INTEGRATED ENERGY POLICY REPORT

2014 IEPR UPDATE

CALIFORNIA ENERGY COMMISSION
EDMUND G. BROWN JR., GOVERNOR

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Preface

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the California Energy Commission to prepare a biennial integrated energy policy report that assesses major energy trends and issues facing the state's electricity, natural gas, and transportation fuel sectors and provides policy recommendations to conserve resources; protect the environment; ensure reliable, secure, and diverse energy supplies; enhance the state's economy; and protect public health and safety (Public Resources Code § 25301a]). The Energy Commission prepares these assessments and associated policy recommendations every two years, with updates in alternate years, as part of the *Integrated Energy Policy Report*.

Preparation of the *Integrated Energy Policy Report* involves close collaboration with federal, state, and local agencies, and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address those issues. Through the spring and summer of 2014, the Energy Commission hosted eight public workshops to solicit the views and recommendations about the Alternative and Renewable Fuel and Vehicle Technology Program from a wide array of technology, business, finance, and policy experts from state and federal government, academia, not-for-profit organizations, and industry. The goals for these workshops were to assess the Energy Commission's progress, efficacy, and achievements in administering the Alternative and Renewable Fuel and Vehicle Technology program, the vision of the state Legislature in reauthorizing program funding, the technologies currently available and over the next decade that will be needed to achieve a low-carbon transportation system, and the challenges that still need to be surmounted before low-carbon, low-emission fuels, and vehicles can become a standard and integral part of California's transportation system.

Furthermore, the Energy Commission hosted workshops in Berkeley on June 25, 2014, to discuss changing trends in California's sources of crude oil and the potential growth of crude oil transport to California by rail, and in Los Angeles on August 20, 2014, to review the reliability of the electricity system in Southern California. The Energy Commission held a workshop on climate change impacts on the transportation system on May 23, 2014, a workshop on the integration of environmental information in renewable energy planning processes on August 5, 2014, and a workshop on the *California Energy Demand Final Forecast 2014-2024* on December 8, 2014. The Energy Commission presented the *2014 Draft Integrated Energy Policy Report Update* for review and comment at a workshop on November 24, 2014. The findings in this report reflect the input received at those workshops and in comments timely filed in response to those workshops, as well as staff and contractor analysis and policy direction from Commissioners.

Abstract

The *2014 Integrated Energy Policy Report Update* provides the results of the California Energy Commission's assessments of a variety of energy issues currently facing California. These issues include the role of transportation in meeting state climate, air quality, and energy goals; the Alternative and Renewable Fuel and Vehicle Technology Program; current and potential funding mechanisms to advance transportation policy; the status of statewide plug-in electric vehicle infrastructure; challenges and opportunities for electric vehicle infrastructure deployment; measuring success and defining metrics within the Alternative and Renewable Fuel and Vehicle Technology Program; market transformation benefits resulting from Alternative and Renewable Fuel and Vehicle Technology Program investments; the state of hydrogen, zero-emission vehicle, biofuels, and natural gas technologies over the next 10 years; transportation linkages with natural gas infrastructure; evaluation of methane emissions from the natural gas system and implications for the transportation system; changing trends in California's sources of crude oil; the increasing use of crude-by-rail in California; the integration of environmental information in renewable energy planning processes; an update on electricity reliability planning for Southern California energy infrastructure; and an update to the electricity demand forecast.

Keywords: California Energy Commission, transportation, Alternative and Renewable Fuel and Vehicle Technology Program, climate adaptation, electric vehicle charging infrastructure, natural gas, oil by rail, *Desert Renewable Energy Conservation Plan*, energy efficiency, Southern California energy infrastructure, electricity demand forecast

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Executive Summary

California continues to be one of the most desirable places to live, play, and work in the world, offering a beautiful and diverse natural environment, as well as a high quality of life for its residents, both economically and culturally. In 2013, the state grew to more than 38 million people and became the eighth largest economy globally. It has also put into place an impressive array of policies and actions to ensure that California's resources, economy, and quality of life are sustainable and continue to prosper. The result is a decades-long commitment to ensure clean air and water, efficient and productive use of energy and resources, healthy communities, and economic vitality in the state.

While California continues to make good progress in these areas by doubling down on proven strategies and taking the lead on developing and implementing some "first-in-the-world" solutions, the magnitude of change needed to address the threats of climate change and meet more stringent federal air quality standards in the state will require even further innovation in the energy and transportation sectors. Indeed, in his inaugural address, Governor Brown proposed "three ambitious goals to be accomplished within the next 15 years: increase from one-third to 50 percent our electricity derived from renewable sources, reduce today's petroleum use in cars and trucks by up to 50 percent, double the efficiency of existing buildings, and make heating fuels cleaner."[1]

Given the importance of making progress in these sectors, the *2014 Integrated Energy Policy Report Update* (*2014 IEPR Update*) focused on next steps for transforming transportation energy use in California. This report highlights the importance of incentives in helping speed this transition and specifically explores the role Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) (AB 8), which makes more than $2 billion available for public investment, can play in helping to achieve this progress. AB 8 extends clean transportation investment programs such as the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) through January 1, 2024. The report also provides updates on incorporating environmental information in renewable energy planning, the electricity infrastructure in Southern California, and the electricity demand forecast.

1 Edmund G. Brown Jr. inaugural address, remarks as prepared, January 5, 2015.

To Meet California's Climate and Clean Air Goals, a Transformation of the Transportation System to Zero- and Near-Zero Technologies and Fuels Is Needed

California's on-road transportation system includes 170,000 miles of highways and major roadways, more than 26 million passenger vehicles and light trucks, and almost 1 million medium- and heavy-duty vehicles. The most recent data available (2012) shows the transportation sector emits 36 percent of the total greenhouse gases in the state and about 83 percent of smog-forming oxides of nitrogen (NO_x). The state has set climate goals in the Global Warming Solutions Act of 2006 (Núñez, Chapter 488, Statutes of 2006) that cap economy-wide California greenhouse emissions at 1990 levels by 2020 and in Executive Order S-3-05 and Governor Brown's Executive Order B-16-2012, which call for reductions in greenhouse gas emissions to 80 percent below 1990 levels by 2050. Further, the federal Clean Air Act calls for an 80 percent reduction in NO_x emissions by 2023.

Retiring older, high-polluting, inefficient vehicles and replacing them with near zero- and zero-emission technologies will be critical to meeting the state's goals. As part of its strategic approach to investing ARFVTP funds to help speed this transformation, the Energy Commission continually assesses the state of fuel and vehicle technologies and markets, including the changing trends in global petroleum pricing.

Hydrogen Fuel Cell Technology is Poised to Become a Zero-Emission Option Across the Transportation Sector

Fuel cell electric vehicles powered by hydrogen will play a key role in fulfilling California's climate, clean air, and petroleum reduction goals and the Governor's *Zero-Emission Vehicle Action Plan* goal of 1.5 million zero-emission vehicles in 2025. Studies and automakers suggest that California needs an initial network of about 100 strategically placed stations to ensure that hydrogen fuel is available for the first wave of fuel cell electric vehicles. Through AB 8, the California Legislature has directed the Energy Commission to invest up to $20 million per year (or 20 percent of the annual ARFVTP funding) to build this preliminary infrastructure.

While the state has put several strategies in place to help reduce early investment risks for this technology and ensure that stations are ready to serve the first wave of fuel cell electric vehicles, station and equipment costs continue to be a barrier. More directed research on hydrogen station storage and dispensing equipment and innovative funding partnerships are needed in this area to bring down hydrogen infrastructure costs and advance market deployment.

The Plug-in Electric Vehicle Market is Growing Steadily and Provides Another Zero-Emission Vehicle Option

Replacing conventional vehicles with battery-electric vehicles and plug-in hybrid electric vehicles—collectively referred to as *plug-in electric vehicles* (PEVs)—is a key component of the state's strategy to meet its climate, clean air, and energy goals.

The PEV market continues to grow in California with 20 models of full battery-electric vehicles and plug-in hybrid vehicles offered by almost every automobile manufacturer to California consumers. In 2013, PEV sales were triple 2012 levels, and as of December 2014 more than 118,000 PEVs were sold in California, representing about 40 percent of national PEV sales.

While Charging Infrastructure Has Steadily Grown, Additional Incentives and Innovations are Needed to Rapidly Increase the Number of Available Stations and to Solve Infrastructure Challenges

As the electric vehicle industry is quickly evolving, electric vehicle charging infrastructure deployment continues to be a key challenge. Challenges associated with electric

vehicle charging station deployment in multi-unit dwellings are one of the biggest barriers to increased plug-in electric vehicles adoption and include cost, the availability of power supply, the proximity to metering equipment, physical limitations in high-rise units, parking issues, homeowner association requirements, allocation of charging costs, and the complexity of decision-making. Furthermore, while PEV drivers have taken advantage of the increasing number of workplace and public chargers available in key metropolitan areas of the state, the costs of installation and equipment continue to limit accessibility of charge points in these locations. Charging infrastructure is expected to expand, however, as a result of a December 2014 California Public Utilities Commission (CPUC) decision authorizing utility ownership of electric vehicle charging infrastructure. Continued strategic investments in charging infrastructure at residential, workplace, multi-unit dwellings, and public sites along with regional readiness plans will be needed to continue advancing adoption of plug-in electric vehicles.

Integrating Large Numbers of Electric Vehicles on the Grid Should be Planned for Proactively

As the number of electric vehicles grows, greater attention to vehicle and electric grid integration will be needed as well. Electric vehicles have the potential to benefit the grid by using their batteries to help manage electricity loads throughout the day, which is a growing concern as renewable solar and wind energy continue to grow in California. To realize these opportunities, smart charging technology that incorporates the flexibility to communicate with customers and electric utilities becomes essential to electric vehicle operation. Further collaboration is needed on research, demonstration, deployment, planning, and market facilitation related to vehicle-to-grid projects.

Transitioning to Zero- and Near-Zero Emission Medium- and Heavy-Duty Vehicles is Necessary to Achieve Climate and Clean Air Goals

California's fleets of medium- and heavy-duty vehicles total more than 900,000 vehicles and include long haul tractors; refuse hauling trucks; package delivery vans, medium-duty work trucks and shuttles; and buses. In 2012 they comprised about 3.7 percent of the total vehicle population in California, yet consumed more than 20 percent of the total fuel and are responsible for as much as 23 percent of transportation-related greenhouse gas emissions and 30 percent of total NO_x emissions. In the San Joaquin Valley and South Coast Air Basins, truck-related NO_x emissions are the leading cause of harmful ozone pollution, fine particulate matter emissions, and resulting respiratory diseases.

While state incentive programs like the Energy Commission's ARFVTP help advance development and commercialization of medium- and heavy-duty vehicle technologies with investments across multiple near-term and long-term fuel pathways that include natural gas, electric drive, hydrogen fuel cell electric drive, and hybrid and range extender combinations, market uptake of the cleanest trucks remains slow due to cost. Targeted incentives to help bring down the cost of electric trucks are an area of opportunity.

Given the immediacy of the need to reduce NO_x emissions in the South Coast and the San Joaquin Valley, advanced, clean (for example, vehicles or engines that are certified to meet the California Air Resources Board's (ARB) voluntary low NO_x standards) natural gas pathways are being explored to determine the potential of these pathways to help reduce emissions from the truck and bus sector, as well as the marine and rail sectors. There are, however, questions about the potential benefits of natural gas due to uncertainties about methane leakage along the natural gas distribution and transmission pipeline systems and upstream at the production wells

and gas collection systems. Many research efforts are underway to reduce uncertainties regarding how much methane is being emitted from the natural gas system and where leaks are located. Continued engagement and research support on this issue will be critical as the state continues to initiate solutions to transform its heavy-duty vehicle sector.

Cleaner Fuels with Lower Carbon Intensity Numbers, Like Biofuels, Have the Potential to Provide Immediate Emission Reduction Benefits

Biofuels will also play a critical role in reducing carbon emissions from the transportation sector and are a key element in the state's approach to a low-carbon transportation future. Growth in the use of biofuels as a blend with gasoline and diesel is being spurred by regulations combined with government incentive funding through the federal Renewable Fuel Standard, the California Low Carbon Fuel Standard (LCFS), a federal blender's tax credit for biodiesel and renewable diesel sales, and ARFVTP co-funding of biofuel production plants.

Biofuels range from first-generation, food-based fuels using feedstocks of corn and soy with modest carbon emissions reductions to advanced second- and third-generation drop-in fuels. Biogas, or renewable natural gas, can be derived from a wide array of urban and agricultural waste streams and has extremely low carbon intensity values. It can be used as a stand-alone fuel in natural gas engines or as a blendstock with natural gas to reduce the carbon content of compressed natural gas and liquefied natural gas fuels. The California biofuels industry is proceeding steadily. Biodiesel and renewable diesel are making tremendous gains in California markets, although feedstock limitations on waste-based oils and greases may prove to be the limiting factor. Biogas production in California is also proceeding, but challenges remain to ensure that biogas can be safely and economically injected into pipelines.

Exploring Opportunities to Leverage Funding May Help to Achieve Deeper Benefits on a Faster Time Frame

California is fortunate to have several programs designed to provide incentives and accelerate the transition to a cleaner transportation future. The infusion of government capital can accelerate the transition of technologies by helping assume risk for investments that markets are not ready to take. Studies by the National Research Council show that the investment in a low-carbon transportation system will accelerate transformation and that the long-term benefits will far exceed costs, even though costs initially exceed benefits for about 10 years. Because of positive feedback effects, however, the earlier the investments are made, the bigger the net benefits over time.

Government incentive or subsidy grants are most needed during the research and initial demonstration phases when private venture capital is often unavailable. To date, the ARFVTP has primarily distributed funding through competitive grants, seeking the most qualified technology development and demonstration projects. As technology matures, however, different forms of government subsidies, such as loans, loan support, or consumer and commercial voucher rebates, may become more appropriate to fill funding gaps.

New leveraging opportunities are also emerging with federal agencies, such as the U.S. Environmental Protection Agency and the U.S. Department of Energy, in the area of fuel cell technology development, and with air districts in California, especially the Bay Area and San Joaquin Air Quality Management Districts, on advanced technology medium- and heavy-duty vehicles.

Table 1: ARFVTP and Air Quality Improvement Program Funding Impact on Infrastructure and Vehicle Deployment in California (Through December 2014)

	Fuel Area	Existing 2009-2010 Baseline Levels	Additions from ARFVT or AQIP* Program Funding	Percent Increase
Alternative Fueling Infrastructure	Electric	2,540 charge points	9,369 charge points *(residential, public, workplace, DC fast charger)*	368
	E85**	39 fueling stations	161 fueling stations	412
	Natural Gas	443 fueling stations	60 stations	14
	Hydrogen	6 public fueling stations	48 fueling stations	800
Alternative Fuel Vehicles	Electric Cars (ARB Vouchers)	13,268 *(mostly neighborhood electric vehicles)*	(21,000 – ARFVTP) 89,314 – Total AQIP***	673
	Electric Trucks	1,409	160	11
	Natural Gas Trucks	13,995	2,725	19

Source: Energy Commission staff *AQIP is the Air Quality Improvement Program that is administered by the ARB **E85 is a blend of 85 percent ethanol and 15 percent gasoline *** Current through December 2014. ARFVTP funding accounts for 24 percent of total Clean Vehicle Rebate Program vouchers.

The ARFVTP Has Achieved Important Benefits to Date and the Program Will Continue to Find Ways to Measure Its Benefits

Based on an assessment of the benefits performed by the National Renewable Energy Laboratory from roughly $500 million invested by the Energy Commission's ARFVTP through September 2014, the program is expected to reduce between 3.4 million and 5.3 million tonnes of carbon dioxide equivalent emissions annually and displace the equivalent of between 441 million and 693 million gallons of gasoline/diesel per year by 2025.

As shown in Table 1, market transformation toward a low-carbon, low-emission transportation system in California is measurably underway, as evidenced by the substantial increases in electric vehicles and chargers, electric trucks, natural gas trucks, and hydrogen fueling infrastructure.

The ARFVTP also creates public health benefits, as a result of the 2 to 5 tons of small particulate matter (PM2.5) expected to be reduced annually by 2025. The program also contributes to economic development, helping to create almost 6,400 new jobs in California and training more than 13,600 technicians and maintenance personnel throughout the state. These benefits will grow as the Energy Commission continues to make additional investments. It will be important to continue tracking these data points as California progresses towards its goals, and to make sure that these metrics continue to be used as information tools when considering future project investments.

Changing Trends in the Sources of California's Crude Oil Highlight the Need for the State to be Vigilant in Protecting Its Ability to Address Safety Concerns and Collect Additional Data

Although California is working to reduce petroleum use, petroleum-based fuels continue to account for about 92 percent of the state's transportation needs. California refineries have increasingly turned to foreign sources of crude oil as production in California and Alaska has declined. On the other hand, there has been a dramatic

rebound in U.S. oil production as a whole due to the widespread use of horizontal drilling and hydraulic fracturing. These activities led to U.S. oil production of 9.05 million barrels per day during October 2014, the highest level of output since February 1986. This increase in domestic production has outpaced the ability of existing pipeline distribution systems, necessitating a shift in crude oil delivery. Oil producers have discounted prices to allow the traditionally more expensive mode of rail delivery to become economically viable for oil refiners outside production areas. As a result, California refineries are pursuing crude-by-rail receiving terminal projects to obtain discounted crude oil and improve profitability.

Reflecting public concern over the safety of crude-by-rail transport, the Governor's Office formed an interagency rail safety working group in January 2014 to proactively assess risk. *Oil by Rail Safety in California* was published in June 2014, highlighting the preliminary findings and recommendations of the group, including a call to improve emergency preparedness and response programs and to request the Department of Transportation expedite the phasing out of older DOT-111 tank cars. In addition, the Energy Commission held an IEPR workshop on June 25, 2014, to bring together representatives from federal, state, and local governments as well as the railroad industry to discuss these trends and clarify which agencies were responsible for overseeing these developments.

Most rail safety regulations are federal and are usually not pre-empted by state laws. In California, the Rail Safety Division of the CPUC works with federal inspectors to ensure safe operations of rail movement for goods and people, while the Energy Commission's role is limited to data collection on crude oil sources and volumes.

Moving forward, state agencies should continue to be proactive and work together to implement the recommendations in *Oil by Rail Safety in California*, monitor the status of federal rulemakings and proceedings to ensure they capture recommendations made by the state, remain open and flexible to the potential need for additional funding, and acquire the data needed to address safety concerns.

Environmental Information in Renewable Energy Planning Processes

In the *2012 IEPR Update* and *2013 IEPR*, the Energy Commission discussed renewable energy planning and land use. The *2014 IEPR Update* addresses renewable energy planning and includes an update on the *Desert Renewable Energy Conservation Plan* (DRECP) and related local government planning initiatives and their relationship to transmission planning and procurement.

The Energy Commission has been involved in several analytical efforts to identify sensitive land-use areas, intending to improve the permitting process for renewable energy projects that are critical to meeting the state's Renewables Portfolio Standards (RPS), which requires that utilities serve 33 percent of retail electricity sales with renewable resources by 2020. The Renewable Energy Transmission Initiative (RETI) was created in June 2007 as a stakeholder-driven effort to identify and quantify cost-effective and environmentally responsible renewable energy resources and needed transmission to achieve California's 33 percent RPS goal. This effort resulted in the identification of 30 competitive renewable energy zones throughout the state with corresponding transmission interconnections and lines.

Building on the RETI experience, the DRECP is intended to advance state and federal conservation goals in the Mojave and Colorado deserts, while promoting the timely permitting of renewable energy projects. The DRECP is focused on the desert regions and adjacent lands of seven California counties—Imperial, Inyo, Kern, Los Angeles, Riverside, San Bernardino, and San Diego—totaling roughly 22.5 million acres of federal and nonfederal California desert land. It will delineate renewable energy development focus areas that are located where large-scale renewable energy development is commercially viable and that are sufficient to help meet California's long-term climate and renewable energy goals out to 2040 and beyond. The DRECP's conservation framework is designed to provide comprehensive conservation for desert ecosystems and covered species.

As a next step, the Energy Commission recommends finalizing and implementing the DRECP, and working with the CPUC and California Independent System Operator (California ISO) to build on recent planning processes and continue to improve renewable energy and transmission planning and coordination in California, particularly for the post 2020 time frame. The Energy Commission also recommends working with local, state, federal, and other partners and stakeholders to advance the current capabilities of the state in performing landscape-scale analysis, including assessing the data and tools currently available, identifying data gaps, and moving forward to advance these analytical capabilities. Potential partnerships should be explored beyond California to include the western United States and international partners in the western interconnected grid.

Electricity Infrastructure in Southern California

The Southern California region's electricity reliability has been of concern for the past several years due to the planned retirement of aging facilities that depend upon once-through cooling technologies, as well as the June 2013 retirement of the San Onofre Nuclear Generating Station (San Onofre). While the once-through cooling phase-out has been ongoing since the May 2010 adoption of the State Water Resources Control Board's once-through cooling policy, the retirement of San Onofre complicated the situation. California ISO studies had revealed the extent to which the Los Angeles Basin and San Diego region were vulnerable to low-voltage and post-transient voltage instability concerns. A preliminary plan to address these issues was detailed in the *2013 IEPR* after a collaborative process with other energy agencies, utilities, and air districts.

If the resource development outlined in the preliminary plan continues as detailed, reliability in Southern California would likely be assured; however, tight resource margins have led energy agencies and the ARB to develop a contingency plan. This contingency plan was discussed at a public workshop in Los Angeles on August 20, 2014, and is detailed further in Chapter 9.

Electricity Demand Forecast

One of the core functions of the Energy Commission is to produce an accurate forecast of electricity and natural gas demand. This demand forecast plays an essential role in the California ISO's transmission planning studies and the CPUC's electricity procurement planning. Prior to 2013, the forecast was released as part of the IEPR process in odd-numbered years; however, as part of the energy agencies' ongoing commitment to process alignment, the Energy Commission will provide an annual update in even-numbered years going forward. This update is expected to assist with the California ISO's annual Transmission Planning Process and the CPUC's Long Term Procurement Planning Process. These annual updates replace economic and demographic drivers used in the previous full IEPR forecast with the most current projections and add another year of historical electricity consumption and peak demand data. The forecast horizon was also extended one year, to 2025, to meet the needs of the Transmission Planning Process.

The Energy Commission held a workshop on December 8, 2014, to discuss the results of the *California Energy Demand Updated Forecast 2015–2025*. In general, current projections for economic growth in California are more pessimistic compared to those used in 2013, resulting in lower forecasts for electricity sales, consumption, and peak demand. By 2024, statewide peak demand in the updated mid scenario is projected to be 1.8 percent lower than the forecast mid case developed in 2013. Updated forecast results for individual planning areas and updated managed forecasts for the investor-owned utility service territories, which incorporate additional achievable energy efficiency savings, are also lower relative to the forecast developed in 2013. The Energy Commission adopted the *California Energy Demand Updated Forecast 2015–2025* at the January 14, 2015 Business Meeting.

CHAPTER 1:
Meeting California's Climate, Air Quality, and Energy Goals Requires Transformation in the Transportation Sector

California's transportation system is a core element of the state's way of life and economic vitality. The state's vast system of roadways and freeways enable Californians to commute from home to work, take children to school, and relax and rejuvenate when vacationing along the coastline or in the mountains. The freight transport system is a core element of the economy, the eighth largest in the world. It enables goods and products to move from the ports of Los Angeles and Oakland throughout regional metropolitan centers in Los Angeles, the San Francisco Bay Area, San Diego, Sacramento, and the San Joaquin Valley. In the Central Valley, a dynamic transportation system is critical to getting crops from fields to processing and packing centers and then to markets in California, the United States, and around the world. Billions of dollars of goods are transported via California's transportation network.

This enormous on-road transportation system includes 170,000 miles of highways and major roadways, more than 27 million passenger vehicles and light trucks, and more than 900,000 medium- and heavy-duty transport trucks. While gasoline consumption has been declining since 2008,[2] it is still by far the dominant fuel. Petroleum comprises about 92 percent of all transportation energy use, excluding fuel consumed for aviation and most marine vessels. Nearly 18 billion gallons of on-highway fuel are burned each year, including 14.5 billion gallons of gasoline (including the ethanol) and 3.4 billion gallons of diesel fuel (including the biodiesel and renewable diesel). In 2013, Californians also used 174 million therms of natural gas as a transportation fuel, or the equivalent of 142 million gallons of gasoline, and 841,345 megawatt hours of electricity for transportation, or about the equivalent of 25 million gallons of gasoline. For 2013, combined alternative fuel use in California was slightly more than 7 percent of total transportation fuel use. Table 2 shows total petroleum and alternative fuel consumption in California for 2013.

A recent trend in global petroleum markets has been the steady decrease in petroleum pricing since July 2014. As measured with the Brent North Sea Oil international benchmark, prices declined from an average of $111.80 during June 2014 to an average of $58.31 per barrel on

2 California Energy Commission. 2013. *2013 Integrated Energy Policy Report*. Publication Number: CEC-100-2013-001-CMF, http://www.energy.ca.gov/2013publications/CEC-100-2013-001/CEC-100-2013-001-CMF.pdf.

Table 2: California Transportation Energy Use During 2013

	Gasoline	Fuel Ethanol	Diesel Fuel	Biodiesel	Renewable Diesel	Propane	Natural Gas	Electricity	Totals
MM Gallons	13,079	1,461	3,294	49	136	35	174 MM Therms	841,345 MWh	
BTUs2	113,927	76,330	129,488	119,550	122,887	84,250	92,974	3,412,000	
MM GGE Units3	13,079	979	3,744	51	146	26	142	25	18,193

Source: California Energy Commission Staff 1) Excludes fuel consumed for aviation and most marine vessel activities. 2) Units are in British Thermal Units (BTU) per gallon, except for natural gas (BTUs/therm) and electricity (BTUs/MWh). 3) GGE refers to gasoline-gallon equivalent units.

December 22, 2014, a decrease of nearly 48 percent.[3] Retail petroleum fuel prices in California have decreased at a similar rate. The Energy Commission is monitoring this price drop and any potential impacts on expansion of California's alternative fuel markets and alternative vehicle sales.

As critical as the transportation system is to California's way of life and economy, it is also the state's biggest source of greenhouse gas emissions that contribute to global climate change. To meet climate goals, the state must reduce greenhouse gas emissions from transportation while safeguarding its transportation system from the risks of climate change. The transportation system also generates air pollutants that contribute to poor air quality and diminished public health in many parts of California. This chapter discusses the state's climate, clean air, and energy goals and highlights how integral the transportation sector is to these goals. Next is a discussion of the vision for transforming the transportation sector and an overview of the Energy Commission's accomplishments to date to help move California to a cleaner, lower carbon transportation system. The chapter closes with a discussion on California's leadership in this area and recommendations that broadly reflect key messages gleaned from the March 27, 2014, Integrated Energy Policy Report (IEPR) workshop.

California's Climate, Clean Air, and Energy Goals

California has enacted an aggressive array of policies to reduce greenhouse gas emissions, other air pollutants, and petroleum use, as shown in Table 3. A key policy is the Global Warming Solutions Act of 2006 (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) that caps economywide California greenhouse emissions at 1990 levels by 2020. Further, the state has a goal of reducing greenhouse gas emissions to 80 percent below 1990 levels by 2050, as reflected in Executive Order S-3-05[4] and Governor Brown's Executive Order B-16-2012.[5] The state also has goals to reduce petroleum use, advance alternative fuels and bioenergy in particular, and reduce the carbon content of petroleum. Governor Brown's

3 The Energy Information Administration (EIA) has Brent North Sea oil prices available on a daily basis going back to May 20, 1987. See http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

4 http://gov.ca.gov/news.php?id=1861.

5 http://gov.ca.gov/news.php?id=17472.

Table 3: Transportation Policy Drivers

Policy Objectives	Policy Origin	Goals and Milestones
Greenhouse Gas (GHG) Reduction	AB 32, California Global Warming Solutions Act	Reduce GHG emissions to 1990 levels by 2020
	Executive Orders S-3-05 and B-16-2012	Reduce GHG emissions to 80% below 1990 levels by 2050 in California
	Low Carbon Fuel Standard	10% reduction in carbon intensity of transportation fuels in California by 2020
Petroleum Reduction	California *State Alternative Fuels Plan*	Reduce petroleum fuel use in California to 15% below 2003 levels by 2020
In-State Biofuels Production	California *Bioenergy Action Plan*	Produce in California 20% of biofuels used in state by 2010, 40% by 2020, and 75% by 2050
Federal Renewable Fuel Standard	Energy Policy Act of 2005, Energy Independence and Security Act of 2007	36 billion gallons of renewable fuel by 2022
Improved Air Quality	Clean Air Act	80% reduction in NOx from current levels by 2023
Increased Zero-Emission Vehicles (ZEVs)	California Air Resources Board's ZEV Mandate, California Executive Order B-16-2012	Infrastructure to accommodate 1 million electric vehicles by 2020 and 1.5 million electric vehicles by 2025 in California

Source: California Energy Commission staff

Executive Order B-16-2012 calls for infrastructure to support 1 million electric vehicles on the road by 2020 and 1.5 million electric vehicles on the road by 2025.[6] Governor Brown further reaffirmed the state's commitment to achieving these goals in his January 5, 2015, inaugural address noting that while "California has the most far-reaching environmental laws of any state and the most integrated policy to deal with climate change of any political jurisdiction in the Western Hemisphere, …[t]hese efforts, impressive though they are, are not enough." Now "…it is time to establish [California's] next set of objectives for 2030 and beyond."[7] The federal Clean Air Act calls for an 80 percent reduction in emissions of oxides of nitrogen (NO_x) by 2023. Each of these policies and goals is driving efforts to fundamentally change energy use in the transportation sector.

Key Role of Transportation to Meet Emissions Reduction and Energy Goals

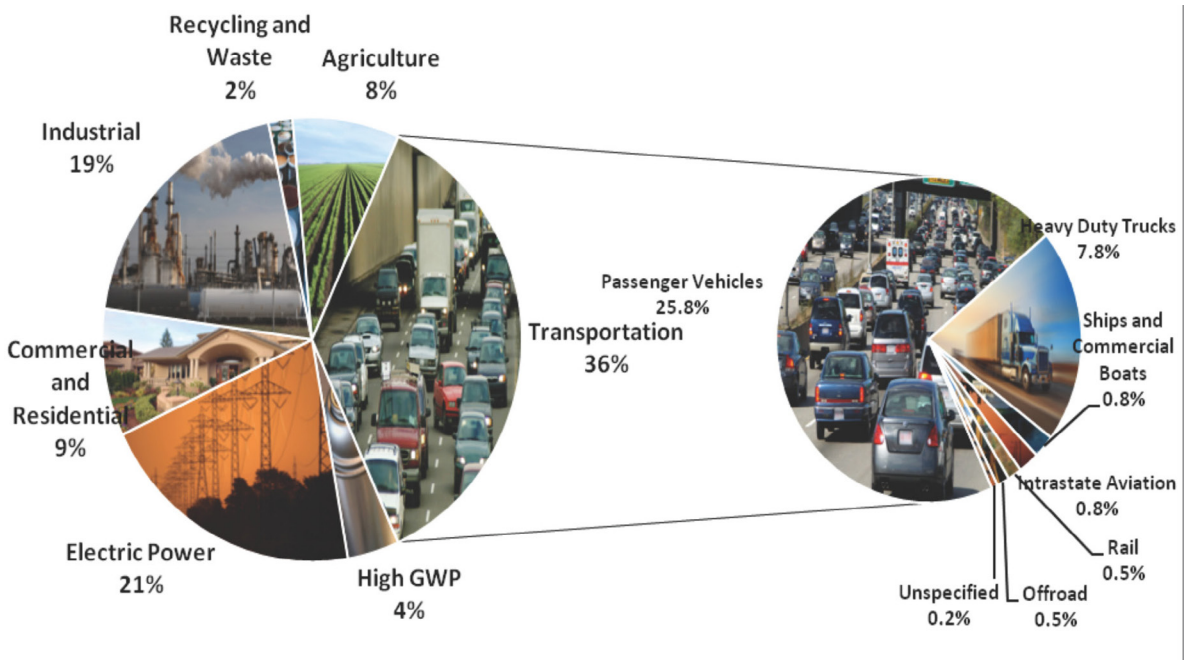
Recognizing that climate change threatens the state's economy and quality of life, California is a leader in addressing climate change. As shown in Figure 1, the transportation sector is the largest source of greenhouse gas emissions, accounting for about 36 percent of the state's greenhouse gas emissions,[8] nearly all of which

6 http://www.gov.ca.gov/news.php?id=17463.

7 Edmund G. Brown Jr. inaugural address, remarks as prepared, January 5, 2015.

8 California Air Resouces Board. (2014). California Greenhouse Gas Inventory for 2000-2012. Retrieved June 19, 2014, from http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_00-12_2014-03-24.pdf.

Figure 1: California Greenhouse Gas Inventory by Sector for 2012



Source: Energy Commission staff based on California Air Resources Board data available at http://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_00-12_2014-03-24.pdf

*Hydrofluorocarbons, perfluorocarbons, and sulfur hexafluoride are the main high global warming potential gases. They have global warming potentials thousands of times that of carbon dioxide meaning that each molecule of these gases traps thousands of times more heat than a molecule of CO_2. High global warming potential gases are emitted mostly during industrial and manufacturing processes.

is from on-road cars and trucks. Also, the transportation sector accounts for about 83 percent of statewide NO_x emissions, most of which are from on-road motor vehicles.[9] Governor Brown acknowledged the important role of transportation, stating, "In terms of greenhouse gases, our biggest challenge remains the amount of gasoline Californians use."[10] At the March 27, 2014, IEPR workshop, experts agreed that reducing emissions in the transportation sector is key to achieving economywide greenhouse gas reduction goals.[11]

Reducing greenhouse gases from the transportation sector is challenging due to consumer dependence on gasoline vehicles, a tendency to undervalue fuel economy when purchasing new vehicles, and the high abatement costs compared to reducing carbon in other sectors.[12] Use of transportation fuels also imposes social and economic costs due to energy security concerns and price shock impacts on the economy.[13]

9 California Air Resources Board. Almanac Emission Projection Data (published in 2013). Retrieved November 10, 2014, http://www.arb.ca.gov/ei/general.htm.

10 Governor Brown's 2014 State of the State Address, http://gov.ca.gov/news.php?id=18373.

11 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 108.

12 Dahl, C. A. (2012). "Measuring Global Gasoline and Diesel Price and Income Elasticities." *Energy Policy,* 41(Feb): 2–13; Greene, D. L., Evans, D. H., & Hiestand, J. (2013). "Survey Evidence on the Willingness of U.S. Consumers to Pay for Automotive Fuel Economy." *Energy Policy,* 61(Oct), 1539–1550; Nauclér, T., and P.-A.Enkvist, (2009). *Pathways to a Low-Carbon Economy: Version 2 of the Global Greenhouse Gas Abatement Cost Curve.* McKinsey & Company.

13 Dahl, C. A. (2012). "Measuring Global Gasoline and Diesel Price and Income Elasticities." *Energy Policy,* 41(0), 2–13.

Vulnerability of the Transportation System to Climate Change

Sea level rise and coastal flooding present the greatest potential threat to California's transportation network.[1] As of 2009, about 1,900 miles of roadways were at risk of flooding during a 100-year storm event. A 55-inch sea level rise would increase this figure to 3,500 miles of roadways and 280 miles of railways. Roadway flooding damages the physical infrastructure and leads to additional maintenance requirements.[2] Changes in land cover and habitat associated with sea level rise such as loss of coastal wetlands and barrier shorelines could also affect operation and maintenance of roadways and railways. Fuel infrastructure, which is critical to the transportation system, is also vulnerable to these extreme events.

