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The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity

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Reducing greenhouse gas emissions 80% below 1990 levels by 2050 is the subject of vigorous policy debate but there has been little physically realistic modeling of the energy and economic transformations required. We analyzed the infrastructure and technology path required to meet this goal in a specific economy (California), using detailed modeling of infrastructure stocks, resource constraints, and electricity system operability. We find that technically feasible levels of energy efficiency and decarbonized energy supply alone are not sufficient. Rather, widespread electrification of transportation and other sectors is required. Decarbonized electricity becomes the dominant form of energy supply, posing challenges and opportunities for economic growth and climate policy. The transformation demands technologies that are not yet commercialized and coordination of investment, technology development, and infrastructure deployment.

Pacala and Socolow proposed a way to stabilize climate using existing greenhouse gas (GHG) mitigation technologies, visualized as interchangeable, global-scale 'wedges' of equivalent emissions reductions (*1*). Subsequent work has produced more detailed analyses, but none combines the sectoral granularity, physical and resource constraints, and geographic scale needed for developing realistic technology and policy roadmaps (*2*–*4*). We addressed this gap by analyzing the specific changes in infrastructure, technology, cost, and governance required to decarbonize a major economy, at the state/provincial level that has primary jurisdiction over electricity supply, transportation planning, building standards, and other key components of an energy transition.

California is the world's sixth largest economy and 12th largest emitter of GHGs, its per capita GDP and GHG emissions are similar to those in Japan and Europe, and its policy and technology choices have broad relevance nationally and globally (*5*, *6*). California's Assembly Bill 32 (AB32) requires the state to reduce GHG emissions to 1990 levels by 2020, a reduction of 30% relative to business as usual assumptions (*7*). Previous modeling work we performed for California's state government formed the analytical foundation for the state's AB32 implementation plan in the electricity and natural gas sectors (*8*, *9*). California has also set a target of reducing 2050 emissions 80% below the 1990 level, consistent with the IPCC emission trajectory for a 450 ppm carbon dioxide equivalent (CO_2e) stabilization path that avoids dangerous anthropogenic interference (*10*). Working at both time scales, we found a pressing need for methodologies that bridge the analytical gap between planning for shallower, near-term GHG reductions, based entirely on existing commercialized technology, and deeper, long-term GHG reductions, which will depend substantially on technologies that are not yet commercialized.

We used a stock-rollover methodology that simulated physical infrastructure at an aggregate level, and built scenarios to explore mitigation options (*11*, *12*). Our model divided California's economy into six energy demand sectors and two energy supply sectors, plus cross-sectoral economic activities that produce non-energy and non-CO_2 GHG emissions. The model adjusted the infrastructure stock (e.g., vehicle fleets, buildings, power plants, and industrial equipment) in each sector as new infrastructure was added and old infrastructure was retired, each year from 2008 to 2050. We constructed a baseline scenario from government forecasts of population and gross state product, combined with regression-based infrastructure characteristics and emissions intensities, producing a 2050 emissions baseline of 875 Mt CO_2e (Fig. 1). In mitigation scenarios, we used backcasting, setting 2050 emissions at the state target of 85 Mt CO_2e as a constrained outcome, and altered the emissions intensities of new infrastructure over time as needed to meet the target, employing seventy-two types of physical mitigation measures (*13*). In the short term, measure selection was driven by implementation plans for AB32 and other state policies (table S1). In the long term, technological progress and rates of introduction were constrained by physical feasibility, resource availability, and historical uptake rates rather than relative prices of technology, energy, or carbon as in general equilibrium models (*14*). Technology penetration levels in our model are within the range of technological feasibility for the U.S. found in recent assessments (table S20) (*15*, *16*). We did not include technologies expected to be far from commercialization in the next few decades, such as fusion-based electricity. Mitigation cost was calculated as the difference between total fuel and measure costs in the mitigation and baseline scenarios. Our fuel and technology cost assumptions, including learning curves, are comparable to those in other recent studies (tables S4, S5, S11, and S12, and fig. S29) (*17*). Clearly, future costs are very uncertain over such a long time horizon, especially for technologies that are not yet commercialized. We did not assume explicit lifestyle changes (e.g., vegetarianism, bicycle transportation) which could have a significant effect on mitigation requirements and costs (*18*); behavior change in our model is subsumed within conservation measures and energy efficiency.

In order to ensure that electricity supply scenarios met the technical requirements for maintaining reliable service, the model featured an electricity system dispatch algorithm that tested grid operability. Without a dispatch model it is difficult to determine if a generation mix has infeasibly high levels of intermittent generation. We developed an electricity demand curve bottom-up from sectoral demand, by season and time of day. Based on the demand curve, the model constrained generation scenarios to satisfy in succession the energy, capacity, and system balancing requirements for reliable operation. The operability constraint set physical limits on the penetration of different types of generation, and specified the requirements for peaking generation, on-grid energy storage, transmission capacity, and out-of-state imports and exports for a given generation mix (table S13 and figs. S20 to S31). It was assumed that over the long run California would not "go it alone" in pursuing deep GHG reductions, and thus that neighboring states decarbonized their generation such that the carbon intensity of imports was comparable to California in-state generation (*19*).

