). Therefore, solving the ZELB problem will likely proceed along the following scenario:

1. "Smart grid" solutions, such as price-based voluntary peak reduction, direct load control, participation in bidding markets, etc., will grow to the extent that they can displace more expensive combustion-based technology;
2. As rules change to allow generation resources to be better-managed, existing ZELB technologies, such as dispatchable hydro, will be deployed;
3. Energy storage technologies will then be deployed as technology matures and costs are reduced and
4. Non-ZELB (combustion-based) technologies will be retired in response to increasingly more stringent GHG emissions targets and/or other policies to actively discourage (or ban) them.

Therefore, making ZELB a priority along with developing low-GHG electricity generation, especially intermittent technology, will be necessary to assure that the electricity sector is sufficiently reliable, low-cost and low-carbon as possible.

Other GHG Reduction Strategies

100% Effective CCS

While CO_2 capture with 90% efficiency is viewed as an achievable target for all combustion technologies (conventional combustion, gasification, and oxyfuel combustion), achieving CCS with 100% CO_2 removal is difficult economically as well as thermodynamically. This is because separation of gases is required in all cases, requiring steeply increasing energy inputs as the efficacy approaches 100%. At 90% capture efficiency, however, costs of all three technologies appear to be roughly equivalent.

The Median Case includes about 30% of fossil fuel-generated electricity with CCS. Thus, even if 100% capture technology were available, it would only save an additional 5 $MtCO_2e$/yr. While such a small incremental savings might be worthwhile in combination with other GHG-reduction strategies, it becomes more important in cases that rely heavily on CCS, such as a fossil/CCS-dominant electricity system, biomass/CCS for producing negative-GHG electricity, or biomass and coal with CCS for producing low-carbon fuels (see Section *Strategies Using Biomass with CCS*).

The discussion below draws on (Schoff, 2011), as well as a set of baseline studies published by the U.S. Department of Energy's National Energy Technology Laboratory (NETL) over the last few years, which are a good resource for plant design/cost studies (DOE/NETL, 2011). NETL has also done work on future CO_2 capture technologies that are described in its recent CO_2 Capture R&D Program Technology Update (DOE/NETL, 2010).

Pre-Combustion Capture

In an integrated gasification combined cycle (IGCC) plant, CO_2 is captured prior to the combustion process, hence the term "pre-combustion." In the process, input feedstocks (coal, natural gas or biomass) are first "gasified" at high-temperature in an oxygen-limited environment to convert them to "syngas," an energy-rich mixture of mostly H_2 and CO. Small amounts of carbon are also converted to other products: slag (a mixture of ash and unconverted carbon), CO_2, CH_4, and COS. These need to be dealt with downstream. To facilitate high levels of carbon capture, CO in the syngas must be converted to CO_2 through the water-gas shift reaction.[28] Typically, 90-95% of CO is converted to CO_2 using two stages of reaction. Higher levels are possible with additional reactors that add cost and thermodynamic inefficiencies to the plant, but reaching 100% conversion is highly unlikely. Most of the COS in the syngas is converted to H_2S in the water-gas shift reaction; in this form it is not a significant impediment to CO_2 capture. The constituent that will cause problems for high levels of carbon capture is CH_4. The amount of CH_4 produced varies from negligible (Shell dry-coal fed gasifier) to ≤5% of the syngas (any gasifier operating at <2000°F) depending on the coal and gasifier selected for the plant. Methane could be converted back to CO_2 and water to increase capture levels, but this is an energy-intensive process that would also add cost to the plant for relatively little increase in CO_2 capture rate.

The next step is actually capturing CO_2 from the pressurized syngas. There are many ways to accomplish this: solvent absorption, solvent adsorption, chemical looping (passing CO_2 from gas

28 The water-gas shift reaction is a chemical reaction in which carbon monoxide (CO) reacts with water vapor (H_2O) to form carbon dioxide (CO_2) and hydrogen (H_2):

$$CO + H_2O \text{ ---> } CO_2 + H_2$$

(Wikipedia, 2011a). The degree of conversion can be controlled by the amount of water introduced. In this case, all CO is converted to CO_2 (which is subsequently removed) and H_2, which is then burned to make electricity.

to solid and subsequently releasing it from the solid), membrane separation of hydrogen from syngas (leaving CO_2 and any other gas constituents), and liquefaction of the syngas stream in a staged process where CO_2 liquefies and the other gas constituents remain in vapor form. Any of these systems could be designed to theoretical maximum CO_2 capture rates, but above 90% CO_2 capture all of the systems become steeply more expensive. For solvent systems, liquid flow rates (with associated pumping, cooling, and stripping demands) go up while CO_2 release pressures drop, resulting in higher compression demands. The other systems will also see increases in size, auxiliary energy requirements, and operating cost.

Studies exist with up to 92% CO_2 capture efficacy, not including the carbon in the solid slag waste product, but to our knowledge, research aimed at higher values has not been pursued.

Post-Combustion Capture

In this approach, CO_2 is captured after the combustion process, hence the name "post-combustion," and is favored as a modification to existing fossil-based plants. While almost all of the carbon in flue gas is present as CO_2, the problem from a chemical engineering perspective is that it is at atmospheric pressure, and diluted by the presence of N_2, O_2 and H_2O. While the partial pressure of CO_2 in an IGCC capture system is in the 200-300 psia range; the partial pressure of CO_2 in post-combustion capture systems is ~5-10 psia. This means that post-combustion capture systems will be inherently less efficient at capturing CO_2. Research has been done on solvent absorption, chilled ammonia, membrane, and other technology approaches to capture CO_2. Each will have similar design limitations described for the IGCC capture systems, where above ~90% capture the system designs become markedly larger and less efficient on an energy per mass of CO_2 basis.