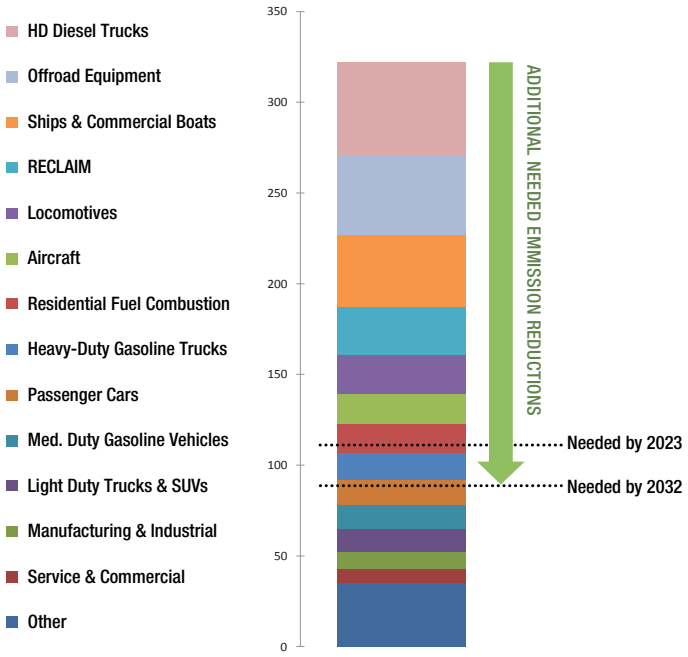
Flooding and sea level rise also impact ports. While deeper water allows for navigation by larger vessels, it also leaves less clearance under bridges. Though most bridges over shipping lanes are designed to accommodate large ships, the Golden Gate Bridge could block large vessels with sea level rise of four to five feet.[3] Changes in water levels and siltation from storm surge may also affect the need for port dredging and maintenance and necessitate changes in port infrastructure alignment.[4]

With both average temperatures and heat wave occurrences expected to increase, infrastructure is likely to face additional stress. High heat can cause pavement to buckle and soften and bridge joints to expand, requiring additional maintenance. Railroads can also buckle due to high heat. Vehicle fleets may also be impacted by heat waves causing more breakdowns. Heat waves are also likely to indirectly affect the transportation system through negative impacts on air quality and worker health. Air quality impacts could influence road siting, and traffic management and maintenance schedules could be affected by impacts on workers.[5] Some locations could benefit from temperature increases, however. For example, damage from snow and ice could be reduced.

The California Department of Transportation is leading state efforts to prepare for climate impacts to the transportation system and is implementing measures to prepare for climate change as well as improve the resilience of the transportation system as a whole.

(See Appendix A for references)

Figure 2: Nitrogen Oxides Emissions in 2023 With Adopted Standards in the South Coast Air Quality Management District



Source: Dr. Wallerstein's presentation at the March 27, 2014, IEPR Workshop *RECLAIM refers to the Regional Clean Air Incentives Market

Transportation-related emissions of smog-forming oxides of nitrogen, toxics, and fine particulate matter are associated with premature death and morbidity, as well as upper and lower respiratory symptoms, bronchitis, asthma, and cancer.[14] Also, there is a growing body of evidence that exposure to the pollution from traffic and major roadways is linked to public health impacts.[15]

California Air Resources Board (ARB) and South Coast Air Quality Management District data show that heavy-duty truck emissions are major contributors to air quality problems in California. Heavy-duty trucks account for only about 3.7 percent of California's total vehicle population, but they are the largest source of NO_x that contribute to ozone, accounting for about 30 percent, and the largest source of diesel particulate matter, about 40 percent statewide.[16] By 2023, mobile source emissions are expected to comprise about 80 percent of all air pollution in the South Coast Air Basin.[17]

Meeting current and expected air quality standards will require a dramatic change in the transportation system. In the South Coast Air Basin, current federal air quality standards require a two-thirds reduction in NO_x emissions over the next nine years, as shown in Figure 2. This is a reduction beyond all existing rules and regulations, including those not yet in effect. By 2032, to meet the Federal Ozone Standard currently in place, the South Coast Air Basin must reduce emissions by at least 75 percent. However, the U.S. Environmental Protection Agency is considering further tightening the ozone standard to 70 parts per billion, roughly equivalent to a 90 percent reduction in NO_x emissions by 2032.[18] Dr. Barry Wallerstein, executive director of the South Coast Air Quality Management District, suggested that although the 2050 greenhouse gas target seems ambitious, the state must speed up plans for meeting it, "Or we'll have no chance of meeting the federal ozone standards in South Coast, San Joaquin Valley, and, in all likelihood…the Sacramento Valley area as well."[19]

14 http://www.arb.ca.gov/research/health/fs/fs2/fs2.htm.

15 http://www.arb.ca.gov/research/health/traff-eff/traff-eff.htm.

16 California Air Resources Board. *California Almanac of Emissions and Air Quality – 2013 Edition*. http://www.arb.ca.gov/aqd/almanac/almanac13/almanac13.htm.

17 Dr. Barry Wallerstein, South Coast AQMD, March 27, 2014, Integrated Energy Policy Workshop, p. 122.

18 Dr. Barry Wallerstein, March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 123.

19 Dr. Barry Wallerstein, March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 124.

Vision for Transforming the Transportation System

Transforming California's transportation market to low-carbon, alternative fuels and advanced vehicle technologies is essential to achieving the state's greenhouse gas reduction goals, improving local air quality, and reducing dependence on petroleum fuel. The State reaffirmed its commitment to this undertaking with the passage of Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) (AB 8), extending the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) through January 1, 2024. AB 8 makes up to an additional $1 billion available for continued efforts in cleaning up the state's transportation sector, placing the state in a position to make progress in attaining clean air, public health, energy security, and climate change policy goals.

At the March 27, 2014, workshop, the Energy Commission invited key legislative members that were instrumental in the passage of AB 8 to share their visions for the implementation of the ARFVTP moving forward. Assemblymember Henry Perea (representing California Assembly District 31), Assemblymember Nancy Skinner (representing California Assembly District 15), and Senator Fran Pavley (representing California Senate District 27) attended, as well as Cliff Rechtschaffen, senior advisor to Governor Brown.

Participants discussed how California's efforts in transforming its transportation market have led to the state having the cleanest vehicles and fleets in the nation; however, it is important to recognize that there is a still a long way to go in achieving climate and air quality goals. It is imperative that the state's limited funds be used efficiently and effectively, providing the greatest environmental benefits to Californians. It was also noted by some that as funding decisions are being made, the State should look for short-term gains with an understanding of smart investments for the long-term.

During workshop discussions, the legislators identified key elements that would contribute to the success of the ARFVTP. For example, Assemblymember Perea recognized how a coalition of legislators, state agencies, and stakeholders came together to promote the passage of AB 8 and how such coordination should be continued throughout program implementation.[20]

Support Infrastructure Development to Increase Public Access and Target Areas of Greatest Need

Assemblymember Skinner identified the importance of continued support for alternative fuel infrastructure for the successful commercialization and deployment of alternative fuels. She also suggested targeting the vehicles that most contribute to smog. Senator Pavley noted the importance of focusing on the state's nonattainment areas, which often correspond with large transportation corridors, and how significant benefits can be gained from continued funding in the truck, freight, and goods movement sectors.[21] She emphasized win-win investments such as alternative fueled school buses that help improve local air quality and reduce greenhouse gas emissions, as well as provide fuel cost savings to schools. Senator Pavley also emphasized the importance of replacing gross polluting vehicles with cleaner gasoline or alternative fuel vehicles through programs implemented by ARB. Assemblymember Perea pointed out the need to increase access and help advance the market by developing fueling infrastructure in regions such as the Central Valley, which is not in attainment with air quality stan-

20 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 36.

21 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 42.

dards and has some of the highest pollution and asthma rates in the country, even if residents cannot yet afford the vehicles.[22] He stressed the importance of equity and investing in infrastructure. Senator Pavley stated, "I agree a hundred percent with Assemblymembers Skinner and Perea, we need to make more investment for all owners of vehicles."[23] Senator Mark DeSaulnier was unable to attend, but in a letter following the workshop wrote that AB 8 "…provides us with an opportunity to ensure that our progress toward a zero-emission vehicle fleet benefits all Californians, not just the more affluent among us."

Invest in a Portfolio of Strategies

At the workshop, there was also strong support for investing in a portfolio of strategies as the state transitions away from conventional fossil-based fuels. Dr. Joan Ogden, Professor of Environmental Science and Policy at the University of California, Davis, and Director of the Sustainability Transportation Energy Pathways Program at the Institute of Transportation Studies, spoke on the importance of a portfolio approach to achieve the interlinked air quality, greenhouse gas, and energy security goals. There are a variety of options for addressing transportation energy challenges, such as more widespread use of low-carbon alternative fuels and vehicle technologies, increased vehicle efficiency, and reduced number of vehicle miles traveled. Studies suggest that a sustainable transportation system will consist of a variety of highly efficient vehicle technologies that will use a variety of low-carbon fuels.[24] When looking to California's transportation future, different fuels and technology types will suit different needs for transportation applications, and for that reason the ARFVTP will continue to support a diverse mix of fuels, associated infrastructure, and vehicle technologies.

"… A portfolio approach will give us the best chance of meeting stringent goals for a sustainable transportation future. Given the uncertainties and the long timelines, it is critical to nurture a portfolio of key technologies toward commercialization. All our work in characterizing pathways and comparing them flows toward this conclusion."

Sustainable Transportation Energy Pathways, a Research Summary for Decision Makers, University of California at Davis, Institute of Transportation Studies, 2011

Incentives are Needed

In combination with regulatory and policy support, incentives will play a key role in supporting and encouraging the use of the alternative fuels and vehicle technologies necessary for transforming California's transportation market. It is important to continue to think of ways to best use state funds to improve affordable access to clean fuels and technologies to consumers, particularly those who are middle to low income, live in areas most challenged with poor air quality, or in regions that are economically depressed. Improving access can include addressing financing gaps by making incentives available that reduce upfront investment costs or by providing incentives that make alternative fuels and vehicles more

22 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 47.

23 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 50.

24 Ogden, Joan. "A Portfolio Approach toward Sustainable Transportation." Presented at the March 27, 2014, Integrated Energy Policy Report workshop. Available at http://energy.ca.gov/2014_energypolicy/documents/2014-03-27_workshop/presentations/05_Joan_Ogden_IEPR_2014-03-27.pdf.

appealing to consumers. These include, but are not limited to, high-occupancy vehicle stickers, parking benefits, or insurance discounts.

Leverage Limited Funds to Maximize Effectiveness

An additional benefit to the incentives being provided under the ARFVTP is that state funding can be leveraged with federal, local, and private investment, bringing key partners to the table and attracting new businesses and jobs to the state.[25] Moreover, throughout implementation of the ARFVTP, the Energy Commission will continue working to increase outreach to and encourage the participation of minority-, women-, and disabled veteran-owned businesses, helping ensure equity in how funds are distributed. To this end, in fall of 2014, the Energy Commission hosted a series of workshops across the state in Oakland, Los Angeles, San Bernardino, Fresno (with live video feeds in Modesto and Bakersfield), and Sacramento.

Act Now—Transformation Requires Investment, Time, and Adaptive Learning

Dr. Ogden also said the institute's studies show that achieving the deep cuts in greenhouse gas emissions and meeting growing needs for mobility can be achieved cost-effectively with benefits exceeding costs.[26] She noted that initially costs will exceed benefits, however, and that the transition will take time. Action is needed now, and success will require public/private partnerships and "adaptive learning."[27]

25 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 60.

26 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 112.

27 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 115.

Programs Like ARFVTP Can Help Transportation Energy Use

Although significant changes are needed in the state's portfolio of transportation fuels and vehicles to meet greenhouse gas reduction, air quality, and energy security goals, it is important that California's commitment to transforming the transportation sector remain strong. Mr. Rechtschaffen from the Governor's Office said, "[The ARFVTP] continues to provide breakthroughs in support technologies that are critical for our long-term clean energy and climate goals. And we look forward to ten more years of this program working."[28] Making incentives available for a portfolio of alternative low-carbon fuels and advanced technologies, leveraging state dollars where possible, and bringing key partners to the table, the ARFVTP remains crucial in accelerating the transformation of the state's transportation sector between now and January 2024, and beyond.

The ARFVTP Plays an Important Role

The Energy Commission is charged with implementing the ARFVTP, which was created to "[d]evelop and deploy innovative technologies that transform California's fuel and vehicle types to help attain the state's climate change policies."[29] The program is funded with up to $100 million annually. The ARFVTP was created in 2007 under Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) (AB 118), amended by AB 109 the following year (Núñez, Chapter 313, Statutes of 2008), and reauthorized in 2013 by AB 8. The reauthorization extended program funding from 2016 to 2024. This continuity provides market

28 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 77.

29 Health and Safety Code Section 44272(a).

certainty and investment consistency that is needed to advance the market as several speakers noted at the March 27, 2014, workshop.

The Energy Commission has invested in a portfolio of projects that have the potential to be transformative, consistent with direction in AB 8 to support advancements "without adopting any one preferred fuel or technology."[30] A map available on the Energy Commission's website[31] shows where the projects are located across the state. The key achievements from ARFVTP investments since program inception through December 2014 are described below.

Deploying Electric Vehicle Charging Infrastructure and Supporting Incentives

The ARFVTP has helped deploy electric vehicle charging infrastructure to support current drivers of electric vehicles. The program has funded more than 9,300 charge points in residential, workplace, and public access locations, including 107 DC fast chargers in urban areas and along intercity corridors. This initial network of electric chargers complements investments from the air districts[32] and NRG[33] via its settlement agreement with the California Public Utilities Commission.

With $4.3 million in seed funding, the Energy Commission is enabling 21 regional government coalitions to create regional readiness plans that assess local needs for charging infrastructure and develop a regionally focused plan that meets the needs of local communities. This is discussed further in Chapter 3. Moreover, The Energy Commission awarded four planning grants to develop plans for multiple alternative fuels and one to focus on hydrogen in an early deployment area for fuel cell electric vehicles.

To date, about $49.6 million in ARFVTP funds have been transferred to ARB's Clean Vehicle Rebate Project to fund incentives for about 21,000 battery-electric vehicles and plug-in hybrid electric vehicles.

Building a Foundation for Hydrogen Fueling Stations

The Energy Commission is funding 48 new and upgraded hydrogen fueling stations in California, making California a global leader in developing and building a hydrogen fueling station network. Similar to the approach for electric charging, the strategy is to front-load hydrogen station development and make California a "center of gravity" that will attract the initial deployments of fuel cell vehicles from major auto manufacturers. By mid 2016, a network of 51 to 54 stations is scheduled to be operational, which will support the initial 6,600 vehicles projected for sale in California in the 2015-2017 time frame.[34]

The Energy Commission has also worked with the California Department of Food and Agriculture, Division of Weights and Measures to ensure accuracy in hydrogen fuel dispensing. This effort ensures that when a consumer buys one kilogram of hydrogen fuel, the consumer receives one kilogram of hydrogen fuel.

Advancing Low-Carbon Biofuels

The Energy Commission's ARFVTP is also helping advance low-carbon biofuels through more than $131 million in investments. The program has funded 44 projects to expand the production of low-carbon biofuels, 35 of which use primarily waste-based feedstocks.

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30 Health and Safety Code Section 44272(a).

31 http://www.energy.ca.gov/drive/projects/map/index.html.

32 The Bay Area AQMD is investing $14.2 million for electric charger installation and PEV support over the 2014 and 2015 fiscal years, Damien Breen, presentation at April 23, 2014, Integrated Energy Policy Report workshop. The South Coast AQMD is investing $8.7 million for electric charger installations in fiscal years 2013 and 2014.

33 NRG will install 200 DC Fast Chargers throughout California and 10,000 level 2"make-ready stubbies," which can be used by charger companies for future charger installations.

34 http://www.arb.ca.gov/msprog/zevprog/ab8/ab8_report_final_june2014.pdf.

Case Studies on Climate Vulnerability

The third *California Climate Assessment*, released in 2012, included a study on the vulnerability of transportation in the Bay Area. During a 100-year storm under current conditions, travel times between transportation nodes increase somewhat, with one location, San Rafael, becoming inaccessible. As sea level rises, the impact of the 100-year storm on the transportation system becomes more severe, with much of the North Bay and the areas around San Francisco International Airport inaccessible and very long travel times across the bay.[1] Modeling results showed that access into the interior North Bay is devastated by inundation and that access to the major transportation road system is impacted in areas such as north San Mateo County.

The assessment also included a case study about the vulnerability of parts of the Port of Los Angeles.[3] It examined the cost-effectiveness of incorporating investments to address sea level rise during capital upgrades that occur about every 20-30 years. In this case, incorporating sea level rise investments during the next capital upgrade appeared cost-justified in just one of the four facilities examined at the port. This is an example of how to incorporate climate change considerations into normal planning.

An ongoing Energy Commission study is investigating the impact of sea level rise on natural gas infrastructure in the Bay Area and Delta regions. The study is using a sophisticated three-dimensional hydrological model that accounts for wave action to simulate flooding associated with sea level rise and a near 100-year storm. Initial results indicate that 275 miles of natural gas pipelines in 498 segments are at risk of inundation with 1.4 meters (or 4.6 feet) of sea level rise. While these results are preliminary and further work is needed to explore the impact of inundation on these pipelines, vulnerabilities have been identified in both the San Francisco Bay and Sacramento-San Joaquin Delta regions. With potential growth in natural gas as a transportation fuel, these vulnerabilities have the potential to impact the transportation system. Furthermore, there are many other pipelines in the region that carry liquid fuels that face similar vulnerabilities.[4]

(See Appendix A for references)

An example is Buster Biofuels' commercial project in San Diego that received more than $2.6 million to install and operate a commercial-scale biodiesel facility. It will divert nearly 5.65 million gallons per year of used cooking oil and locally produce 5 million gallons of biodiesel transportation fuel per year. The project is expected to increase the cost-efficiency associated with the production, distribution, and use of biodiesel in the San Diego regional market. This project is estimated to produce 60 to 62 full-time jobs.

ARFVTP investments have helped spur rapid market growth and market acceptance of biofuels. Biodiesel consumption in California grew from 5 million gallons in 2010 to 48 million gallons in 2013. The market growth of renewable diesel has been even more rapid, growing from fewer than 2 million gallons in 2010 to 135 million gallons in 2013.

Accelerating Fleet Turnover with Natural Gas Vehicle Incentives and Infrastructure

The ARFVTP is also providing natural gas vehicle and infrastructure incentives to help accelerate fleet turnover and displace polluting diesel-fueled trucks. The program has invested $16.3 million to fund 60 natural gas and renewable natural gas fueling stations and more than $55 million for vehicle incentives for about 2,700 trucks and 1,600 light-duty vehicles. Much of the funding is targeted to help school districts transition to cleaner, natural gas buses.

An example is the Bear Valley Unified School District (San Bernardino County), which received a $300,000 award to install a compressed natural gas fueling station. The infrastructure will be used to fuel the district's existing natural gas-fueled school buses and to allow the district to acquire additional natural gas-fueled buses. Currently, refueling the district's compressed natural gas (CNG) buses involves a 68-mile roundtrip drive. By being able to fuel at its own fueling station, the district will save money on both travel time to refuel and the cost of fuel. Buses can be fueled overnight for use the next day. The proposed system also has a fast-fill option that could be used for midday refills or by buses from other school districts traveling into the valley.

Incubating Innovation in Medium- and Heavy-Duty Advanced Technology Vehicles

The ARFVTP is also incubating innovation in medium- and heavy-duty advanced technology vehicles. These technologies are being demonstrated through 31 projects totaling $58.7 million that include advanced natural gas engines, electric, hybrid-electric, and fuel cell vehicles.

Motiv Power Systems of Foster City is an example of technological innovation from the Silicon Valley. Motiv won an initial ARFVTP grant in 2009 to further develop its battery control systems for electric drive shuttles, which resulted in an initial fleet of Class 4 electric drive shuttles that were used at Google, Cisco, Facebook, and Stanford University. Motiv has continued to develop its battery and drivetrain control systems and has expanded its vehicle line to include electric drive school buses that are used in California, electric drive package delivery vans that will be used by United Parcel Service (UPS) and the U.S. Postal Service, and Class 8 electric refuse haulers that are used in Chicago, Illinois.

California is working to reduce carbon and criteria emissions from the goods movement and freight sectors, especially near California's ports. Through the ARFVTP, the Energy Commission is funding five demonstration truck projects that will use zero- or near-zero-emission technologies in heavy-duty Class 8 tractors. These include all-electric-drive trucks from TransPower and Artisan, a plug-in electric drive truck from Volvo with 10-mile electric drive range, and an electric drive truck demonstration with Siemens, Volvo, and TransPower that can operate in electric mode with power from overhead catenary lines. While just in the demonstration phases, zero-emission truck technologies such as these will be essential in reducing carbon and criteria emissions from freight transport corridors at California ports.

Supporting Manufacturing in California

The ARFVTP has funded 18 manufacturing projects totaling $47 million, most of which have been related to electric drive-related batteries. Manufacturing and technology development grants have enabled companies like Electric Vehicles International (EVI), Motiv, TransPower, and Wrightspeed to build electric truck manufacturing plants in California. EVI deployed 100 ZEV trucks with UPS, the nation's largest deployment of electric trucks. TransPower used a series of ARFVTP grants to design and construct a series of Class 8 electric drive tractors for use in the Ports of Los Angeles and Long Beach. Wrightspeed has leveraged two ARFVTP manufacturing grants to develop a range-extended electric drivetrain that can be used to retrofit medium- and heavy-duty trucks from diesel to electric drive. They recently announced plans to relocate and expand their production facility to an old hanger building at the former Alameda Naval Air Station and anticipate scaling up their workforce from 25 to over 250 employees.[35]

Advancing Workforce Training and Development

The program also aligns clean technology investments with economic development. The program has invested about $25 million to help provide training for more than 13,600 individuals, 600 businesses, and 14 municipalities to support all aspects of alternative fuel technologies. The program has also provided funding to community colleges in Northern, Central, and Southern California for curriculum development, train-the-trainer programs, essential equipment needs, and other approved activities to support alternative fuel and advanced vehicle technology training and education. California community colleges continue to lead in the training of alternative fuels and advanced vehicle technologies in California by focusing on employer needs within each community and having those employers support new and existing training programs. Funding to the Employment Training Panel delivers training across multiple fuel and technology types and requires employers to commit matching funds, along with proving retention of trained employees on the 91st day after completion of their training.

Continually Evaluating Technology Trends and Market Needs

The program remains flexible by working closely with the public and various stakeholders to understand the needs of Californians. For example, the annual investment plan of up to $100 million is developed through a series of public meetings, with the input and expert advice of a stakeholder advisory committee representing a diverse range of interests – including environmental organizations, academic institutions, state agencies, fuel and technology organizations, and other nongovernmental organizations. Throughout the process, stakeholders have multiple opportunities to comment at public meetings or in writing.

Once funding allocations are determined and the investment plan is adopted, program staff works closely with stakeholders and industry to design solicitations to help ensure program funding is targeted as effectively as possible to advance California's transportation goals. Thereafter, staff holds preapplication workshops to engage a broad set of potential applicants to explain the grant process, proposal requirements, scoring criteria, and tips on developing successful proposals. In these ways, the program is constantly engaging the public as it strives to help transform California's transportation system.

While the annual investment plan lays out a framework for funding, it also builds in flexibility that allows the program to respond to market developments. For example, the Energy Commission positions itself to take advantage of emerging opportunities by reserving funding to cofund the state match portion of projects receiving federal awards. Funding can also be used for projects using technologies that do not readily fit current investment plan categories.

35 "Green Company Wrightspeed Moving from San Jose to Alameda" San Jose Mercury News, January 21, 2015.

California Leads the Way

A theme identified throughout the March 27, 2014, workshop was that although transforming California's transportation market is a huge undertaking, policies and programs like the ARFVTP make California a leader in clean fuel innovations. As such, California is a testing ground for innovating, developing, and demonstrating cutting-edge transportation technologies and supporting them on the path to commercial deployment. At the March 27, 2014, workshop, Dr. Alan Lloyd, the president emeritus of the International Council on Clean Transportation, described California's leadership in developing air quality and greenhouse gas emission reduction standards. He noted that the air quality standards are based on public health impacts and are not adjusted to reflect the capability of existing technology. Instead, the standards have successfully forced technology innovation that can meet air quality standards.[36] Continued innovation and breakthroughs are needed to meet the state's goals.

The drive for cleaner transportation technologies requires significant and smart investments, making it important to leverage efforts and lessons learned with other states and countries. California has been able to leverage the work done on electric vehicles with other states and recently signed a memorandum of understanding with seven other states identifying actions to be taken by each state and to cooperatively expand consumer awareness and demand for zero-emission vehicles. Moreover, Governor Brown has signed agreements with the National Development and Reform Commission of the People's Republic of China, and California is the first subnational government to sign agreements with China on climate change, air pollution, and clean energy that include a call for cooperation in increasing electrified transportation and

"Taking significant amounts of carbon out of our economy without harming its vibrancy is exactly the sort of challenge at which California excels. This is exciting, it is bold, and it is absolutely necessary if we are to have any chance of stopping potentially catastrophic changes to our climate system."

Governor Edmund G. Brown's inaugural address, remarks as prepared, January 5, 2015.

36 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 141.

expanding clean energy markets.[37] Dr. Lloyd suggested that meeting climate goals requires a revolution in the transportation sector, and that the world "…badly needs California's continued leadership."[38]

Recommendations

Transportation plays a critical role in meeting climate, clean air, and energy goals. California is a leader in this area. To stay on the path of transforming the state's transportation system, the Energy Commission recommends the following:

» **Continue to invest in a broad portfolio of projects.** A broad portfolio of technologies and innovative implementation tools are needed to transform California's transportation sector. The Energy Commission should also keep long-term goals in the forefront when making investments.

» **Make equitable investments.** When making public investments, the Energy Commission should ensure that the benefits accrue broadly throughout the state. Also, the Energy Commission should investigate and initiate strategies to target Alternative and Renewable Fuel and Vehicle Technology Program funding into areas with the highest need, such as disadvantaged communities and nonattainment air basins. The program should also seek opportunities to achieve multiple benefits when making investments.

» **Continue to coordinate with the California Air Resources Board on incentive investment strategies.** The Energy Commission and California Air Resources Board should continue to coordinate public investments in programs targeted to reduce greenhouse gas emissions and programs targeted to reduce criteria and particulate matter emissions to maximize the benefits of each.

» **Collaborate to leverage opportunities.** The Energy Commission should work in collaboration with the Legislature; other state, local, and federal agencies; and others. Leveraging efforts will help maximize the effectiveness of investments.

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37 Cliff Rechtschaffen presentation at the March 27, 2014, Integrated Energy Policy Report workshop, http://energy.ca.gov/2014_energypolicy/documents/2014-03-27_workshop/presentations/02_Cliff_Rechtschaffen_2014-03-27_IEPR_Workshop.pdf.

38 March 27, 2014, Integrated Energy Policy Report workshop transcript, p. 149.

CHAPTER 2:
Opportunities to Leverage Funding Needed to Transform Transportation Energy Use

Chapter 1 explained why transformation of California's transportation system is necessary and important to achieve greenhouse gas emission reduction goals, air quality standards, and energy security goals. Incentives can help speed the transition away from older, higher-polluting vehicles and carbon-intense fuels toward newer, less polluting vehicles and fuels.

This chapter reviews the mechanisms the Energy Commission uses to fund transportation innovations from initial research to commercialization and explores opportunities to leverage funds. First is a discussion of the funding sources available and the need for incentives. Next is a discussion of funding mechanisms used in the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP), the nexus between the ARFVTP and the Energy Commission's research and development efforts, and emerging options to maximize the effectiveness of program funds. Finally, there is a discussion of opportunities to partner with other organizations to further leverage ARFVTP funds and recommendations for further work.

Funding Sources Available to Help Advance Transformation of California's Transportation Energy Use

California is fortunate to have several programs designed to provide incentives and accelerate the transition to a cleaner transportation future. Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) (AB 8) authorizes more than $2 billion for clean fuel and programs including the ARFVTP, the Air Quality Improvement Program incentives for alternative fuel vehicles, the Enhanced Modernization Fleet Program for incentives to retire eligible older vehicles,[39] and the Carl Moyer and Assembly Bill 923

39 http://www.arb.ca.gov/msprog/aqip/efmp/efmp.htm.

(Firebaugh, Chapter 707, Statutes of 2004) local air district funds for diesel emission reduction program.[40] More than $800 million from the California Air Resources Board's (ARB) Cap-and-Trade program is being used in the 2014-2015 fiscal year to advance the greenhouse gas reduction goals of Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) (AB 32).[41] The Energy Commission's Electric Program Investment Charge (EPIC) provides about $162 million annually from 2012-2020 primarily to address policy and funding gaps related to the development, deployment, and commercialization of improvements to the state's electricity system, with about $1.3 million annually for transportation projects.[42,43] The Energy Commission's Natural Gas Research, Development and Demonstration program[44] invests in improvements to California's natural gas systems, including about $4 million invested annually for focused transportation applications.

Incentives Are Needed

At the Energy Commission's April 23, 2014, Integrated Energy Policy Report (IEPR) workshop, Dr. David Greene (a senior fellow at the Howard H. Baker, Jr. Center for Public Policy, University of Tennessee, and a research professor in the Department of Civil and Environmental Engineering) noted that the transition to a low-carbon future will require substantial government investment in a portfolio of technologies and policies.[45] Dr. Greene spoke about studies by the National Research Council, the *Transitions to Alternative Vehicles and Fuels* report, and studies conducted at the Baker Center for Public Policy, which show that the costs to invest in a low-carbon transportation system will initially exceed benefits for a period of about 10 years but that total long-term benefits are expected to far exceed costs. He said that transformation "… is a difficult problem in which you have to proceed with policies even though the benefit is yet to come in the future."[46] The Baker Center's Safe Transition Study examined scenarios for technology and policy options and for a 50 percent reduction in petroleum consumption by 2030 and an 80 percent reduction in petroleum consumption and greenhouse gas emissions by 2050.[47]

The economic theory supporting the use of incentive programs such as the ARFVTP is that public policy goals can be achieved more rapidly when government capital is introduced and made available to technology development enterprises.[48,49] This infusion of government capital can accelerate the transition of technologies because government assumes the risk for investments that private capital markets are not ready to assume. Moreover, the timing of government-funded incentives is important. Because of positive feedback

40 http://www.arb.ca.gov/msprog/moyer/moyer.htm.

41 http://www.arb.ca.gov/cc/capandtrade/auctionproceeds/auctionproceeds.htm.

42 http://www.energy.ca.gov/research/epic/.

43 EPIC funds are limited to projects that provide benefits to ratepayers in the Southern California Edison, Pacific Gas and Electric, and San Diego Gas & Electric service territories.

44 http://www.energy.ca.gov/research/.

45 April 23, 2014, Integrated Energy Policy Report workshop transcript, p. 21-28.

46 April 23, 2014, Integrated Energy Policy Report workshop transcript, p. 29.

47 April 23, 2014, Integrated Energy Policy Report workshop transcript, p. 27-28.

48 Dr. David Greene, Baker Center for Public Policy, University of Tennessee, presentation at the April 23, 2014, Integrated Energy Policy Report workshop.

49 Melaina, Marc. National Renewable Energy Laboratory, *Program Benefits Guidance Report: Analysis of Benefits Associated With Projects and Technologies Supported by the Alternative and Renewable Fuel and Vehicle Technology Report,* Energy Commission Contractor Report No. CEC-600-2014-005D, June 2014.

Figure 3: Alternative Vehicle Technology Commercialization Phases

Source: Energy Commission Staff

effects, the earlier the investments are made, the bigger the net benefits over time.[50]

The Type of Incentives Needed Varies by Commercialization Phase

A funding gap between basic research and commercialization can cause a project to fail. Figure 3 illustrates the phases of alternative vehicle commercialization from the initial research phase to commercial launch and deployment. Government incentive or subsidy grants are most needed during the *research* and *initial demonstration* phases because private venture capital is often unavailable. As the technology matures and initial field trials have been completed, different forms of government subsidies may become more appropriate to fill funding gaps, such as loans, loan support, or consumer or commercial voucher rebates.

Leveraged Funds go Further

Through the EPIC, the Natural Gas Research, Development and Demonstration program, and the ARFVTP, the Energy Commission dedicates about $105 million annually in support of each of the alternative vehicle and fuel commercialization phases. This level of funding alone is not enough to support the needed transformation of California's transportation sector. Consequently, the Energy Commission is exploring opportunities to better leverage the funds available to make ARFVTP dollars go further.

50 April 23, 2014, Integrated Energy Policy Report workshop transcript, p. 27-28.

Current and Potential ARFVTP Funding Mechanisms

Since the passage of Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) (AB 118) in 2007, the Energy Commission has prepared six ARFVTP investment plans that guide allocation of $650 million in incentive funding across a portfolio of alternative fuel and vehicle technology areas.

As of December 2014, the Energy Commission has committed $532 million to more than 460 projects, while the remaining allocated funds are planned for future funding solicitations. Funding this large portfolio of projects was the result of the Energy Commission issuing nearly two dozen solicitations and reviewing more than 600 technical proposals from entities seeking ARFVTP funding. The demand for this funding nearly always exceeds the available amount, and the Energy Commission is able to award only $1 for each $1.80 in qualified funding requests. This means that 45 percent of the qualified advanced technology transportation projects submitted to the Energy Commission are not funded.

Nexus Between Research and Development and the ARFVTP

The Energy Commission strategically supports advancements in transportation technologies and fuels throughout the development process, from basic research and development (R&D) to commercialization. Many of the Energy Commission's transportation R&D efforts develop technologies and strategies that help lower the cost or add functionality to transportation electrification. The Commission's near- and midterm transportation R&D efforts focus on optimization of natural gas vehicles, with engines sized appropriately for the duty cycle or service that the vehicle provides. Below are examples of projects that have received support from the Energy Commission's R&D program and have gone on to successfully participate in the ARFVTP.

Electric Vehicle Charger Placement. The Energy Commission's R&D program supported modeling and analysis work with the UC Davis Plug-In Hybrid Electric Vehicle Center to make recommendations on optimal placement of electric vehicle chargers. The modeling and analysis results will be used to develop the DC fast charging analysis that complements the *Statewide Plug-In Electric Vehicle Infrastructure Assessment* (please see Chapter 3 for more information about the *Statewide Plug-In Electric Vehicle Infrastructure Assessment*).

Development and Commercialization of Heavy-Duty Natural Gas Engines. With the support from the Energy Commission's R&D and ARFVTP funding, Cummins Westport Innovations developed and then commercialized the 12 liter ISX G natural gas engine for heavy-duty vehicles. Energy Commission funding supported the alpha and beta engine development and on-road demonstrations in California. The engine became available for commercial sale in 2014 with an estimated 4,000 engines sold to date.

Converting Waste to Renewable Natural Gas. Energy Commission R&D supported development and early demonstration of an anaerobic digester system for low-carbon biogas production from organic waste feedstocks. Later, the ARFVTP supported a demonstration with Clean World Partners to convert 100 tons per day of food waste to 566,000 diesel gallon equivalent of renewable natural gas and 3.17 million kilowatt hours of electricity annually.

The ARFVTP has Primarily Distributed Funding Through Grants

To date, the vast majority of ARFVTP funds have been allocated on a competitive grant basis, seeking the most qualified technology development and demonstration projects. The Energy Commission has distributed about $88.6 million to local, state, and federal agencies via 22 interagency or exempt agreements, which are quicker to develop, approve, and execute relative to a competitive grant award. For example, South Coast Air Quality Management District (AQMD) received a $6.7 million transfer to fund the upgrade and retrofit of three to five hydrogen fueling stations in Southern California. The Energy Commission is negotiating with UC Irvine to develop a pilot program to distribute natural gas truck vouchers in California and is evaluating the potential benefits of using block grants.

Alternative Funding Mechanisms Can Attract Private Capital for Projects Near Commercialization

Alternative financing options can leverage limited state capital funds in new ways and may prove effective at attracting private investment capital for technologies that are more commercially mature. Electric vehicle charging stations are an example of a market segment that appears ready for alternative finance mechanisms since multiple vendors offer competing products and consumer demand is growing. Another example of a market sector possibly ready for alternative financing options is the rapidly expanding biodiesel industry in California as multiple companies begin to use local waste-based feedstocks of oil and grease for biodiesel and renewable diesel production. As of December 2014 the ARFVTP biodiesel portfolio includes 17 projects totaling $53.3 million in grant awards, with six projects being commercial-scale biodiesel refineries.

Options in Alternative Funding

AB 118 provides the Energy Commission with the option to use "competitive grants, revolving loans, loan guarantees, loans, or other appropriate funding measures"[51] when disbursing funds for advanced technology, low-carbon transportation projects. The Energy Commission continues to explore the best opportunities for leveraging program funds. The April 23, 2014, IEPR workshop gathered a variety of experts, including industry representatives, public and private financing entities, government agencies, and academia, to discuss financing strategies and techniques that the ARFVTP can use to best leverage limited state funds. Some of the financial mechanisms highlighted at the workshop are outlined below.

Matching fleets with fueling is a way to ensure adequate fuel demand to support the installation of a fueling station. For example, hydrogen purchase agreements are modeled after solar power purchase agreements, where developers arrange for the installation of a solar energy system at little to no cost in exchange for an agreement with the developer to purchase the solar energy produced. In the instance of a hydrogen purchase agreement, organizations with fleets agree to adjust the size of their hydrogen fleet orders to match the output of a station, while hydrogen generation companies agree to put in a hydrogen fueling station with private capital if a hydrogen purchase agreement is in place. Charles Myers, president of the Massachusetts Hydrogen Coalition, spoke at the workshop about how his organization is developing a program that he expects will result in three to five fuel cell electric vehicle fleets and hydrogen fueling stations up and running by the end of 2015.[52] He also stressed that its goal will be to build to a critical mass of stations using this model, with an eventual transition to having stations entirely supported by retail (rather than fleet) business.