Electrification required to meet 80% reduction target. Three major energy system transformations were necessary to meet the target (Fig. 2). First, energy efficiency had to improve by at least 1.3% yr^{-1} over 40 years. Second, electricity supply had to be nearly decarbonized, with 2050 emissions intensity less than 0.025 kg CO_2e/kWh. Third, most existing direct fuel uses had to be electrified, with electricity constituting 55% of end-use energy in 2050, compared to 15% today. Results for a mitigation scenario including these and other measures are shown in Fig. 1. 28% of emissions reductions relative to 2050 baseline emissions came from energy efficiency; 27% from decarbonization of electricity generation; 14% from a combination of energy measures including smart growth, biofuels, and rooftop solar photovoltaics (PV); 15% from measures to reduce non-energy CO_2 and non-CO_2 GHGs; and 16% from electrification of existing direct fuel uses in transportation, buildings, and industrial processes. Table 1 shows changes from 2010 to 2050 in primary and end use energy and emissions by sector and fuel type for the baseline and mitigation cases, along with per capita and economic intensity metrics.

The most important finding of this research is that, after other emission reduction measures were employed to the maximum feasible extent, there was no alternative to widespread switching of direct fuel uses (e.g., gasoline in cars) to electricity in order to achieve the reduction target. Without electrification, the other measures combined produced at best 2050 emissions of 210 Mt CO_2e, about 50% below the 1990 level. The largest share of GHG reductions from electrification came from transportation, in which 70% of vehicle miles traveled—including almost all light duty vehicle miles—were powered by electricity in 2050, along with 20% from biofuels and 10% from fossil fuels. Other key applications for fuel switching occurred in space and water heating and industrial processes. Figure 3A shows that even with aggressive EE keeping other demand growth nearly flat, fuel-switching to electricity led to a doubling of electricity generation by 2050. "Smart charging" of electric vehicles was essential for reducing the cost of electrification, by raising utility load factors and reducing peak capacity requirements through automated control of charging times and levels (Fig. 3B).

In the electricity sector, three forms of decarbonized generation—renewable energy (RE), nuclear, and fossil fuel with carbon capture and storage (CCS)—each has the potential to become the principal long-term electricity resource in California, given its resource endowments. All currently suffer from technical limitations and high cost relative to the conventional generation alternative, natural gas, so it is not obvious which if any of these will dominate in the long run. Therefore, we built separate high RE, high nuclear, and high CCS scenarios that met the target, plus a mixed case. Because these technologies have very different operating characteristics—CCS, when commercialized, is expected to be dispatchable; nuclear is baseload; and the most abundant RE resources (wind and solar) are intermittent—they also have very different needs for supporting infrastructures, including capacity resources, high-voltage transmission, and energy storage. Figure 3C shows the generation scenarios. The high RE case has the highest requirements for installed capacity, transmission, and energy storage; the high nuclear case requires the largest export market for excess generation, along with an expansion of upstream and downstream nuclear fuel cycle infrastructure; and the high CCS case requires construction of CO_2 transportation and storage infrastructure. In addition, water, land use, and siting issues are quite different for each of these options. Residual electricity sector carbon emissions in 2050 came primarily from combustion of natural gas for peaking generation and CCS. CCS fleet-average carbon storage efficiency in 2050 was 90%, but new CCS units were required to reach 98% efficiency. Within the western grid of which California is part, all existing conventional coal plants were retired at the end of their planning lives of 30 years.

Some studies suggest that 100% of future electricity requirements could be met by renewable energy, but our analysis found this level of penetration to be infeasible for California (*20*, *21*). We found a maximum of 74% renewable energy penetration despite California's high renewable resource endowment, even assuming perfect renewable generation forecasting, breakthroughs in storage technology, replacement of steam generation with fast-response gas generation, and a major shift in load curves by smart charging of vehicles. Using historical solar and wind resource profiles in California and surrounding states, the electricity system required 26% non-renewable generation, from nuclear, natural gas, and hydro, plus high storage capacity to maintain operability. It would be possible to forecast higher penetration in cases with a higher resource base and/or much lower energy demand, for example due to lower population growth or lower economic growth.

Unprecedented energy efficiency, limited contribution from biofuels. The rate of EE improvement required to achieve the target and enable feasible levels of decarbonized generation and electrification—1.3% yr^{-1} reduction relative to forecast demand—is less than the level California achieved during its 2000-2001 electricity crisis (*22*), but is historically unprecedented over a sustained period. This level is, however, consistent with the upper end of estimates of long-term technical EE potential in recent studies (*23*, *24*). In our model, the largest share of GHG reductions from EE came from the building sector, through a combination of efficiency improvements in building shell, HVAC systems, lighting, and appliances. EE improvements were complemented by other measures to reduce new energy supply requirements for electricity, transportation, and heating. EE in combination with on-site distributed energy resources in the form of solar hot water and rooftop PV reduced the net consumption of grid-supplied electricity and fuels in new residential and commercial buildings to zero by 2030 (*25*). Structural conservation in the form of "smart growth" urban planning to reduce driving requirements was responsible for 5% of total emission reductions in 2050.