Oxy-Combustion Capture

In oxy-combustion, the feedstock is burned in pure oxygen and thus the flue gas contains only O_2, CO_2 and H_2O (in addition to other trace constituents that are less important from a CO_2 capture perspective). Some of the flue gas is recycled to the front of the boiler and mixed with pure oxygen to promote combustion. Whereas in a post-combustion capture system the primary separation is between CO_2 and N_2, in an oxy-combustion process, the CO_2 must be separated from H_2O. This is helpful, as conventional condensation-based separation can be used. However, CO_2 is soluble in water, so some CO_2 is lost to the water that is condensed out of the flue gas. Assuming ~1% of the CO_2 is absorbed in the condensed water, approximately ~99% of the CO_2 remains in a stream with O_2 and any remaining trace constituents. In some cases, a second separation of CO_2 and O_2 is required, as oxygen at elevated levels can cause problems for the compressor (cavitation issues), the pipeline (corrosion issues), or the storage site (issues with downhole chemistry). Cryogenic separation is usually employed, but again, some of the CO_2 is lost to the O_2 product stream. The net result is ~96% (or greater) CO_2 recovery.

Fischer-Tropsch Process

The situation with Fischer-Tropsch is a bit more complex than in IGCC, even though both approaches employ the same basic gasification process. Because the water-gas shift reaction is not used to produce the maximum amount of CO_2 to be captured (because the appropriate ratio of CO and H_2 must be created to react together over a catalyst to produce the desired long-chain hydrocarbon products), the CO_2 must be removed upstream of the Fischer-Tropsch reactor, since the CO_2 will act

as an inert dilutant, causing the reactor size to increase. Likewise, all sulfur constituents in the syngas must be removed or the sulfur will foul the catalyst as well as create undesirable side-products. Therefore, high levels of CO_2 capture are encouraged, but it is still a cost-benefit trade-off limited by chemical engineering principles. In work by (Liu et al., 2011), conventional one-through designs capture ~73% of the CO_2 not bound up in liquid fuel products, but an advanced design captures up to 89% of the non-fuel CO_2.[29]

Discussion and Research Directions

There has been very little research on very high levels of CO_2 capture, since the additional benefit appears to be outweighed by steeply increasing cost. Oxy-combustion may be best positioned to get >95% CO_2 removal without having to over-design the plant. Pre- and post-combustion capture are both capable of ~95% removal, but the cost per ton of CO_2 captured will be higher for anything over 90%.

For a given desired separation, the more one captures, the more energy the process requires, and thus the more expensive it becomes. Above 90% capture efficiency, the pre-combustion capture IGCC process, which separates CO_2 from H_2, may be the least costly to increase, because capture forms a relatively small part of the total cost of the system (IGCC being expensive by itself, without CCS).

The next most expensive technology to push beyond 90% capture appears to be oxy-fuel combustion[30], where the separation is between N_2 and O_2, two relatively inert gases that must be separated cryogenically, and that low-temperature process requires significant energy. Non-cryogenic separation technologies currently being explored, such as Ion Transport Membranes (ITM), may hold promise for lowering the energy penalty of separation and thus overall cost of this process.

Post-combustion separation of CO_2 from N_2 is somewhat easier because the acidity of CO_2 can be exploited chemically by dissolving it in various solvents, but the dilute solution (about 13% CO_2) makes high recovery challenging.

CO_2 capture and sequestration with 100% capture efficiency was only estimated to save an additional 5 $MtCO_2e$/yr in the Median Case, because CCS technology was not extensively employed in that case, and the ~30% of electricity demand produced from natural gas with CCS resulted in low GHG emissions. However, if CCS were used more widely for electricity production, or if it were also used in combination with biomass to produce negative-GHG electricity or fuels (see, Section *Strategies Using Biomass with CCS*), improving the capture efficiency of CCS would result in larger GHG savings.

Eliminating CCS from the Electricity Mix

Another way to reduce CO_2 is to eliminate CCS altogether, and rely on nuclear energy, renewable energy, or a combination for making electricity. The stress tests explored in (Richter et al., 2011) and (Greenblatt et al., 2012a) indicate that it is possible to greatly increase the reliance on either of these technologies, though for renewable electricity, with an increased load balancing challenge that must

29 This is achieved by converting light hydrocarbon byproducts (consisting of 1 to 4 carbon atoms) from Fischer-Tropsch synthesis back to CO and H_2 in an autocatalytic reaction, and then converting the CO to CO_2 using the conventional water-gas shift reaction.

30 However, Clean Energy Systems, Inc. is building a large-scale (60 MW) demonstration oxy-fuel combustion plant with CCS near Bakersfield, CA that claims to capture 99% of the produced CO2 at a competitive cost of electricity (Hollis et al., 2012).

be met. The residual emissions from the CCS process would be eliminated, plus some associated "upstream" emissions from the processing, transport and use of the fossil fuels. For the Median Case scenario, eliminating fossil/CCS from the electricity portfolio would reduce emissions by 9 $MtCO_2e$/yr, almost double the savings from 100% effective CCS alone.[31]

However, provided CCS were successfully developed on a large scale, the use of it both as a means of continuing to use fossil fuels for electricity, as well as in conjunction with biomass for making electricity or fuels (see, Section *Strategies Using Biomass with CCS*), it is expected that this technology would be used if it became available at reasonable cost and sufficiently low risk. Therefore, eliminating CCS from the electricity sector is an unlikely option, especially given the relatively small reduction in emissions gained as a result.

Mitigation of Non-Energy GHG Emissions

Note: The following section was adapted from (Wei et al., in press).

Non-energy sector GHG emissions [CH_4 from landfills, CH_4 and N_2O from agriculture, CO_2 from forests, and hydrofluorocarbons (HFCs) and other high global warming potential (GWP) gases from industry[32]] were not included in the original CEF analysis (CCST, 2011) or its spreadsheet tool. However, given that high-GWP emissions in particular are projected to increase rapidly over the next decade (CARB, 2010a), and that, assuming sustained growth in emissions, this source is projected to make up over one-sixth of total 2050 emissions in the BAU case (139 $MtCO_2e$), reductions in non-energy GHGs represent a potentially important additional set of mitigation strategies for which little is currently known.