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51 California Health and Safety Code 44272(a).

52 April 23, 2014, Integrated Energy Policy Report workshop transcript, http://www.energy.ca.gov/2014_energypolicy/documents/2014-04-23_workshop/2014-04-23_transcript.pdf, p. 57.

Public/Private partnerships were also discussed at the April 23, 2014, workshop. John Rhow, senior portfolio advisor at Kleiner Perkins, explained that such partnerships are "an alignment of what the policy objectives are of the government or entity, and identification of where the market is and what gaps there are in the market, and where the public government can serve to fill these gaps."[53] He pointed out that the purpose of a public/private partnership is to reach a sustainable model that does not rely upon government subsidies to continue long-term. While it is important for government to get private investment up and running, a well-run partnership will create the proper market behavior and incentives to ensure capital is being used appropriately. He suggested AB 118 funds could be used as a loan instead of grants. "…[This] not only leverages your dollars, but frankly creates a return, … because if the cars show up, then by definition the utilization goes up, your cash flow goes up, the returns go up on behalf of the state, and that money can… be redeployed… so now you have a revolving loan program."[54]

Property Assessed Clean Energy (or PACE) programs allow cities and counties to run programs that allow homeowners and business owners to finance renewable energy projects, energy efficiency improvements, or water efficiency projects on their properties and repay it through their property tax bill. Cisco DeVries, president and chief executive officer of Renewable Funding, spoke about PACE programs at the workshop, explaining that it is a public/private partnership where "… the state has enabled a security mechanism, in this case the property tax, to be used as a tool for repayment. And that certainly enhances and provides additional credit for private investors to bring in money."[55] He noted that PACE could be used to finance the cost of charging stations and other fueling systems on privately held commercial properties, which could present an opportunity for the Energy Commission to reduce costs or provide an easier process for commercial property owners. Rather than trying to capture people's attention when they are not in the market to make property improvements, he suggested PACE programs could be marketed to commercial property owners as part of a bundle during existing property or tenant improvements.

Loan loss reserve programs provide financial assistance in the form of a loan loss reserve[56] to financial institutions that typically provide loans to finance distributed generation renewable energy projects or energy efficiency improvements on residential or commercial properties. One such example was the result of Assembly Bill X1 14 (Skinner, Chapter 9, Statutes of 2011), which authorized the California Alternative Energy and Advanced Transportation Financing Authority (CAEATFA) to administer a loan loss reserve program to facilitate the financing of energy efficiency retrofits on California residential properties. Participating financial institutions receive an initial 15 percent reserve contribution for each qualified loan, while CAEATFA may provide up to 100 percent coverage on qualified loan defaults. Renee Webster-Hawkins, executive director of the California Pollution Control Financing Authority, spoke at the workshop about the success of her organization's CalCAP program, a loan loss reserve program targeted to small businesses in California. She noted that in the previous year nearly half of CAEATFA's loans were microloans, loans less than $40,000. She suggested that microloans could be a well-suited and easy-to-administer tool to promote the installation of charging stations by small businesses or other hosts.[57] The Energy Commission is in discussions with CAEATFA considering a pilot loan loss reserve program to install electric vehicle supply equipment throughout California.

53 Ibid., p. 98.

54 Ibid., pp. 101-102.

55 Ibid., p. 68.

56 Loan loss reserves are accounting entries banks make to cover estimated losses on loans due to defaults and nonpayment.

57 April 23, 2014 Integrated Energy Policy Report workshop transcript, p. 82.

Opportunities to Leverage ARFVTP Funding With Other Government Funding Programs

The Energy Commission has coordinated closely with federal, fellow state, and regional agencies' incentive funding programs since the ARFVTP was established in 2007, including ARB and the South Coast AQMD. This coordination has enabled several agencies to pool funds and sponsor innovative advanced technology demonstration projects at much larger scales than would have been possible by a single agency. Such close coordination also ensures that programs complement each other and are not duplicative. New leveraging opportunities are emerging with federal agencies such as the U.S. Environmental Protection Agency (U.S. EPA) and the U.S. Department of Energy (DOE), and with other air districts in California, especially the Bay Area and San Joaquin AQMDs.

At the April 23, 2014, IEPR workshop, representatives from federal agencies and local air quality management districts all cited similar overall goals. In general, programs were designed to work toward improving air quality and advancing cleaner transportation technologies. Though programs shared general overarching themes, each had a different focus. Sunita Satyapal, Director of the Fuel Cell Technologies Office with DOE, noted that her office's program focused primarily on research and development, with an emphasis on hydrogen, "Our mission is really to enable widespread commercialization of hydrogen and fuel cell technologies."[58] Penny McDaniel with the U.S. EPA said the EPA did a lot of work on low- and zero-emission medium- and heavy-duty vehicle technologies. Her office's focus on air quality improvement means much of its effort is geared toward the South Coast and San Joaquin Valley air basins. "Relative to the rest of the country, those two air basins affect a very… large percentage of the national population to unhealthful air quality. …The more that we can demonstrate here in California in these air basins, the more those can flood out into the rest of the country, too, because as we know, California serves as a great incubator for the rest of the nation when it comes to clean technologies."[59]

Representing local agencies, Damian Breen with the Bay Area AQMD said that to reach its overall goal of improving public health and air quality, his organization sees advanced technology for transportation and alternative fuels as "one of the principal methods that we can use to tackle mobile sources of air pollution."[60] He shared several examples where his organization had leveraged state or federal money for various projects, noting that "as we look at our sources of local funding, we're always driving at two goals, one…is to leverage other sources of funding, and then our ultimate goal is to reduce emissions."[61]

Two Examples of Leveraging Funding to Achieve Mutual Transportation Goals

The 100-electric-truck deployment project in California by Electric Vehicles International (EVI) and United Parcel Service (UPS) exemplifies how a technology demonstration project can be amplified in terms of number of vehicles and geographic scale when incentive funding from regional, state, and federal agencies is pooled and coordinated. Incentive funds from U.S. EPA's Diesel Emission Reduction Act were combined with regional Technology Advancement Program funds from the Sacramento, South Coast, and San Joaquin AQMDs and state-level funds from ARB's Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project and the Energy Commission's ARFVTP to create the largest deployment of electric drive trucks in the country. These trucks are being demonstrated at UPS distribution hubs in West Sacramento, San Bernardino, and the San Joaquin Valley.

58 April 23, 2014 Integrated Energy Policy Report workshop transcript, p. 115.

59 April 23, 2014 Integrated Energy Policy Report workshop transcript, pp. 131-132.

60 April 23, 2014 Integrated Energy Policy Report workshop transcript, p. 147.

61 April 23, 2014 Integrated Energy Policy Report workshop transcript, p. 151.

An important emerging opportunity for leveraging state and federal incentive funding also is being made available through the DOE's Office of Fuel Cell Technology. According to Office Director Dr. Sunita Satyapal, DOE is now able to transition from an intensive research phase of $2 billion in federal funding for fuel cell technology development to a demonstration phase where fuel cell power technologies are integrated into medium- and heavy-duty electric drivetrains.[62] The Office of Fuel Cell Technology is making $25 million available for such demonstrations, and three California projects have won awards: the Vision Motors fuel cell range-extended Class 8 drayage truck at the Port of Long Beach, the Fed-Ex fuel cell package delivery van project in Oakland, and most recently, a demonstration of 17 fuel cell electric drive package delivery vans for UPS.

Recommendations

» **Create a pilot program to demonstrate appropriate financing mechanisms**. The California Pollution Control Financing Authority (CPCFA) and the Energy Commission should develop a pilot loan product for the strategic installation of electric chargers. The CPCFA should work with commercial lenders to offer loans to install electric chargers for public or employee use, and the Energy Commission should commit Alternative and Renewable Fuel and Vehicle and Technology Program (ARFVTP) funds to compensate for potential default on the loans. This will create a financing opportunity for entities unable to secure financing from standard commercial lenders. The pilots should highly leverage private capital and provide incentives to invest in electric vehicle charging stations for multi-unit dwellings and disadvantaged communities.

» **Continue to explore opportunities to collaborate with other public and private funding entities**. The Energy Commission should continue to work with other public and private funding entities to identify needs and strategically leverage funding to accelerate deployment of advanced technology vehicles and associated infrastructure. Also, the Energy Commission should consider joining groups like the U.S. Environmental Protection Agency's West Coast Collaborative that provide opportunities to strategically leverage funds to reduce diesel emissions and advance clean air technologies and practices.

» **Continue to explore alternative funding strategies that can further leverage funds**. The Energy Commission should continue to identify, assess, and initiate alternative funding strategies that can extend the leveraging power of ARFVTP and Electric Program Investment Charge funds and that are commensurate with the commercialization phase of the technology.

62 Dr. Sunita Satyapal, Office of Fuel Cell Technologies, US Department of Transportation, "Fuel Cell Technologies Office Overview: Leveraging ARFVTP Funding," presentation at the April 23, 2014, Integrated Energy Policy Report workshop.

CHAPTER 3:
Advancing Statewide Plug-In Electric Vehicle Infrastructure

In 2012, the transportation sector in California accounted for 36 percent of greenhouse gas emissions. Petroleum remains the predominant fuel, accounting for about 92 percent of transportation fuel use in 2013. To achieve California's climate change, air quality improvement, and petroleum reduction goals, the state must transition away from fossil fuels to using predominantly zero-emission and near-zero-emission vehicles. Replacing gasoline-powered vehicles with battery-electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs) driven in "electric mode" will reduce greenhouse gas emissions, air pollution, and gasoline consumption while providing fuel savings to consumers and strengthening local economies. BEVs and PHEVs are collectively referred to as *plug-in electric vehicles* (PEVs).

This chapter reviews the rapid growth in electric vehicles (EVs) in California and the state's leadership in advancing charging infrastructure. It explores the infrastructure challenges that face the PEV market in California and opportunities to address those challenges. It also summarizes the Energy Commission's role in advancing PEV infrastructure in support of accelerating the adoption of PEVs in California and provides recommendations for future work.

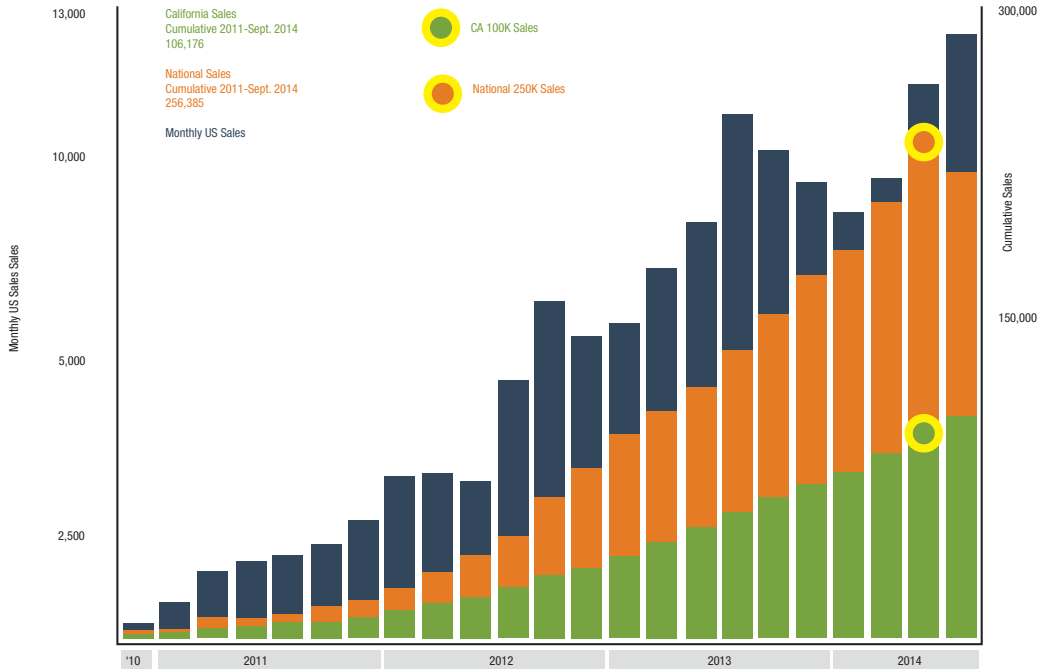
Sales of Electric Vehicles in California are Rapidly Growing

PEVs have become an increasingly common sight on California's roadways in the past two years, especially in metropolitan areas. These include 20 models of full BEVs and PHEVs offered by almost every automobile manufacturer.[63] In 2013, PEV sales were triple 2012 levels. As of December 2014, more than 118,000 PEVs were sold in California, representing about 40 percent of national PEV sales as shown in Figure 4. While sales are increasing, consumer awareness of EVs remains low, and many more sales are needed to expand the market and achieve the state's climate change, air quality improvement and petroleum reduction goals.

63 http://www.pluginamerica.org/vehicle-tracker?make=All&drivetrain=All&class=CarOrTruck&cvrp=All&availability=Available+in+US&items_per_page=20, accessed on December 16, 2014.

Figure 4: Plug-in Electric Vehicle Sales

California Reaches 100K PEV Sales in 2014



Note: Approximation assumes CA sales are 40% of national sales.
Source: PEVC Dashboard www.PEVCCollaborative.org from hybridcars.com and Baum & Associates

Source: Plug-in Electric Vehicle Collaborative

ARFVTP Infrastructure Investments Help Solve the Chicken-or-Egg Problem

The Energy Commission's early investments in EV infrastructure dating back to the early 1990s helped address the "chicken-or-egg" dilemma; these investments helped give consumers confidence that if they bought an EV, they would have an adequate number of places to recharge.

In fact, since 2009, through the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP), the Energy Commission has provided significant support to the PEV industry in California. As of December 2014, the ARFVTP has:

» Established the foundation for a zero-emission transportation future by investing roughly $38 million to provide 9,369 electric vehicle charging stations (EVCS), contributing to the largest network of electric charging stations in the country. [64]

» Invested $5.1 million to establish 10 initial PEV planning regions and 18 regional readiness plans. Each PEV planning region is led by a coordinating council consisting of at least four public agencies. (See Appendix B for a list of regions and key elements of their plan.) The key readiness activities include streamlining permitting and inspection for EVCS installation, updating building codes, developing EVCS infrastructure plans, and expanding consumer education and outreach.

64 DOE Alternative Fuel Data Center as of 9-11-14, http://www.afdc.energy.gov/locator/stations/.

» Provided nearly $60 million in funding for advanced technology zero-emission and low-emission medium- and heavy-duty truck demonstrations and deployment.

» Provided $47 million in seed funding for start-ups and small manufacturers of advanced technology vehicles, components, and batteries to expand their plants and assembly lines and help make California a hub of electric drive vehicle development, manufacturing, and use.

» Contributed $49 million, or enough to offer incentives for 21,000 cars, and $4 million for 150 trucks via the California Air Resource Board's (ARB) Clean Vehicle Rebate Project for BEV and PHEV cars and the ARB's Hybrid and zero-emission vehicle (ZEV) Truck and Bus Voucher Incentive Project.

Infrastructure, Incentives, and Technology Advancements Continue to Advance the Market

Enticed by a host of incentives and new charging stations, consumers purchased PEVs in increasing numbers, and within the first two years, PEV sales were roughly double those of hybrid-electric vehicles in the respective introductory phase. The rate of PEV adoption in California has continued to increase. "Build it and they will come" became a reality—for example, the EV Project in San Diego demonstrated that with the proliferation of EVCS in the San Diego area, there was a marked increase in the area of travel for Nissan Leaf drivers.[65]

The availability of new vehicle models, greater driving range from improved battery technology, and increased availability of charging infrastructure, along with incentives such as carpool lane access stickers, federal tax credits, and state and air district rebates, have contributed to an expanding market for PEVs. Furthermore,

65 *Electric Drive Vehicle Demonstration and Infrastructure Evaluation* Final Project Report, Grant ARV-09-005-02, May 2014.

Vehicle Types

Plug-in Electric Vehicle (PEV)

A PEV is any motor vehicle that can be recharged from an external source of electricity such as a PHEV or a BEV.

Hybrid Electric Vehicle (HEV)

HEVs are powered by an Internal Combustion Engine (ICE) and by an electric motor that uses energy stored in a battery. The battery is charged through regenerative braking and by the ICE. The vehicle cannot be plugged in to charge.

Plug-In Hybrid Electric Vehicle (PHEV)

PHEVs are powered by an ICE and by an electric motor that uses energy stored in a battery. The battery can be charged by plugging into an electric power source, through regenerative braking, and through the ICE.

Battery-Electric Vehicle (BEV)

BEVs are powered by an electric motor that uses energy stored in a battery. BEV batteries are charged by plugging the vehicle into an electric power source and through regenerative braking.

Fuel Cell Electric Vehicle (FCEV)

FCEVs are fueled with pure hydrogen gas stored directly in the vehicle. The hydrogen fuel cell produces electricity to power an on-board electric motor emitting no pollutants—only water and heat.

consumers are realizing that PEVs are fun to drive and can satisfy a large percentage, if not all, of their daily transportation needs.

Governor Brown's Leadership

On March 23, 2012, Governor Brown issued Executive Order B-16-2012[66] to advance zero-emission vehicles (ZEVs) in California, setting a long-term goal of 1.5 million ZEVs on California's roadways by 2025. ZEVs include PEVs as well as fuel-cell hydrogen electric vehicles (FCEVs). The executive order established milestones for three periods: 2015, 2020, and 2025. Infrastructure goals stipulate that by 2015, California's major metropolitan areas will be able to accommodate ZEVs through infrastructure plans; by 2020, California's ZEV infrastructure will be able to support up to 1 million vehicles; and by 2025, 1.5 million ZEVs will be on California's roadways with easy access to infrastructure. On January 5, 2015, Governor Brown proposed an ambitious goal to reduce "today's petroleum use in cars and trucks by up to 50 percent" and he envisioned that a "wide range of initiatives" including "millions of electric and low-carbon vehicles" could help California to achieve its goals.[67] California has made significant progress on achieving the 2015 goal of having the state's major metropolitan areas able to accommodate ZEVs through infrastructure plans and streamlined permitting. All of the state's major metropolitan areas now have infrastructure plans in place and have established strategies to streamline permitting.

To meet the milestones of the Governor's executive order, an interagency group led by the Governor's Office and including the Energy Commission developed the *2013 ZEV Action Plan*[68] with stakeholder input. The *2013 ZEV Action Plan* outlines significant actions that each agency must take arranged into four broad categories: complete needed infrastructure and planning, expand consumer awareness and demand, transform fleets, and grow jobs and investment in the private sector. The Energy Commission is the lead on several actions in the plan and has made considerable progress on them.[69]

Challenges and Opportunities for Infrastructure Deployment

California's transportation system is complex and large as it serves 482 municipalities in 58 counties and includes 170,000 miles of roadways. Also, the EV industry is also quickly evolving. Automakers are producing an increasing number of PEV models with improved battery density and performance, the regulatory and legislative landscape is in transition, the business case for charging infrastructure is evolving, and the electricity grid is adapting to the integration of renewable energy sources. These factors add to the challenges of infrastructure planning. For example, as PEV range increases, the optimal placement and number of EVCS changes. In addition, consumer knowledge, behavior, perceptions, and experience with PEVs are changing, making it difficult to predict or model.

66 http://gov.ca.gov/news.php?id=17463.

67 Edmund G. Brown Jr. inaugural address, remarks as prepared, January 5, 2015.

68 http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf.

69 Information on the Energy Commission's ZEV Implementation activities is available at http://www.energy.ca.gov/2013-ALT-01/index.html.

In General, Consumers Lack Awareness About Electric Vehicles

At the "NextSTEPS Sustainable Transportation Energy Pathways" held by UC Davis Institute of Transportation Studies on December 11, 2014, Ken Kurani gave a presentation on consumer awareness of PEVs. General consumer knowledge of PEVs is low: when survey respondents—who represent vehicle-owning households in CA—were asked to identify both a BEV and PHEV model for sale, only 8 percent could correctly identify at least one of each. Yet electricity is chosen as a likely replacement for gasoline and diesel "should we ever have to": electricity is the most frequently selected replacement (60 percent). Awareness of PEV incentives is surprisingly low, with only 18 percent of respondents able to identify California alternative fuel incentives. There may be regional variation in this awareness; unfortunately, residents within a region with higher state incentives (San Joaquin Valley Air Pollution Control District) appear to have lower awareness. The majority of households express some support for financial incentives for household purchase of PEVs and home recharging equipment, and public infrastructure. Overall, households remain uncertain about much regarding PEVs and charging infrastructure.

The California Public Utilities Commission (CPUC) also has an ongoing rulemaking, R.13-11-007, which investigates the possible roles of investor-owned utilities in promoting EVCS deployment. In November 2014, the assigned Commissioner released a Proposed Decision for Phase 1 of this rulemaking, and on December 18, 2014, the CPUC approved a decision that lifts the prohibition against utility ownership of electric vehicle charging infrastructure. This decision is expected to encourage the expansion of charging infrastructure and widespread deployment of PEVs.[70] Pacific Gas and Electric (PG&E), San Diego Gas and Electric (SDG&E), and Southern California Edison (SCE) each have charging infrastructure proposals before the CPUC.[71] The Energy Commission will give careful consideration to avoiding redundant investments in EVCS in light of the new utility role.

Charging Locations

Existing and prospective PEV drivers need to know they can have access to convenient, safe, reliable, and competitively priced refueling infrastructure. The roles of industry and the public sector in providing this infrastructure differ, and the Energy Commission is carefully evaluating its role in funding initiatives to reduce barriers to PEV adoption, including charging infrastructure deployment. Advancements in PEV technology and PEV infrastructure are made daily, and industry is extremely innovative in addressing marketplace challenges. The state's role is to support the market until economies of scale can be achieved, prices reduced, and the funding gaps bridged, as discussed in Chapter 2. The market must be supported in key areas that can have the most significant effect on PEV adoption.

California is continuing to work in partnership with the governments of Alaska, British Columbia, Oregon, and Washington through the Pacific Coast Collaborative (PCC) on a number of actions to address climate change, including the promotion of clean technology vehicles and the regional infrastructure to support them. As a result, the PCC has initiated the West Coast Green Highway, an initiative among the states of Washington, Oregon, and California to establish a corridor with intermittent alternative energy fueling stations that will support electric and alternative fuel-powered vehicles along the Interstate 5/ Highway 99 corridor from Southern California to Whistler, British Columbia.

Near-term PEV charging will occur primarily at home, so this is the greatest opportunity for charging infrastructure support for the next few years. Other outstanding

70 http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M143/K682/143682372.PDF.

71 For more information on the proposals see http://www.cpuc.ca.gov/PUC/energy/altvehicles/.

Table 4: Electric Vehicle Supply Equipment Options

	Amperage	Voltage	Kilowatts	Charging Time	Primary Use
AC Level 1	12 to 16 amps	120V	1.3 to 1.9 kW	2 to 5 miles of range per hour of charging	Residential and workplace charging
AC Level 2	Up to 80 amps	208V or 240V	Up to 19.2 kW	10 to 20 miles of range per hour of charging	Residential, workplace, and public charging
DC Fast Charging	Up to 200 amps	208V to 600V	50 to 150kW	60 to 80 miles of range in less than 20 minutes	Public charging

Source: Alternative Fuel Data Center (http://afdc.energy.gov)

near-term infrastructure opportunities include workplaces and multi-unit dwellings (MUDs) for situations where management has indicated support for infrastructure and surveys indicate likely PEV adoption, garaged fleet locations that have or will have significant numbers of PEVs; and crowded airport and commuter parking locations, provided certain conditions are met. In many cases, there should be a reasonable belief that installed EVCS will be used by significant numbers of PEVs; however, there are compelling reasons to consider installing EVCS besides expected short-term use—for example, to address safety and convenience concerns, as well as to build consumer confidence in PEVs and associated infrastructure.

Early PEV adopters charge their vehicles primarily at home with Level 1 or Level 2 charge points and have taken advantage of the increasing number of workplace and public chargers available in key metropolitan areas of the state. Table 4 describes the attributes of the types of charging options available. As existing BEV drivers gain confidence in their driving range, they often find that home charging will take care of most of their driving needs. PHEV drivers also rely on home charging but often are highly motivated to maximize their electric miles driven and may take advantage of workplace and public charging to increase their "e-miles." The next generation of PEV drivers will most likely rely primarily on home charging to refuel their PEVs; however, to make the decision to purchase or lease a PEV, they will need a clear understanding of PEV technology and refueling options and must view these options as convenient, safe, reliable, and cost-competitive.

The success of early PEV market adoption has resulted in charging station congestion in major metropolitan areas across California—especially the Bay Area, where BEVs are more prevalent than PHEVs. A balance is needed between expanding the number of charge points at these congested areas and expanding infrastructure into areas where PEV adoption is currently low. Expanding charging infrastructure in areas where few PEVs exist may result in low use of chargers initially but can encourage PEV adoption and ensure a backbone of available infrastructure to existing PEV drivers. The incremental cost of adding charge points can be significant depending on the original expectation of electricity use at the site. Older buildings tend to have smaller panel sizes than newer homes because they were appropriately sized for the level of electricity use at

the time they were constructed. Multi-unit dwellings may have panels grouped in an area far from the parking lot, so adding charging infrastructure requires expensive wiring for panel upgrades due to the distance. If adding charge points to a facility is too expensive, levying a charging fee can reduce congestion and help ensure availability for drivers who have a critical need.

The PEV charging requirement proposal for the 2015 California Green Building Standards Code[72] will lower future EVCS installation costs for new residential single- and multi-family dwellings. For new one- and two-family dwellings and townhouses with attached private garages, a raceway (an enclosed conduit that forms a physical pathway for electrical wiring) that can accommodate up to 80 amperes will be required. For projects with 17 or more multi-family dwelling units, the number of EVCS will be based on 3 percent of the total number of all parking spaces, with a design minimum of one EVCS required. Local agencies may also adopt voluntary measures that require pre-wiring for one- and two-family dwellings.

Residential Charging—Single-Family Homes

Residents of single-family homes can charge their vehicles by plugging in to a wall outlet or installing Level 2 EVCS using time-of-use utility rates, if available. These rates provide lower off-peak rates and enable substantial fuel savings for PEV drivers. PHEV drivers are often satisfied with Level 1 outlets since they may recharge their battery within 6 to 10 hours, whereas BEV drivers may prefer Level 2 charging equipment to fully recharge their vehicles in 4-8 hours.

The cost to install charging equipment at single-family homes is a potential barrier, particularly the permitting cost. According to a 2013 Electric Power Research Institute (EPRI) Report, the cost to install charging equipment declined between 2009 and 2013, and the average cost to install a single-family EVCS is about $1,600.[73] Installation costs vary depending on the need for longer conduit runs, limited panel capacity, and trenching work.[74] Although charging equipment and installation costs have declined, permit fees have risen as a percentage of total costs from 12 percent in 2009 to 22 percent in 2013.[75] Progress has been made in many cities with regard to streamlining the permitting, inspection, and installation of home EVCS. Regional PEV planning grants have assisted many cities and regions with these streamlining efforts; however, there is room for improvement. Permitting costs, for example, still vary significantly across the state and may hinder PEV adoption. Many cities have adopted same day, online, or over-the-counter permit issuance, while other cities still lack policies to facilitate permits for home charging. Encouraging a more standardized approach to permitting home charging could help address this challenge.

Residential Charging—Multi-unit Dwellings

Multi-unit dwellings (MUDs) include homes such as apartments, condominiums, high-rise buildings, duplexes, and mobile homes. In many areas of California, more than half of the population resides in MUDs, and in major metropolitan areas such as San Francisco, that percentage is even higher. At the June 5, 2014, Integrated Energy Policy Report (IEPR) workshop, J.R. DeShazo from the Luskin Center of Innovation at UCLA noted that the MUD sector has tremendous latent demand for PEVs; however, challenges associated with EVCS deployment in MUDs are one of the biggest barriers to increased PEV adoption.[76]

The primary barriers to EVCS installations in MUDs include cost, the availability of power supply, the proximity

72 http://www.bsc.ca.gov/Home/CALGreen.aspx.

73 http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002000577.

74 Ibid. pp. 3-5.

75 Ibid. pp. 3-4.

76 April 10, 2014, Integrated Energy Policy Report workshop transcript, p. 147.

to metering equipment, physical limitations in high-rise units, parking issues, homeowner association requirements, allocation of charging costs, and the complexity of decision-making.[77] For those that live in MUDs, a key factor that may influence their decision to purchase an EV is the availability of a place to charge. EVCS must be available in their buildings, at work, or at very convenient locations. During his presentation at the June 5, 2014, IEPR workshop, Ed Kjaer of SCE said about 80 percent of drivers commute less than 20 miles per day, suggesting that most drivers could meet their needs with level 1 charging for four to five hours at one location.[78] About 75 percent of charging is done at home, and close to 15–20 percent is done at the workplace.[79]

The cost of MUD EVCS installations is about $3,700, which is more than double the average cost of the single-family residential installation.[80] The main costs of EVCS include electrical upgrades and the EV parking space, which, in some cases, may be valued at $100 to $350 per month.[81] Installation costs depend on where the parking spot is located in proximity to the electrical panel. In addition to level 2 charging station costs of up to $2,000, costs may include a new circuit, electricity meter, and/or conduit installation for the 220/240 volt connecting line. The closer a parking space is to the electrical panel, the lower the cost. Without an existing conduit from the panel to the parking space, significant costs must be incurred to accommodate the new EVCS. In some cases, the total price can be as high as $30,000 or more for panel upgrades and related costs. In other cases, parking spots are not available within the MUD, and EVCS must be located on the street or in adjacent buildings or lots.

At the June 5, 2014, workshop, there were differing ideas on how to overcome the high capital costs issue. Richard Lowenthal from ChargePoint recommended that the Energy Commission provide MUD grants in the range of $30,000 to cover the initial capital costs.[82] Richard Schorske with EV Communities Alliance suggested providing PEV drivers with a $5,000 cash voucher to give to their landlord would help defray EVCS investment costs in MUDs.[83] He also suggested encouraging the colocation of EVCS in commercial districts where parking spots can be used by the public during the day and MUD residents at night.[84]

New business models and strategies are developing to accommodate EVCS in MUDs. In the Bay Area a company called Power Tree is attracting MUD site owners by offering a combination of solar photovoltaics, energy storage, and EVCS that provides a revenue stream resulting in a free system for building owners.[85] The Energy Commission is providing grants to a variety of MUD models, including the Power Tree model, and will continue to explore ways to promote EVCS in MUDs. At the workshop, Mr. DeShazo recommended that a voluntary precommitment program be established to help building owners

77 http://www.pevcollaborative.org/MuD and https://www.sdge.com/sites/default/files/documents/PreppingMultiUnitsforPlugIn-Vehicles.pdf?nid=3350

78 , April 10, 2014, Integrated Energy Policy Report workshop transcript, p. 126.

79 April 10, 2014, Integrated Energy Policy Report workshop transcript, p. 130.

80 http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002000577, pp. 3-5.

81 Richard Schorske of EV Communities Alliance and John Kalb of EV Charging Pros, *Analysis and Engagement of the Bay Area Multi-Unit Residential Development Market for Electric Vehicle Charging and EV Deployment*, Supplement to the Bay Area EV Corridor Project Final Report for the California Energy Commission, January 31, 2014.

82 April 10, 2014, Integrated Energy Policy Report transcript, p. 118.

83 June 5, 2014, Integrated Energy Policy Report workshop transcript, p. 147.

84 Richard Schorske, June 5, 2014, Integrated Energy Policy Report workshop transcript, p. 101.

85 Analysis and Engagement of the Bay Area Multi-Unit Residential Development Market for Electric Vehicle Charging and EV Deployment, Supplement to the Bay Area EV Corridor Project Final Report for the California Energy Commission, by Richard Schorske of EV Communities Alliance and John Kalb of EV Charging Pros, January 31, 2014.

let residents and employees know that they are willing to install EVCS when residents/employees are ready to purchase PEVs.[86]

Depending on the EVCS project decision maker, the goals of EVCS installations will vary. A chief financial officer may be interested in return on investment, a chief executive officer may look for an increase in the asset value of a building, a sustainability director may look at the green profile, and the operations manager may be concerned about managing and financially reconciling the purchase.[87] Quite often, the PEV driver and the MUD owner or apartment manager have different motivations. Tenants often request charging stations but may be asked to pay for installation.

At the workshop, John Kalb of EV Charging Pros encouraged the funding of an "EV Charging Design and Decision" program that would 1) provide a grant program designed to independently educate, train, and certify individuals and organizations to help MUDs understand, plan for, and make commitments regarding potential EVCS installations and 2) fund those that are certified to help MUDs prepare for Energy Commission financing opportunities in advance.[88] When solicitations become available, there is often insufficient time for management to evaluate the EVCS strategy and develop a proposal in a timely manner. If MUDs have a precommitment to EVCS, prospective tenants who want to buy or lease a PEV will be able to count on charging availability. Even as vehicle battery sizes increase, the need for MUD charging will remain an important option for future tenants.

Stakeholders continue to work together to address many of these issues. The Statewide PEV Collaborative has developed *PEV Charging Infrastructure Guidelines for MUDs*[89] and utilities such as San Diego Gas & Electric have led efforts in supporting MUD EVCS installations and addressing utility-side barriers.

Workplace and Public Charging

Workplace charging provides PEV drivers with increased driving range and the ability to make additional trips beyond their normal roundtrip work commute. Public charging covers a broad spectrum of locations, including shopping centers, airports, public garages, libraries, hospitals, restaurants, and parks. Charging at commercial and public locations provides drivers flexibility in daily trips and maximizes miles driven in electric mode. The location and type of EVCS sited should match the PEV "dwell" time or parking duration. Workplace and public charging may also provide a potential option for those who live in MUDs that do not have dedicated parking spaces for charging. Supporting the deployment of workplace charging infrastructure is a simple way to increase electric miles driven for PHEV drivers and extend the range of BEV drivers. Prospective PEV drivers may make the decision to purchase an EV based on the availability of workplace charging.

In a survey done by the PEV Collaborative, companies were asked to identify the top challenges they faced in installing EVCS. The top two challenges were the cost of installation, which varied from $1,500 to $30,000, and the cost of equipment—ranging from $3,000 to $5,000.[90] More than one-third of workplaces surveyed received some level of grant funding, while the remaining two-thirds covered their costs within their operating budget or with third-party ownership or financing. While two-thirds of workplaces surveyed provide free charging to their employees, some charge a fee for parking and/or charging to encourage efficient use of EVCS.

Congestion at chargers is an increasing concern, especially in the Bay Area and areas such as Silicon Valley

86 April 10, 2014, Integrated Energy Policy Report workshop transcript, p. 148.

87 Kalb, John, EV Charging Pros, presentation, *EV Infrastructure Roundtable Multifamily Overview,* July 28, 2014.

88 Letter to 2014 IEPR Docket, August 18, 2014 from John Kalb EV Charging Pros.

89 http://www.pevcollaborative.org/multi-unit-dwelling.

90 http://www.pevcollaborative.org/sites/all/themes/pev/files/WPC_Report4web.pdf, p. 7.

with a large number of high-tech workplaces. Appropriate fees can help balance supply and demand of EVCS. At the June 5, 2014, workshop, Mike Nicholas from the UC Davis Plug-in & Hybrid Research Center suggested that another way to increase capacity is through requiring payment for charging or providing employees with charging credit vouchers so that even with "free" charging drivers will be more mindful of charger use.[91] In cases where charger congestion is occurring, Mr. Lowenthal recommended that the Energy Commission consider providing funds to provide incentives for expansion of charging stations. Mr. Kjaer with SCE also suggested that the Energy Commission has an opportunity to facilitate more cars on a circuit using a UCLA demonstration idea of one charge box with four ports that could sequence four cars at level 1.[92] This model could be deployed in workplaces, public garages, or MUDs.

The EPRI report noted that it is important to "right-size" infrastructure to minimize the cost of electrical work. There are techniques that include providing various combinations of Level 1 and Level 2 charging, increasing circuits by reworking panels, and improving energy efficiency to reduce electrical demand.[93] The report also noted that workplace charging is less costly to install than at public sites, and fleet charging is the least expensive type of commercial installation.

Another key strategy to increase workplace charging is to provide outreach and education. Organizations such as the Statewide PEV Collaborative and CALSTART are providing much needed support with education and outreach, and auto companies such as Nissan are reaching out to companies to encourage workplace charging with ride-and-drive events and employer education.