Biofuels, while essential because not all transportation can be electrified, made only a modest 6% contribution to the 2050 emissions reduction when feedstocks were constrained to be carbon neutral, produced in the U.S., and limited to California's consumption-weighted proportional share of U.S. production (*26–28*). This feedstock was sufficient to provide 20% of transportation fuels in the form of cellulosic ethanol and algal biodiesel, assuming these technologies achieve commercialization (fig. S15). In our model, biofuel feedstocks were dedicated to the production of transportation fuels as their highest-valued economic use, and these fuels allocated to applications for which electrification is not a practical option, such as long-haul freight trucking and air travel. A small amount of biomethane was used in power generation.

In the baseline forecast, 2050 emissions of non-energy CO_2 (e.g., from cement manufacturing) and non-CO_2 GHGs (e.g., methane and nitrous oxide from agriculture and waste treatment, and high global warming potential (GWP) gases used as refrigerants and cleaning agents) were 145 Mt CO_2e, more than the entire economy-wide target of 85 Mt CO_2e. Compared to CO_2 emissions from energy sectors, scientific understanding of long-term mitigation potential for these sectors is poorly developed (*29–32*). Nevertheless, it was clear that if these emissions were not abated, the 2050 target could not be met. We modeled mitigation based on extrapolating California's AB32 implementation plan for 2020 (*7*), in three broad areas. Agricultural and forestry measures contributed 48 Mt CO_2e of reductions, cement-related measures contributed 8 Mt CO_2e, and industrial and other measures contributed 62 Mt CO_2e, for a total reduction of 116 Mt CO_2e below the 2050 baseline, which maintained the current share of non-energy/non-CO_2 in overall emissions.

There is evidence that the three key energy system transformations identified here are broadly generalizable to developed economies. A recent report on 80% GHG reductions in the EU found similar transformations were required, including electrification of transportation and buildings (*33*). In other studies where reductions rely on energy efficiency and generation decarbonization but not electrification, lower GHG reduction levels were achieved. For example, in a recent IEA study of technology paths in OECD countries as a whole, the most aggressive scenario had a 2050 reduction of about 50% below 1990 levels, with a 6% contribution from electrification (*34*). The consistency among these results is predictable, in that developed economies broadly share the same challenges for reaching deep reduction targets—the need to virtually eliminate fossil fuel use in electricity supply and in final consumption, especially in vehicles and buildings.

Infrastructure deployment and technology investment require coordination. In contrast to Pacala and Socolow, we found that achieving the infrastructure changes described above will require major improvements in the functionality and cost of a wide array of technologies and infrastructure systems, including but not limited to cellulosic and algal biofuels, CCS, on-grid energy storage, electric vehicle batteries, smart charging, building shell and appliances, cement manufacturing, electric industrial boilers, agriculture and forestry practices, and source reduction/capture of high-GWP emissions from industry (*35*).

Not only must these technologies and systems be commercially ready, they must also be deployed in a coordinated fashion to achieve their hoped-for emission reduction benefits at acceptable cost. For example, switching from fuels to electricity before the grid is substantially decarbonized negates the emissions benefits of electrification; large-scale deployment of electric vehicles without smart charging will reduce utility load factors and increase electricity costs; without aggressive energy efficiency, the bulk requirements for decarbonized electricity would be doubled, making achievement of 2050 goals much more difficult in terms of capital investment and siting. Figure 3D shows the impact of aggressive EE on three key metrics of decarbonized electricity supply: generating capacity, energy storage, and miles of high-voltage transmission line. For the mixed generation case, achieving the 2050 target with baseline levels of EE raised the requirement for annual construction of decarbonized generation from a very formidable 3.7 GW yr^{-1} to a practically unachievable 7.0 GW yr^{-1}, and the requirement for new transmission from 400 to 960 miles yr^{-1}.

Our model shows a net mitigation cost to California relative to the baseline of 0.5% of gross state product (GSP) in 2020, 1.2% in 2035, and 1.3% in 2050 ($65 billion or $1200 per capita) (Fig. 4 and fig. S34). The transportation sector bore the highest share of these costs, reflecting the cost of fleet electrification. These results are highly sensitive to both measure costs and fuel price assumptions; using the upper value of the EIA long-term crude oil price forecast makes net mitigation costs negative (fig. S12). Cumulative net costs from 2010 to 2050 were $1.4 trillion. The average cost of carbon in 2050 was $90/t CO_2e, while the highest average cost by measure type was $600/t CO_2e for electrification measures (*36*). Because mitigation measures reduce fuel use by investing in energy efficient infrastructure and low carbon generation, a much higher percentage of energy cost will go to capital costs; our model indicates a cumulative investment of $400-500 billion in current dollars (figs. S35 and S36) for electricity generation capacity in the mitigation case, a factor of about ten higher than the baseline case (*37*).