To estimate emissions from non-energy sectors, we rely on earlier published reports from the CEC (Brown et al., 2004; Choate et al., 2005), CARB (2010a, 2010b, 2010c), EPA (2001), and extrapolations to 2050, and briefly touch on known measures for emission reduction measures and related challenges. No estimate of the overall reduction potential from non-energy GHGs is given, however, due to the large uncertainties in 2050 Median Case emissions.

High GWP Sources

High GWP gases include SF_6, NF_3, and various hydrofluorocarbons (HFCs). A key challenge here is the high projected growth of high GWP sources. CARB projects an extremely high annual growth rate in emissions (8.3%) between 2008 and 2020, even larger than historically high rates of growth from 2000-2008 (6.3%) (CARB 2010a, 2010c). Extrapolating this growth with some reduction in the rate (we assume annual growth drops to 2.5% by 2050), this implies that high GWP gases will account for 71 $MtCO_2e$/yr in 2050. Given the much higher growth rate of HFCs compared with other gases, essentially 100% of high GWP emissions will be from HFCs by 2050.

Abatement options exist for semiconductor manufacturing using high-GWP process gases (SF_6, NF_3) to reduce emissions by up to 92% (Choate et al., 2005). These include processing techniques to control and/or or reduce emissions through plasma etch abatement, remote cleaning, catalytic abatement, capture/recovery with membranes, and thermal destruction.

31 Specifically, in addition to the residual emissions of 5 $MtCO_2e$/yr eliminated from natural gas/CCS, the electricity and fuel from producing the additional ~10 billion therms/yr (~8.5 bgge/yr) of natural gas used in CCS, resulting in emissions of 4 $MtCO_2e$/yr, would also be eliminated.

32 SF_6 emitted from the electricity sector is also considered to be a high GWP gas

SF_6 is also used in the electric sector in substation switching equipment. Mitigation measures for SF_6 can reduce emissions up to 100% emissions with leak reduction and recovery through leak detection (e.g., using infrared imaging systems), leak repair, and recycling of gases (Choate et al., 2005). CARB is considering a reduction of SF_6 emissions from gas-insulated switchgear as a possible emission reduction measure within its Scoping Plan (CARB, 2010b).

More challenging is HFC control and reductions. These emissions represent about 75% of overall high-GWP sources in the state, and are projected to constitute 95% of high-GWP emissions by 2020. HFC emissions from refrigeration and air-conditioning in California are expected to grow steadily in the next decade as a result of the phasing out of ozone-depleting substances currently used in these applications and replacing them with HFCs. (Choate et al., 2005) projects a technical potential of up to 25% reduction by 2020. Key measures include improved system components, HFC-134a replacement, compressor system and secondary loop design optimization, leak reduction and repair, and recovery and recycling of refrigerant during equipment service and disposal. We assume an overall 29% reduction in CO_2-equivalent emissions from reference levels in 2020 (Choate et al., 2005) and a 47% reduction in 2050 for high GWP sources based on an earlier reference from the EPA (2001).

Agriculture and Forestry

Agriculture and forestry emissions are projected to increase by about 1.3% per year and are projected to hold steady at about 6% of overall state emissions from 2011-2050. The long-term emissions reduction strategy includes two key thrusts: reducing emissions levels from current sources, mainly livestock- and fertilizer-related emissions, and second, to pursue sequestration opportunities in forests and rangelands. Currently, livestock-associated emissions (digestive processes and manure) are about 70% and fertilizers about 30% of agriculture non-energy emissions.

Key measures for manure management include the installation of lagoon covers or plug flow (non-mixed) digesters. Manure management systems can capture methane emissions and utilize them to produce heat or electricity. Plug flow digesters can possibly be centralized with food processing wastes, and optimized multi-stage digestion systems are possible. These measures are projected to reduce overall manure emissions by 65% in 2020.

In land management, (Brown et al., 2004) estimates up to 345-887 $MtCO_2$ savings over a 20-year time window, or approximately 17-44 $MtCO_2$ per year at a cost of \$5.50-\$13.60/$MtCO_2$ from the afforestation of rangelands (see Table 24). These changes would cover 2.7-12% of California land. It would provide the most cost-effective carbon reduction practice with over two orders of magnitude greater impact than other management practices, such as lengthening of forest management rotation or increasing forest riparian buffer width from protected streams. Conservation tillage has an estimated potential of 3.9 $MtCO_2$ per year, but at unknown cost in California. With the combination of aggressive manure management and rangeland afforestation, the state appears to have a technical path to achieve an 80% reduction in overall agriculture/forestry emissions from the 1990 level, although we do not consider the interaction of rangeland afforestation with the desire for maximal production of in-state biomass for fuels. Without considering rangeland afforestation potential, overall savings of 48% is estimated for this sector in 2020 and 2050 relative to reference case levels, primarily from improved manure management.

Activity	Quantity of C - MMT CO_2			Area Available - Million Acres		
	20 years	40 years	80 years	20 years	40 years	80 years
Forest Managment						
Lengthen rotation						
</=$13.60 (discounted C)	3.47	--	--	0.31	--	--
</=$13.60 (undiscounted C)	2.16	--	--	0.3	--	--
Increased riparian buffer-width						
</$13.60	3.91 (permanent)				0.044	
Grazing Lands						
Afforestation						
</=$13.60	887	3,256	5,639	12.03	17.79	20.76
</=$5.50	345	3,017	5,504	2.72	14.83	19.03
</=$2.70	33	1,610	4,569	0.2	5.68	13.34

Table 24. Carbon savings from forest management practices in price per metric ton CO_2 (from Brown et al., 2004)

Landfills

Methane (CH_4) is the greatest non-CO_2 GHG contributor in California. Methane is emitted during the production, transportation, and refining operations of petroleum and natural gas systems, and is a by-product of anaerobic decomposition that occurs in landfills, wastewater treatment systems and manure-management systems. Methane from petroleum and natural gas systems is treated in the industrial section, and is sharply curtailed with downsizing of the fossil fuel industry.