The Energy Commission has provided grant funding for workplaces and will continue to consider various strategies to further encourage workplace EVCS installations. At the June 5, 2014, workshop, Scott Briasco of the Los Angeles Department of Water and Power suggested that providing rebates to help defray the costs of installing workplace charging may be more effective than grants because applying for grant applications can be too arduous for many workplaces.[94] Mr. Lowenthal of ChargePoint, however, indicated that 62 percent of ChargePoint's business is workplace charging and that 95 percent of its business does not require a subsidy.[95] At workplaces, charging stations average about three charges per circuit per day of use.[96]

The Energy Commission is also working with the California Pollution Control Financing Authority (CPCFA) in the State Treasurer's Office to implement the new EVCS Financing Program. The EVCS Financing Program will be a sustainable financing program that will leverage state funding to access private capital and will be reinvested in the program once loans are repaid. Capital through the EVCS Financing Program will be used to procure and install EVCS needed to support strategic widespread EV adoption while meeting the State's ZEV goals. The launch of the EVCS Financing Program is expected in early 2015.

Fast Charging

For longer-distance BEV travel, fast charging along highway corridors will be essential. Even though motorists may not typically drive beyond their daily driving route, many existing and prospective BEV drivers expect to have interregional and interstate recharging options in the event a longer trip is necessary. DC fast charging

91 June 5, 2014, Integrated Energy Policy Report workshop transcript, pp. 146-147.

92 UCLA Smart Grid Energy Research Center: http://smartgrid.ucla.edu/projects_evgrid.html.

93 http://www.epri.com/abstracts/Pages/ProductAbstract.aspx?ProductId=000000003002000577, p. xvii.

94 June 5, 2014 2014, Integrated Energy Policy Report workshop transcript, p. 93.

95 June 5, 2014 2014, Integrated Energy Policy Report workshop transcript, p. 113.

96 June 5, 2014 2014, Integrated Energy Policy Report workshop transcript, p. 115.

allows BEV drivers the ability to recharge their vehicles to 80 percent of battery capacity within about 30 minutes. Fast charging can also be used when a driver needs to "top off" to make an extra trip if there is insufficient time to recharge at levels 1 or 2. Fast chargers are located within major metropolitan areas, at retail sites, and on highway corridors to meet a driver's need to recharge in a relatively short time frame.

Many efforts are underway in California to deploy DC fast chargers with CHAdeMO, SAE Combo, and Tesla standards.[97] Under the NRG Settlement with the CPUC, eVgo is committed to installing at least 200 DC fast chargers equipped with CHAdeMO and SAE Combo connectors throughout California.[98] As of November 7, 2014, Tesla has installed 17 superchargers in California for its Model S owners to travel between cities as part of its national coast-to-coast network of 126 stations.[99] Nissan has installed several fast chargers with CHAdeMO connectors at its dealerships and other locations around the state and many local air districts have plans to install DC fast chargers. In October 2014, the Governor's Office of Business and Economic Development (GO-Biz) signed a memorandum of understanding with the New Energy and Industrial Technology Development Organization of Japan (NEDO) for NEDO to establish a network of 50 DC fast chargers in Northern California connecting the Bay Area to Lake Tahoe and to the Monterey Peninsula. This demonstration will allow NEDO to gather data on driver use. Of course, California PEV drivers will benefit from the addition of these interregional DC fast chargers. The initial wave of DC fast charger installations was primarily in metropolitan areas, and the second wave includes interregional and interstate highway corridors. As of December 2014, the Energy Commission funded several dual connector DC fast charger installations in California, including:

» 3 fast chargers for the EV Project in San Diego.

» 20 fast chargers with South Coast Air Quality Management District.

» 16 fast chargers with energy storage for Green Charge Networks.

» 10 fast chargers with U.S. Green Vehicle Council on Interstate 5 and Highway 99 corridors.

» 10 fast chargers at a plaza in Encinitas with Corridor Power.

» 1 fast charger at the Los Angeles State Historic Park.

Figure 5 shows existing DC fast chargers in California as of December 2014.

Although DC fast chargers are proliferating around the state, the acceleration has not been easy in most cases, even with public funding available. The key challenges have been finding willing site hosts; the cost of hardware, installation, and maintenance; power upgrades required for the site and the impact on the local transformer; the time required to obtain permits; addressing high demand charges incurred by fast charger energy use; and the evolving understanding of where to best place DC fast chargers.

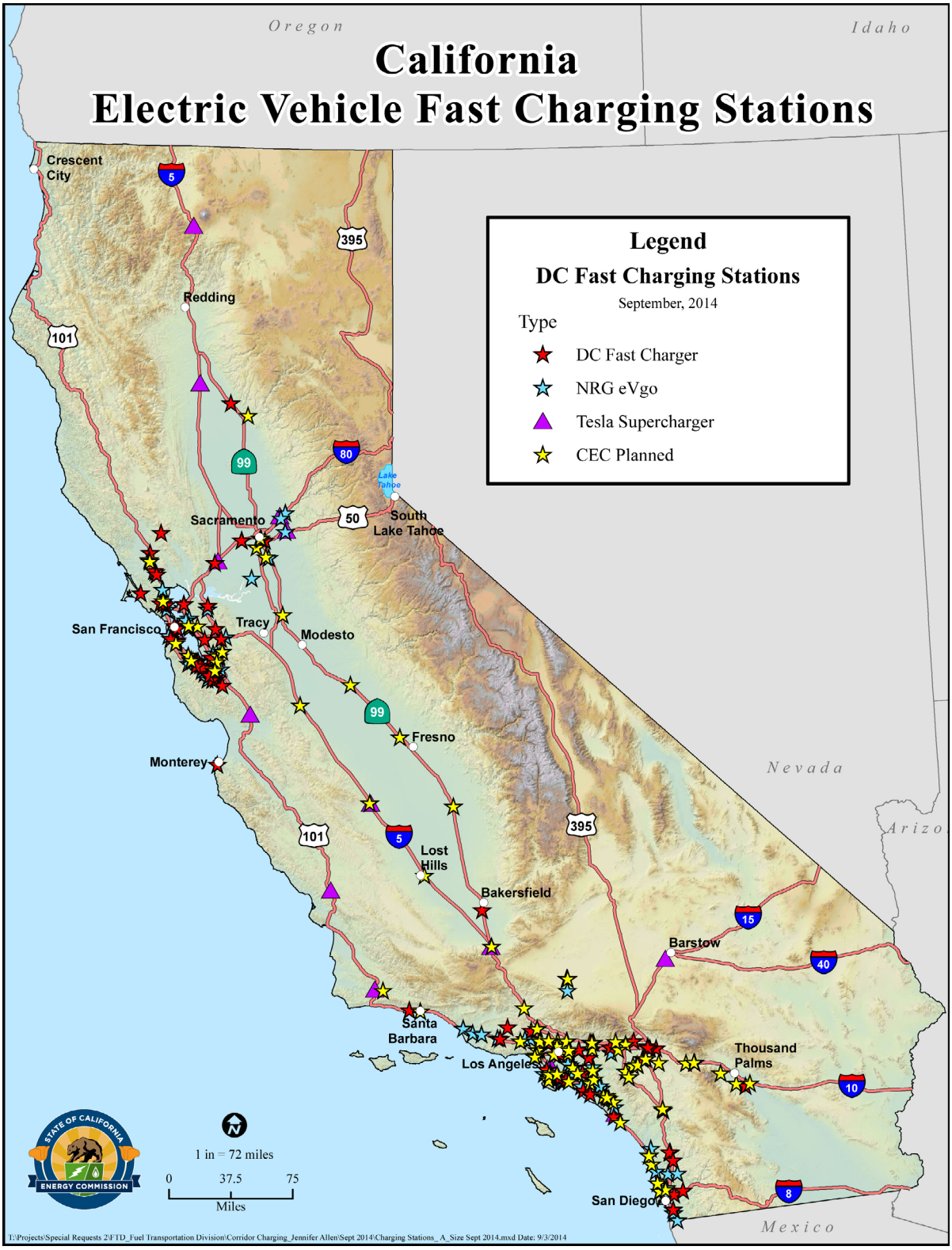
Finding sites to host DC fast chargers can be challenging for a variety of reasons. Site hosts may question the overall business case of hosting DC fast chargers in light of the total project costs, revenues, benefits, and parking capacity. The high power requirements compounded by the complex contract requirements for the site hosts

97 http://www.chademo.com/ and http://www.sae.org/servlets/pressRoom?OBJECT_TYPE=PressReleases&PAGE=showRelease&RELEASE_ID=2252.

98 http://www.cpuc.ca.gov/PUC/hottopics/1Energy/120427_NRG_FERC.htm.

99 http://www.teslamotors.com/supercharger

Figure 5: Existing Electric Vehicle Fast Charging Stations in California (December 2014)



Source: Energy Commission staff

are additional barriers.[100] The average hardware costs are declining but may range from $6,500 for the relatively new BMW 24 kW DC fast charger to more than $20,000 for a single port and $40,000 for a dual port.[101] Installation costs vary considerably, but for the EV Project DC fast chargers, average installation costs are $20,800.[102] Operation and maintenance costs, which include equipment maintenance, insurance costs, property taxes, electricity costs, and parking lot maintenance, can exceed $1,000 per month.[103]

Another barrier to the deployment of DC fast chargers is the impact on the electricity distribution system and associated demand charges for peak power use. In Rulemaking 13-11-007, the CPUC is considering how demand charges with regard to transportation might be reduced. Utility demand charges for DC fast chargers per month range from no charge to more than $1,460, depending on the utility service area.[104] The Energy Commission recently funded Green Charge Networks to deploy 16 DC fast chargers at various locations throughout California. These fast chargers are paired with energy storage and management systems that reduce the site host's peak energy demand, thereby reducing utility demand charges.

Another challenge is the optimal siting of DC fast chargers in California. David Peterson with Nissan noted that the time it takes a driver to charge is the number one consideration when seeking a DC fast charge; so locating them in convenient places is critical for enabling existing drivers and spurring PEV adoption.[105] Much of the emphasis to date has been on installing fast chargers in the major metropolitan areas, but to extend the range of BEVs, DC fast chargers are increasingly being installed on interregional highway corridors and areas with lower PEV adoption. The UC Davis Institute of Transportation Studies recently presented results from its study on "DC Fast Charging in the Context of Bigger Batteries."[106] The study concludes that as batteries get larger, fewer DC fast chargers are needed. Specifically, the study shows that 1) DC fast charging is necessary to address statewide travel needs even when Level 2 EVCS are "ubiquitous" 2) for 200-mile-range BEVs, 95 percent of statewide miles are possible with only Level 2 charging, and almost all trips can be done with two or fewer fast charges and 3) for 200+ mile BEVs, most demand occurs on Interstate 5 and California Highway 99, with some demand on other long distance corridors. At the April 10, 2014, IEPR workshop, Mark Duvall from EPRI said the state "needs to migrate from a primarily metro-based infrastructure to a regional distribution at the highest value and lowest cost."[107] Still, access to fast charging in metropolitan areas is important, and availability can be limited in high-use areas. To address congestion issues in major metropolitan areas, Mr. Schorske from EV Communities Alliance recommended providing funding for a bank of 10–15 DC fast chargers in key downtown areas throughout the state. This would serve drivers who are living in the city and those passing through or visiting.[108]

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100 *Electric Drive Vehicle Demonstration and Infrastructure Evaluation*, Grant ARV-09-005-02, Final Project Report, Alternative and Renewable Fuel and Vehicle Technology Program, May 2014, p. 94.

101 Chargepoint, "California Public EV Infrastructure: Background Data on Costs, Utilization, and Finance" presentation, July 14, 2014.

102 Electric Power Research Institute, *2013 Technical Report: Electric Vehicle Supply Equipment Installed Cost Analysis*, updated October 2014.

103 Terry O'Day of eVgo, California Energy Commission staff meeting, January 2014.

104 The EV Project, *Lessons Learned - The EV Project DC Fast Charge - Demand Charge Reduction*,http://www.theevproject.com/downloads/documents/2.%20DC%20Fast%20Charge-Demand%20Charge%20Reduction%20V1.0%20Revised%20(2).pdf, May 2012.

105 April 10, 2014, Integrated Energy Policy Report workshop transcript, p. 105.

106 http://www.its.ucdavis.edu/research/publications/publication-detail/?pub_id=2002.

107 April 10, 2014, Integrated Energy Policy Report workshop transcript, p. 102.

108 April 10, 2014, Integrated Energy Policy Report workshop transcript, p. 124.

The Energy Commission's PEV Infrastructure Strategy

To achieve the Governor's objectives with respect to PEV infrastructure, the Energy Commission has embarked on three phases of EVCS deployment that may be referred to as "experimentation," "optimization," and "wide rollout."[109]

Experimentation

The first phase (from 2009—2011), established prior to the *2013 ZEV Action Plan*, frontloaded PEV infrastructure in partnership with federal American Reinvestment and Recovery Act grants. Infrastructure was deployed in key metropolitan areas such as San Francisco, Los Angeles, San Diego, and Sacramento to create an EV-friendly environment. Since then, California has become the center of gravity in North America for PEV sales, technology development, and manufacturing support. This progress has involved partnerships with all levels of government, utilities, industry, the California Plug-in Electric Vehicle Collaborative, and other nongovernmental organizations.

A crucial step was the release of a U.S. Department of Energy (DOE) PEV readiness solicitation and an Energy Commission solicitation that resulted in the development of 10 regional PEV plans to account for PEV microclimates and local objectives. Rather than a "top-down" approach, this regional planning effort engages communities and local agencies on everything from streamlining the permitting and inspection processes for EVCS to developing regionally tailored infrastructure plans. At the same time, the Energy Commission contracted with the National Renewable Energy Laboratory (NREL) to develop a statewide PEV infrastructure assessment to provide guidance for state-level policy, high-priority locations for infrastructure, consideration of interregional corridors, and guidance to local communities and regions as they plan for EVs. The assessment provides a high-level estimate of EVCS deployment and complements the equally important regional PEV infrastructure plans.

109 UC Davis Plug-In Hybrid & Electric Vehicles Research Center, PEV Market Briefing, May 2014.

Optimization

The second stage (from 2011—2014) involves continued support and monitoring of the PEV market to assess consumer needs. From the Energy Commission's first solicitation for charging infrastructure projects, the focus has been on finding the right ratio of residential, workplace, and public chargers to meet drivers' needs and preferences. The latest efforts have focused on siting fast chargers, addressing the challenges of MUDs, encouraging workplace charging, and ensuring that the disbursal of public funds is coordinated with regional PEV readiness plans.

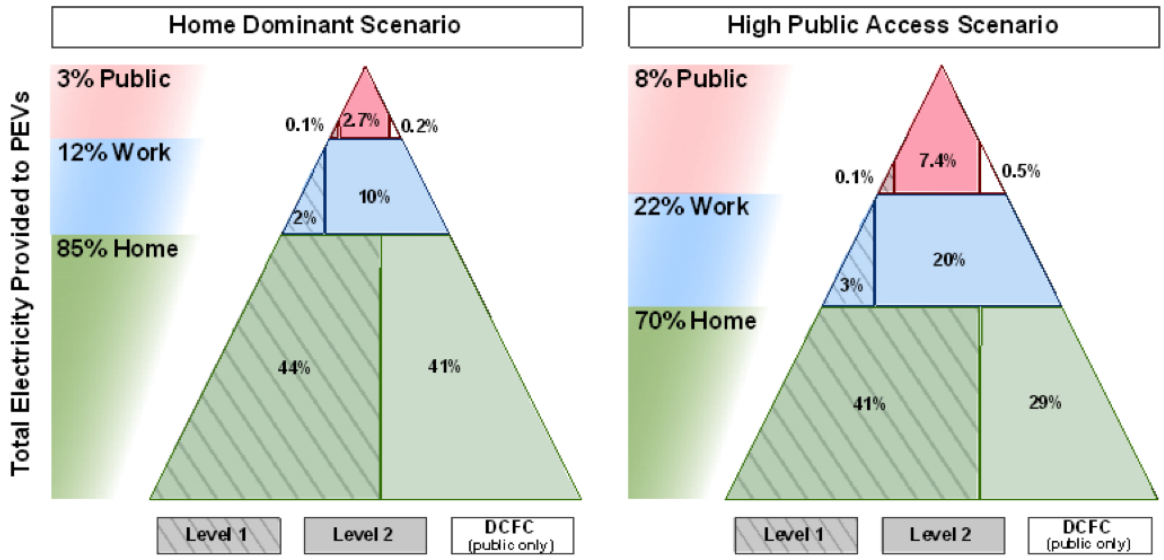
In January 2013, the Energy Commission, in collaboration with the Governor's Office, the ARB, and the California PEV Collaborative, held a public workshop to solicit input in developing a statewide PEV infrastructure assessment. Attendees participated in sessions focused on regional plans, statewide and interregional issues, cost-effective EVCS coverage, and the interoperability of EVCS. NREL used the stakeholder input as a basis for developing the *Statewide PEV Infrastructure Assessment*.

While information on current technology and market trends may be sufficient to support PEV infrastructure planning at the local and regional levels, data evaluating infrastructure expansion trends along corridors or at a statewide or interstate level are more limited. Consequently, the assessment uses scenario analyses to project future EVCS requirements. Figure 6 shows the two quantitative scenarios, "home dominant" and "high public access," that are used to illustrate the EVSE expansion needed to meet California's goal of 1.5 million ZEVs by 2025.

Home Dominant Scenario: While both scenarios assume most PEV charging occurs at home, this scenario assumes that 85 percent of the electricity needed for PEV drivers is provided at home, compared to 70 percent in the "high public access" scenario. Workplace and public charging provide 15 percent of PEV electricity.

High Public Access Scenario: This scenario assumes that 1) future PEV drivers place a higher premium on workplace and public charging, with 30 percent of electricity for PEV drivers provided outside the home, and

Figure 6: NREL Assessment PEV Infrastructure Scenarios



Source: NREL *Statewide Plug-in Electric Vehicle Infrastructure Assesment*

that 2) EVSE installers and suppliers receive significant benefits from installing EVSE stations.

Table 5 summarizes the range of charge points that may be needed statewide by 2020. Estimates of the total EVSE charge points needed by type and location for each California planning region are also quantified, as shown in Figure 7.

The *Statewide PEV Infrastructure Assessment* is a framework for evaluating the need for EVCS in California based on a set of assumptions. Additional empirical and statistical data are needed to further refine and calibrate efforts. Key data needs include:

» **Trends in EVSE product and network development**, to better inform decision-making on the best locations to install different types of EVSE and to enable efficient use of capital.

» **Trends in usage of and demand for Level 1 EVSE (standard electricity connections used in homes) and Level 2 EVSE (higher-power connections that charge vehicles more quickly) in workplace and public settings**, to evaluate investment tradeoffs between charging levels and locations, depending on local objectives.

» **Trends in usage of and demand for DC fast charging stations that can charge a vehicle fully in about 30 minutes**, to better understand the need and best location for additional fast chargers to increase range confidence and PEV adoption.

» **Customer payment methods used, prices, and associated customer response**, to help develop predictive EVSE demand models for planning.

Wide Rollout

The third phase (2014 onward) involves deploying PEV infrastructure based on refinements to the *Statewide PEV Infrastructure Assessment*. This phase requires additional data gathering, stakeholder input, and coordination of regional readiness plans. It also involves close coordination with the 10 initial planning regions and sharing lessons learned across the state. The Energy Commission will also examine regional readiness plans from around the nation to gather best practices, then evaluate existing regional readiness plans to improve upon and fill in any gaps. As regions work to determine local infrastructure needs, the NREL Assessment suggests that entities should identify their objectives for installing EVSE before trying to

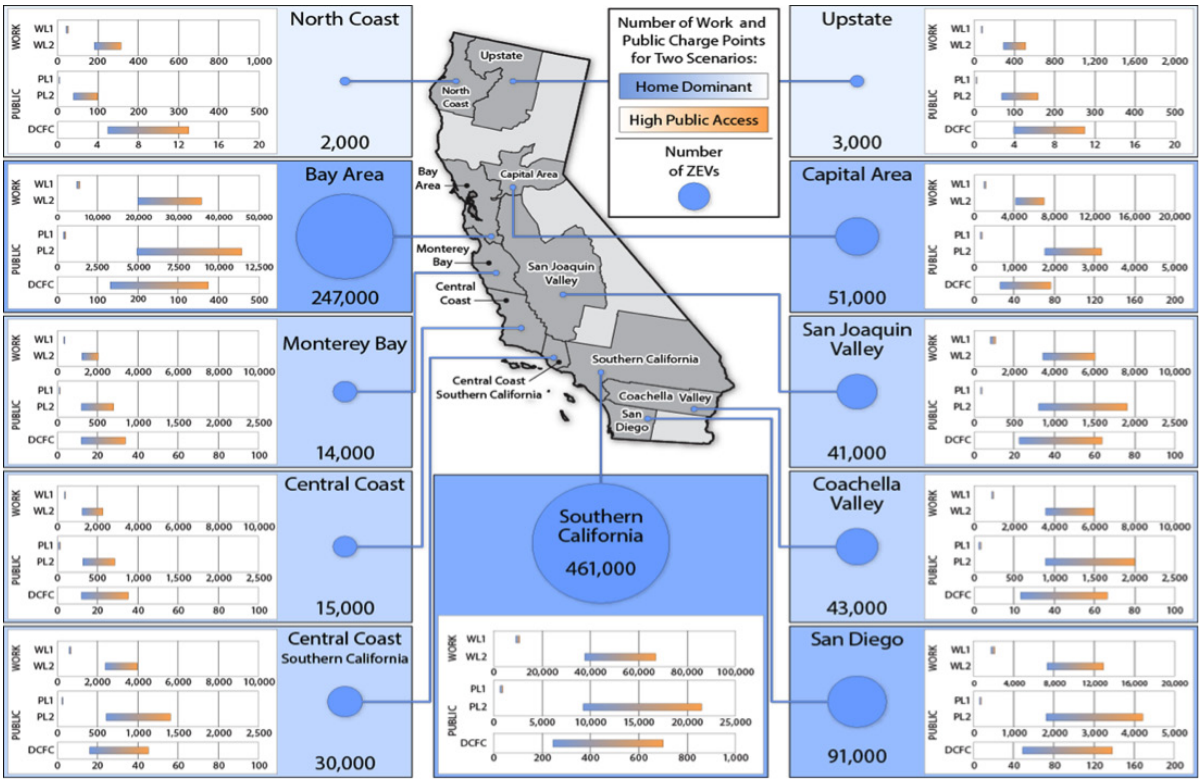
Table 5: Total Statewide EVSE Charge Points by Location and Type (2020)

Total Statewide EVSE Charge Points by Location and Type (2020)							
Scenario	L1 Home	L2 Home	L1 Work	L2 Work	L1 Public	L2 Public	DCFC*
Home Dominant	511,000	365,000	20,100	82,000	1,620	20,100	551
High Public Access	517,000	289,000	22,900	144,000	2,100	46,500	1,550

*Direct current fast charging (DCFC)

Source: NREL, *Statewide Plug-in Electric Vehicle Infrastructure Assessment*

Figure 7: Estimated Workplace and Public EVSE Stations by Region (2020)



Source: NREL, *Statewide Plug-in Electric Vehicle Infrastructure Assessment*

determine EVCS numbers, types (such as, Level 1, Level 2, or fast charge), and locations. Many of the regions have already done so, while others are just beginning.

The Energy Commission is developing a DC fast charger siting analysis in coordination with NREL, UC Davis, and the Governor's Office of Planning and Research that will identify gaps on highway corridors. As part of the infrastructure assessment that NREL completed for the Energy Commission, NREL notes that locations along some corridors linking multiple urban areas, specific destinations, and those locations mentioned above that lack management support and/or whose surveys are inconclusive should require additional analyses before committing to PEV infrastructure installation. The Energy Commission will bear this in mind as it completes its DC fast charger analysis. This analysis, combined with regional PEV infrastructure plans, will help pinpoint where future DC fast chargers might be sited.

As EVCS deployment continues, a need exists for (1) better PEV infrastructure data (current and planned locations, operating hours, numbers and types of chargers, and so forth), including access to real-time data via mobile applications or onboard vehicle systems, for example; (2) highly refined models capable of evaluating potential locations for public charging stations based on a variety of factors and objectives; and (3) expanded outreach and enhanced collaboration among stakeholders. The Energy Commission intends to support these types of efforts and has already begun to in some cases.

Examples of Regional PEV Infrastructure Plans

Ten regional PEV readiness plans were funded in the first Energy Commission planning solicitation, and a later planning solicitation (PON-13-603) awarded an additional eight projects.[110] Each of the regional plans addresses barriers and reflects regional population characteristics, regional PEV data, topography, land uses, local objectives, and other factors. Each region has a unique PEV microclimate; one size does not fit all. Examples of infrastructure plans are described below.

South Coast Association of Governments' PEV Readiness Plan

The UCLA Luskin Center for Innovation developed a PEV readiness plan and atlas for the South Coast Association of Governments (SCAG). Jointly funded by the Energy Commission, the SCAG, the South Coast Air Quality Management District, and DOE, this plan will help nearly 200 cities meet demand for PEV charging.

The *Southern California PEV Atlas* provides a comprehensive series of neighborhood maps that characterize PEV ownership by neighborhood and project PEV ownership growth by council of government and utility service areas. Using a regional travel model, the Atlas also estimates time-of-day proximity of PEVs to charging opportunities at workplaces and retail centers. The Atlas also maps additional charging opportunities at multi-unit dwellings and parking facilities.

The Bay Area Quality Management District PEV Readiness Plan

Similarly, the Bay Area estimated the demand for publicly available infrastructure needed to support PEV forecasts. The analysis considers a variety of parameters when identifying suitable locations for EVCS, such as vehicle characteristics, PEV demand, and parking characteristics. The analysis is performed for various charging types and levels, including residential, workplace, opportunity, and DC fast charging.

North Coast PEV Readiness Plan

The North Coast PEV Readiness Plan represents Del Norte, Humboldt, and Trinity Counties in the northwestern corner of the state. The Schatz Energy Research Center and GHD, an international engineering consulting firm, developed the plan and model with a macro- and microlevel analysis for infrastructure deployment. The macrolevel

110 http://www.energy.ca.gov/contracts/PON-13-603_NOPA_Revised4.pdf.

analysis included the development and use of a computer simulation model to determine the number and type of EVCS needed to support a given level of PEVs. The model simulated individual PEV drivers traveling throughout the region to model their behaviors and assess their charging needs. An estimate of infrastructure costs and a plan for a phased rollout over time are also provided. Furthermore, a microlevel analysis included a metric to assist municipal planners in siting EVCS at the spatial level of a parking lot.

On September 9, 2014, the Energy Commission released a "Planning for ZEVs" solicitation (PON-14-603) for $3.3 million to support new and existing planning efforts for PEVs and fuel cell EVs.[111] These funds can be used for developing new ZEV readiness plans or implementing activities within existing plans, such as streamlining the permitting and inspection processes, updating building codes, EVCS siting, PEV signage, and other activities.

Next Steps

To support the Governor's *ZEV Action Plan* goals for infrastructure over the next decade, the Energy Commission will support efforts to deploy convenient, safe, reliable, and competitively priced charging infrastructure. These efforts include preparing California cities and regions for PEVs and ensuring sufficient charging infrastructure to support the vehicles. To that end, next steps include:

» Continuing to support regional PEV readiness plans and fund PEV readiness activities at the local level.

» Developing solicitations to fund charging infrastructure at lowest cost and with the highest benefit for PEV consumers.

» Developing a DC fast charger analysis identifying charging infrastructure gaps on highway corridors and strategies for addressing those gaps.

» Developing strategies to 1) remove barriers to MUD and workplace charging infrastructure deployment, 2) address charging congestion in metropolitan areas, and 3) increase PEV driver range confidence and electric miles driven.

» Refining the assumptions used in the NREL *Statewide PEV Infrastructure Assessment* by gathering and analyzing data on consumer behavior with regard to PEVs and charging infrastructure.

The Energy Commission will work with other state agencies, industry partners, the Statewide PEV Collaborative, academic institutions, consumer advocacy groups, and the Governor's Office as it embarks on these efforts.

Recommendations

» **Collect data and conduct market assessments to stay abreast of current and emerging challenges and opportunities to advance plug-in electric vehicle (PEV) infrastructure**. The Energy Commission should conduct an ongoing assessment of the state of the industry, the regulatory and legislative landscape, utility grid impacts, and consumer needs and desires as part of its efforts to deploy infrastructure to spur PEV adoption. In support of this effort, the Energy Commission should collect information needed to fill data gaps including information on trends in electric vehicle charging station (EVCS) products and networks, demand for various charging levels at various locations, information on customer payment methods and prices, and consumer behavior. The Energy Commission should serve as a convening agency to bring the many stakeholders together to collect the above data.

111 http://www.energy.ca.gov/contracts/PON-14-603/.

» **Continue to strategically invest in charging infrastructure at residential, workplace, multi-unit dwelling, and public sites to spur PEV adoption**. The National Renewable Energy Laboratory's *Statewide PEV Infrastructure Assessment*, the UC Davis presentation on DC fast charging,[112] and other state, regional, and local planning documents will help inform charging infrastructure expansion. The Energy Commission should:

- » Provide funding support for EVCS in cases where the business case is weak but the need is vital for existing and potential PEV drivers. Be mindful of low-cost, innovative, and suitable EVCS technology for each location.

- » Evaluate utility investments in EVCS in light of the role of utilities in the California Public Utilities Commission decision on R-13-007 that lifts the prohibition against utility ownership of electric vehicle charging infrastructure and consider how Energy Commission investments can complement utility investments in EVCS.

- » Provide highly leveraged and easily accessed support for workplace charging to increase the effective range of battery-electric vehicles and maximize electric miles for plug-in hybrid electric vehicles. Consider various financial mechanisms as well as education and outreach strategies.

- » Reduce barriers to residential charging by working with the Governor's Office of Business and Economic Development (GO-Biz) to seek ways to standardize permitting templates and provide guidance on permit fees while recognizing local goals and resource constraints.

- » Reduce barriers to EVCS deployment in multi-unit dwellings (MUDs) by supporting efforts to inform key MUD decision makers and encourage innovative business models to address MUD challenges. Consider providing funds for panel upgrades where the cost is prohibitive but the benefits are clear.

- » Continue to partner with the Governor's Office to help complete the West Coast Green Highway connecting California to Oregon and support deployment of DC fast chargers in convenient locations along highway corridors in California. This will provide PEV drivers with a reliable backbone of refueling options.

- » Provide support to address congested EVCS in metropolitan areas. Explore and demonstrate new refueling and pricing strategies to efficiently deploy EVCS so that PEV drivers can reliably recharge when needed.

» **Continue to support and fund regional PEV readiness plans**. The Energy Commission should monitor the completion of ongoing regional PEV readiness plans and coordinate EVCS siting plans with statewide efforts. Furthermore, the Energy Commission should continue providing funds to help all regions of California prepare for electric vehicles.

112 http://www.its.ucdavis.edu/research/publications/publication-detail/?pub_id=2002.

CHAPTER 4: Alternative and Renewable Fuel and Vehicle Technology Program—Measuring ARFVTP Success, Benefits, and Metrics

As noted previously, the purpose of the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) is to "…develop and deploy innovative technologies that transform California's fuel and vehicle types to help attain the state's climate change policies."[113] By definition, the primary metric for evaluating the effectiveness of the ARFVTP is to measure the near- and long-term reductions in petroleum fuel use and greenhouse gas (GHG) emissions from the transportation sector. The program, however, generates many additional benefits for Californians, including technology advancement, air quality benefits, economic development, and market transformation.

The accomplishments of the ARFVTP are summarized in Chapter 1, while the resulting benefits are quantified below. The Energy Commission has reported on the benefits of the program, in accordance with Assembly Bill 109 (Núñez, Chapter 313, Statutes of 2008) (AB 109), since 2011 in the *Integrated Energy Policy Report* (IEPR). This chapter first provides an overview of the benefits generated from the ARFVTP, followed by findings from an analysis conducted by the National Renewable Energy Laboratory (NREL) to estimate GHG emission reductions and petroleum displacement resulting from program investments. As achieving these and other benefits are the driving force of the program, the chapter discusses how the Energy Commission applies the metrics included in Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) (AB 8) to make funding decisions. Also presented are insights from experts who participated in the June 12, 2014, workshop to discuss their experience with applying metrics and their recommendations for the Energy Commission's program. Next is a summary of NREL's preliminary estimate of public health and social benefits, put into monetary values. Finally, the chapter closes with recommendations for future work.

Benefits of the ARFVTP to Date

The ARFVTP statutes list a series of directives and preferences that can be used as metrics to measure and evaluate the benefits of the ARFVTP. These metrics include petroleum and GHG emissions reductions, market transformation, technology advancement, sustainability, air quality benefits, economic development,

113 Health and Safety Code Section 44272(a).

and benefit-cost.[114] In many cases, these metrics are interrelated. For example, low-carbon electric drive or fuel cell electric cars and trucks also create air quality benefits through reduced levels of criteria emissions and particulate matter (PM), which create public health benefits that can be monetized to reflect dollar-equivalent value. When the companies that manufacture these technologies are located in California, they also create employment and economic development benefits and generate a series of intellectual properties that, in turn, leverage additional technology advancements and economic development.

Table 6 illustrates how measureable changes in California's transportation system can be viewed in the context of the ARFVTP statutory requirements and funding preferences. The roughly $500 million the Energy Commission's ARFVTP has invested is expected to reduce between 3.4 million and 5.3 million tonnes carbon dioxide equivalent (CO_2e) and displace between 441 million and 693 million gasoline gallon equivalents/diesel gallon equivalents annually by 2025. ARFVTP is improving air quality and will reduce from 100 to 178 tons of PM2.5 by 2025. ARFVTP has helped create almost 6,400 new jobs in California and is funding the training of more than 13,600 technicians and maintenance personnel throughout the state. As the Energy Commission makes additional investments, these benefits will grow. As shown, the ARFVTP is meeting the statutory objectives and is contributing to several key policy goals articulated in Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007) (AB 118) and AB 8. Key metrics and benefits are discussed in greater detail in subsequent sections of this chapter.

Table 7 illustrates that the market transformation toward a low-carbon, low-emission transportation system is underway, as evidenced by the substantial increases in electric vehicles and chargers, electric trucks, natural gas trucks, and hydrogen fueling infrastructure. ARFVTP investments in technology development and manufacturing support for medium- and heavy-duty electric and fuel cell electric trucks will further market transformation toward cleaner solutions in a transportation sector that represents the largest overall contribution to California's total GHG, criteria, and particulate emissions.

AB 8 directs the Energy Commission to invest in a portfolio of vehicle technologies and fuels, stating that the Commission should "…develop and deploy technology and alternative and renewable fuels in the marketplace, without adopting any one preferred fuel or technology."[115] The basic distribution of ARFVTP funding among the four primary fuel categories ranges from 18 to 30 percent of total funding. The Energy Commission initiated this portfolio investment approach in the initial *2008-2009 ARFVTP Investment Plan* and has maintained it throughout program implementation.

Market diversity can be assessed by comparing the number of market participants in 2009-2010 when ARFVTP funding began to the current number of market participants. For example, in 2009 there were three companies developing and operating hydrogen fueling stations in California; now there are nine. There were about 5 primary providers of electric charging equipment; now there are more than 15.

The ARFVTP is contributing to the state's efforts to reduce petroleum consumption and GHG emissions and is contributing to better air quality in many parts of California. The ARFVTP sustainability goals are also being achieved; forest and meadow wildlands are not being converted to bioenergy crops or plantations, and sensitive habitats and ecosystems are not being impacted.