The transition to an energy efficient, low-carbon, electrified infrastructure thus requires mobilizing investment and coordinating technology development and deployment on a very large scale over a very long time period. How best to achieve this is an active debate over the relative roles of markets, government, carbon pricing, R&D policy, regulation, and public investment (*38*). Many consider carbon pricing the key to achieving efficient investment and providing incentives for consumer adoption, while others argue that carbon pricing is insufficient, and requires complementary policies to address market failures, public goods, and coordination problems (*16*, *39*, *40*). Some make the specific case that pollution pricing is effective in encouraging technology adoption, but not technological innovation (*41*, *42*). Others are concerned that the venture capital model is mismatched with the scale and timeline of investment required for an energy transformation (*43*) and with the risks created by the need for multiple technologies to achieve commercialization in parallel (*44*). These concerns have led to calls for novel public-private partnerships to address investment failures through government absorption of private capital risk (*43*), and to address coordination and sequencing through industry-government roadmapping (*45*).

Electricity's role in future energy costs and climate policy. The second model result deserving special attention is the expanded role of electricity, which increases from 15% to 55% of end-use energy, essentially switching places with petroleum products, which fall from 45% to 15% (Table 1). If electricity does become the dominant component of the 2050 energy economy, the cost of decarbonized electricity becomes a paramount economic issue. Our results show that generation mixes dominated by renewable, nuclear, and CCS, in the absence of cost breakthroughs, would have roughly comparable costs, raising the present average cost of electricity generation by a factor of about two, a result also noted by other researchers (*17*). These findings indicate that minimizing the cost of decarbonized generation should be a key policy objective. By some estimates, aggressive R&D policies could reduce the cost of low-carbon generation in the U.S. from 2020 to 2050 by about 40% or $1.5 trillion (*17*).

For electrified transportation, the inherently higher efficiencies of electric drive trains would still allow a net reduction in fuel costs even with electricity prices doubled and oil prices at $100/barrel, as well as shifting cash flows away from foreign oil imports toward domestic purchases of electricity. On the other hand, electrification of direct fuel uses will increase residential, commercial, and industrial sector costs, especially for heating, emphasizing the need for energy efficiency and design of new infrastructure in these sectors to minimize lifecycle costs. Because much of the required technology and infrastructure for the energy-system transformation is not yet commercialized, comparative lifecycle costs are highly uncertain. However, because decarbonized generation technologies are dominated by capital costs and insensitive to oil and natural gas price volatility, an electrified economy would have a long-term cost stability that could lower investment risk and make the optimal level of energy efficiency more certain (*46*). Even varying measure costs from one-half to twice the nominal values in the mitigation scenario produced no more variation in overall energy system costs than did varying crude oil prices in the baseline scenario over the range in the EIA's long-term forecast (fig. S12).

The climate policy community has proposed a suite of policies to complement carbon pricing (e.g., EE and RE standards, R&D support) that reflect not only economic and technology goals but also sociopolitical considerations such as equity, local initiative, and adaptability (*16*). The central role of electricity in our results suggests the importance of electricity sector governance as a tool of climate policy, but this has received relatively little attention until recently (*47*). Although some argue that regulation impedes innovation and increases implementation costs (*43*), state-level electricity regulation has existing tools for pursuing many climate policy goals, through both market mechanisms and direct regulation: requirements that utilities procure renewable generation, limit carbon intensities, and implement customer energy efficiency and distributed energy programs; and set rates that encourage conservation and electric vehicle charging, internalize pollution costs, and allocate the costs of these policies equitably (*7*, *48*). Given the political challenges of achieving comprehensive federal climate legislation, it is worth further exploring decentralized electricity governance as a climate policy mechanism.

Assuming plausible technological advances, we find that it is possible for California to achieve deep GHG reductions by 2050 with little change in lifestyle (although the potential for lifestyle change deserves further study). The logical sequence of deployment for the main components of this transformation is energy efficiency first, followed by decarbonization of generation, followed by electrification. This transformation will require electrification of most direct uses of oil and gas. In California no single generation technology, RE, nuclear, or CCS, can be used to decarbonize all electricity; a mixed generation portfolio is required. If it is true that the low-carbon path features electricity, then the question is how best to mobilize investment and coordinate R&D and infrastructure roll-out to achieve this end, and what climate policy modalities will be most effective. If the oil economy is replaced by the electric economy, it is instructive to consider the implications of the price of a decarbonized kWh replacing the price of a barrel of oil as a benchmark for the overall economy.

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Fig. 1. Emission reduction wedges for California in 2050. (above) Measures grouped into seven "wedges" reduce emissions from 875 Mt CO_2e in the 2050 baseline case to 85 Mt CO_2e in the mitigation case. In the 2020 model results, the wedge contributions are consistent with implementation plans for California's policy objectives (AB32) for 2020. (below) Reductions by wedge are shown for the 2030 and 2050 mitigation cases, in Mt CO_2e and as a percentage of total reductions. The top three contributions are from energy efficiency (28%), electricity decarbonization (27%), and electrification of direct fuel uses (16%). For each wedge, the types of measures included and key assumptions are shown.