Methane emissions from landfills are assumed to grow at 2% per year to 2050. The technical potential reduction from landfills is estimated to be 85% savings in 2020 (Choate et al., 2005). Landfill emissions can be reduced by capturing the CH_4 before it is emitted into the atmosphere. This can be done by installing direct gas-use or electricity projects with backup flare systems to recover and use CH_4. We assume that landfill emissions can be sharply reduced from the greater utilization of biomass sources that are directed to supply biomass for biofuels, as well as technical potential improvements in methane recovery options, and assume up to 85% savings from reference case levels for both 2020 and 2050.

IV. Overall Discussion and Conclusions

To illustrate how we might go beyond the Median Case, we looked individually at several possible strategies. These strategies are not comprehensive and we have not evaluated their relative efficiencies or costs, but they illustrate some possible pathways using technologies that are more or less available. Here they are presented in order of increasing GHG reduction potential as calculated by the CEF spreadsheet model:

1. Develop the technology to make CCS 100% effective and economical. In the Median Case, CCS is assumed to be only 90% effective, based on best available technology.
2. Eliminate fossil fuels with CCS from the electricity mix, and rely on nuclear, renewables or a combination for making electricity.
3. Increase the amount of load balancing that is achieved without emissions from 50% to 100%.
4. Produce biomass with net zero carbon emissions, by eliminating net emissions from land use change.
5. Reduce energy demand through ubiquitous behavior change.
6. Produce hydrogen fuel (from coal with CCS) and use it to reduce fuel and electricity use.[33]
7. Burn all domestic biomass with CCS to make electricity with net negative GHG emissions, creating an offset for the required fossil fuel use.
8. Increase the supply of sustainable biomass twofold, and use it to make low-carbon biofuels, using feedstocks that best fit efficient conversion to the needed energy mix.
9. Gasify coal and biomass together with CCS, and use it to make low-carbon fuels plus some electricity. (This approach almost doubles the fuel output relative to a biomass-only route, with similar net GHG emissions).
10. Using CCS, convert biomass to fuels (plus some electricity) with net negative GHG emissions, creating an offset for the required fossil fuel use.

Figure 7 shows the impacts of each of these single strategies on GHG emissions, which are also summarized in Table 25. Of the strategies explored to lower California's emissions beyond the 60% reduction level, three appear capable of meeting the 80% reduction target on their own (doubled biomass supply, biomass and coal with CCS to make fuels, and biomass with CCS to make fuels), while the remaining strategies would have to be deployed in combination.

33 The options for making hydrogen without CCS are limited to using biomass or low-carbon electricity. Biomass supplies are probably limited and would need to be used to make required hydrocarbon (mostly liquid) fuels. Making the required hydrogen from electricity results in a portrait with similar net GHG emissions as from coal with CCS, but is deemed more difficult due to the challenge of almost doubling electricity supply.

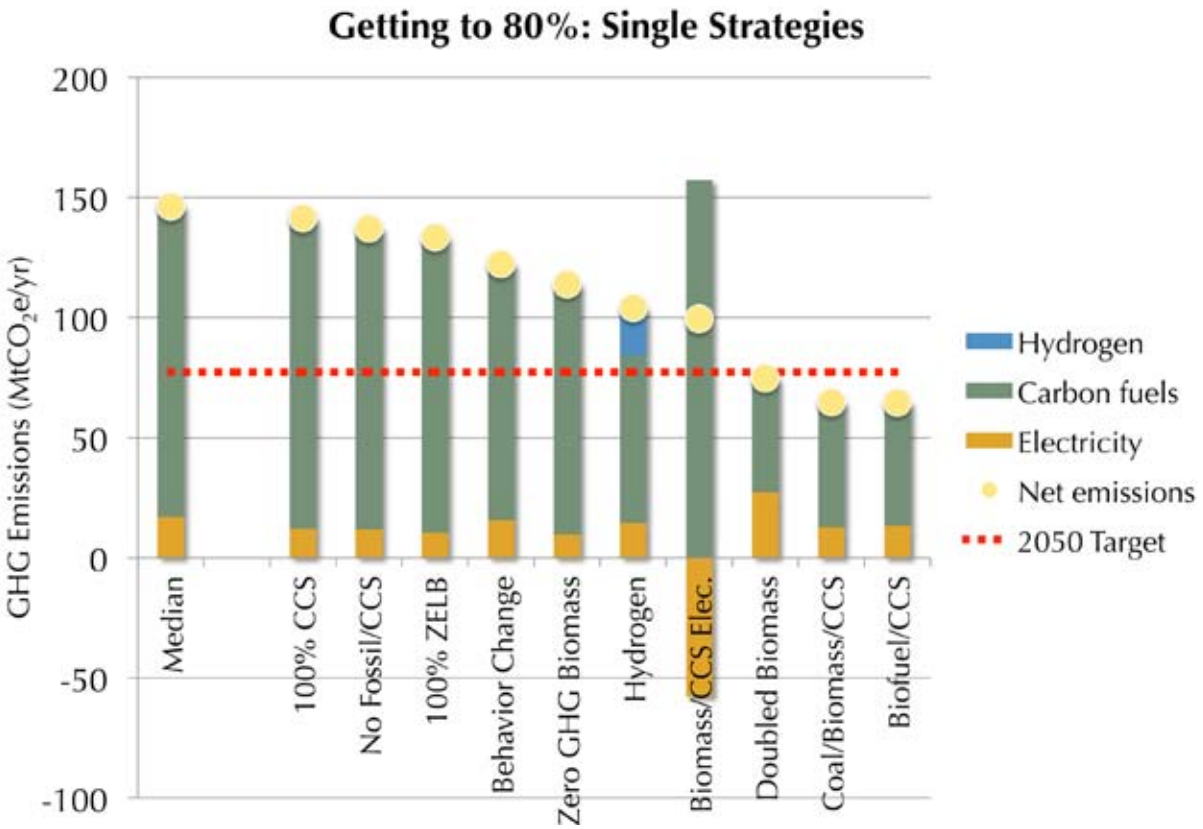

Figure 7. Effects of Single Strategies on Reducing GHG Emissions

	Electricity	Carbon fuels	Hydrogen	Net energy emissions	Difference from Median
Median Case	17	129	0	146	0
80% Strategy					
100% CCS	12	129	0	142	-5
No Fossil/CCS	12	125	0	137	-9
100% ZELB	11	123	0	133	-13
Behavior Change	16	107	0	122	-24
Zero GHG Biomass	10	104	0	114	-32
Hydrogen	14	70	20	104	-42
Biomass/CCS Electricity	-58	157	0	99	-47
Doubled Biomass	27	48	0	75	-71
Coal/Biomass/CCS	13	52	0	65	-82
Biofuel/CCS	13	51	0	65	-82

Table 25. Greenhouse Gas Emissions (in $MtCO_2e/yr$) by Sector and Strategy
Note that only the last three strategies (highlighted) achieve the 80% reduction target on their own.