114 Health and Safety Code Section 44272(d).

115 Health and Safety Code Section 44272(a).

Table 6: Measurable Changes in California's Transportation System Using ARFVTP Statutory Guidance and Preferences as Metrics

ARFVTP Statutory Guidance*	Metric	Measurable Change	
"Transform California's fuel and vehicle types"	Increase in diversity and quantities of alternative fuels and vehicles	See Table 7.	
Portfolio Approach: Develop and deploy technologies and fuels without a preferred fuel or technology	Diversity of ARFVTP investments across multiple alternative fuels and vehicle technologies	From Table 3: ARFVTP Funding by Fuel Category	Biofuels 20% Electric Drive 30% Natural Gas 16% Hydrogen 18% Program Support 16%
Measurable transition from petroleum to alternative fuels	1: Absolute change in petroleum fuel use in California	California's on-road petroleum fuel use has declined 7.3 percent (1.1 billion gallons) for gasoline between 2003 and 2013 and increased by 5.5 percent (182 million gallons) for diesel during the same period. (source: Energy Commission staff)	
	2: Changes in petroleum fuel use attributable to ARFVTP investments	On-road petroleum fuel use is projected to decrease from 441 million to 693 million gallons by 2025.	
Consistency with climate change policy and low-carbon fuel standard	1: Absolute change in transportation sector greenhouse gas emissions in California.	On-road greenhouse gas emissions have declined 4.7 percent between 2000 and 2011, decreasing from 162.9 million metric tonnes to 155.11 million metric tonnes (ARB *Greenhouse Gas Inventory 2000-2011*)	
	2: Changes in transportation carbon emissions attributable to ARFVTP investments.	Greenhouse gas emissions are projected to decrease by 3.4 to 5.3 million metric tonnes by 2025.	
Ability to reduce air quality impacts	Projected reductions in NO_x** and particulate matter emissions from ARFVTP investments	Transportation-related PM2.5 is projected to decrease by 100 to 178 tons by 2025.	
Decrease life-cycle discharge of water or other pollutants	1: Water use of alternative fuels compared to water use of petroleum on equivalent per-gallon basis.	The Energy Commission is tracking the progress of ongoing studies investigating the relative water use and waste water discharge rates of alternative fuels compared to petroleum fuels.	
	2: Relative water use of projects proposed in response to a specific ARFVTP solicitation.	Water use rates are part of the sustainability scoring criteria applied in each solicitation.	
No adverse impacts on sustainability of natural resources	1: Number of California Environmental Quality Act findings of Significant Adverse Effect due to an ARFVTP project.	Zero. In fact, the vast majority of ARFVTP projects are classified as Categorically Exempt under CEQA.	
	2: Number of acres of wildland converted for feedstock supplies as part of an ARFVTP project.	Zero. No projects have been approved that would result in the conversion of wildland to managed production of an alternative fuel feedstock.	
Provides nonstate matching funds	Amount of applicant-furnished match funding.	Current ratio of ARFVTP grant amounts to applicant-furnished match is 1:1.6. For $482.5 million in ARFVTP capital project grants, total match amount is $762.3 million.	

(Continued on next page)

Table 6: Measurable Changes in California's Transportation System Using ARFVTP Statutory Guidance and Preferences as Metrics (Continued)

ARFVTP Statutory Guidance*	Metric	Measurable Change
ARFVTP Statutory Guidance*	Metric	Measurable Change
Provides economic benefits or promotes California firms and jobs	1: Economic assessment of total economic benefits attributable to ARFVTP. 2: Estimate of number of jobs to be created as a result of ARFVTP projects.	To be conducted as part of the programmatic assessment underway by RAND Corporation. Through July 2013, total estimated job creation from ARFVTP projects was 6,374.
Uses existing or proposed fueling infrastructure	Project categories that can or cannot use existing fueling infrastructure.	Electricity and natural gas fueling can tier from existing bulk transmission infrastructure but require new interface for vehicle fueling. Ethanol, biodiesel, biogas and hydrogen require new infrastructure.
Reduces life-cycle emissions by more than 10 percent.	Carbon intensity values of ARFVTP projects.	All currently funded ARFVTP projects have carbon intensity values that provide greater than a 10 percent reduction from the petroleum baseline. The primary alternative fuels vary by category but range from an 18 percent reduction for liquefied natural gas (LNG) fueling stations to negative 114 percent for biogas from high solid anaerobic digestion.
Uses alternative fuel blends of greater than 20 percent	Number of projects that meet 20 percent threshold requirement.	All ARFVTP-funded projects meet this threshold.
Drives new technology advancement and promotes deployment	Number of projects that do or do not drive technology advancement and deployment.	All ARFVTP capital project grants drive new technology advancement and deployment in California.
Additional preference for projects with higher benefit-cost scores.	Relative cost per ton of CO2-equivalent greenhouse gas emissions.	Benefit-cost considerations are part of each solicitation. The relative weight of the benefit-cost score varies by commercial maturity of the technology.

*Statutory guidance reflects Health and Safety Code Section 44272 (c) and (d).
**NO_x refers to oxides of nitrogen

Source: Energy Commission staff

Table 7: ARFVTP and Air Quality Improvement Program Funding Impact on Infrastructure and Vehicle Deployment in California (Through December 2014)

	Fuel Area	Existing 2009-2010 Baseline Levels	Additions from ARFVT or AQIP Program Funding	Percent Increase
Alternative Fueling Infrastructure	Electric	2,540 charge points	9,369 charge points *(residential, public, workplace, DC fast charger)*	368
	E85	39 fueling stations	161 fueling stations	412
	Natural Gas	443 fueling stations	60 stations	14
	Hydrogen	6 public fueling stations	48 fueling stations	800
Alternative Fuel Vehicles	Electric Cars (ARB Vouchers)	13,268 *(mostly neighborhood electric vehicles)*	(21,000 – ARFVTP) 89,314 – Total AQIP*	673
	Electric Trucks	1,409	160	11
	Natural Gas Trucks	13,995	2,725	19

* Current through December 2014. ARFVTP funding accounts for 27 percent of total CVRP vouchers.

Source: Energy Commission staff

Petroleum Reduction and GHG Reduction Benefits from ARFVTP

For the *2014 IEPR Update*, the Energy Commission contracted with NREL[116] to calculate the expected benefits of the ARFVTP consistent with the statutory requirements of AB 109. Dr. Marc Melaina, principal investigator, and his team expanded on the methods, data, and timeline developed for the 2013 Benefits Report.[117] NREL analyzed updated ARFVTP project data for 290 projects totaling $515 million, representing project updates as of September 2014, including important recent project announcements, such as the Energy Commission's award for 28 new hydrogen stations in May 2014.[118]

NREL has developed a framework of four quantifiable benefit categories for petroleum reduction, GHG emissions reductions, and criteria emissions reductions:

Baseline Benefits expected to accrue without support from ARFVTP.

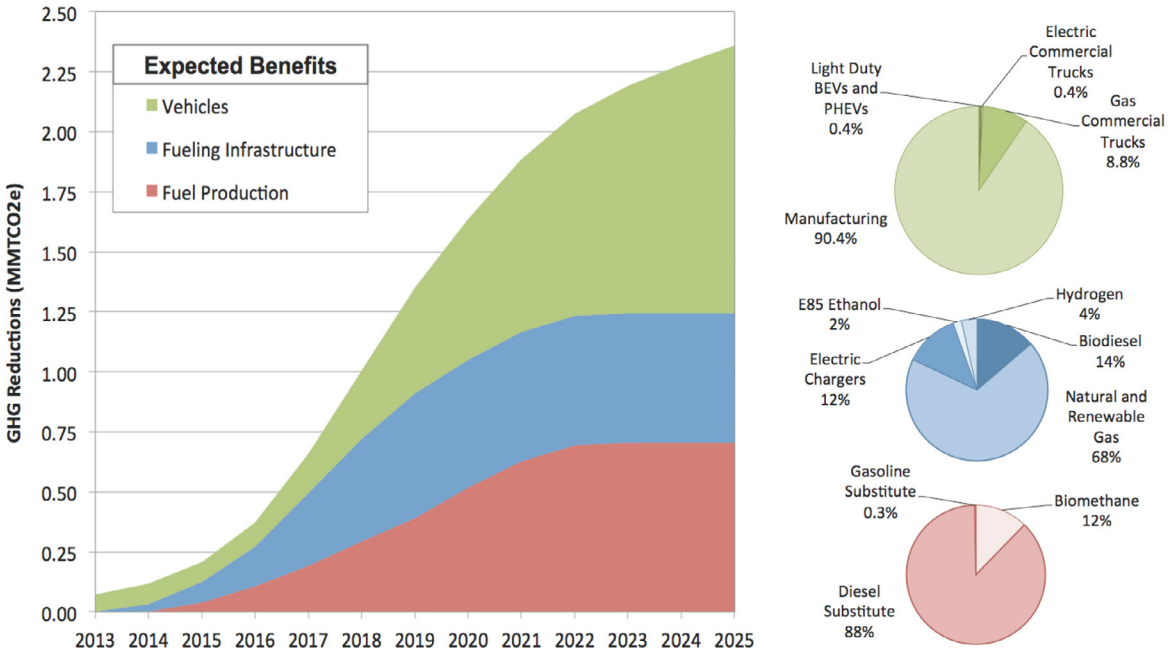
Expected Benefits directly associated with vehicles and fuels deployed through projects receiving ARFVTP funds. Expected benefits are quantified as the most likely benefits to occur from ARFVTP projects being executed successfully, assuming one-to-one substitution of the service or technical performance of the new technology replacing the existing technology. Project categories include vehicles, refueling infrastructure, and fuel production.

116 California Energy Commission Agreement Number 600-11-002.

117 Melaina, Dr. Marc et al, National Renewable Energy Laboratory, *Draft Analysis of Benefits Associated with Projects and Technologies Supported by the Alternative and Renewable Fuel and Vehicle Technology Program,* November 2013.

118 Melaina, Dr. Marc et al, National Renewable Energy Laboratory, *Draft Analysis of Benefits Associated with Projects and Technologies Supported by the Alternative and Renewable Fuel and Vehicle Technology Program,* June 2014, CEC-600-2014-005-D. The draft analysis was supplemented with a final set of benefits calculations submitted to the Energy Commission by NREL in December 2014.

Figure 8: Summary of Annual GHG Emissions Reductions Through 2025 From Expected Benefits of 178 Funded Projects



Source: NREL

NREL evaluated 223 of the 461 total projects funded as of September 2014, to determine expected benefits.

Market Transformation Benefits accrue due to the influence of ARFVTP projects on future market conditions to accelerate the adoption of new technologies. Influences include increased availability of public electric vehicle supply equipment and hydrogen refueling stations, consumer incentives for zero-emission vehicles (ZEVs), investments in ZEV demonstrations and manufacturing facilities, deployment of next-generation fuel production facilities, and advanced truck demonstrations. NREL evaluated these seven categories of ARFVTP-funded projects to determine market transformation benefits.

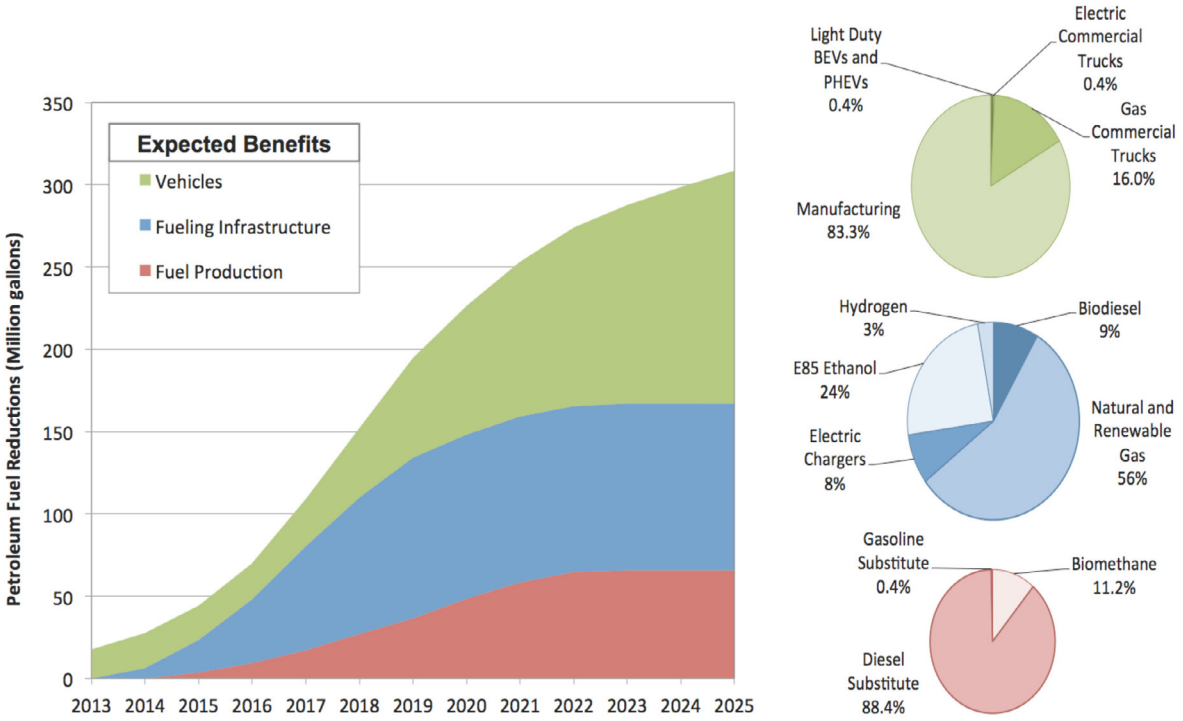
Required Carbon Market Growth Benefits: associated with projections of future market growth trends comparable to those needed to achieve deep reductions in GHGs by 2050.

See Appendix C for the full list of ARFVTP projects analyzed by NREL and Appendix D for information on the methods used to estimate expected benefits.

Expected Benefits Results

Of the projects NREL analyzed for expected benefits, ARFVTP has invested $110 million (17 projects) in vehicles, $160 million (139 projects) in refueling infrastructure, and $120 million (38 projects) on fuel production infrastructure. Figure 8 shows estimated total GHG emissions reductions across broad project categories. The GHG emission reductions are comparable among the three categories by 2025, ranging from 0.5 to 1.1 MMT-CO_2e. The steady growth in GHG reductions in the vehicle category is due largely to electric drive vehicle production and manufacturing projects for medium- and heavy-duty trucks. The pie charts to the right of the figure indicate the percentage of cumulative reductions over the period for various project subcategories, with manufacturing, natural and renewable natural gas, and diesel substitute dominating the vehicles, fueling infrastructure, and fuel production categories, respectively.

Figure 9: Summary of Annual Petroleum Fuel Reductions From Expected Benefits Through 2025



Source: NREL

Figure 9 shows total petroleum use reductions across these major project categories. Annual petroleum use reductions by 2025 includes 141 million gallons per year from vehicle projects, 102 million gallons per year from refueling infrastructure, and about 66 million gallons from fuel production projects. In sum, petroleum fuel reductions for all three expected benefit categories approach 308 million gallons per year by 2025.

In comparing petroleum fuel and GHG reductions, the refueling infrastructure makes a larger relative contribution to petroleum fuel reductions than GHG reductions. This is due largely to ethanol and natural gas refueling stations displacing large volumes of petroleum fuel, despite the relatively high fuel carbon intensity compared to fuels used in other projects.

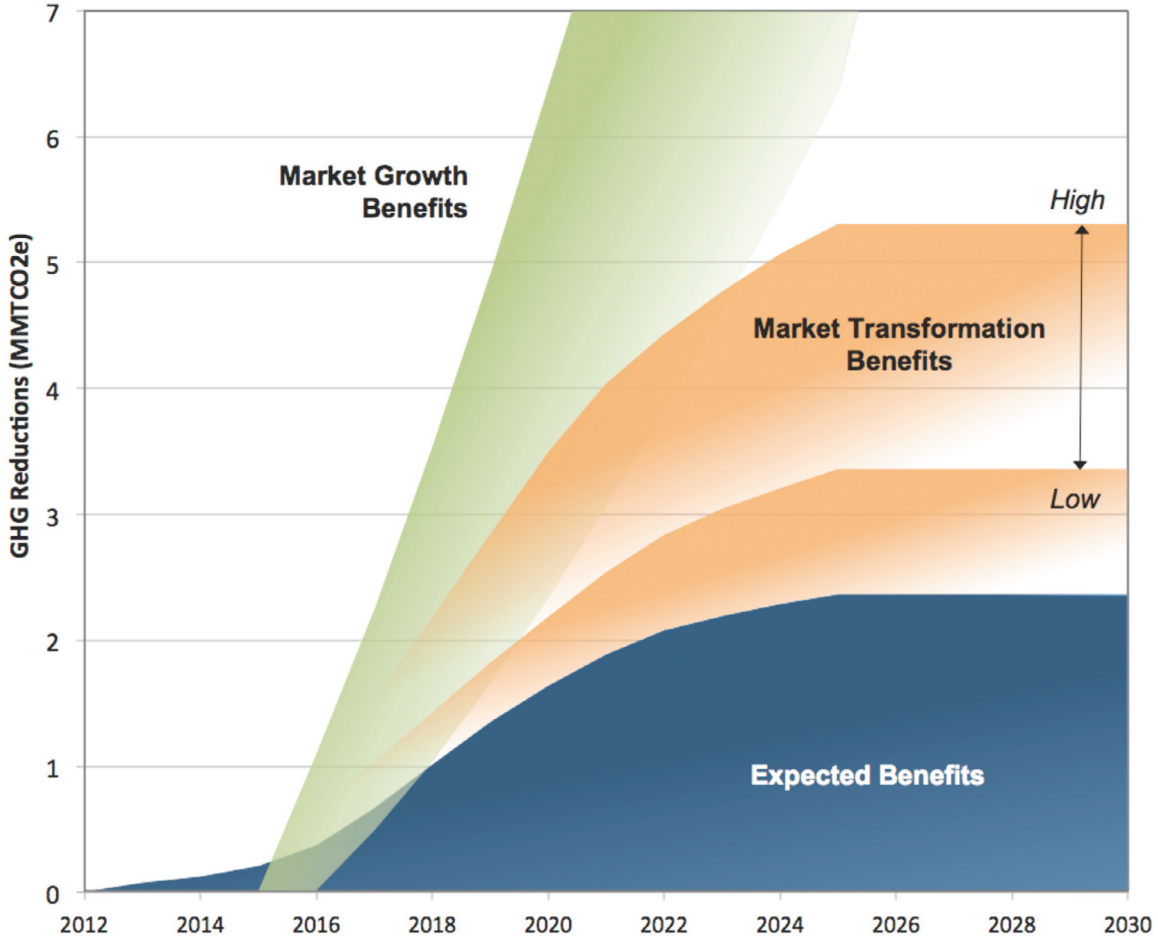
See Appendix E for more detailed information on the progression of GHG and petroleum fuel reductions over time in five-year increments.

Market Transformation

The Energy Commission's core mission with ARFVTP is to transform California's petroleum-based transportation system into a low-carbon, low-emission transportation system. Market transformation benefits are as real and tangible as the direct or expected benefits described earlier. They are, however, based upon more uncertain data and more hypothetical estimation methods than the expected benefits in terms of GHG reductions and petroleum use reductions.

Market transformation may be *second order* benefits that follow from successful deployment of technologies. For example, the goal in demonstrating a small-scale biofuel production process would be to validate the technology, production process, and production costs, all of which are critical to future market success. Yet this important technology validation would yield only a small volume of low-carbon fuel that is directly attributable to the initial ARFVTP project grant (expected benefit). A

Figure 10: GHG Reductions From Expected and Market Transformation Benefits in Comparison to Needed Market Growth Benefits



Source: NREL

successful demonstration project would increase the likelihood of larger-scale deployment by the initial company and perhaps by other companies. A successful demonstration would also provide performance and potential market data to attract new private or public funding. The magnitude of these future benefits is measured by NREL as market transformation benefits. For more information on the methods used to measure market transformation benefits, see Appendix D.

Market Transformation Benefits Results

Market transformation benefits are additive to the expected benefits. Figure 10 shows the total range of expected and market transformation GHG reduction benefits from ARFVTP projects, which are projected to range from 3.4 to 5.3 $MMTCO_2e$ by 2025. Overall, California expects the suite of adopted transportation sector measures, including the Low Carbon Fuel Standard and the Advanced Clean Cars program, will result in GHG emission reductions of

23 $MMTCO_2e$ in 2020.[119] The largest proportion of these emission reductions are expected to come from the Low Carbon Fuel Standard program, reducing 15 $MMTCO_2e$ in 2020.[120] Significant ongoing public and private sector investments will be needed to continue developing advanced technologies, low-carbon fuels, fueling infrastructure, and vehicles to build consumer and commercial market acceptance for these products. See Appendix D for more detailed results of NREL's analysis of market transformation benefits.

How the ARFVTP Implements Metrics in Statute

Existing law asks the Energy Commission to "…provide preferences to those projects that maximize the goals of the Alternative and Renewable Fuel and Vehicle Technology Program, based on [11 criteria]."[121] These projects include those that help transition away from petroleum to a diverse portfolio, are consistent with climate change policy, help reduce pollution, and provide economic and other social benefits.

Each of the criteria provided in the ARFVTP statute is used to varying levels in each ARFVTP solicitation as a series of weighted scoring factors. The weight factors are adjusted to fit the characteristics of each technology area. For example, biofuels projects with the potential to impact natural resources have relatively high sustainability scoring criteria, while mature market technologies with multiple vendors may have relatively higher benefit-cost scoring criteria than technologies still in the development and demonstration phases. Implementation of the cost-benefit criteria is discussed in more detail below.

Integration of the ARFVTP statutory preferences began in 2008 with the initial ARFVTP rulemaking and eventual adoption of program regulations by the Energy Commission. Each of the statutory preferences has been incorporated into program regulations.[122] The initial sustainability provision resulted in one of the most comprehensive sustainability regulations ever devised for an alternative transportation funding program. In addition to preferences for alternative fuel and vehicle projects with very low-carbon intensity values, the Energy Commission established a series of sustainability factors that include preferences for projects that:

- Maximize the use of waste-based feedstocks.
- Avoid disruption or conversion of wildlands for energy crop production.
- Use energy crops suited to California soils and climate.
- Minimize the use of water for irrigation or fuel production.
- Maximize the use of renewable energy.
- Maintain the ecological integrity of forest stands when biomass is collected through thinning or forest management. Use third-party sustainability certifications, such as the Roundtable on Sustainable Biofuels or the Forest Stewardship Council.

119 California Air Resources Board, *First Climate Change Scoping Plan Update*, Table 5. "Meeting the 2020 Emissions Target," May 2014.

120 California Air Resources Board, Low Carbon Fuel Standard Advisory Board Meeting, Staff Presentation, May 19, 2014, as reported by Jim McKinney, staff presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

121 Health and Safety Code, Sec. 44272(c).

122 Final Regulation Language: Alternative and Renewable Fuels and Technologies Program, Title 20, California Code of Regulations Sections 3100- 3108, CEC-600-2008-013- F, April 2009.

Implementation of Cost and Benefit-Cost Metrics in the ARFVTP

AB 8 introduced a new element into the list of policy and scoring preferences for ARFVTP: the GHG benefit-cost score. The benefit-cost score is defined as "…a project's expected or potential greenhouse gas emissions reduction per dollar awarded by the Commission to the project."[123] AB 8 also directs the Energy Commission to "…give additional preference to funding those projects with higher benefit-cost scores."[124]

A standard ARFVTP solicitation for project proposals contains from five to eight scoring factors that are used to evaluate each proposal. These scoring factors include team qualifications, business and financial plans, technology readiness, project readiness under the California Environmental Quality Act (CEQA), project budget and benefit-cost, economic benefits, and sustainability. Each scoring criterion is assigned a weight factor that denotes the relative importance of one criterion versus another. Each proposal is scored by an Energy Commission staff review team using a 10-point scale, then each evaluation criterion receives a score that is multiplied by the weighting factor, and the highest scoring proposals are awarded funding.

The benefit-cost provision is already used as a weighted scoring factor in most ARFVTP solicitations in the budget section, and consistent with the direction in AB 8, the Energy Commission will continue to use the benefit-cost provision as a preference applied at the solicitation level among similar types of projects.[125]

The Energy Commission's implementation of cost-benefit metrics for project-level evaluation is consistent with advice from numerous experts at the 2014 IEPR workshops. For example, Tom Cackette, consultant and former deputy executive officer for the ARB, suggested that the benefit-cost metric is best used when comparing similar projects and should be only one factor in identifying projects.[126] Jeff Rosenfeld of ICF International presented a matrix of benefit-cost assessments for a variety of diesel pollution control measures and alternative fuel technologies on behalf of Southern California Edison.[127] He emphasized that single-factor, benefit-cost assessments for oxides of nitrogen (NO_x), PM, or GHG emissions would risk underestimating the total societal and public health benefits of alternative fuels and technologies. As examples, he said that a compressed natural gas (CNG) transit bus and electric forklift would score well in a broad metric system that integrated petroleum reduction, GHG emissions, NO_x, and PM, but stated these same technologies would score very low on a single-factor benefit-cost analysis. The Energy Commission's current project evaluation and scoring process balances the competing attributes among projects within a common technology band by using scoring factors based on the 11 preferences defined in statute.

Energy Commission staff prepared four examples to illustrate how the program is planning to calculate the GHG benefit-cost scores for fuels and technologies in varying phases of commercialization or market maturity. These examples include biodiesel production, workplace electric chargers, heavy-duty CNG trucks, and hydrogen fueling stations. For each example, staff calculated a high- and low-range scenario for the amount of petroleum that would be displaced by each project type over a 10-year period. This petroleum reduction was multiplied

123 Health and Safety Code, Sec. 44270.3(a).

124 Health and Safety Code, Sec. 44272(d).

125 Charles Smith, California Energy Commission, staff presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

126 Tom Cackette, Tom Cackette Consulting, presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

127 Jeff Rosenfeld of ICF, presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

Table 8: Examples of GHG Benefit-Cost Scores

Workplace EVSE (Level 2)	Low Case	High Case
ARFVTP cost:	$8,000	$3,000
KWh charged per day:	7.0	20.0
Work days per year:	250	250
KWh charged per year:	1,750	5,000
GGE displaced per year (inc. EER):	178	509
gCO2e/MJ of alternative fuel (inc. EER):	36.5	30.8
GHG emissions reductions/ year:	1.3	4.2
10-year GHG emissions reductions:	13.4	41.7
10-year GHG benefit cost (tonne/$1M):	**1,670**	**13,886**

Heavy-Duty CNG Truck Incentive	Low Case	High Case
ARFVTP share:	$20,000	$20,000
Displaced vehicle's annual VMT:	15,000	50,000
Displaced vehicle's miles per DGE:	7.0	4.0
Annual DGE displaced:	2,143	12,500
EER of NG vehicles:	0.95	0.95
gCO2e/MJ of alternative fuel (inc. EER):	71.58	71.58
GHG emissions reductions/year (tonnes):	7.6	44.6
10-year GHG emissions reductions:	76	446
10-year GHG benefit cost (tonne/$1M):	**3,822**	**22,293**

Diesel Substitute Production Facility-Commercial	Low Case	High Case
ARFVTP share:	$5,000,000	$2,600,000
Annual production (DGE):	365,000	4,800,000
Annual DGE displaced:	365,000	4,800,000
gCO2e/MJ of alternative fuel:	30	15
GHG emissions reductions/year (tonnes):	3,351	53,784
10-year GHG emissions reductions (tonnes):	33,507	537,840
10-year GHG benefit cost (tonnes/$1M):	**6,701**	**206,862**

Hydrogen Fueling Station	Low Case	High Case
ARFVTP share:	$2,000,000	$1,500,000
Daily station capacity (kg):	180	300
Annual station capacity (kg):	64,800	108,000
Miles per kg of average FCV:	65	65
MPG of displaced conventional vehicle:	25	25
Annual GGE displaced:	168,480	280,800
gCO2e/MJ of alternative fuel (inc. EER):	40.9	29.2
GHG emissions reductions/year (tonnes):	1,175	2,353
10-year GHG emissions reductions (tonnes):	11,753	23,533
10-year GHG benefit cost (tonnes/$1M):	**5,877**	**15,689**

Source: Energy Commission estimates. Note: Blue shaded cells denote inputs or variable, white/yellow cells are outputs, and green cells reflect the final value of GHG emissions reduced per $1 million in ARFVTP funding.

by the carbon intensity value of the alternative fuel to estimate a total volume of GHG emissions that would be reduced during 10 years of project operation. This figure was then divided by the ARFVTP investment to get a final GHG benefit-cost score expressed in terms of tons of GHG emissions reduced per $1 million in ARFVTP funding.

As shown in Table 8, the GHG benefit score can vary widely depending on what assumptions are used for each fuel and technology category. For the low-case scenarios, each of the four examples is within an order of magnitude and ranges from a high of 6,701 tonnes of carbon reduced per million dollars of ARFVTP funding for a biodiesel biorefinery to a low of 1,670 tonnes of carbon reduced for a workplace level 2 charger. For the high-case scenarios, which assume very high throughput and use rates and the lowest reasonable carbon intensity values, there is a much wider range of benefit-cost scores. The biodiesel biorefinery has a score of 206,862 tonnes of carbon reduced per million dollars of ARFVTP investment, and the workplace level 2 charger has the lowest cost-effectiveness with a score of 13,886 tonnes of carbon reduced per million dollars invested.

The Energy Commission's current strategy is to place higher emphasis on the benefit-cost score for technologies that are more commercially mature and have multiple competing vendors and standardized design and technical performance attributes, and to de-emphasize the benefit-cost score for technologies that are in the precommercial demonstration phase. In cases where there is an absolute numeric tie between competing proposals within a single solicitation, the Energy Commission will break the tie by using the benefit-cost score.

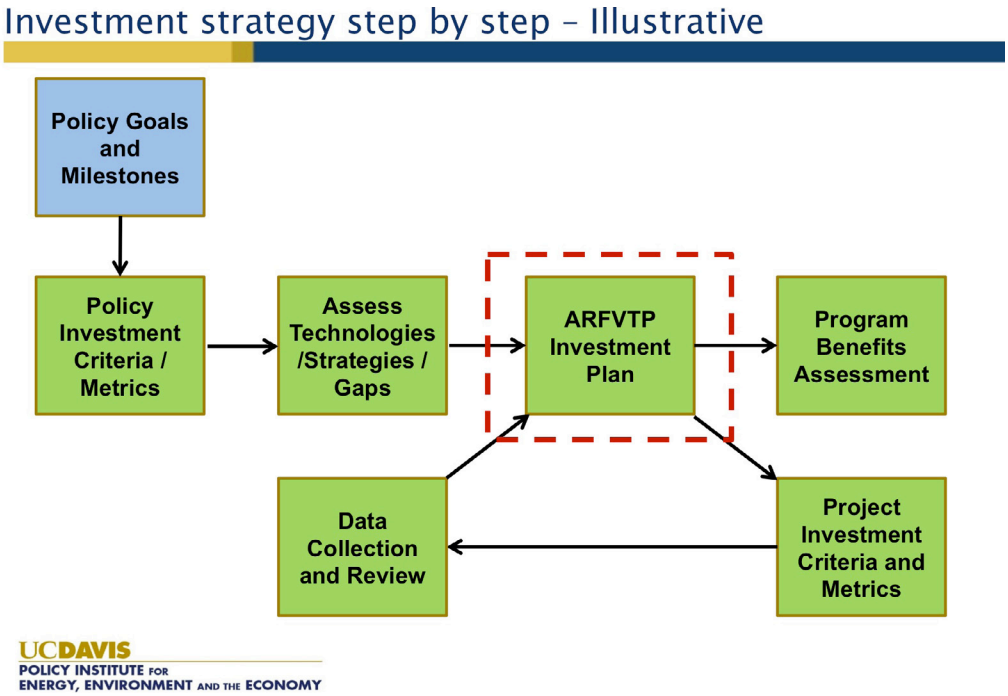
Energy Commission staff has used variations on the benefit-cost concept since the initial round of funding solicitations. In earlier solicitations, this concept was expressed in terms of budgeting or project efficiency. For example, did the project proposal have a budget that was commensurate with the scale and commercialization phase of the technology? Was it judicious in its allocation of public funding to equipment, engineering, or salaries? In later solicitations, such as the 2012 alternative fueling infrastructure solicitation, this criterion evolved to include cost-effectiveness with a relatively high weighting factor. Commercially mature technologies with superior cost-effectiveness quotients were scored more highly than less cost-effective projects. In 2013 and 2014, solicitations evolved again to explicitly include benefit-cost as a scoring criterion.

Additional Perspectives on Applying Metrics to Funding Decisions

At the June 12, 2014, IEPR workshop, representatives from federal and state agencies, regional air quality regulatory agencies, environmental groups, utilities, and academia provided insights and recommendations on applying metrics to funding decisions. Anthony Eggert of the UC Davis Policy Institute for Energy, Environment, and the Economy presented a typology for evaluating the ARFVTP that the Energy Commission could use to inform investment choices. Mr. Eggert used the ARFVTP statutory metrics to evaluate projects in terms of progress developing alternative, low-carbon, and low-emission technologies for the transportation sector. Shown in Figure 11 is a graphic he presented showing how information derived from metrics can be used to inform future Investment Plan funding levels.[128] Mr. Eggert encouraged the Energy Commission to more fully use the program benefits reporting data from NREL and summary project-level data from completed projects to evaluate whether Investment Plan funding allocations policies were meeting the original policy goals articulated in each Investment Plan and discussed in Advisory Committee meetings.

128 Anthony Eggert, University of California Davis Policy Institute for Energy, Environment and the Economy, presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

Figure 11: Relation Among Policy Goals, Project and Market Information, and ARFVTP Investment Plan Funding Levels



Source: UC Davis Policy Institute for Energy, Environment, and the Economy

In addition to providing a framework to evaluate program benefits, this approach can also provide a way of adapting and continuously improving the program and project selection going forward.

Others at the workshop provided information about how they apply metrics to inform their funding decisions. Federal, state, and regional air quality regulatory agencies have long used benefit-cost criteria to evaluate projects under programs such as the federal Diesel Emissions Reduction Act program or the state's Carl Moyer or Proposition 1B Goods Movement programs.

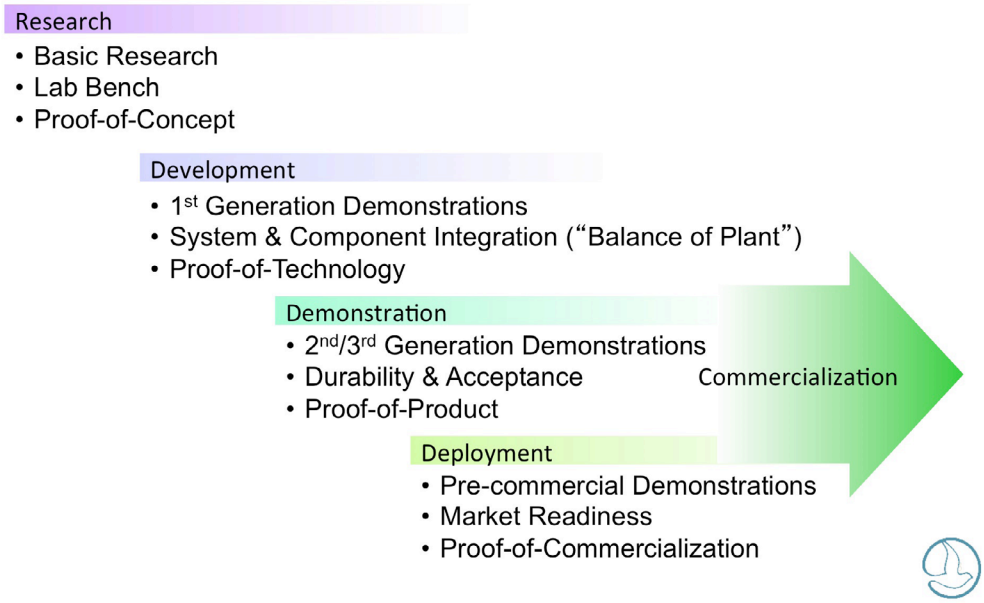
Amy Zimpfer from the U.S. Environmental Protection Agency (U.S. EPA) reported that her agency uses a series of regulatory, public health, and carbon metrics for regulatory and project funding purposes.[129] The U.S. EPA calculates the long-term benefits of air quality regulations as part of its regulatory impact analysis requirements on new industry regulations intended to reduce air emissions. Ms. Zimpfer said that the monetized public health benefits typically exceed costs to industry by wide margins, often measuring in the billions of dollars. She encouraged the Energy Commission to include air quality and public health benefits in its assessment of benefits.

Erik White, Chief of the Mobile Source Control Division, reported that the California Air Resources Board (ARB) uses a variety of benefit-cost metrics when evaluating projects for funding from the Carl Moyer and Proposition 1B Goods Movement Emission Reduction programs.[130] Both programs provide incentive funding for retirement and replacement of diesel trucks and use a rigorous and well-defined benefit-cost metric when selecting projects. However, in response to AB 8, ARB staff

129 Amy Zimpfer, U.S. Environmental Protection Agency, presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

130 Erik White, California Air Resources Board, presentation at the June 12, 2014 Integrated Energy Policy Report workshop.

Figure 12: Technology Development Phases



Source: South Coast Air Quality Management District

developed a set of GHG benefit-cost metrics that will be applied to the Clean Vehicle Rebate Project and the Hybrid Bus and Truck Incentive Program. ARB staff developed six additional metrics for these programs that include GHG emission reductions, market transformation benefits, and air quality and public health benefits.