Fig. 2. The three main energy system transformations required to reduce GHG emissions 80% below 1990 levels by 2050 in California. End use energy efficiency (EE) must be improved very aggressively (annual average rate 1.3% y^{-1}), electric generation emissions intensity must be reduced to less than 0.02 kg CO_2e/kWh, and most direct fossil fuel uses in transport, buildings, and industry must switch to electricity, raising the electricity share of end-use energy from 15% today to 55% in 2050. Both economics and the current state of technology development suggest a staged deployment in large-scale infrastructural transformation. Without aggressive levels of EE, the scale of decarbonized generation required to simultaneously replace fossil plants and meet both existing and newly electrified loads would be infeasible. Until high levels of electricity decarbonization are achieved, emission benefits from electrification would be limited. Without electrification, constraints on the other measures would limit total reductions to about 50% below 1990 levels.

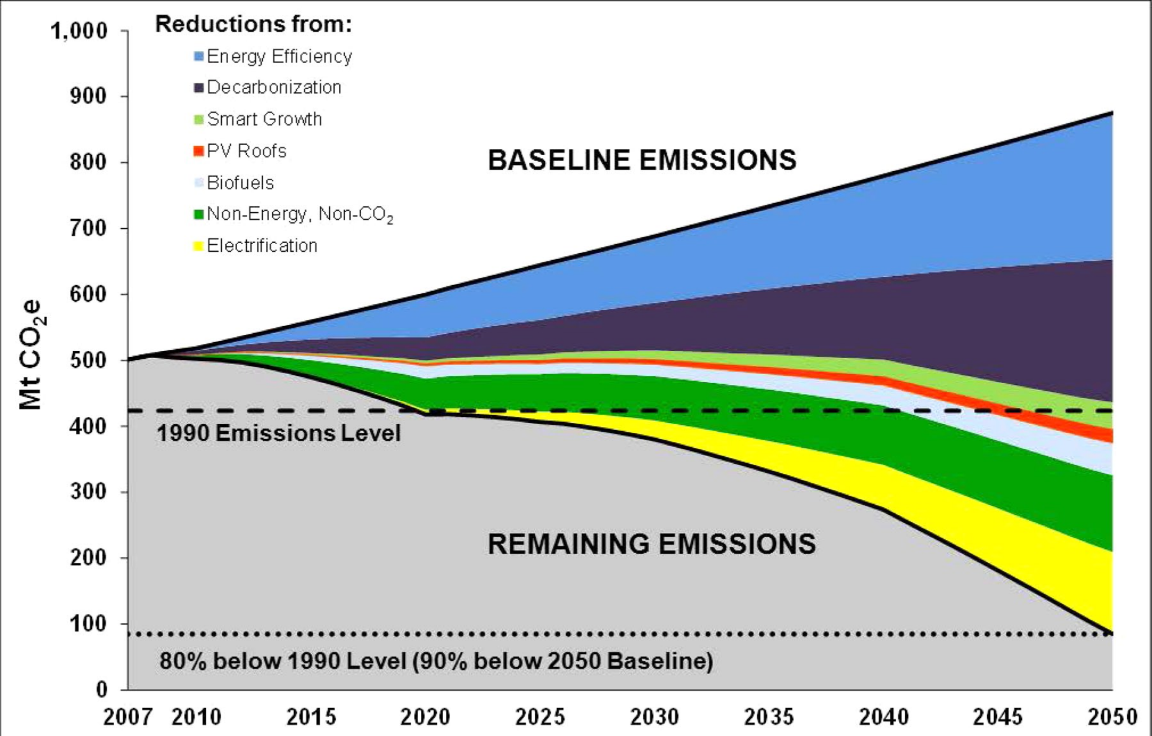
Fig. 3. Electricity consumption, load profiles, and fuel mix in baseline and mitigation scenarios. (**A**) In the mitigation case, aggressive end-use efficiency flattens baseline load growth. However, electrification of transportation adds a major new load, so that 2050 consumption is similar in both cases. (**B**) Smart-charging of electric vehicles flattens the average daily load curve, reducing capacity requirements. (**C**) In the 2050 baseline scenario, load growth is met primarily with natural gas generation. Four mitigation scenarios are shown with different fuel mixes, constrained by California's existing fuel mix and policy requirements (e.g., 33% renewable portfolio standard, continued licensing of existing nuclear generation). The "mixed" case, which contains all three generation types, yields the results discussed in this paper and shown in Figs. 1 to 3. (**D**) New capacity requirements for each generation fuel mix are shown for generation, transmission, and energy storage. Without aggressive EE, new capacity requirements increase by roughly a factor of two. The high renewables case has higher new capacity requirements than the high CCS and high nuclear case; however, high renewables does not have the CCS case requirements for CO_2 transmission and storage capacity, nor the nuclear case requirements for upstream and downstream nuclear fuel cycle facilities.