While there are many combinations that could meet the target, one set of examples is shown below in Figure 8. Here the impact on GHG emissions of sequentially applied strategies is illustrated. These are: develop 100% zero-emission load balancing (ZELB); produce biomass with net zero GHG emissions; encourage widespread behavior change to reduce demand; produce and use hydrogen fuel wherever possible; burn domestic biomass (with CCS) for electricity rather than making biofuels; and increase biomass supply. The application of the first three strategies in combination could bring emissions down to the 2050 target, while the application of additional strategies could result in emissions below the target or even net negative emissions, allowing California to become a net exporter of carbon reduction credits and/or provide flexibility if other components of the solution prove more difficult. However, it should be stressed that the challenges are great for implementing even one of these strategies, let alone several.

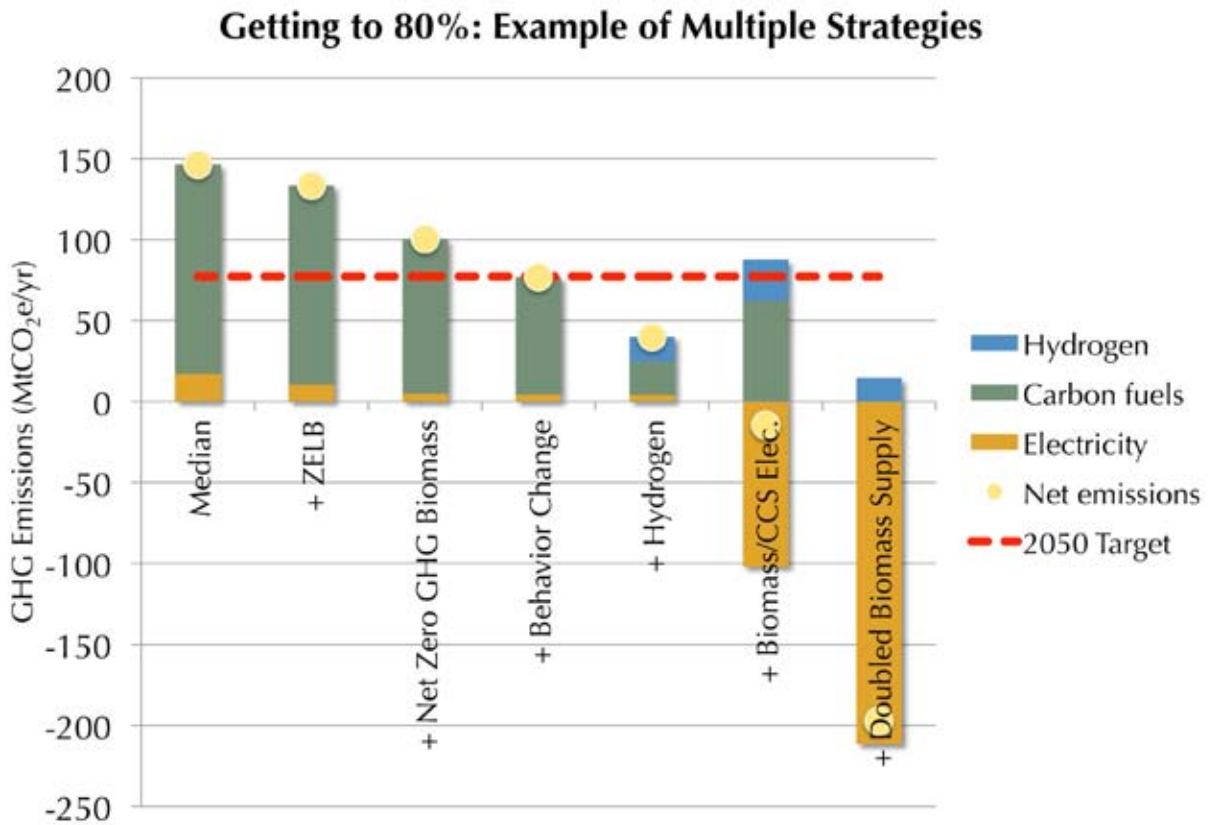

Figure 8. Example of Multiple Strategies That Reduce Emissions to 80% Below 1990 Level

Two other themes emerge as important for reaching California's 2050 GHG goal. The first is the availability of sustainable biomass, while the second is the role of CCS in utilizing this biomass. We discuss each issue in turn.

The most efficient uses of different biomass types, availability of certified imported bioenergy, and proximity to meet end-use needs should be carefully considered to make the best use of available biomass. The amount of biomass has a large impact on overall GHG emissions, because it directly displaces fossil fuels (petroleum and natural gas) that otherwise must be burned; other parts of the energy economy have already been "decarbonized" as fully as possible by switching to low-carbon electricity. Reducing the carbon footprint of using biomass for energy is also important. Care must

be taken to ensure that implementation and expansion of biomass for energy does not result in unwanted social, economic, or environmental impacts. It is possible to conceive of biomass-derived energy without disastrous impacts on food supply, if the biomass for energy production is limited to marginal lands, wastes and off-season cover crops, but this is not something to take for granted. Additional study of the sustainable biomass potential for energy use in California, in the context of bioenergy potential in the U.S. and globally, will be needed to thoroughly assess our options. Having alternatives to biomass for low-carbon fuel is an important hedge against the probability that there will not be enough biomass to provide all the fuel we would like.