Dr. Matt Miyasato with the South Coast Air Quality Management District (AQMD) discussed market transformation and the potential for meaningful impacts as important considerations when evaluating precommercial technology projects. Based on the South Coast AQMD's emissions inventory, heavy-duty trucks are a leading contributor to poor air quality as sources of NO_x, PM, and toxic emissions. By focusing on advanced zero- and low-emission technologies in the truck sector, such as electric drive, fuel cell electric drive, and low NO_x emitting natural gas, the South Coast AQMD can focus and maximize the effectiveness of its funding, which averages $10 million to $20 million per year.[131]

Dr. Miyasato reported that the South Coast AQMD uses different metrics for different phases of technology development.[132] For Moyer and Proposition 1B funding for clean diesel trucks, it uses the same stringent benefit-cost metrics that the U.S. EPA and ARB use to identify the most cost-effective projects. He said that the Technology Advancement Program funds that the South Coast AQMD administers are similar to ARFVTP with its emphasis on demonstration and pre-commercial advanced technology truck projects. Figure 12 shows this progression from research to commercially viable projects.

Dr. Miyasato offered three suggestions for Energy Commission consideration in choosing metrics: 1) maintain the portfolio approach; 2) leverage collaborative funding relationships with regional, state, and federal funding agencies; and 3) create market pull through policy directives or regulation so that the private commercial sector buys and uses the advanced technology vehicles being funded by government incentives.

131 Dr. Matt Miyasato, South Coast Air Quality Management District, presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

132 Dr. Matt Miyasato, South Coast Air Quality Management District, presentation at the June 12, 2014 Integrated Energy Policy Report workshop.

Mr. Cackette advised that the Energy Commission's primary metric should correspond to the carbon reduction policy goals of Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) (AB 32) and AB 8 and focus on the 80 percent reduction in GHG emissions that will be needed in 2050.[133] He offered a range of metrics for consideration:

» Will the project contribute to the policy goal?

» Is it a necessary technology or fuel or infrastructure?

» Can it have a large impact, or will it be a niche contribution?

» Is there a realistic long-term business case?

» What is the risk of success and failure?

V. John White of the Center for Environmental Efficiency and Renewable Technology recommended that the Energy Commission "keep its eye on the prize" by focusing on technologies and projects with the potential to achieve the very deep cuts in GHG emissions needed by 2050 and the deep cuts needed in NO_x emissions in 2023 and 2032.[134] He added that the areas with severe nonattainment for NO_x—the San Joaquin Valley and South Coast air districts—also tend to be the most disadvantaged communities that suffer the impacts of poor air quality and environmental justice. Mr. V. John White said that nonquantifiable variables like social equity and environmental justice need to be considered alongside quantifiable metrics. He advised that "there is no substitute for judgment … The metrics and the data and the quantification are to inform your judgment, but they're not to substitute for your judgment."

The Energy Commission is mindful of the limitations of single-attribute evaluation factors and of the limitations of overemphasizing any single technology against the broad benefits inherent with the portfolio approach to investing ARFVTP funds. If benefit-cost scores were to be weighted such that they predominate over other important factors like team qualifications, technology readiness, business and financial planning, or sustainability, the Energy Commission would risk overemphasizing projects that may not prove viable or successful over the long run, but that have the lowest near-term costs. Mr. White's suggestion to use metric information to inform judgments but not dictate them appears sound and reflects how Energy Commission staff evaluates project proposals along multiple equally important performance factors.

The Energy Commission is also mindful of the multiple benefits inherent with the portfolio approach. Results from the NREL benefits analysis show that the near-term reductions in petroleum and greenhouse gas emissions will come from biodiesel, E85 ethanol, and natural gas blended with biogas. ZEV technologies such as electricity and hydrogen figure moderately in the Expected Benefits but provide more substantial contributions to petroleum and GHG emissions reductions in later years as quantified with the Market Transformation benefits. If the Energy Commission had limited its early investments to ZEV technologies, the near-term petroleum and GHG emissions benefits from biodiesel, E85, and natural gas may have been diminished or precluded. As carbon loading to the atmosphere is cumulative, this could have meant higher ongoing carbon emission rates in the near term as ZEV technologies mature commercially and technologically. By using the portfolio approach, the Energy Commission is optimizing ARFVTP investment to create near-term and long-term benefits across multiple categories.

133 Tom Cackette, Tom Cackette Consulting, presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

134 V. John White, Center for Energy Efficiency and Renewable Technology, presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

Public Health and Social Benefits

Employment and Workforce Development Benefits

While the primary policy goals of the ARFVTP are the reduction of petroleum fuel use and transportation greenhouse gas and criteria emissions, economic development and job creation are important ancillary benefits. Based on the most recent survey data from 2013, the total number of direct jobs created through the construction and operation of ARFVTP-funded projects is almost 6,400; this includes about 3,200 long-term jobs and nearly 3,200 short-term jobs.

Workforce training and development are vital to the Energy Commission's efforts to advance California's clean transportation market. Skilled workers are necessary to address the alternative fuels and advanced vehicle technology market in California. To date, the $25 million in workforce development grants have created training opportunities for more than 13,600 individuals at more than 600 California businesses.

Public Health and Social Benefits

For the first time in 2014, NREL provided estimates of criteria and PM emissions reductions from ARFVTP-funded projects as part of its contract to provide projections of petroleum and carbon emissions reductions. As reported, projects supported through the ARFVTP result in significant reductions in vehicle tailpipe emissions, GHG emissions, and petroleum fuel use. These reductions result in social and environmental benefits, some of which can be quantified and then monetized to allow for comparisons to program costs or comparable benefits achieved through other efforts. The health benefits of reduced PM2.5 emissions include reduced premature deaths and morbidity, including avoided instances of upper and lower respiratory symptoms, bronchitis, asthma exacerbation, hospital and emergency room visits, and work-loss days. These health benefits can be quantified and monetized. GHG reductions can be monetized in terms of a *social cost of carbon* metric, and petroleum fuel import reductions can be monetized in terms of the economic costs of price spikes and pressure on global market demand.[135] Several other benefits may accrue due to ARFVTP projects, such as water use reductions or boosts to local and regional economies.

NREL estimated monetized benefits from reductions in PM2.5 tailpipe emissions, GHGs, and petroleum fuel use using quantitative methods that are more established and less uncertain compared to the monetization estimation methods proposed for other types of benefits.[136] Reductions in PM2.5 emissions are estimated for electric-drive vehicles, primarily light-duty PHEVs, BEVs and FCEVs, as well as some medium-duty PHEVs and BEVs. The health benefits from reduced PM2.5 tailpipe emissions are primarily due to reduced premature deaths and morbidity. These reductions range from 2 to 5 tons per year in 2025.[137] The monetized values of these PM2.5 reduction benefits range from $4 million to $8 million per year, with the benefit-per-unit reduction (million dollars per ton PM2.5 reduced, or $M/ton) varying significantly by county and averaging to $1.7 million per ton across all

135 Also referred to as an *oil security premium*, as discussed in Leiby, P. N. (2012). *Approach to Estimating the U.S. Oil Security Premium for the 2017-2025 Light -Duty Vehicle GHG/Fuel Economy Rule*. Supporting Doc for EPA Corporate Average Fuel Economy Rules, 1–12.

136 NREL Letter Memo, *Health Benefits for ARFVTP*, *Preliminary Analysis Results*, September 12, 2014.

137 These projected decreases in PM2.5 emissions from the transportation sector reflect only the emissions reductions attributable to Expected Benefits from direct ARFVTP investments as reported in the NREL Benefits Report. The PM2.5 emissions reductions reported earlier in Table 5 reflect total reductions attributable to Expected and Market Transformation Benefits.

Table 9: Summary of Total Monetized Health and Social Benefits From 178 Projects Funded Through August 2014

Benefit Estimate Type	Annual Benefit by 2025 ($M/year)	Annual Reduction		Benefit per Unit	
		Value	(units)	Value	(units)
Expected Benefits Only					
PM2.5 Reductions (High)	$8	5	tons	$1.7	$M/ton
PM2.5 Reductions (Low)	$4	2	tons	$1.7	$M/ton
Expected and Market Transformation Benefits					
GHG Reductions (High)	$314	4,248	103 tonnes CO2eq	$74	$/tonne
GHG Reductions (Low)	$42	2,809	103 tonnes CO2eq	$15	$/tonne
Petrol Reductions (High)	$104	566.2	million gal	$0.18	$/gal
Petrol Reductions (Low)	$62	338.6	million gal	$0.18	$/gal
All Benefit Estimate Types					
Combined (High)	$427				
Combined (Low)	$108				

Source: NREL

counties. Table 9 summarizes projected annual monetized public health and other social benefits achieved by 2025 due to the current ARFVTP investment portfolio.

These PM2.5 unit reduction benefits are based on damage costs derived from extensive studies of emissions and air quality dynamics resulting in adverse health impacts.[138] For this analysis, unit damage cost results by county, expressed in dollars per ton of PM2.5 vehicle tailpipe, brake wear, and tire wear emissions, have been used based upon U.S. EPA's Diesel Emission Quantifier modeling tool and data.[139] Given this geographic resolution, it is possible to estimate the value of reducing PM2.5 with respect to project location and likely vehicle operating areas, taking into account factors such as population density, demographics, and general ambient air quality.

Figure 13 shows variations by county in the results of this analysis, with Los Angeles, Orange, and San Francisco counties having the highest cumulative health benefits due to expected ZEV deployments resulting from ARFVTP projects. Moreover, the Energy Commission believes the total PM2.5 reduction health benefits from all ARFVTP projects funded to date are probably higher than these estimates given that many other non-ZEV projects can also result in PM2.5 reductions. Additional research is ongoing to better characterize the health benefits resulting from PM2.5 emission reductions associated with California climate policy influences.[140]

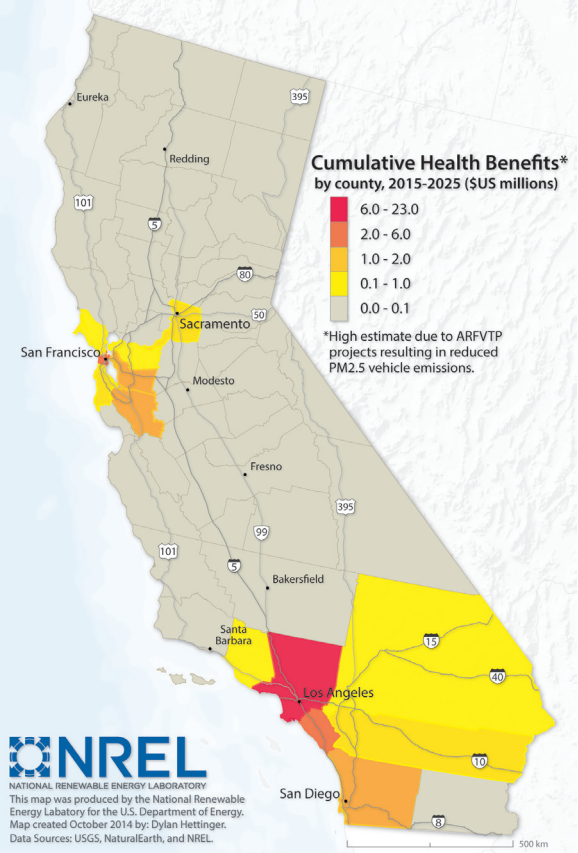
The U.S. EPA developed and uses the *social cost of carbon* values as part of its regulatory impact analysis for new federal regulations addressing GHG emissions. Ms. Zimpfer from EPA Region 9 described how the carbon reduction benefits from greenhouse gas reduction regulations generally measure billions of dollars in net social

138 Fann, N., Fulcher, C. M., and Baker, K. (2013). "The Recent and Future Health Burden of Air Pollution Apportioned Across U.S. Sectors." *Environmental Science & Technology*, 47(8), 3580–3589

139 Benefit per unit values by county based upon EPA's BenMAP model, as reported in the Diesel Emission Quantifier tool http://www.epa.gov/cleandiesel/quantifier/index.htm, (personal communication, John Mikulin, September 2014).

140 Zapata, C., Muller, N., and Kleeman, M. J. (2012). "PM2.5 co-benefits of climate change legislation part 1: California's AB 32." *Climatic Change*, 117(1-2), 377–397.

Figure 13: Monetized Health Benefits for Areas With High Electric Vehicle Penetration Resulting From Reduced PM2.5 Emissions, Shown by County in 2025



Source: NREL

benefits.[141] *Social cost of carbon* benefits associated with GHG reductions are due to reductions across a wide range of impacts associated with climate change. Climate change impacts include property damage and loss of agricultural and economic activity due to temperature changes, sea level rise, increase in extreme storm events, and increase in wildfires. The human health impacts include increases in cancers, heart attacks, and strokes, and incidents of respiratory disease. The corresponding social benefits are estimated by multiplying the GHG reductions from the Benefits Report by a high and low range of $75 and $15 per tonne of carbon dioxide equivalent emissions. Carbon benefit reduction values range from $42 million to $314 million per year by 2025. This is only one possible range that can be used to reflect GHG reduction benefits and is taken from a range of values reported in the multiagency Social Cost of Carbon report.[142]

NREL also calculates a range of energy security benefits from reduced petroleum fuel use. These benefits range from $62 million to $104 million per year. The social benefits estimated for petroleum fuel use reductions are based upon estimates of the national economic benefits of reducing petroleum fuel imports. These economic benefits include reductions in market disruptions resulting from oil price shocks and the monopsony premium due to increased pressure on global oil markets due to the size of U.S. demand. Spikes in the price of oil, which is determined by global markets, translate into increased domestic fuel costs. Reduced impacts to the U.S. economy from reductions in petroleum fuel use are categorized as *energy security benefits.*

The total monetized public health and social benefits from the current ARFVTP investment portfolio range from $108 million to $427 million per year in 2025 (Table 11). Cumulative benefits accrued from 2015 through 2025 may be on the order of four to six times greater, depending upon the rate at which projects are implemented and vehicles and fuels deployed. This rough estimate results in a range of $0.4 billion to $2.6 billion in total accrued benefits by 2025. As noted above, only a subset of total benefits is accounted for in this estimate. Including a broader range of social and environmental benefits would increase the total monetized benefits associated with the ARFVTP.

141 Amy Zimpfer, EPA Region 9 Air Division, presentation at the June 12, 2014, Integrated Energy Policy Report workshop.

142 IAWG, U. S. (2010). *Technical support document: Social Cost Of Carbon For Regulatory Impact Analysis Under Executive Order 12866*. Interagency Working Group on Social Cost of Carbon, United States Government, Washington, DC.

Recommendations

» **Expand outreach and increase participation of disadvantaged communities in Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) activities**. In keeping with the spirit of Senate Bill 535 (De León, Chapter 830, Statutes of 2012), "Investments to Benefit Disadvantaged Communities," the Energy Commission will continue to expand outreach to communities that have not traditionally been well-represented in ARFVTP funding activities. The Energy Commission anticipates coordinating with the California Environmental Protection Agency and California Air Resources Board as it carries out these activities. The Energy Commission will continue outreach efforts to inform a broader range of communities about the ARFVT program and solicitation process and continue to develop strategies that can direct ARFVTP funding to disadvantaged communities, as defined by the California Environmental Protection Agency, including scoring preferences, set-asides, and geographically focused solicitations.

» **Incorporate more project and programmatic-level data into future Investment Plans and solicitations**. Building on the approach presented by Anthony Eggert of UC Davis, the Energy Commission should investigate methods to better incorporate data collection, analysis and lessons from past ARFVTP projects to evaluate projects, market growth, and business plans for target technologies and sectors and to use that information to adapt and improve future Investment Plans and funding solicitations. Specifically, the Energy Commission should investigate how aspects of the U.S. Department of Energy's Annual Merit Review might be adopted and adapted for project and technology sector program review for ARFVTP. Also, the Energy Commission should incorporate more information from programmatic-level reviews, such as the National Renewable Energy Laboratory Benefits Report, technology roadmaps from U.S. Department of Energy and others, and the UC Davis Next STEPS Reports, into funding considerations and recommendations for Investment Plans.

» **Continue to incorporate health-based metrics and other social metrics**. Building on the recommendations of Amy Zimpfer of U.S. Environmental Protection Agency's (U.S. EPA) Region 9 Air Division, Energy Commission staff should continue to collect data and develop assessment tools that will allow for the reporting of health-based benefits and metrics. Also, building on the U.S. EPA's work on the Social Cost of Carbon, the Energy Commission should continue to develop data and reporting methods for the Social Cost of Carbon benefits.

» **Correlate ARFVTP statutory funding preferences with solicitation-level scoring criteria**. Energy Commission staff should develop a template that links the 11 statutory funding preferences to the scoring and evaluation criteria used in each solicitation (with the understanding that not all 11 preferences are used or equivalently weighted in every solicitation).

» **Continue to explore options for calculating and incorporating AB 8 benefit-cost metrics into the ARFVT program**. Energy Commission staff will continue to incorporate greenhouse gas benefit-cost metrics into solicitations as appropriate, commensurate with the commercial state of each technology. Commission staff will continue to work with a broad set of experts in metrics to explore various ways in which the benefit-cost could be calculated and incorporated into the ARFVTP.

» **Work with the Workforce Investment Board to promote advanced transportation and economic development**. A portion of ARFVTP funding provides support to help train today's workforce on advanced transportation technologies. The Energy Commission should continue to work with the Workforce Investment Board to ensure these training opportunities are available.

CHAPTER 5:
The State of Transportation Technologies Over the Next 10 Years

As described in Chapter 1, meeting California's climate, clean air, petroleum reduction, and energy security goals will require a transformation of the transportation system. Retiring older, high-polluting, inefficient vehicles and replacing them with near-zero and zero-emission technologies will be critical to meeting the state's goals. The need is even more urgent in places like the San Joaquin Valley and the South Coast Air Quality Management District (AQMD), where agencies are working diligently to meet the Clean Air Act's public health standards. Assessing vehicle technology developments and advances in alternative fuels is an important part of the state's efforts to identify the best opportunities for making transformative investments. Investments also need to be well-timed, as studies led by Dr. Joan Ogden at UC Davis[143] and Dr. David Greene[144] at the University of Tennessee have shown, to have the most effect on accelerating commercialization of technologies or fuels.

Assembly Bill 8 extends funding of the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) and other air quality improvement programs through the end of 2023. This extension will culminate in $1.5 billion in funding support for low-carbon and low-emission fuels and vehicles through the end of 2023. As part of its strategic approach to investing ARFVTP funds, the Energy Commission continually assesses the state of alternative fuel and vehicle technologies and markets when setting policy direction, funding levels, and technical guidance in its investment plan and solicitations. This work began with publication and adoption of the *State Alternative Fuels Plan* in 2007[145] and has continued through succeeding *Integrated Energy Policy Reports* (IEPR) and *ARFVTP Investment Plans*.

Some of the goals from the *State Alternative Fuels Plan* are being achieved, such as use of the portfolio approach to achieve long-term petroleum and greenhouse gas reduction targets. While the Plan called for alternative fuels to comprise 9 percent of total fuel use by 2012, actual alternative fuel use is slightly more than

143 See for example, Ogden and Anderson, *Sustainable Transportation Energy Pathways, A Research Summary for Decision Makers,* UC Davis Institute for Transportation Studies, 2011.

144 *Transitions to Alternative Fuel and Vehicles*, National Research Council, 2013. Dr. Greene was at Oak Ridge National Laboratory when he conducted his research for the National Research Council study. He is now at the University of Tennessee.

145 California Energy Commission, *State Alternative Fuels Plan*, Publication No. CEC-600-2007-011-CMF (Prepared in accordance with the statutory direction of AB 1007).

7 percent through 2013. Other policy recommendations from the 2007 report have been superseded with evolving policies from other Energy Commission and California Air Resources Board (ARB) programs. Agencies such as the ARB also continually assess technology status and policy directions through major policy documents such as the *AB 32 Scoping Plan Updates*, *Air Quality Improvement Program Funding Plans*, the *Low Carbon Fuel Standard*, *Vision for Clean Air*, and the technology assessments. Energy Commission staff has and will continue to monitor changes in petroleum fuel prices and the possible impacts on development and sales of the alternative fuels and vehicle technologies discussed in this chapter.

As part of the *2014 IEPR Update* proceeding, the Energy Commission hosted a workshop on April 10, 2014, to evaluate the state of key transportation technologies and markets over the next 10 years. The Energy Commission also held a workshop on June 23, 2014, focusing on electric and natural gas vehicles. Experts from industry, government, and academia also shared their views, knowledge, and recommendations on how the Energy Commission can use its ARFVTP investments strategically to surmount specific technology and market barriers to widespread commercialization and consumer and commercial fleet acceptance of next-generation low-carbon fuel and vehicles.

This chapter draws on the April 10, 2014, workshop discussion to describe the current state of key transportation vehicles and fuels—hydrogen, electric, zero- and low-emission trucks, and biofuels—and the opportunities and challenges for commercialization. The chapter closes with recommendations for how to help achieve the full potential of these technologies.

Hydrogen Fuel Cell Electric Vehicles and Fueling Infrastructure

Hydrogen fuel vehicles will play a key role in fulfilling the Governor's *ZEV Action Plan*[146] goals for 1.5 million zero-emission vehicles in 2025. Fuel cell electric vehicles will add another option to California consumers for zero-emission transportation. They can travel from 250 to more than 300 miles on a tank of hydrogen and can be refilled in 5 to 10 minutes, which is comparable to fueling gasoline-powered vehicles. Fuel cell electric drivetrains can be scaled up and used in larger sedans, vans, SUVs, and light trucks, which will create more zero-emission transportation options than are available with battery-electric vehicles. Fuel cell electric vehicles may also prove attractive to consumers who want zero-emission transportation but do not have access to charging infrastructure.

California Needs an Initial Network of 100 Hydrogen Fueling Stations to Support Introduction of Fuel Cell Electric Vehicles

A network of hydrogen fueling stations is required to support the rollout of fuel cell electric vehicles. Fuel cell electric car drivers need access to hydrogen fueling stations that are convenient and close to their daily driving routes and patterns. Studies show that California needs an initial network of about 100 strategically placed stations to ensure that hydrogen fuel is available for the first wave of fuel cell electric vehicle (FCEV) drivers. Through Assembly Bill 8, the California legislature has directed the

146 http://opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf.

Energy Commission to invest up to $20 million per year (or 20 percent of the annual ARFVTP funding) to building this preliminary infrastructure. Automakers also believe that an initial network of 100 stations should be enough to kick-start fuel cell vehicles. During the IEPR workshop, for example, Toyota's representative Mathew McClory noted that a network of 100 high performance stations that offer standardized, dependable, and reliable service that would enable customers of all vehicle models a convenient and predictable fueling experience.[147] Mr. McClory stated that a properly located network of dependable, high-capacity stations with current technical standards should build consumer confidence and accelerate sales of FCEVs.

California currently has 11 operational hydrogen fueling stations. Through ARFVTP, the Energy Commission has funded 48 new and upgraded stations with a cumulative investment of $81.5 million. The bulk of these stations are expected to be operational by the end of 2015. By late 2015, the California network of operational hydrogen stations is projected to include up to 46 stations, with four additional stations scheduled to come online in the first quarter of 2016, and the remaining four by second quarter of 2016. This network of 51 to 54 stations will support the initial 6,600 vehicles projected for sale in California in the 2015–2017 time frame.[148]

Creating a completely new fueling system for hydrogen FCEVs presents a series of planning, technical, and financial challenges that require close collaboration between government and private sector stakeholders to resolve. One critical issue is the timing and coordination between hydrogen station deployment and FCEV deployment by the automakers: FCEVs cannot be deployed at commercial scales without a minimum network of hydrogen fueling stations; yet stations need demand for fuel from FCEV drivers to have a working business model.

As with the automakers, private station development companies have invested substantial amounts of private capital to develop fuel delivery, storage, and dispensing systems. A potential reward with this type of early market investment is to establish brand recognition and capture early market share for an entirely new market sector. While the automakers can control their product development and market launches, the station development industry assumes additional financial risk by not being able to predict or control FCEV sales, even though they are being asked to develop and open the initial fleet of hydrogen fueling stations. The Energy Commission has used several strategies to help lower this early investment risk by the hydrogen station development industry, including higher government share of capital costs and the introduction of supplemental government incentives for operations and maintenance to help ensure that early market hydrogen stations open and remain open as the FCEV sales develop.

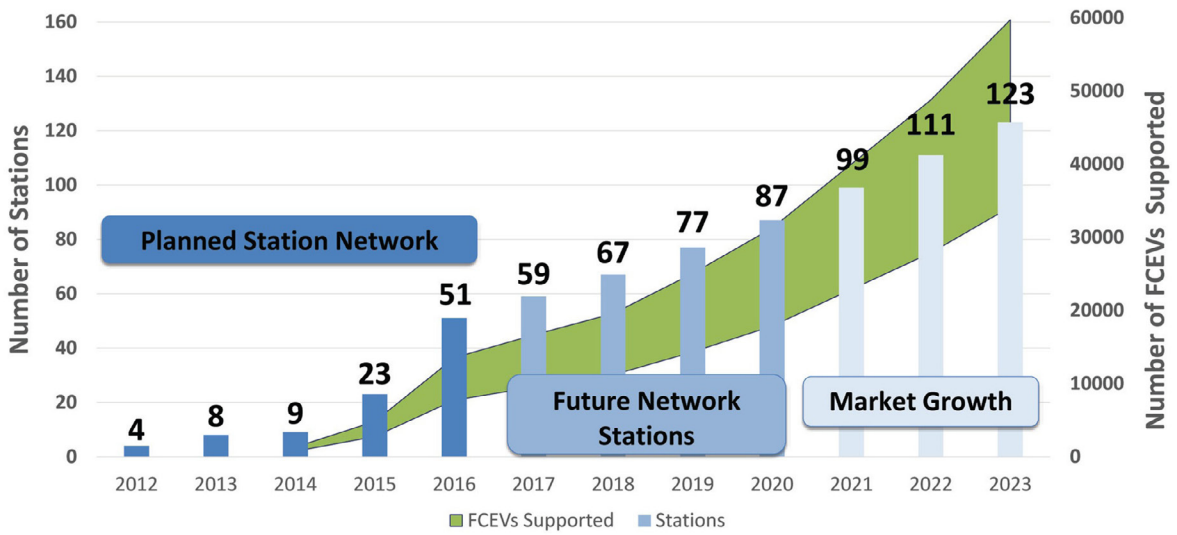
Stations that open in advance of FCEV customers risk sitting idle with negative revenue streams until sufficient vehicles are deployed in volumes that can generate the fuel sales and revenues that station developers and operators need to recover capital investment costs. Energy Independence Now performed station economic modeling work and demonstrated that most California hydrogen stations would operate at a loss in the early years of FCEV commercialization due to low volumes of vehicles and fuel demand.[149] The *Hydrogen Network Investment Plan* documented the need for additional government incentive support for operations. As a result, the Energy Commission developed operation and maintenance grant funding

147 Matthew McClory's presentation at the April 10, 2014 Integrated Energy Policy Report workshop, http://energy.ca.gov/2014_energypolicy/documents/2014-04-10_workshop/presentations/05_Toyota_FCV_CEC_IEPR_workshop.pdf.

148 California Air Resources Board, *Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development* (AB 8 Report) June 2014. Note that the AB 8 report identifies three currently open stations as being at risk of closure in late 2015 if additional operations or equipment upgrade funding is not secured.

149 Energy Independence Now, *Hydrogen Network Investment Plan*, 2013. Conducted under contract to the California Fuel Cell Partnership.

Figure 14: Relation Between Planned Number of Hydrogen Stations and Number of Fuel Cell Vehicles



Source: California Fuel Cell Partnership, 2014

awards of up to $100,000 per year for three years as offset funding for operations and maintenance costs.

However, it is a fine balance because original equipment manufacturers may shy away from delivering vehicles if they perceive that the needed infrastructure isn't there. As stations experience higher rates of use, station capital and operating costs will be distributed over greater volumes of hydrogen sales, reducing costs to consumers. This schedule coincides with announced schedules of automakers such as Hyundai, Toyota, and Honda, who are or soon will be offering fuel cell electric passenger vehicles to the public: the current forecast is that fuel cell vehicle automakers will sell an estimated 6,600 vehicles in California in the 2015-2017 time frame and then an estimated 18,500 vehicles by 2020.[150] California is on the forefront of hydrogen station deployment. Globally, only Germany and Japan have such similarly aggressive and detailed goals for hydrogen station development.

Figure 14 shows the relationship between station development and potential vehicle sales in California.[151]

Figures 15 and 16 show the distribution of this initial set of hydrogen stations in Northern and Southern California. Eighteen are in development in Northern California with a focus on the San Francisco Bay Area. A destination station in Truckee and an early market station in the Sacramento area are also included. Nine stations are operational in Southern California, with another 30 in development from Santa Barbara to San Diego.

The Energy Commission has provided hydrogen station funding through three solicitations and has eased the expansion of the market of vendors and station developers from two in 2010 to nine in 2013. This is a key milestone toward creating a self-sustaining competitive market. Eight of the Energy Commission-funded 48 stations will be

150 California Air Resources Board, *Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development* (AB 8 Report) June 2014.

151 California Fuel Cell Partnership, *A California Roadmap: The Commercialization of Hydrogen Fuel Cell Vehicles, 2014 Update: Project Progress, Priorities and Opportunities Report.* July 2014.

Figure 15: Hydrogen Fueling Stations in Northern California: Existing and in Development

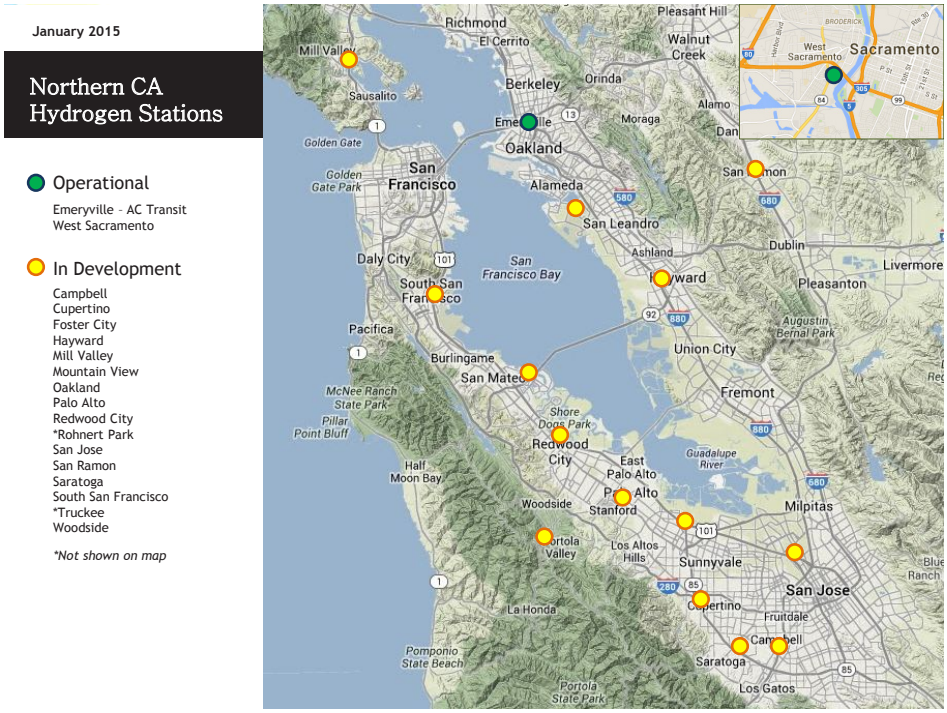
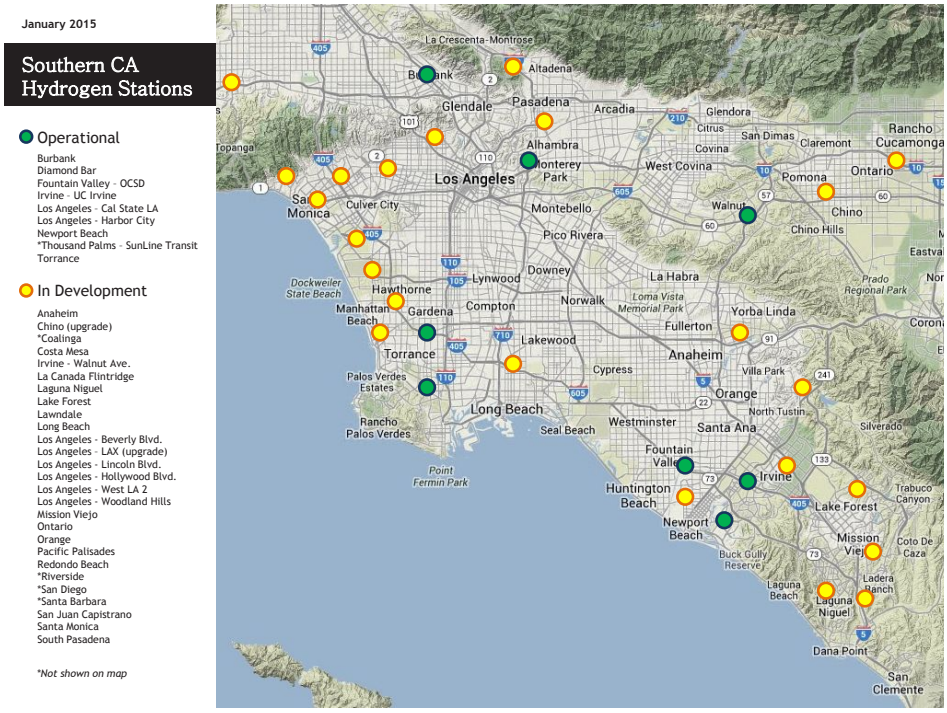


Figure 16: Hydrogen Fueling Stations in Southern California: Existing and in Development



Source: California Fuel Cell Partnership (Note: "In Development" denotes stations funded in 2010 and 2012 that are in permitting or construction. "NOPA" [or proposed] denotes the 28 stations recently funded in the Energy Commission's May 2014 Notice of Proposed Award for Hydrogen Fueling Stations).

100 percent renewable hydrogen, including several small-scale electrolysis hydrogen generators. HyGen Industries is an example of a new grantee that will specialize in generating and dispensing renewable hydrogen through on-site electrolysis at three new station sites.

Planning the first generation of hydrogen fueling stations has been guided by the analysis and recommendations of automakers, station developers, government, and academia through the California Fuel Cell Partnership. The 2012 report *A California Roadmap: The Commercialization of Hydrogen Fuel Cell Electric Vehicles*[152] called for an initial network of 68 stations clustered in five zones in Southern and Northern California that corresponded to automaker and academic projections of early core markets for first-adopter customers. This initial network of stations clustered within six minutes of one another would create sufficient station coverage to alleviate range anxiety and allow for a fueling experience comparable to retail gasoline sales.

In 2014, the California Fuel Cell Partnership released an update to the *2012 Roadmap* titled *2014 Update: Hydrogen Progress, Priorities and Opportunities Report*.[153] This report describes progress in meeting the goals established for 68 stations in the 2012 report and describes how the 100-station network defined in AB 8 will further support the commercial launch of FCEVs in 2014–2015 by providing fueling capacity for 25,000 to 40,000 vehicles in 2020.

In accordance with the new AB 8 requirements for station network evaluation, the ARB released its first assessment of hydrogen fuel station network capacity. This report also presented the results of the first automaker survey for FCEV deployment in California: as of June 2014, 125 FCEVs are registered through the California Department of Motor Vehicles, 6,650 FCEVs are projected to be sold by the end of 2017, and 18,500 FCEVs are anticipated to be on California's roads by the end of 2020.[154] The ARB found that under the current pace of planning and development for hydrogen fueling stations, sufficient capacity will be available through 2018 but that additional capacity will be needed to support expanding FCEV sales through 2020. The report identified a deficit of hydrogen fueling stations in the Berkeley-Oakland target zone of the San Francisco Bay Area and the future need for larger capacity stations than currently funded through ARFVTP.

California Law Requires 33 Percent Renewable Content in Publicly Sold Hydrogen

California law requires all hydrogen sold at publicly funded stations to contain at least one-third renewable hydrogen; therefore, the Energy Commission requires all fuel cell station owners and operators to have at least one-third renewable hydrogen in their hydrogen fuel products. Industry experience and commitments demonstrate that providing a hydrogen fueling stream that is derived from at least 33 percent renewable hydrogen is feasible. Air Liquide, a supplier of hydrogen all around the globe and a California station developer, has set a corporate goal to have 50 percent of its hydrogen be "carbon free" by 2020. Air Liquide plans to integrate renewable energy sources into its hydrogen production systems and develop water-based hydrolysis and biogas feedstocks in conjunction with carbon capture techniques for its natural gas supply chains.[155] The renewable hydrogen content of hydrogen fuel from central station steam reforming plants can also be increased by using biogas or landfill gas as a feedstock substitute for natural gas. For example, two of First Element's 19 stations will sell 100 percent renewable hydrogen based on this method. According to Energy Commission staff analysis, the projected system aver-

152 *A California Road Map: Bringing Hydrogen Fuel Cell Vehicles to the Golden State*, California Fuel Cell Partnership, 2012.