Fig. 4. Mixed case net cost by mitigation type in 2020, 2035, and 2050. For each year shown, the left hand column shows incremental mitigation costs in excess of baseline costs, and the right hand column shows incremental savings relative to baseline fuel costs. "Other" mixed case costs include measure implementation costs not associated with energy efficiency, electrification, generation decarbonization, or biofuels. "Other" savings include jet fuel and natural gas purchases for

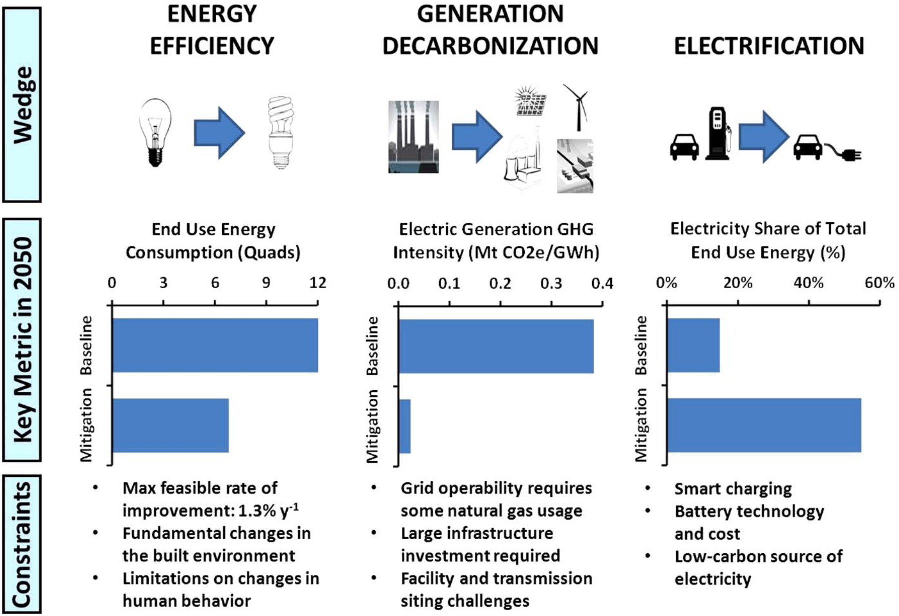
direct use (e.g., heating). Net costs are $15 billion dollars in 2020, $45 billion dollars in 2035, and $65 billion dollars in 2050. This is equivalent to $320 per capita or 0.5% of the statewide GSP in 2020, $910 per capita or 1.2% of the statewide GSP in 2035, and $1,200 per capita or 1.3% of the statewide GSP in 2050.

Table 1. Primary and end use energy and emissions by sector and fuel type in 2010 and 2050. The numerical difference between primary and end use energy is due to conversion and other losses. Sources for population and economic data are given in the supporting online material.