The second issue, the use of carbon capture and storage (CCS) in combination with biomass, is an often-overlooked strategy because biomass is generally viewed as a low-carbon energy source already. But as was discussed earlier in the report, the application of CCS to biomass, whether to make fuels, electricity or both, may have a powerful additional GHG benefit. Utilizing biomass in combination with coal (or another fossil input) may have the added benefit of greatly increasing the domestic supply of low-carbon fuels, reducing or even possibly eliminating the need for imported petroleum-based fuels. However, the widespread availability of CCS is not a foregone conclusion; much development work remains to be done before the technology enters "bin 1." The prospect of lowering the carbon content of fuels — possibly greatly — elevates CCS from its widely-held view as one decarbonization strategy among many for producing electricity, to a single, pivotal strategy for biomass. Without CCS, California still has options (as shown in Figure 8), but it becomes more important that most (or all) of them succeed. So, while CCS is normally thought of as a technical strategy for electricity, we conclude it may be more important in California as a strategy for dealing with low-emission fuel.

Outside of the fuel and load balancing challenges outlined in Sections *Solving the Fuel Problem* and *Solving the Load-Balancing Problem*, other strategies for reducing GHG emissions remain important, in particular those which focus on emissions originating outside of the energy sector. Emissions of so-called "high global warming potential" gases are projected to grow rapidly; however, mitigation options also appear more tractable than in the energy sector. More research in this area is clearly needed to better characterize both the size of the challenge and its potential resolution.

Finally, the role of breakthrough technologies, exemplified by artificial photosynthesis in Section *Artificial Photosynthesis*, remain critical to pursue as alternative strategies both to deal with the possibility that current pathways prove insufficient to meet our GHG goals, as well as to provide additional technical options for success in 2050 and beyond.

Appendix A: Median Case 60% Solution Tables

Demands for electricity and fuels (see Tables 26 and 27) were developed based on feasible efficiency and electrification levels, relative to a business-as-usual (BAU) projection (for details, see (Greenblatt et al., 2012b) and (Yang et al., 2011), while energy supply was based on estimated availability of resources. Assumptions were based on literature citations and modeling results of many researchers wherever possible. Failing that, we used the expert opinions of the committee members as described below.

Drivers of demand — primarily population and gross state product (GSP) — were taken from a single median scenario based on (McCarthy et al., 2006), which itself was based on extensions of projections from California's Integrated Energy Planning Reports (IEPR) from 2003 and 2005 (CEC, 2003; CEC, 2005). Changes in these drivers have a large impact on resulting demand, but to make analysis tractable, only a single set of demand drivers was used, representing a neutral-to-optimistic view of future growth in the state. From this single set of drivers, we generated a small number of demand cases (differing in the way energy carriers were apportioned within each sector) upon which a wide range of supply solutions was then developed. The demand scenarios are documented fully in (Greenblatt et al., 2012b) and (Yang et al., 2011), while the resulting portraits are discussed below and in the accompanying supply technology reports (Richter et al., 2011; Greenblatt et al., 2012a; and Youngs et al., in preparation).

Greenhouse gas emissions in Table 28 were calculated by the CEF spreadsheet tool, described in Appendix B. Greenhouse gas emission factors for each source of energy are presented in Table 29. Full lifecycle GHG emissions were included for each fuel, based on estimates from CARB and NETL (CARB, 2011; Gerdes, 2009). As a result, to avoid double-counting, petroleum and natural gas refining within California were not included in statewide emissions totals.

Demand	TWh[a]/yr	% of total
Stationary Sectors		
Residential	145.2	27.9%
Commercial	123.1	23.7%
Industrial	108.7	20.9%
Agricultural	20.1	3.9%
Other stationary	17.2	3.3%
Subtotal	414.3	79.6%
Transportation Sectors		
Light-duty vehicles	73.1	14.0%
Heavy-duty vehicles	8.7	1.7%
Buses	4.6	0.9%
Passenger rail	1.4	0.3%
Freight rail	1.0	0.2%
Subtotal	88.9	17.1%

Base demand	503.2	96.7%
Scenario-specific Additions		
Storage demand[b]	8.4	1.6%
Refining demand	8.6	1.6%
Total Median Case demand	520.3	
Supply	**TWh/yr**	**% of total**
Biomass	25.3	4.9%
Biomass/CCS	0.0	0.0%
Coal	0.0	0.0%
Coal/CCS	0.0	0.0%
Coal/biomass/CCS	0.0	0.0%
Natural gas	26.1	5.0%
Natural gas/CCS	161.3	31.0%
Nuclear	161.3	31.0%
Other renewables	146.4	28.1%
Total	520.3	100.0%
Zero-emission load balancing fraction (not counted in supply sum above)	26.1	5.0%

Table 26. Median Case 2050 Demand and Supply Assumptions for Electricity
[a] TWh = terawatt-hours = 10^{12} W-h
[b] Assuming all zero-emission load balancing is storage with 75% efficiency

Demand	bgge[a]/yr	Billion therms/yr
Gaseous fuel		
- Building heat (plus ag/other)	1.82	2.10
- Industrial heat	5.13	5.92
- Non-CCS natural gas electricity	1.80	2.08
- Additional natural gas from refining	1.86	2.15
- Subtotal	10.62	12.25
Not included in above:		
- Natural gas/CCS electricity[b]	8.46	9.76
Liquid fuel		
- Industrial heat	2.49	
- Light-duty vehicles	5.71	
- Heavy-duty vehicles	4.46	
- Aviation	0.25	
- Bus/rail	0.00	
- Marine	0.40	
- Additional oil from refining	0.59	
- Oil for electricity		
- Subtotal	13.89	
Not included in subtotal:		
- Balance of aviation[c]	2.82	
- Balance of marine[c]	1.21	
Total carbon fuel demand	24.51	
Supply	**bgge/yr**	**mdt/yr**
Raw biomass[d]		
- Domestic (in-state)	7.52	94
- Imported	7.52	94
- Total	15.04	188
Biomass product	**bgge/yr**	**% of Biomass**
- Electricity (Table 26)	2.03	13.5%