153 California Fuel cell Partnership, *A California Roadmap, The Commercialization of Hydrogen Fuel Cell Vehicles, 2014 Update: Hydrogen Progress, Priorities and Opportunities Report*, July 2014.

154 ARB AB 8 Report, 2014.

155 Air Liquide presentation at the April 10, 2014, Integrated Energy Policy Report workshop.

age for renewable hydrogen in the 48 California stations funded by the Energy Commission will be 38 percent when the stations come on-line in 2015.

Challenges and Opportunities to Advance Hydrogen Fueling Infrastructure Development

There are three primary challenges with developing hydrogen fueling infrastructure in California: station planning and siting, station and equipment costs, and greening of the hydrogen supply chain. These challenges and opportunities to address them are discussed below.

Hydrogen Station Planning and Permitting Challenges

A challenge is the overall inexperience with building retail hydrogen stations. In the initial stage, the Energy Commission observed that awardees experienced difficulty in finding station owners and operators who were willing to share the early market financial risks and liability common to new technology introduction. Seven of the original eight private sector station sites from the first Energy Commission solicitation in 2009-2010 needed to be changed due to the inability of station owners and station developers to reach agreement on commercial lease negotiations. The San Francisco Airport Commission cancelled its station outright. In addition to the financial risks, it also proved challenging to find urban gasoline stations with sufficient space to accommodate the new set of storage tanks, compression equipment, and control equipment needed to deliver hydrogen fuel. The Energy Commission helped resolve this issue by requiring firm documentation of station owner support upfront.

Another initial challenge was the development of permit applications and permit review times by local government. Although hydrogen fueling systems are no more hazardous than petroleum fueling systems, they are different. Most local jurisdictions were not familiar with the safety codes and standards used to guide and control installation of high-pressure, gaseous fueling equipment. The industrial gas companies that won the initial Energy Commission funding awards also had little experience with retail station development and interaction with local planning jurisdictions and fire marshal offices.

The Energy Commission helped resolve this issue by working with the Governor's Office of Business and Economic Development (GO-Biz) to create a new position of ZEV Infrastructure Project Manager. The primary responsibility for the new Project Manager is to work with local government permitting entities and station developers to streamline and accelerate hydrogen station permitting. As evidenced by multiple meetings with GO-Biz, Energy Commission staff, and permitting jurisdictions, this strategy appears to be successful in standardizing the way local government reviews permit applications and reducing permitting time.

Hydrogen Station Capital and Operating Costs

Hydrogen fueling systems are in the early precommercial development stage and have high capital and operating costs. At present, hydrogen fueling stations are expensive, ranging from $1.5 million to $4 million per station, depending on the size, design, and location. They are also expensive to operate and maintain, and numerous companies have expressed concern about opening hydrogen stations and operating at a revenue loss until sales levels grow sufficiently to cover and then exceed initial investment and operating costs.

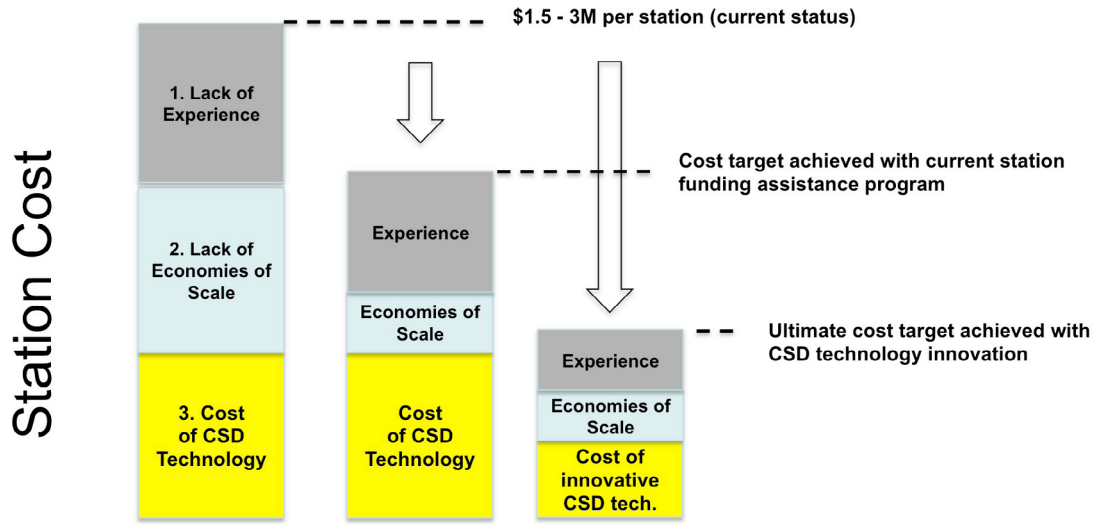
Opportunities to Reduce Costs

Directed research, increased incentives, and innovative partnerships to leverage opportunities are all options to bring down the costs of hydrogen and advance market deployment.

Directed Research

High station capital costs are a result of nonstandard station designs, low economies of scale, high materials and fabrication costs, and limited numbers of vendors

Figure 17: Factors to Reduce the Cost of Hydrogen Fueling Stations



Source: Sandia National Laboratories

along the equipment supply chain. One initiative to reduce station costs is the H2 First collaboration. Sandia National Laboratory has partnered with the National Renewable Energy Laboratory (NREL) to form the H2 First collaboration. A key goal of this partnership is to push down station development and operations costs through research and investigations into materials, manufacturing, and operations challenges. According to Dr. Daniel Dedrick of Sandia, costs for three of the critical elements for a hydrogen station—compression, storage, and dispensing—can all be reduced through industry experience, ongoing research into materials components, and economies of scale.[156] See Figure 17.

While industry experience and economies of scale are market functions that should evolve over time and result in lower costs, Sandia believes that directed research into high-cost materials and the potential substitutes for hydrogen storage tanks, compressors, and dispensing equipment is an important government function that can also help lower costs. Dr. Dedrick cited an example of research into alternative materials for high-pressure hydrogen pipes that could help reduce costs by 60 percent for a critical element of hydrogen fueling stations. Other opportunities to reduce the hydrogen station costs include improved and standardized station designs, enhanced equipment supply chains, less costly compressors, and facilitation of permitting and approval processes.[157]

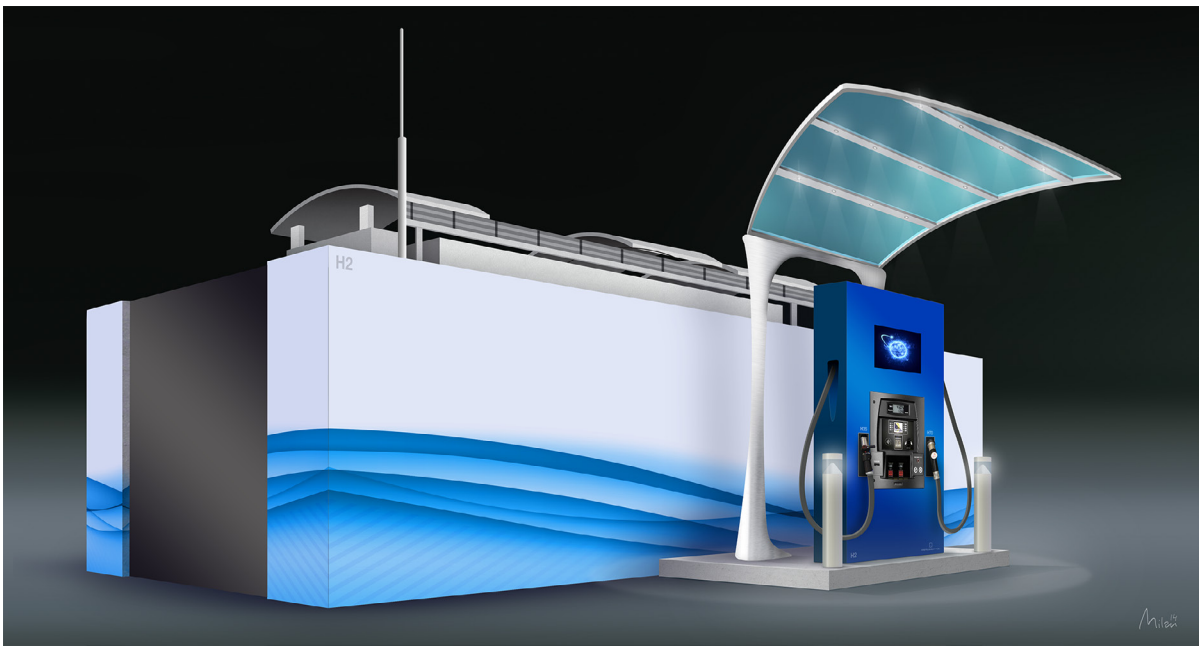
Increased Incentives

To offset high capital costs and spur private sector investment and more rapid market development, the Energy Commission increased its capital offer in 2013 to 85 percent of station costs or up to $2.1 million for a standard hydrogen station. Market response was strong, and the

156 Dr. Daniel Dedrick, Sandia National Laboratory, *Hydrogen Station Infrastructure: Opportunities for Cost Reduction and Improved Customer Experience,* Presentation at the April 10, 2014, Integrated Energy Policy Report workshop.

157 Melaina, M. W., Steward, D., Penev, M., McQueen, S., Jaffe, S., and Talon, C. (2012). *Hydrogen Infrastructure Market Readiness: Opportunities and Potential for Near-term Cost Reductions*. National Renewable Energy Laboratory, Golden, CO. Report Number BK-5500-55961, available online: http://www.nrel.gov/docs/fy12osti/55961.pdf.

Figure 18: FirstElement Hydrogen Dispenser



Source: FirstElement Fuel

Energy Commission received 61 station proposals totaling more than $100 million in funding requests. Twenty-eight stations plus a mobile refueler are being funded through this solicitation.

Innovative Partnerships

An important evolution in the early hydrogen fueling market is exemplified by the business model of FirstElement Fuel. FirstElement is the first hydrogen station developer to attract private capital from the automotive sector, which has enabled it to submit substantially lower bids for its hydrogen stations. To date, FirstElement has secured support funding from Toyota and Honda.[158] Even though the Energy Commission increased its maximum award, FirstElement was able to decrease its bid, and because of the AB 8 benefit-cost scoring criteria (see chapter 4 for more information on how benefit-cost is used in scoring), it proved successful and won 19 of 28 station awards. FirstElement plans to draw from multiple equipment suppliers and has secured a major construction and engineering firm to manage station construction for an initial fleet of 19 stations in Northern and Southern California.[159] FirstElement expects better ability to manage procurement costs by ordering in larger volumes than previously possible and to better manage station development costs by using standardized designs. Figure 18 illustrates the hydrogen fueling dispenser FirstElement is developing in collaboration with Air Products and Chemicals and Bennett Pump Company.

158 Bloomberg, "Toyota Joins Hydrogen Station Funding Push in California" May 2, 2014 http://www.bloomberg.com/news/2014-05-01/california-awards-46-6-million-for-hydrogen-car-stations.html.

Green Car Reports, November 19, 2014, http://www.greencarreports.com/news/1095563_honda-to-loan-first-element-14-million-for-hydrogen-fueling-stations.

159 California Energy Commission, Notice of Proposed Awards for Hydrogen Fueling Infrastructure for Public Opportunity Notice 13-607," May 1, 2014.

Hydrogen Fuel Production and Greening of the Hydrogen Fuel Supply Chain

Hydrogen is produced and consumed at industrial scale by several companies using steam methane reforming at large-capacity plants operated by companies such as Air Products and Chemicals, Linde, and Air Liquide. Hydrogen is used in petroleum refining and chemical production. Natural gas is subjected to high-pressure steam to convert methane to hydrogen. At present, the standard and most cost-efficient method for supplying hydrogen fueling stations is to truck the hydrogen from a central station plant by high-pressure tanker to the retail fueling sites.

Converting Natural Gas to Hydrogen is Relatively Inefficient

Conversion of natural gas to hydrogen is relatively inefficient; the raw carbon intensity value for compressed hydrogen from the Low Carbon Fuel Standard (LCFS) look up table is 98 grams of carbon dioxide equivalent per megajoule (gCO_2e/MJ),[160,161] which is comparable to gasoline. However, when the energy efficiency of the fuel cell vehicle electric motor is factored in (2.5 energy efficiency rating for FCEVs), the carbon intensity value falls dramatically. When factoring a 33 percent renewable content, one-third of the carbon intensity value of California hydrogen drops further to 31.3 gCO_2e/MJ, which is about the same as the electricity used for electric vehicle charging in California.

Opportunities to Reduce Carbon Content of Hydrogen

Discussed below are promising opportunities to increase the renewable content of hydrogen fuel or otherwise reduce the carbon content of hydrogen and advance California's emission reduction and energy security goals.

Using Biogas Feedstocks

A recent NREL report finds that up to 11 million fuel cell vehicles could be powered by renewable hydrogen if biogas feedstocks from landfills, wastewater treatment plants, and dairies were used for hydrogen production.[162] The report also finds that California has some of the largest biogas feedstock potential in the United States.

Electrolyzing Water

The carbon content of hydrogen can be completely eliminated through electrolysis of water using 100 percent renewable energy. Five of the 48 stations currently funded by the Energy Commission will produce 100 percent renewable hydrogen using this process. HyGen's three recently awarded stations will use this method for on-site hydrogen production, and ITM Power and HTEC Industries will also use on-site electrolysis at their stations. At present, on-site renewable hydrogen production is more expensive than central station production and delivery, but costs are expected to decline as the technology matures and volume increases.

Blending Renewable Natural Gas

The potential for commercial and industrial-scale green hydrogen production is being investigated by major California utilities like the Southern California Gas Company and the U.S. Department of Energy (DOE). Dr. Jeffrey Reed summarized SoCalGas' vision for greener natural gas and hydrogen supplies at an IEPR Workshop.[163] Carbon emissions reductions would occur through increasing the blend of renewable natural gas, or biogas, into the supply chain, followed by blends of green hydrogen derived from large-scale electrolysis, renewable power conversion to hydrogen, and eventual, direct solar conversion.

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160 LCFS pathway HYG003.

161 The raw carbon intensity score for liquefied hydrogen, which can be transported and stored at greater volumes than compressed hydrogen gas, is 133 gCO_2e/mj, as defined in LCFS pathway HYG002.

162 Saur, G. and A. Milbrand. *Renewable Hydrogen Potential from Biogas in the United States*, National Renewable Energy Laboratory Technical Report Number 5400-60283, July 2014.

163 Dr. Jeffrey Reed, Southern California Gas Company, *Natural Gas Pathways to Achieve Air Quality Goals*, presentation at April 10, 2014, Integrated Energy Policy Report workshop.

Using Surplus Renewable Energy

The potential for large-scale renewable hydrogen production and storage is being investigated by DOE, NREL, and many universities. Surplus renewable electricity generation from wind farms, solar thermal arrays, and large hydroelectric facilities may become available during daytime peak-load hours as renewable power installations increase in California and the United States. One scenario under investigation is to use this surplus renewable electricity to power large-scale electrolysis systems and create renewable hydrogen that can be stored for later use in stationary fuel cells, industrial facilities, injection into natural gas pipelines, or delivery to fuel cell vehicles.

Brendon Shaffer of the Advanced Power and Energy Program at the University of California, Irvine, described how stationary fuel cells can be used to capture surplus renewable energy generation and store it as hydrogen at major substations, where it can be dispatched as needed using fuel cells to meet load demand.[164] Mr. Shaffer described opportunities for large-scale storage of surplus generation from hydropower projects, wind, and solar farms and off-peak nuclear generation through a Transmission Integrated Grid Energy Resource, or TIGER System. Mr. Shaffer also summarized the status of stationary fuel cells for on-site power generation in California, stating that 81 megawatts of stationary power have been installed. He stated that continuing development of stationary fuel cells and TIGER stations could have crossover benefits for the transportation sector by increasing economies of scale for fuel cell power stack production and increasing public and commercial awareness of hydrogen as a fuel for transportation and power generation.

164 Brendon Shaffer, UC Irvine Advanced Power and Energy Program, presentation at April 10, 2014, Integrated Energy Policy Report workshop.

Zero-Emission and Near-Zero-Emission Medium- and Heavy- Duty Vehicles

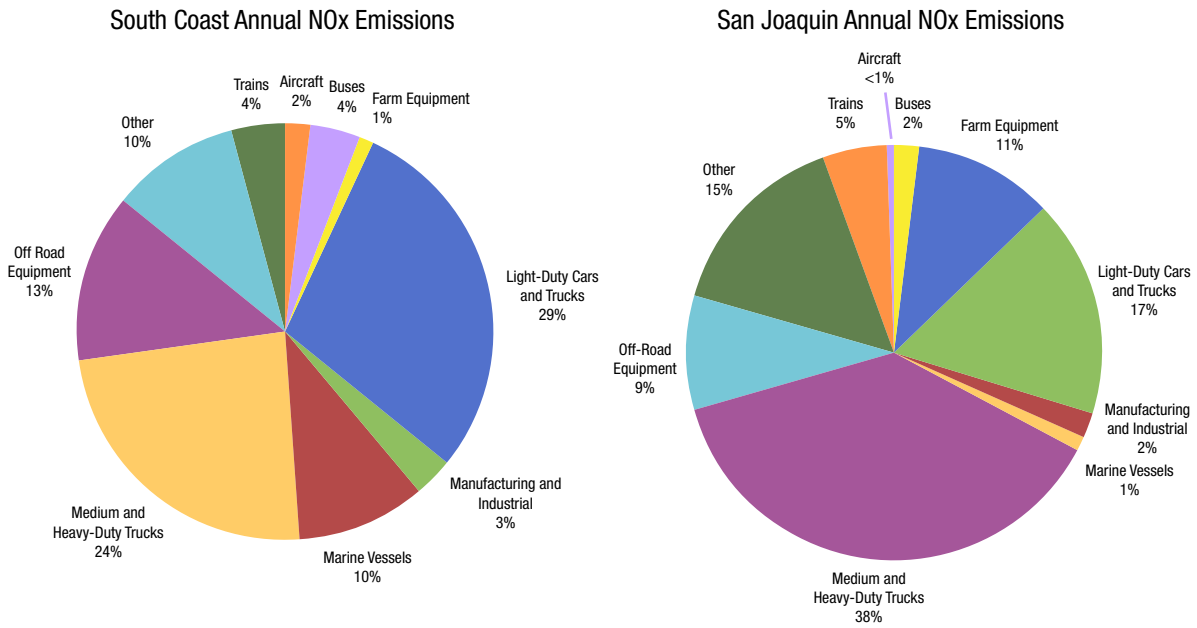
California's vehicle fleets total more than 900,000 medium- and heavy-duty vehicles and include Class 7 and 8 long-haul tractors; Class 8 refuse hauling trucks, Class 6 and 7 package delivery vans, medium-duty work trucks and shuttles; and buses. In 2012 they comprised about 3.7 percent of the total vehicle population in California, yet consumed more than 20 percent of the total fuel and are responsible for as much as 30 percent of total smog forming NO_x emissions[165] and 23 percent of transportation-related greenhouse gas emissions.[166] In the San Joaquin Valley and South Coast Air Basins, truck-related oxides of nitrogen (NO_x) and fine particulate matter (PM2.5) emissions are the leading cause of ozone pollution and resulting respiratory diseases.[167] Reducing criteria and greenhouse gas emissions from the medium- and heavy-duty sector is a priority for California's air quality agencies in the San Joaquin Valley and South Coast AQMD, ARB, and the U.S. Environmental Protection Agency (U.S. EPA).

165 California Air Resources Board. California Almanac of Emissions and Air Quality – 2013 Edition. http://www.arb.ca.gov/aqd/almanac/almanac13/almanac13.htm.

166 California Air Resources Board. California Greenhouse Gas Emission Inventory: 2000-2012, May 2014.

167 Dr. Matt Miyasato, South Coast Air Quality Management District, April 10, 2014, Integrated Energy Policy Report workshop.

Figure 19: NO_x Emissions Inventory for the San Joaquin Valley Air Basin



Source: Energy Commission staff using 2012 Air Resources Board District Level Emissions Inventory Data

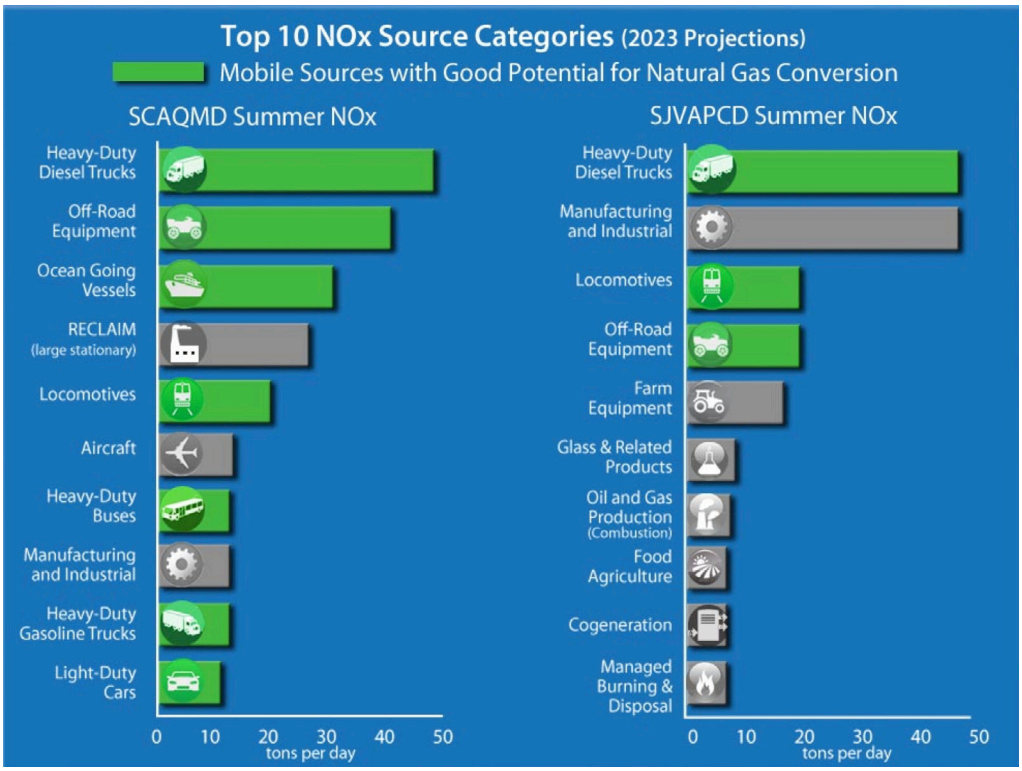
Role of Truck Emissions in Nonattainment Air Basins in California

The U.S. EPA sets National Ambient Air Quality Standards for pollutants that are considered harmful to public health and the environment and designates areas as either attainment (meeting the standards) or nonattainment (not meeting the standards). U.S. EPA has designated both the San Joaquin Valley and the South Coast air basins as extreme nonattainment under the 8-hour ozone standard. NO_x emissions are one of the primary precursor pollutants for the formation of ground-level ozone. In both the San Joaquin Valley and the South Coast air basins, heavy-duty diesel engines are the primary source of NO_x emissions. As shown in Figure 19, in 2012 NO_x emissions from the trucking sector comprised 38 percent of total NO_x emissions in the eight-county San Joaquin air basin and 24 percent in the South Coast air basin.

As discussed in Chapter 1, NO_x emissions need to be reduced by 70 to 90 percent from the transportation sector by 2023 for the South Coast Air Quality Management District (AQMD) to reach attainment with federal public health standards. Dr. Matt Miyasato of the South Coast AQMD described how on-road heavy-duty truck emissions are the largest contributor to NO_x emission levels in his region. To meet the pending federal air quality standards and climate goals, every vehicle sold in the South Coast Air Basin from 2025 to 2030 would need to be a zero-emission vehicle. Dr. Miyasato described the range of public health impacts from this poor air quality, stating that it disproportionately affects children and the elderly in terms of respiratory disease, impacts to brain development and IQ levels, and the premature death of up to 5,000 people each year.[168]

168 Dr. Matt Miyasato, South Coast Air Quality Management District, *Transforming Transportation: the Air Quality Need for Zero and Near-Zero Emission Technologies,* Presentation at the April 10, 2014, Integrated Energy Policy Report workshop.

Figure 20: NO_x Emission Reduction Potential in the San Joaquin and South Coast Air Basins From Potential Conversion to Natural Gas Engines and Fuels



Source: Gladstein, Neandross and Associates

The Potential for Natural Gas

In the near term, natural gas engines offer a potential option to reduce carbon and criteria emissions from the long-haul truck sector as shown in Figure 20.[169]

At present, there are limited alternative fueling options for long-haul freight: biodiesel has higher NO_x emissions than diesel fuel; renewable diesel is not yet available in the volumes needed to satisfy long-haul routes; and battery electric and fuel cell electric drive trucks are in early phase demonstration trials. Natural gas offers fleet operators substantial savings in fuel costs due to the fuel price differential of nearly 50 percent. Several additional series of advanced natural gas engines are poised for commercial deployment, and companies like Clean Energy are investing substantial private sector capital in trans-continental natural gas fueling stations.

Advanced natural gas engines have the potential to operate at extremely low emission levels that could be "electric vehicle equivalent" on a life-cycle emissions basis.[170] The Energy Commission is pooling ARFVTP funds with the South Coast AQMD to fund the development of low NO_x natural gas engines that would be 80 percent cleaner than current engine technologies (0.01 grams per brake-horsepower hour). The combination of low NO_x natural gas engines and biogas fuel blends creates the potential for a natural gas fuel pathway with the same environmental attributes as electric drive or hydrogen fuel cell trucks.

169 Eric Neandross, Gladstein, Neandross and Associates, presentation at June 23, 2014, Integrated Energy Policy Report workshop.

170 Dr. Matt Miyasato, *ibid.*

The South Coast AQMD's Strategy

The South Coast Air Basin comprises four counties with 17 million residents that represent 44 percent of the state's population. The Ports of Los Angeles and Long Beach are the sixth largest ports in the world and help generate very high volumes of truck traffic throughout the South Coast Air Basin, estimated at 2 million trucks per day traversing the region. The South Coast AQMD's strategy for technology development in the heavy-duty truck sector has been to focus initially on natural gas engines and fuels that could be used to displace pre-2010-compliant diesel trucks and buses. The goal is to develop natural gas engines and fuel blends that are "power plant equivalent" and meet the same environmental performance standards for carbon and criteria emissions as electric drive vehicles. This strategy can leverage the low fuel costs of natural gas and leverage market forces to meet the same environmental and public health goals that could be achieved with other more costly zero-emission technologies. The other key element in the South Coast AQMD strategy to decarbonize the freight sector is to continue developing zero-emission technologies using battery electric, hybrid, and fuel cell electric drivetrains, as well as electrification of entire roadways with catenary-type power systems. Dr. Miyasato stated that a mix of incentive funding and regulations will be needed in the future to create a "market push" for engine and truck developers and a corresponding "market pull" to offer incentives to fleet owners and operators to adopt advanced technology, zero-, and near-zero-emission truck technologies into their fleets.[171]

The Energy Commission's Near- and Long-Term Strategy to Facilitate the State's Goals

The state's goals for the medium- and heavy-duty vehicle sector are to reduce diesel fuel use, reduce carbon emissions, improve air quality, and improve public health. The

171 Dr. Matt Miyasato, "Transforming Transportation: The Air Quality Need for Zero and Near-Zero Emission Technologies," presentation at the April 10, 2014, Integrated Energy Policy Report workshop.

ZEV Truck Potential at California Ports

California's ports generate large volumes of heavy-duty truck traffic that generate large amounts of air pollutants and carbon dioxide emissions. CALSTART[1] has analyzed how ZEV or hybrid trucks can be used in the Los Angeles and Long Beach port area along Interstate 710 to reduce emissions associated with moving cargo to and from the ports. It identified ZEV zones around the port based on the number of miles that a truck can be driven in zero-emission mode. By targeting specific routes within a zone, ZEV trucks with limited e-mile ranges can still be deployed in congested regions that are suffering from heavy criteria and particulate truck emissions. Several ARFVTP-funded ZEV truck projects would be able to haul freight within these zones when they complete the demonstration-phase field trials.

TransPower is one of the ARFVTP-funded California companies working to develop all-electric Class 8 tractors that can be used in drayage operations and short-haul duty cycles in California ports. At the April 10, 2014, IEPR workshop, TransPower's Chief Executive Officer Mike Simon encouraged the Energy Commission and other state and federal agencies to sponsor larger-scale demonstration projects using 10 to 50 vehicles, continue funding manufacturing facilities and assembly lines, and continue small-scale, early commercial phase demonstrations of one to five vehicles. Mr. Simon further described the market potential for electric trucks in 2023, stating that—with the right mix of incentives—a 12 percent share of all commercial trucks sales could result in an electric truck market of 35,000 units nationwide.

[1] http://www.calstart.org/Libraries/I-710_Project/I-710_Project_Zero-Emission_Truck_Commercialization_Study_Final_Report.sflb.ashx.

Table 10: ARFVTP Truck Sector-Related Funding Through September 2014

Technology	Funding Level ($ millions)	No. of Vehicles, Fueling Stations, or Projects
Natural Gas Trucks	54.4	2,735 Trucks
CNG-LNG-RNG Fueling Stations	16.7	60 Stations
Commercial Propane Trucks	7.3	600 Trucks
Commercial ZEV Trucks (Class 6 Package Delivery)	4	160 Trucks
Advanced Technology Truck Demonstration or Manufacturing	74.6	38 Projects
Total Funding	**157**	

Source: Energy Commission staff

Energy Commission's strategy for helping to achieve these goals is to promote development and commercialization of medium- and heavy-duty truck technologies for goods movement and freight transport with ARFVTP investments across multiple near-term and long-term fuel pathways that include advanced natural gas, electric drive, hydrogen fuel cell electric drive, and hybrid and range extender combinations.[172] Table 10 shows Energy Commission ARFVTP investments in the medium- and heavy-duty truck sectors.

Currently, the Energy Commission's near-term strategy is to deploy advanced natural gas trucks and fueling stations, which create modest but immediate near-term benefits by reducing greenhouse gas emissions by one-third over diesel fuel and by displacing toxic diesel PM emissions. The Energy Commission's long-term strategy is to fund the development of zero-emission electric and fuel cell electric drive truck and bus technologies, and near-zero-emission natural gas engine technologies. For example, TransPower has used a series of ARFVTP grants to design and construct a series of Class 8 electric drive tractors that can pull 80,000-pound containers in the Ports of Los Angeles and Long Beach. The Energy Commission is funding three additional companies that are developing Class 8 drayage trucks using electric drive motors with range extenders and plug-in configurations, plus the demonstration of a catenary-electric drive system being developed by Volvo and Siemens and cofunded with the South Coast AQMD.

In the medium-duty package delivery sector, ARFVTP funding has helped create a new California industry for electric drive truck manufacturing. A series of manufacturing and technology development grants have enabled companies like Electric Vehicles International (EVI), Motiv, and Wrightspeed to build electric truck manufacturing plants in California. The EVI 100-ZEV truck deployment project with United Parcel Service (UPS) remains the nation's largest deployment of electric trucks.

Biofuels

Biofuels will play a critical role in reducing carbon emissions from the transportation sector and are a key element in the Energy Commission's portfolio approach to a low-carbon transportation future. Ethanol has already displaced 10 percent of petroleum fuel as a blend in the 14.5-billion-gallon-per-year, gasoline-based, light-duty passenger vehicle sector, and biodiesel and renewable diesel could increase threefold to sixfold by 2020 to

172 Jim McKinney, Energy Commission Staff, moderator introduction presentation at April 10, 2014, Integrated Energy Policy Report workshop.

displace part of the 3.6-billion-gallon-per-year diesel fuel market as a fuel blend in trucks and buses. Low-carbon-intensity feedstocks such as waste residues and some sustainable purpose-grown crops have begun to displace corn ethanol and soy biodiesel as sources for biofuel production. Large volumes of these moderate to low-carbon intensity biofuels not only displace petroleum, but offer an opportunity to reduce large amounts of greenhouse gas emissions over the next 10 years. In addition, these low-carbon fuel biofuel options can be used in California's existing 26 million passenger cars and 1 million trucks and buses. The potential job growth is significant from development of California biofuel production plants, particularly in the San Joaquin Valley, where many plants are located or planned.

The growth in the use of biofuels as a blend with gasoline and diesel is being spurred by regulations combined with government incentive funding. The federal Renewable Fuels Standard, the California LCFS, a federal blender's tax credit for biodiesel and renewable diesel sales, and cofunding of biofuel production plants have stimulated a California market for low-carbon intensity biofuels. As a result, California has seen growth in imports of low-carbon fuels from other states and nations and the development of California production plants.

Biofuels range from first-generation food-based fuels using feedstocks of corn and soy with modest carbon emissions reductions to advanced second- and third-generation drop-in fuels. An example of an advanced biofuels is renewable diesel that can be made from waste-based feedstocks and that is fungible and blendable with current diesel fuel products without the need for supplemental transport and fueling infrastructure. At present, corn-based ethanol is the only biofuel in use at industrial scale in California.

Biogas, or renewable natural gas, can be derived from a wide array of urban and agricultural waste streams and has extremely low carbon intensity values. It can be used as a stand-alone fuel in natural gas engines or used as a blendstock with natural gas to reduce the carbon content of compressed natural gas (CNG), liquefied natural gas (LNG), or as a hydrogen fuel feedstock.

To meet its climate, clean air, and energy security goals, California is working toward decarbonizing the transportation system. Regulations like the LCFS, which requires a 10 percent reduction in the carbon intensity of California transportation fuels by 2020, are the building blocks for achieving these overarching goals. The Energy Commission invests its ARFVTP funds into projects that can help support these goals and should look for opportunities to support projects such as co-location of biogas with natural gas and hydrogen fueling stations. This work will help develop commercial products and markets for a range of biofuels that include ethanols, green gasoline, biodiesel, renewable diesel, and biogas. Biofuels funding for fuel production and infrastructure comprises 29 percent of the current ARFVTP investment portfolio.

The Potential and Challenges for Biofuels

Over the next 10 years, biofuels have the potential to displace significant quantities of petroleum fuels.[173] Products such as cellulosic ethanol from waste-based feedstocks have been expected to play a key early role in displacing gasoline as electric and hydrogen ZEV technologies continue their path to commercialization and broad acceptance by the public. For the long-haul trucking sector, biodiesel and renewable diesel are widely expected to play a key role in displacing diesel fuel. Natural gas is the only other alternative fuel with potential over the near term and midterm to displace diesel from this sector in significant volumes.

At the April 10, 2014, workshop, Dr. Nathan Parker from the UC Davis Institute for Transportation Studies reported that the most recent California Biomass Collaborative

173 Energy Commission staff will continue to monitor changes in petroleum prices to identify any potential impacts to biofuel and other alternative fuels sales in California. According to the EIA, as of December 2014, petroleum fuel prices declined 48 percent since July 2014.

estimate is that biomass resources could produce from 1.5 billion to 2 billion diesel gallons equivalent (dge) of biofuel annually.[174] However, nearly half of the potential feedstock base consists of agricultural prunings and forest management remains for which there is not yet an economic cellulosic or gasification process technology. Dr. Nathan Parker reported that while California has a substantial knowledge base for research and production of biofuels, its production capacity is far behind the Midwest or Brazil. UC Davis identifies 74 active companies in California, but only 19 total biofuel plants, many of which are in the demonstration and pilot phase.

Despite its potential, the biofuels industry continues to work to surmount challenges in process technologies, cost containment, feedstock procurement, and public acceptance. Sustainability concerns about large scale shifts in North American crop production or tropical forest loss in the Amazon basin and Southeast Asia also affect the viability of commercial scale biofuel production and use.

The three primary regulatory systems that govern biofuel production and carbon valuation also face significant legal and technical challenges: in-state biogas and landfill gas cannot be injected into California's natural gas pipeline system until the California Public Utilities Commission completes its work on technical standards and cost recovery under Assembly Bill 1900; the LCFS is contending with legal challenges and a readoption process for the entire regulation. The ARB Board will consider readoption of the LCFS with proposed amendments in 2015 in response to state appellate court directions to address procedural issues with existing regulations. The federal Renewable Fuel Standard continues to be controversial with its biofuel categorization system and volumetric approach. The implementation of the federal Renewable Fuel Standard continues to be inconsistent and marked by long delays in annual decisions about biofuel volumes for compliance by obligated parties.

174 Dr. Nathan Parker, UC Davis Institute for Transportation Studies, presentation at April 10, 2014, Integrated Energy Policy Report workshop.