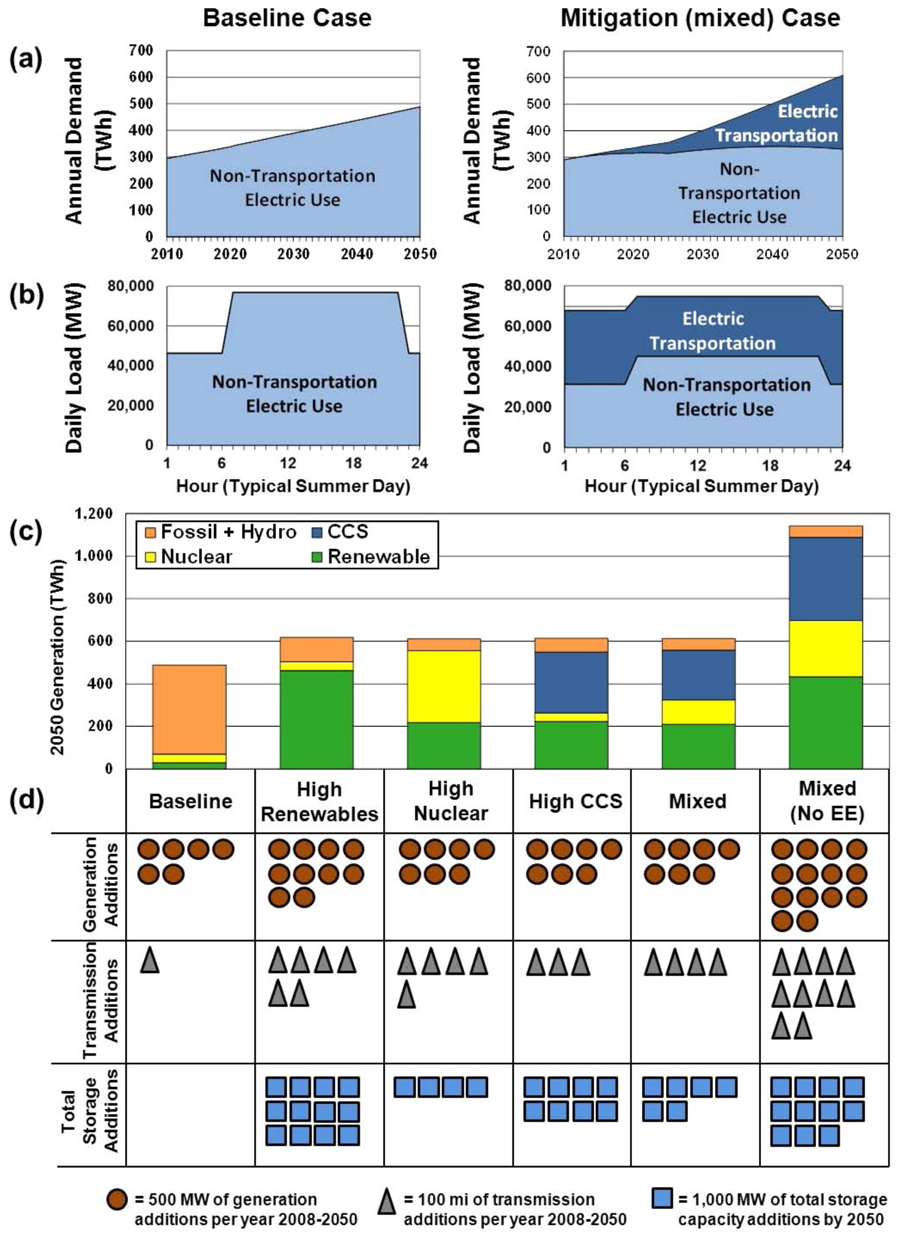
	Energy consumption (EJ)					Emissions (Mt CO_2e)		
	2010	2050 Baseline	2050 Mitigation	2010 (%)	2050 Mitigation (%)	2010	2050 Baseline	2050 Mitigation
Primary energy consumption and emissions, by sector								
Residential	1.60	2.56	0.52	18%	8%	71.3	117.1	5.4
Commercial	1.68	2.60	0.94	19%	14%	70.9	114.5	10.0
Industrial	1.41	1.39	0.96	16%	14%	67.4	67.3	6.4
Petroleum	0.81	0.82	0.58	9%	9%	46.7	47.5	5.6
Agriculture	0.34	0.52	0.21	4%	3%	16.3	27.1	1.0
Transportation	2.86	5.67	3.60	33%	53%	189.4	374.1	45.0
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total all sectors	8.70	13.56	6.81	100%	100%	518.4	875.4	84.8
Primary energy consumption and emissions, by fuel type								
Direct fuel use								
Natural gas	2.73	3.40	0.38	31%	6%	148.9	185.1	20.5
Gasoline	2.09	4.36	0.13	24%	2%	135.9	283.4	8.3
Diesel	0.73	1.23	0.39	8%	6%	50.2	84.7	26.6
Jet fuel	0.04	0.08	0.04	0%	1%	3.3	6.0	3.4
Biomethane and biofuels	0.00	0.00	0.73	0%	11%	0.0	0.0	0.0
Total direct fuel use	5.59	9.06	1.67	64%	25%	338.3	559.2	58.8
Electric generation (primary)								
Natural gas (non-CCS)	1.45	2.90	0.01	17%	0%	72.1	135.3	0.4
Coal (non-CCS)	0.49	0.49	0.00	6%	0%	43.2	43.2	0.0
Fossil fuel w/ CCS	0.00	0.00	2.18	0%	32%	0.0	0.0	10.6
Nuclear	0.30	0.26	0.74	3%	11%	0.0	0.0	0.0
Renewables and hydro	0.71	0.66	2.04	8%	30%	0.4	0.4	0.8
Other	0.16	0.18	0.16	2%	2%	8.0	9.6	2.9
Total electric generation	3.11	4.49	5.14	36%	75%	123.7	188.4	14.7
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total all fuel types	8.70	13.56	6.81	100%	100%	518.4	875.4	84.8
End-use energy consumption and emissions, by fuel type								
Total direct fuel use	5.59	9.06	1.67	85%	45%	338.3	559.2	58.8
Electricity (end-use)	0.98	1.63	2.03	15%	55%	123.7	188.4	14.7
Direct fuel use + electricity	6.57	10.69	3.70	100%	100%	462.0	747.6	73.4
Non-energy, non-CO_2 GHG emissions						56.4	127.8	11.4
Total end use by fuel type	6.57	10.69	3.70	100%	100%	518.4	875.4	84.8
Intensity metrics								
CA population (millions)	38.8	56.6	56.6					
Per capita energy use rate (kW/person)	7.1	7.5	3.8					
Per capita emissions (t CO_2e/person)	13.3	15.5	1.5					
Energy intensity ($/GJ)	$249	$383	$762					
Economic emissions intensity (kg CO_2e/$)	0.239	0.169	0.016					
Electric emissions intensity (kg CO_2e/kWh)	0.42	0.39	0.02					