- Gaseous fuel	5.49	36.5%
- Liquid fuel	7.52	50.0%
- Biofuel subtotal	13.01	
Fossil Product	**bgge/yr**	**% of Demand**
- Gaseous fuel	5.13	20.9%
- Liquid fuel	6.37	26.0%
- Fossil fuel subtotal	11.50	46.9%
Not included in subtotal:		
- Gaseous fuel for natural gas/CCS electricity (see demand above)[b]	8.46	

Table 27. Median Case 2050 Demand and Supply Assumptions for Carbon Fuels
[a] bgge = billion gallons gasoline-equivalent
[b] Natural gas/CCS fuel demand not included because these emissions are sequestered
[c] Following CARB accounting rules, 92% of aviation and 75% of marine fuel use takes place outside California, and is thus not counted in inventory
[d] The Median Case assumed the median estimate from a biomass supply range that might be sustainably available in California, and then assumed that an equal amount of imported biomass would be available.

Electricity	$MtCO_2e/yr$
Biomass	5.7
Natural gas	6.5
Natural gas/CCS	4.8
Nuclear	0.0
Other renewables	0.0
Subtotal	17.0
Gaseous Fuels	
Building heat (plus ag/other)	10.8
Industrial heat	30.3
Subtotal	41.1
Not included in subtotal:	
- Industrial heat from refining[a]	11.0
Liquid Fuels	
Building heat (plus ag/other)	0.0
Industrial heat	16.9
Light-duty vehicles	37.1
Heavy-duty vehicles	29.9
Aviation	1.6
Bus/rail	0.0
Marine	2.8
Subtotal	88.2
Not included in subtotal:	
- Industrial heat from refining[a]	4.0
- Balance of aviation[b]	18.3
- Balance of marine[b]	8.3
Total	146.4
CO_2 Storage	
Natural gas/CCS	43.5

Table 28. Median Case 2050 Greenhouse Gas Emissions and Sequestered CO_2
[a] Included in lifecycle GHG emissions factors from fossil fuels
[b] Following CARB (2009) accounting rules, 92% of aviation and 75% of marine fuel use takes place outside California, and is thus not counted in inventory

Fuel	Lifecycle GHG emissions factor	Lifecycle Markup
Natural gas	8.33 $kgCO_2e$/therm	120%
Gasoline	11.46 $kgCO_2e$/gge	140%
Diesel	11.83 $kgCO_2e$/gge	140%
Jet fuel	11.45 $kgCO_2e$/gge	140%
Residual/bunker fuel	11.83 $kgCO_2e$/gge	130%
Biomass	20% of lifecycle fossil fuel emissions	N/A
Electricity	**GHG Emissions Factor (gCO_2e/kWh)**	
Biomass	224	
Biomass/CCS[a]	-768 (–410)[b]	
Coal	800	
Coal/CCS[a]	80	
Coal/biomass/CCS[a]	13	
Natural gas	399[c]	
Natural gas/CCS[a]	30[d]	
Nuclear	0	
Oil	905	
Other renewables	0	
Hydrogen	**GHG Emissions Factor (gCO_2e/gH_2)**	
From onsite natural gas	13.7	
From coal/CCS	1.98	
From electricity	Depends on electricity GHG emissions factor	

Table 29. Greenhouse Gas Emissions Parameters

[a] CO_2 capture efficiency assumed to be 90% in all cases

[b] For case where electricity is co-produced along with fuel

[c] Revised from (CCST, 2011) assuming 43% efficiency (8000 BTU/kWh) for simple-cycle natural gas plants, based on state-of-the-art performance of existing plants (e.g., GE, 2012a)

[d] Revised from (CCST, 2011) and (Greenblatt et al., 2012a) assuming 57% efficiency (6000 BTU/kWh) for combined-cycle natural gas plants with CCS, based on state-of-the-art performance of existing combined cycle plants (e.g., GE, 2012b)

Appendix B: CEF Spreadsheet Tool

The CEF spreadsheet tool was developed as a way to integrate the many numerical inputs and assumptions provided by committee members and produce a cohesive statewide picture of future energy systems and their associated GHG emissions. It is a simple accounting tool that does take into account certain feedbacks in the energy system, such as the impact of biofuel demand on petroleum refining. It also provides for evaluation of numerous scenarios (or portraits) for 2050 in a compact, single-column format.

The CEF spreadsheet insures that our portraits of the 2050 energy system have:

- Accounted for all major demands for energy in the future as modified by efficiency gains.
- Matched each of these demands with a source of energy (e.g., sunlight, coal, etc.) and the carrier for that energy (e.g., electricity, or various fuels).
- Kept track of all the emissions that will result from utilizing these sources.
- Estimated the required build-out rates for the technologies invoked in the portrait.

Efficiency and electrification progress, and hydrogen fuel switching measures can be specified by the user. Because the end-use efficiency also depends on the energy carrier, this factor is built into the spreadsheet.

The user can also modify the technology used for load balancing and the spreadsheet will modify energy demands associated with this choice. In some cases, the choice of energy supply technology changes the total demand (e.g., use of fossil fuel increases the total demand for fuel because refining consumes some energy) and this calculation is also included. Resource limitations, such as the total amount of available biofuels, are also specified by the user.

Figure 9 illustrates the way the spreadsheet calculates the set of energy end-use demands separated into energy carriers: electricity, gaseous hydrocarbon fuels, liquid hydrocarbon fuels and hydrogen. Figure 10 illustrates how the choices of energy source for each carrier, as specified by the user, is used to calculate the total emissions.