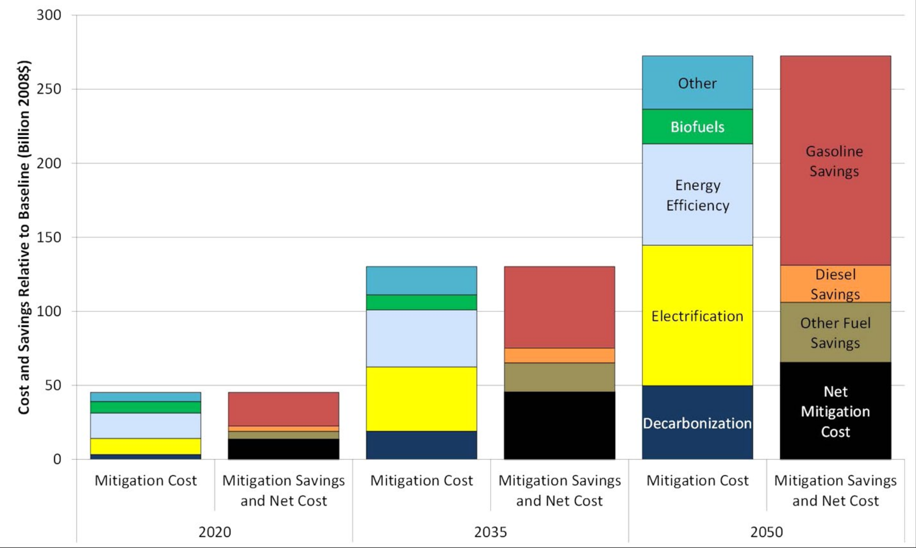
Wedge Category:	Emissions Reduction Mt CO_2e (% of Total) 2030	2050	Types (and Numbers) of Measures Used	Key Attributes in 2050
Energy Efficiency	102 (33%)	223 (28%)	Building EE (18); Vehicle EE (9); Other EE (6)	Improve energy efficiency 1.3% per year on average for 40 years
Electricity Decarbonization	72 (23%)	217 (27%)	High renewables, high nuclear, high CCS, and mixture of the three	Meet 90% of generation requirement with CO_2-free sources. Equivalent decarbonization in each scenario.
Smart Growth	13 (4%)	41 (5%)	Reductions in vehicle miles traveled (VMT) (6)	VMT reduced in light duty vehicles (LDV) by 10%; freight trucks 20%; other transportation 20%
Rooftop PV	8 (3%)	21 (3%)	Residential and commercial PV roofs (2)	Rooftop PV displaces 10% of electricity demand by 2050.
Biofuels	18 (6%)	49 (6%)	Transportation biofuels: ethanol, biodiesel, biojet fuel (9); Residential, commercial, industrial biomethane (3)	By 2050, biomethane displaces 2% of natural gas use in buildings, and biofuels displace 10-20% of petroleum-based fuels for vehicles
Non-Energy, Non-CO_2	67 (22%)	116 (15%)	Cement, agriculture, and other (3)	Non-fuel, non-CO_2 GHG emissions reduced 80% below baseline
Electrification	29 (9%)	124 (16%)	Transportation electrification (9); Other end-use electrification (5)	75% of LDV gasoline use displaced by PHEVs & electric vehicles; 30% of fuel use in other transport sectors electrified; 65% electrification of non-heating/cooling fuel use in buildings; 50% electrification of industrial fuel uses
Baseline Case Emissions	**688**	**875**		
Mitigation Case Emissions	**380**	**85**		
Total Reduction	**308**	**791**		



Wedge
ENERGY EFFICIENCY
GENERATION DECARBONIZATION
ELECTRIFICATION
Key Metric in 2050
End Use Energy Consumption (Quads)
0
3
6
9
12
Baseline
Mitigation
Electric Generation GHG Intensity (Mt CO2e/GWh)
0.0
0.1
0.2
0.3
0.4
Baseline
Mitigation
Electricity Share of Total End Use Energy (%)
0%
20%
40%
60%
Baseline
Mitigation
Constraints
• Max feasible rate of improvement: 1.3% y-1
• Fundamental changes in the built environment
• Limitations on changes in human behavior
• Grid operability requires some natural gas usage
• Large infrastructure investment required
• Facility and transmission siting challenges
• Smart charging
• Battery technology and cost
• Low-carbon source of electricity



Baseline Case
Mitigation (mixed) Case
(a)
Annual Demand (TWh)
Non-Transportation Electric Use
Electric Transportation
Non-Transportation Electric Use
(b)
Daily Load (MW)
Hour (Typical Summer Day)
Non-Transportation Electric Use
Electric Transportation
Non-Transportation Electric Use
(c)
2050 Generation (TWh)
Fossil + Hydro
CCS
Nuclear
Renewable
(d)
Baseline
High Renewables
High Nuclear
High CCS
Mixed
Mixed (No EE)
Generation Additions
Transmission Additions
Total Storage Additions
= 500 MW of generation additions per year 2008-2050
= 100 mi of transmission additions per year 2008-2050
= 1,000 MW of total storage capacity additions by 2050



Cost and Savings Relative to Baseline (Billion 2008$)
300
250
200
150
100
50
0
Other
Biofuels
Energy Efficiency
Electrification
Decarbonization
Gasoline Savings
Diesel Savings
Other Fuel Savings
Net Mitigation Cost
Mitigation Cost
Mitigation Savings and Net Cost
Mitigation Cost
Mitigation Savings and Net Cost
Mitigation Cost
Mitigation Savings and Net Cost
2020
2035
2050