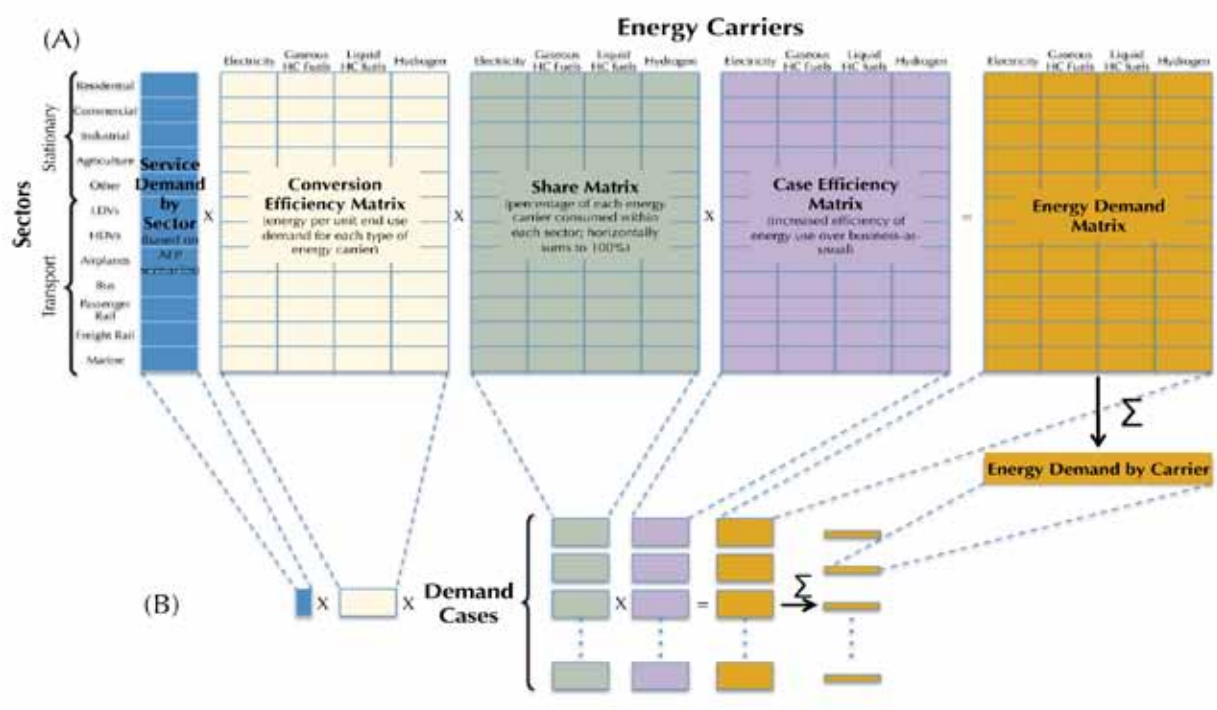

Figure 9. CEF Spreadsheet Tool: Block Diagram of Demand Calculation Logic

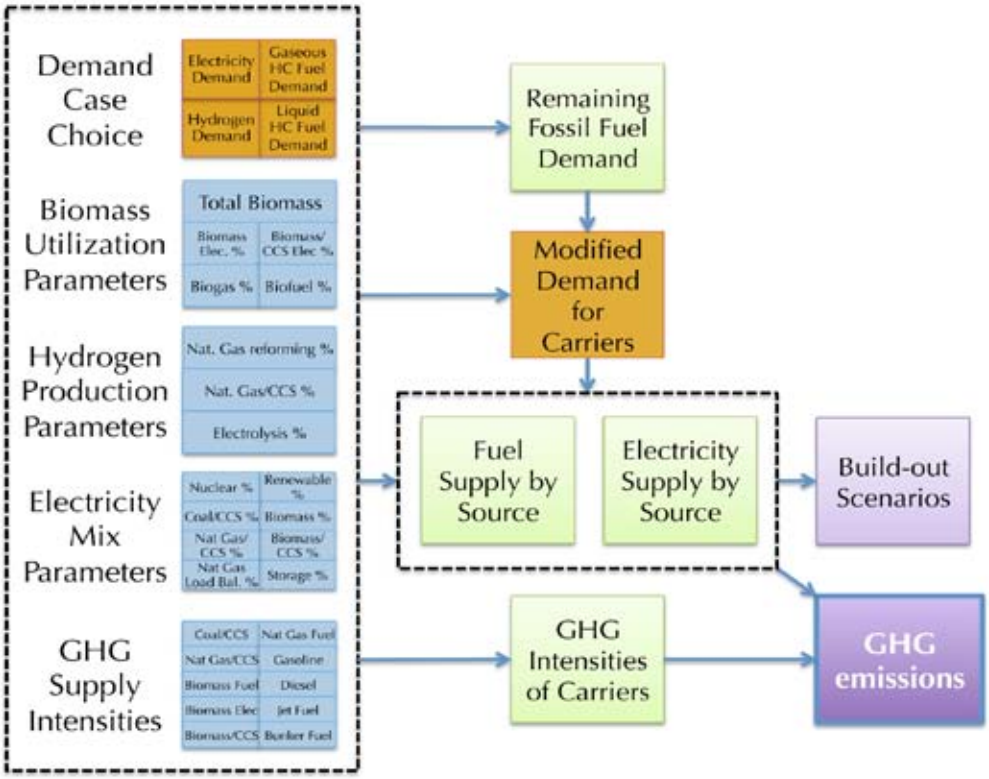

Figure 10. CEF Spreadsheet Tool: Parameters Used and Logic Flow for Calculation of GHG Emissions

The spreadsheet is set up to calculate the GHG emissions of many dozens of portraits simultaneously, and group them for plotting in various ways. The adjustable input parameters that determine each portrait, including GHG intensities, are summarized in a single column. While portraits describe the energy system for a single year (2050), the spreadsheet also makes some simple calculations concerning the build-out of various technologies from 2005 to 2050, using input parameters from selected portraits.

The spreadsheet tool offers the opportunity to explore the effects of different assumptions and policies on the outcomes for 2050. For example, the CEF study only used one value of population growth and economic growth. It would be useful to know how given choices would be affected by a range in these values. We have made assumptions as well about the amount of available biomass and the carbon intensity of various technologies. These will surely be updated over time, and the effect of new information can be calculated. Most importantly, various advocates present one idea or another as important for our energy future. The CEF spreadsheet is a tool that can be used to see just how important each of these ideas actually is.

The CEF spreadsheet is freely available for download at: http://ccst.us/publications/2011/2011energy.php.

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