Increasing the amount of biofuels available is a key component to affecting the level of transformation needed in the transportation sector. The Energy Commission's investments in the biofuels sector help displace petroleum as the predominant transportation fuel in California, support the LCFS goal of a 10 percent reduction in the carbon intensity of California transportation fuels, and develop commercial products and markets for a range of biofuels that include ethanols, green gasoline, biodiesel, renewable diesel, and biogas. Biofuels funding for fuel production and infrastructure comprises 29 percent of the current ARFVTP investment portfolio.

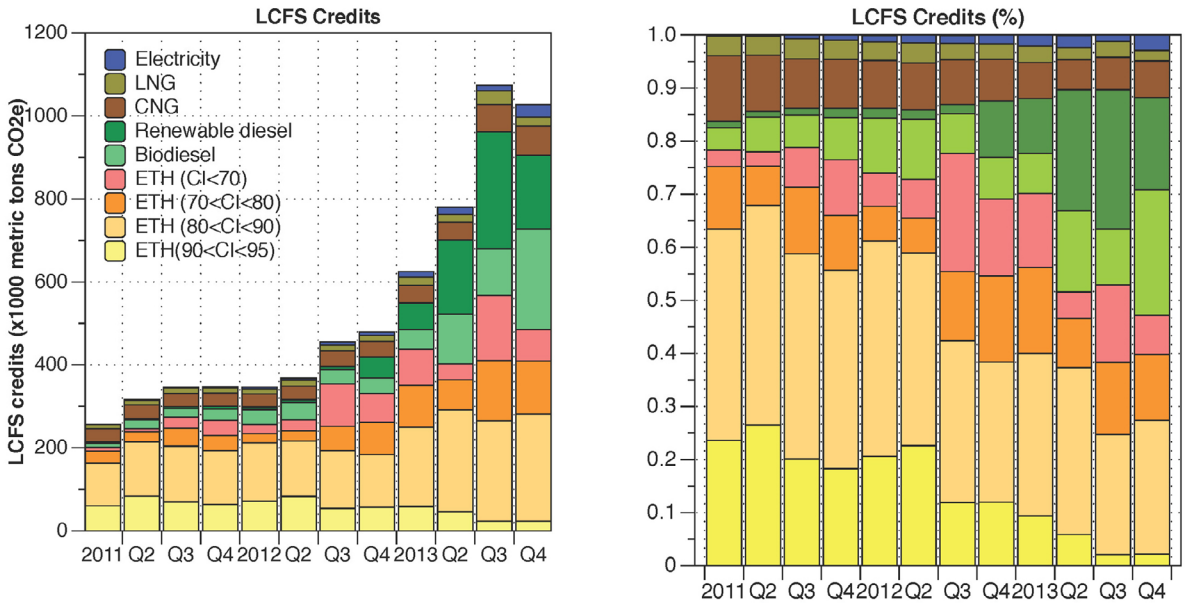
California Biofuel Use and the Low Carbon Fuel Standard

The LCFS was established by Executive Order S-01-07 in 2007[175] and developed as a regulation shortly thereafter, requiring transportation fuels sold in California to reduce their average carbon intensity by 10 percent by 2020. There is a gasoline standard and a diesel standard. Obligated parties are producers and some distributers of petroleum and other transportation fuels. The standard is phased in over several years, and compliance is based on a graduated scale to reach 10 percent in 2020. Obligated parties can achieve reductions in a variety of ways, including purchasing low-carbon fuels; investing in low-carbon, nonpetroleum options; buying credits from others that provide a low-carbon fuel; or any combination of the above. Most alternative fuels qualify as eligible low-carbon-intensity fuels based on a life-cycle comparison of greenhouse gas emissions to diesel and gasoline. ARB administers the program.

Through ARB's LCFS, biofuels are part of ARB's core strategy to reduce carbon and criteria emissions from California's transportation sector. At present, the evolution of the biofuels industry is proceeding unevenly in California; biodiesel production and demand are surging, but cellulosic ethanol production remains primarily in the pilot phase of commercialization.

175 http://www.arb.ca.gov/fuels/lcfs/eos0107.pdf.

Figure 21: Total Net LCFS Credits by Fuel Type per Quarter: Number of Credits (top) and Percentage Shares (bottom)*



Source: UC Davis Institute for Transportation Studies, *Status Review of California's Low Carbon Fuel Standard*, July 2014. *CI is carbon intensity, in grams CO_{2e} per megajoule (qCO_{2e}/MJ)

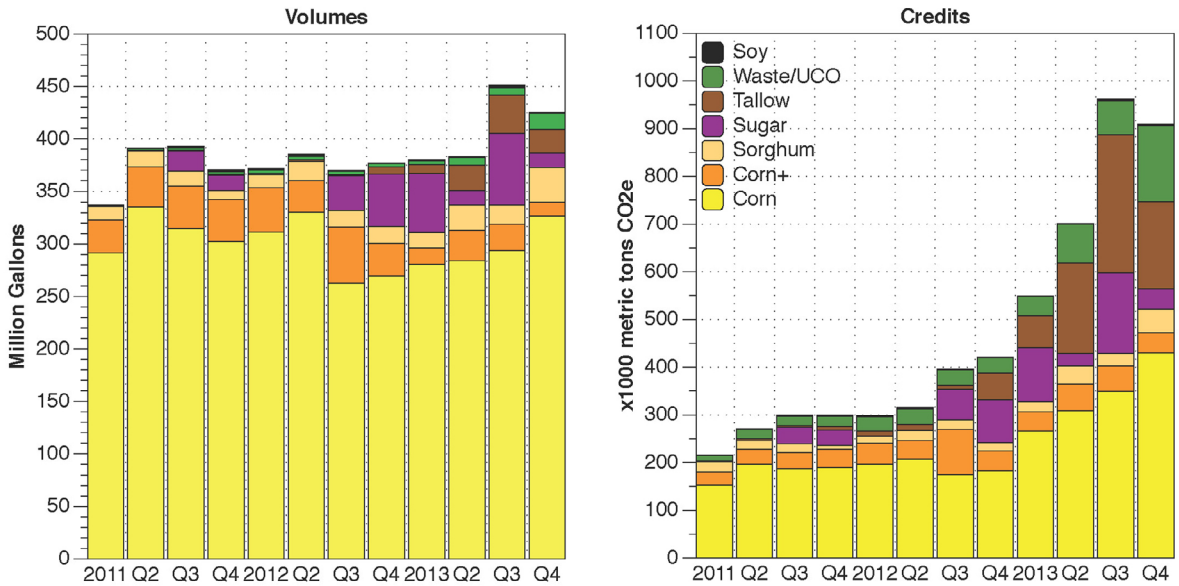
Ethanol, biodiesel, and renewable diesel account for the large majority of alternative fuels and credits with the LCFS. As reported by the UC Davis Institute for Transportation Studies, biofuels account for 88 percent of the LCFS credits generated between 2011 and 2013, while CNG and LNG account for 11 percent, and electricity accounts for less than 2 percent.[176] Figure 21 shows the total number of LCFS credits by fuel type between 2011 and 2013. Note the large increases in lower-carbon ethanol and very low-carbon biodiesel and renewable diesel.

On a volumetric basis, ethanol forms the large majority of the biofuels sold in California, with more than 1 billion gallons gasoline equivalent (gge) in 2013. Figure 22 illustrates that the large volume of ethanol accounts for a far smaller fraction of the LCFS credit distribution shown in Figure 22, which indicates that the very low-carbon-intensity biodiesel and renewable diesel fuel products from waste-based feedstocks generate the same amount of LCFS credits with just a fraction of the fuel volume as ethanol.

As part of the readoption of the LCFS, ARB staff released a series of draft proposed revisions to carbon intensity standards and potential compliance scenarios that may occur when the readoption is complete and compliance rates increase past 1 percent to 10 percent in 2020. Much of these proposed revisions are driven by updates to software models used to estimate carbon intensity values. For example, the carbon intensity value for ultra-low-sulfur diesel is expected to increase by about 4.5 grams, raising it from98 gCO_2e/MJ to 102.7 gCO_2e/MJ. The carbon intensity values of compressed natural gas fuel pathways are also expected to increase due to updated estimates of methane leakage rates and transmission energy, although ARB staff has not established new carbon intensity values. ARB staff also conducted extensive investigations on the future potential availability of low-carbon alternative fuels

176 UC Davis Institute for Transportation Studies, *Status Review of California's Low Carbon Fuel Standard*, July 2014.

Figure 22: LCFS Biofuels by Feedstock per Quarter: Volumes (top) and Number of Net Credits Generated (bottom)



Source: UC Davis Institute for Transportation Studies, Status Review of California's Low Carbon Fuel Standard, July 2014. *"Corn" pathways include corn ethanol and corn oil biodiesel. "Corn+" pathways include fuels using mixed feedstocks: corn, wheat slurry, and sorghum, plus relatively small volumes of 100 percent canola biodiesel. The "Waste/UCO" category includes diesel substitutes from used cooking oil, and waste beverages to ethanol.

and fossil-based fuels. The staff forecasts substantial national supplies and international supplies of many fuels and predict that many of these fuels will be sent to California to take advantage of LCFS credits.[177] For example, ARB staff estimates that up to 14.8 billion gallons of corn-based ethanol will be available in the United States in 2020, along with 0.8 billion to 1.7 billion gallons of sugarcane ethanol from Brazil. Cellulosic ethanol supplies in the United States could range from 100 million to 250 million gallons, with Brazilian cellulosic ethanol adding another 150 million to 300 million gallons per year by 2020. ARB staff also estimates that between 0.6 billion and 1.2 billion dge of natural gas may be used in 2020, along with 250 million to 500 million dge of renewable natural gas. Using a subset of this estimated U.S. availability of low-carbon-intensity alternative fuels, ARB staff subsequently presented an LCFS compliance scenario for meeting the 2020 goal of a 10 percent reduction in carbon intensity.

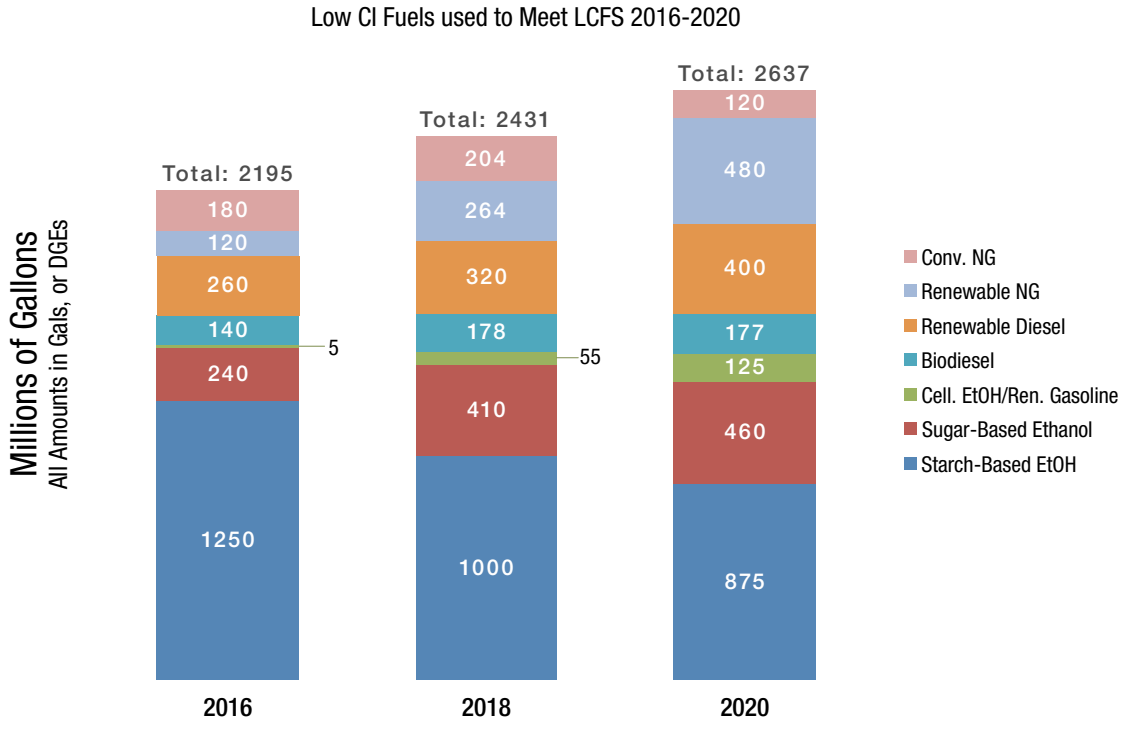
Figure 23 shows that illustrative LCFS compliance scenario between 2016 and 2020.[178] The LCFS is fuel-neutral and performance-based, so the actual volumes and carbon intensities of low-carbon intensity fuels used to comply with the LCFS in the coming years may be quite different than the illustrative example, but the scenario does present a potential pathway to compliance.

Lastly, ARB staff also developed a series of charts showing the relationship between higher future LCFS credit values, carbon intensity values, and the dollars-per-ton premium that could accrue to low-carbon fuels. For example, waste-based biodiesel with a carbon intensity value of 15 gCO_2e/MJ could see per-gallon premiums of between $0.55

177 California Air Resources Board, "Low Carbon Fuel Standard Reconsideration: Fuel Availability," September 25, 2014.

178 California Air Resources Board, "Low Carbon Fuel Standard Reconsideration: Proposed Compliance Curves and Cost Compliance Provision," October 27, 2014.

Figure 23: Sample Compliance Scenario Based on Low-Carbon-Intensity Biofuels



Source: ARB LCFS Staff

to $2.19 as LCFS credit prices rise from $50 to $200 per credit.[179] These low-carbon price premiums would realize the supplemental revenue streams for low-carbon fuel producers that have long been predicted by government analysis and sought by the low-carbon alternative fuel industry.

Renewable Fuel Standard

The Renewable Fuel Standard Program (RFS2), administered by the U.S. EPA, sets the minimum volume of renewable transportation fuel that must be sold in the United States with a mandate of 36 billion gallons of renewable fuel to be blended into transportation fuels nationwide by 2022. Within this volume, the RFS2 has established four specific types of renewable fuel: cellulosic (D3 or D7), biomass-based diesel (D4), advanced biofuel (D5), and renewable fuel (D6).

The U.S. EPA proposed some changes in the 2014 Renewable Fuel Standards that have begun to affect the biofuels market and the volumetric goals of the RFS2. Specifically, the U.S. EPA expanded the scope of fuels that are eligible to generate Renewable Identification Numbers (RINs) for cellulosic biofuel to include CNG and LNG produced from biogas from landfills, municipal wastewater treatment facility digesters, agricultural digesters, and separated municipal solid waste digesters. This revised pathway has the potential to provide a significant volume of cellulosic biofuel to help meet volumetric goals for the RFS2. In contrast, the U.S. EPA also proposed to reduce the volumetric requirements for the biomass-based diesel and advanced biofuels categories from the original 2007 statutory requirements.

179 California Air Resources Board, Low Carbon Fuel Standard Reconsideration: Fuel Availability, September 25, 2014.

The Energy Commission and the ARB provided a comment letter to the U.S. EPA on January 28, 2014,[180] expressing how reducing requirements for biomass-based diesel and advanced biofuels would adversely impact RIN values and the economic viability of biofuel companies in California. The letter requested that the U.S. EPA increase, rather than decrease, the requirement for the D4 and D5 categories to set stronger required volumetric obligation levels. "The proposed rule also jeopardizes the development and expansion plans of numerous California biofuel projects that are projected to annual production of nearly 380 million gallons of biomass-based diesel and 180 million gallons of advanced biofuels by 2020." Should this portfolio of advanced, low-carbon biofuels begin to falter due to the proposed reductions, it could impede the state's efforts to reduce the carbon intensity of transportation sector fuels by 2020, as envisioned in the Global Warming Solutions Act and Low Carbon Fuel Standard. The Energy Commission's biofuel grantees and stakeholders have stated they believe that this proposed ruling "would significantly harm the economic viability and future potential of the state's emerging biofuels industry."[181] In December 2014, the U.S. EPA announced that it would finalize the 2014 standards in 2015.[182]

Cellulosic Ethanol: Technology and Market Status

Dr. Parker discussed the challenges for cellulosic process technologies and reported that the current projects were smaller and required more capital than predicted in the academic literature. He said that for a commercial-scale cellulosic ethanol plant to be economical, it would have to be at a much bigger scale than currently planned and that there is insufficient private capital to finance a large-scale cellulosic biorefinery. The carbon markets with the LCFS and Renewable Fuel Standard were intended to provide capital funding for commercial-scale facilities, but the current volatility of the credit markets are eliminating that financing potential. He said there is still a great deal of industry learning that must occur with the enzymatic processes and materials needed for cellulosic ethanol.

Tom Griffin, Chief Technology Officer for Edeniq, provided an industry perspective on the status of cellulosic ethanol production in California. Edeniq operates a pilot-scale cellulosic ethanol biorefinery in Visalia with grant funding from DOE and the Energy Commission's ARFVTP. Edeniq is also developing a series of "bolt-on" technologies for feedstock pretreatment and enzymatic processing that can be added incrementally to existing ethanol biorefineries, such as the four corn-based facilities in California.

Key Challenges to Cellulosic Ethanol

A core challenge for the cellulosic ethanol industry is to reduce the costs of:

- Enzymes and the enzymatic phase of the process technology.
- Pretreatment phase needed to grind feedstocks into uniform particles for processing.
- Feedstock collection.

Methods to collect uniform feedstocks must also be developed to avoid challenges with feedstock inconsistency.

Source: Tom Griffin, Edeniq

180 California Energy Commission and ARB staff. Letter to U.S. EPA, dated January 28, 2014.

181 California Energy Commission and ARB staff. Letter to U.S. EPA, dated January 28, 2014. Energy Commission staff survey of ARVTP biofuel grantees for comment letter, "Survey of Biofuels Recipients and Grantees," January 10–28, 2014.

182 U.S. Environmental Protection Agency, "Delay in Issuing 2014 Standards for the Renewable Fuel Standard Program," Federal Register, Vol. 79, No. 236, Page 73007, December 9, 2014.

Figure 24: Cellulosic Ethanol Feedstock Assessment Summary

Edeniq-CEC
Feedstock Assessment Summary
Yields and Implications for California Feedstock Potential

Feedstock Class	Sugar Yield (kg/ton equiv)	Ethanol Potential (1) (gal/ ton)	Comments/ Other Factors
Nut Crop Residues	139	19	almond, peanut, walnut husks
Wood - Citrus	272	41	extensive work earlier in R&D pilot
Wood - Pine	133	19	useful cellulosic content low
Other Grain Crops (rice, milo) (2)	182 - 220	25 - 31	projections based on composition
Corn Stover	260 - 315	36 - 45	extensive CCM work with CA stover
Energy Cane (3)	460 - 518	66 - 75	cane bagasse

notes

1- assumes 92% efficiency of C6 fermentation; 75% for C5
2- high inorganic feedstocks; appear detrimental to Celluntor wear (separate tests)
3- surrogate for energy cane (CA programs in development)

- CA stover has high potential and is already available
- Energy crop projects appear to have the highest process potential; uncertain practicality due to land use issues
- Citrus wood is a possible target, but aggregation logistics uncertain
- Other feedstocks studied are disadvantaged

Edeniq 10

Source: Edeniq, Inc.

Mr. Griffin stated that the core challenge for the cellulosic ethanol industry was to reduce the cost of the enzymes and enzymatic phase of the process technology, and to reduce the cost of the pretreatment phase needed to grind feedstocks into uniform particles that can be efficiently processed. The cost of feedstock collection is a barrier to commercialization, and Edeniq stated that methods to collect uniform feedstocks must be developed to avoid challenges with feedstock inconsistency at the pretreatment and process phases.

Mr. Griffin summarized some of the analysis Edeniq and other organizations have conducted on a range of California feedstocks, including nut crop residues, citrus and pine wood, corn stover, and energy cane. As shown in Figure 24, California corn stover offers high sugar content and an ethanol production potential of 36 to 45 gallons per ton of feedstock.

Edeniq is also working to identify optimal enzymes and enzyme blends that can be formulated for specific feedstocks and to develop enzyme enhancers to advance the efficiency of this phase of cellulosic ethanol production.

Mr. Griffin reported that the Visalia pilot plant has exceeded the DOE performance standard for 1,000 hours of operation with 90 percent "up time." During trials with corn stover as the feedstock, the plant operated for 1,500 hours. Edeniq's business strategy is to proceed incrementally and continue developing its bolt-on technology package that can be integrated into existing corn ethanol biorefineries, rather than seek to develop a commercial-scale stand-alone facility.

Biodiesel: Technology and Market Status

Dr. Parker reported that the California biofuels industry is making better progress in the biodiesel sector and that incremental improvements to the ethanol sector, such as efficiency gains and minor adjustments in feedstocks, are proving to be economical and successful. He cited feedstock supply constraints for waste oils but said they are yielding low-carbon, high-value fuels that should be developed and marketed. He concluded that breakthroughs in process technology for cellulosic ethanol or algae-based biodiesel are needed to achieve commercial-scale production in California, but that the business case for these pathways is not clear.

Harry Simpson, chief executive officer of Crimson Renewable Energy, provided an industry perspective on in-state biodiesel production. Crimson owns and operates the Crimson Renewable biodiesel refinery in Bakersfield, which is the state's largest biodiesel producer at 10 million gallons per year (MGY) in production capacity. Due to a recent ARFVTP grant, the project will scale up to 17 MGY in early 2015. The biorefinery processes waste oils into very low-carbon-intensity biodiesel (12-15 gCO_2e/MJ) and markets its products to major oil companies such as Chevron, Exxon, and Valero, who use it as a blendstock with diesel.

Mr. Simpson sees strong growth in biodiesel and renewable diesel production and demand in California. Mr. Simpson also cited investment in fuel terminal infrastructure that can blend biodiesel with diesel. There was just one facility in 2010, but seven more projects had been developed by major oil and pipeline companies since then, with more terminals planned by Kinder-Morgan, Chevron, and Tesoro.[183]

Mr. Simpson described a major shift away from food-based oils as the primary biodiesel feedstock. Soybean oil accounted for 90 percent of the U.S. feedstock base in 2008 but represented 53 percent in 2013. Waste oils and fats and corn oil remains from ethanol production are emerging as key feedstocks. Virgin seed oils from alternative energy crops like canola, mustard seed, and jatropha have no LCFS pathway and have limited availability, while palm oil from Southeast Asia continues to face significant sustainability challenges. Mr. Simpson foresees brown grease and tall oils as the next generation waste-based feedstocks that are available at scale, but said processing challenges will need to be overcome. In particular, he cited three emerging process technologies with the potential to convert the high free fatty acid (FFA) content of these feedstocks: supercritical high-pressure, high-temperature processes; the introduction of enzymatic technology; and the use of heterogeneous catalysts to convert the FFA into usable esters and biodiesel. He said that commercial-scale biorefineries using these process technologies have been built elsewhere in the United States, Europe, and Asia.

Algae-Based Biodiesel

Algae-based biodiesel holds tremendous potential to produce commercial-scale volumes of low-carbon biofuels with a lower impact to natural resources than food-based feedstocks. Algae can be cultivated in closed systems with sugar and carbon dioxide as inputs, or in open ponds or raceways in areas with high ambient air temperatures and sunlight. Two key challenges to algae cultivation are 1) developing large volumes of low-cost sugars as in input for closed systems and 2) siting large-scale, open-air cultivation environments. For the harvest and processing of algae to retrieve the oils that will serve as biodiesel feedstocks, cost-effective processing techniques are still in development and require further research. A particular challenge is reducing the large energy inputs needed to dewater and dry large volumes of algae before processing. Research is underway in California at research centers such as UC San Diego's Center for Algae Biotechnology, and at private firms such as Solazyme and Sapphire.

Energy Commission Funding and Strategy for Advanced Technology Biofuels

Through $91 million in ARFVTP funding, the Energy Commission is funding 33 biofuels projects that will advance process technology development and expand production capacity for second- and third-generation biofuels made from waste-based feedstocks with very low-carbon-intensity values. These biofuels include conventional and cellulosic ethanol, biodiesel and renewable diesel,

183 Harry Simpson, President and CEO, Crimson Renewable Fuels, presentation at April 10, 2014, Integrated Energy Policy Report workshop.

and biogas. Nearly all the projects in this portfolio use waste streams or alternative energy crop feedstocks and avoid the sustainability issues associated with food-based feedstocks such as corn and soy beans or oil palm from Southeast Asia. Sustainability considerations are important in selecting projects for ARFVTP funding. In accordance with Energy Commission ARFVT Program regulations for sustainability, feedstocks with high ecological impacts to forest or aquatic ecosystems or prime farmlands, or with high water demands, are discouraged and do not score well in project evaluations.[184] In addition, many biofuels projects demonstrate that co-products such as green electricity, green chemicals, and animal feed products such as wet distillers grains can create additional value streams from biofuels production.

The market share for biodiesel and renewable diesel is growing quickly; biodiesel consumption in California grew from 5 million gallons in 2010 to 20 million gallons in 2012 to 49 million gallons in 2013.[185] The market growth of renewable diesel has been increasing even more rapidly, growing from fewer than 2 million gallons in 2010 to 9 million gallons in 2012 to 136 million gallons in 2013.[186] ARFVTP investments have helped spur this rapid market growth and market acceptance of biofuels.

The carbon intensity value for these diesel substitute fuels is very low at about 15 gCO_2e/MJ, 85 percent less than diesel. Crimson Renewable Fuels is an example of a modern biodiesel company. Through two ARFVTP awards, it has expanded its Bakersfield biorefinery to produce 17 million gallons per year using waste greases and oils as the feedstock. The total production capacity for biodiesel and renewable diesel projects in California funded via ARFVTP is 126 million dge per year.

Biogas from municipal, agricultural, and food processing organic waste streams; wastewater treatment plants; and landfills have some of the lowest carbon intensity values of any commercially available fuel in California, ranging from 15 to negative 13 gCO_2e/MJ. Biogas can be used as a transportation fuel in trucks with natural gas engines or blended with natural gas. It also is an important feedstock for the production of renewable hydrogen. When co-located at landfills, wastewater treatment plants, or near hydrogen fueling stations, biogas projects can create additional benefits by helping resolve landfill diversion obligations, creating biogas fueling opportunities for local truck and school bus fleets, or providing low-carbon renewable hydrogen feedstock supplies.

Through ARFVTP funding, the Energy Commission has invested nearly $39 million in 12 biogas projects with a combined production capacity of 9.6 million dge per year. Clean World Partners in Sacramento has used two ARFVTP grants to construct and operate an anaerobic digestion processing facility that can convert 100 tons per day of diverted municipal solid waste into 566,000 dge of renewable natural gas each year. The total ARFVTP-funded production capacity for biogas projects in California is 9.6 million dge per year.

Five projects have been cancelled, primarily due to the grantee's inability to secure matching funds. This is indicative of the continuing financial risks associated with advanced alternative fuel projects.

Table 11 summarizes the ARFVTP biofuels investment portfolio by biofuel category. Waste-based biodiesel accounts for more than half the total production capacity at 78.8 million dge, reflecting the maturation of the biodiesel industry and its ability to develop and finance commercial-scale projects in California. Renewable diesel project awards have increased in recent years, demonstrating a similar level of technology and market maturation. Biogas

184 California Energy Commission, Final Regulation Language, Alternative and Renewable Fuel and Vehicle Technology Program, Title 20, California Code of Regulations, Sections 3100-3108, April 2009, Publication No. CEC-600-2008-013-F (Sustainability Regulations at Section 3101.5).

185 J1 Monthly Biodiesel Production Reporting (M810E), data reported to the Energy Commission in compliance with Petroleum Industry Information Reporting Act (PIRRA).

186 J2 Vessel Volumes, data reported to the Energy Commission in compliance with Petroleum Industry Information Reporting Act (PIRRA).

Table 11: ARFVTP Biofuels Portfolio

	Production (million dge)	Funding ($millions)	Average CI (gCO2e/MJ)	Project Count
Biomethane	9.6	50.9	-10.6	15
Ethanol	8.9	23.5	49.1	11
Cellulosic Ethanol	0.02	3.9	23.6	1
Biodiesel	78.8	36.1	11.3	12
Renewable Diesel	47.9	17.1	21.8	5
Total	145.3	131.6	8.0	44

Source: Energy Commission Staff

projects have the lowest average carbon intensity value, with many being carbon-negative projects. The ratio of production level to project funding indicates the still-high production costs for biomethane production in California.

About 60 percent of the funding is allocated to commercial-scale projects, and the other 40 percent is distributed between feasibility studies and midscale demonstration projects. The ARFVTP biofuels portfolio has just one cellulosic demonstration project and no green gasoline projects, which is indicative of the early and precommercial aspect of these process technologies.

In summary, the California biofuels industry is proceeding steadily, if unevenly. Biodiesel and renewable diesel are making tremendous gains in California markets with a reasonably priced, very low-carbon alternative fuels product. Feedstock limitations on waste-based oils and greases may prove to be the limiting factor on this surging portion of the biofuels portfolio. Biogas production in California is also proceeding well, but serious challenges remain to finding cost-effective production methods. Cost-effective compliance methods or alternative funding for AB 1900 compliance must be found so that biogas can be transmitted via California's vast natural gas pipeline infrastructure. Biogas is poised to play a key role in future natural gas and hydrogen fuel markets as a blendstock that can significantly reduce the carbon footprint of these two fossil-based alternative fuels.

From another perspective, the California biofuels industry is making good progress in displacing diesel truck fuels, and the potential for future displacement is strong. With gasoline and light-duty vehicle fuels, however, many technical and cost hurdles must be surmounted for cellulosic ethanol and green gasoline to become competitive and displace gasoline and corn-based ethanol.

Natural Gas and Renewable Natural Gas Fuels and Vehicles Assessment

Since the first round of *ARFVTP Investment Plans* and funding solicitations in 2009 and 2010, the Energy Commission has viewed natural gas as a near-term bridging fuel that offers a modest 30 percent carbon reduction from petroleum fuels, especially in the truck and bus sectors. Natural gas was providing about a 33 percent price differential over diesel fuel through the third quarter of 2014 ($1.40 per dge), which has meant that fleet operators with high-mileage haul routes could enjoy substantial savings on fuel costs and recoup the incremental investment needed for natural gas engines and fuel systems. Given the recent price drops in petroleum and diesel fuel, however, the price

differential has shrunk by half to a 17 percent differential of $0.60 per dge.[187] Large fuel providers such as Clean Energy and Shell are bringing private capital to natural gas fueling systems focused on truck fleets.

Historically, natural gas engines were cleaner than diesel engines and could readily meet the 0.2 grams per brake-horsepower-hour (g/bhp-hr) NO_x standard. Many fleets began the change to natural gas fuels and engines as a cost-effective compliance option for meeting this NO_x emissions standard, and natural gas trucks and buses displaced large volumes of older diesel trucks and buses. As diesel truck fleets begin to comply with the 2010 emissions standards, natural gas no longer offers large benefits over diesel for particulates and criteria emissions. However, ARB passed a voluntary regulation in 2013 that would lower natural gas NO_x emissions 80 percent to 0.02 g/bhp-hr, which would again place natural gas technology ahead of diesel engine technologies for cleaner combustion and emissions cycles.

Over the long-term, natural gas engines have the potential to operate at extremely low emission levels that could be "electric vehicle equivalent" on a life-cycle-emissions basis.[188] When combined with the current low fuel costs and the blending opportunity with biogas and renewable hydrogen, natural gas has the potential to displace large volumes of diesel fuel in the on- and off-road sectors, as well as the marine and rail sectors.

An immediate concern with natural gas is the potential for the modest carbon intensity benefit to be reduced or eliminated due to the leakage of methane at points all along the distribution and transmission pipeline systems and upstream at the production wells and gas collection systems, as discussed in chapter 6. The current challenge is to determine the appropriate role for natural gas as an alternative fuel in California's portfolio of alternative fuels and vehicle technologies in the face of the policy and scientific uncertainty about methane leakage and the ultimate carbon intensity value for natural gas a vehicle fuel.

Status and Potential for Low-Carbon, Low-Emission, Natural Gas Engines

Industry experts provided the Energy Commission with their best insights on the current status and near-term potential for natural gas engines that are near zero or zero emissions.

Low-emission natural gas engines are feasible

Gladstein, Neandross and Associates (GNA) also sees a technology pathway for natural gas engines that leads to very low-emission engines with 90 percent less NO_x emissions (0.02 grams) than current regulatory standards that would be "power plant equivalent" in terms of emissions and efficiency, as shown in Figure 25. Adding blends of renewable natural gas with very low carbon intensity values would substantially lower the carbon footprint of natural gas-fueled trucks and help fleets conform with the 2050 greenhouse gas emission reduction targets.

As noted earlier, the South Coast AQMD's initial strategy for technology development in this sector focused on natural gas engines and fuels that could be used to displace pre-2010-compliant diesel trucks and buses. In the early 2000s, the South Coast AQMD worked with NREL and the DOE to fund development of natural gas engines that could meet the pending 2010 standard for NO_x of 0.2 g/bhp-hr. South Coast AQMD seeks to repeat this strategy by collaborating on developing the next generation of natural gas engines that can meet the voluntary standard for NO_x of 0.02 g/bhp-hr in the 2018 time frame.

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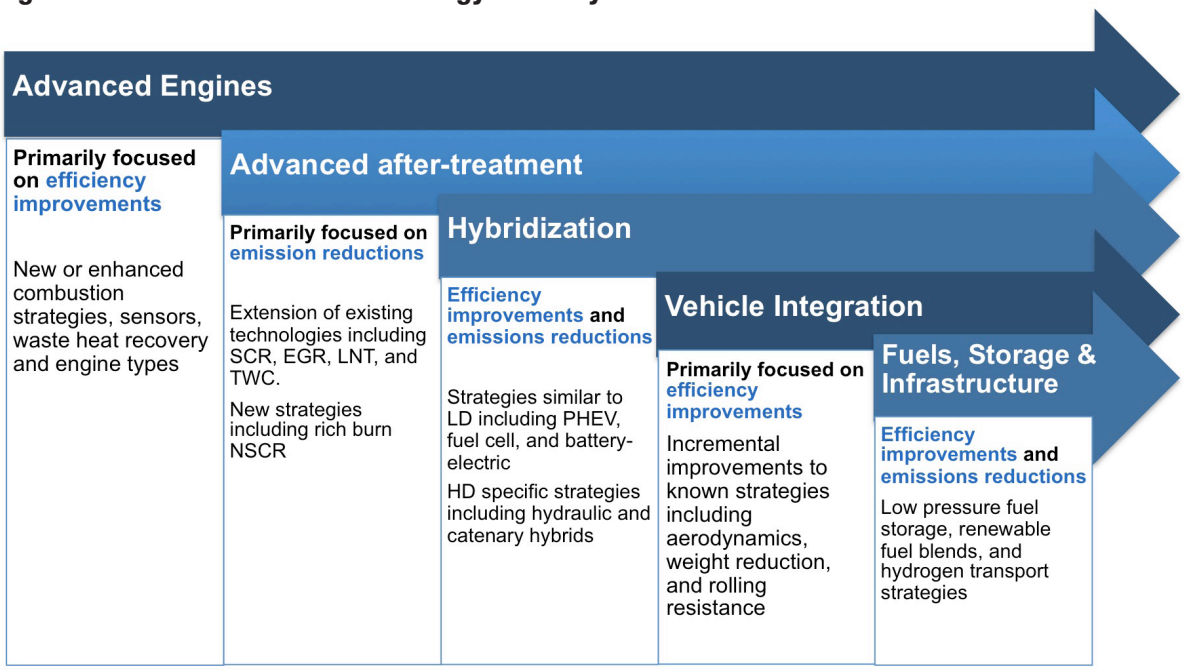
187 Pacific Gas and Electric Company, Tariff Schedule G-NGV2 for compressed natural gas, January 1, 2013 to December 31, 2014 (Energy Commission staff conversion from gge to dge).

U.S Energy Information Agency, Weekly California No. 2 Ultra Low Sulfur Diesel Retail Price Series for 2014. http://www.eia.gov/dnav/pet/hist/LeafHandler.ashx?n=PET&s=EMD_EPD2DXL0_PTE_SCA_DPG&f=W.

188 Dr. Matt Miyasato, presentation at the June 23, 2014, Integrated Energy Policy Report workshop.

Figure 25: Five Natural Gas Technology Pathways



Source: Gladstein, Neandross, and Associates

Natural gas fuel providers and engine developers see a broader market for natural gas engines and are developing engines to serve those markets

Todd Campbell of Clean Energy Fuels attested to the large market growth in natural gas vehicles and fuels in the United States.[189] He stated that natural gas vehicles are in use at 40 percent of the nation's airports and that 30 percent of transit buses and 60 percent of new refuse hauling trucks use natural gas fuels. The long-haul truck sector, railroads, and marine freight companies are also beginning to investigate transitions to natural gas engines and fueling systems.

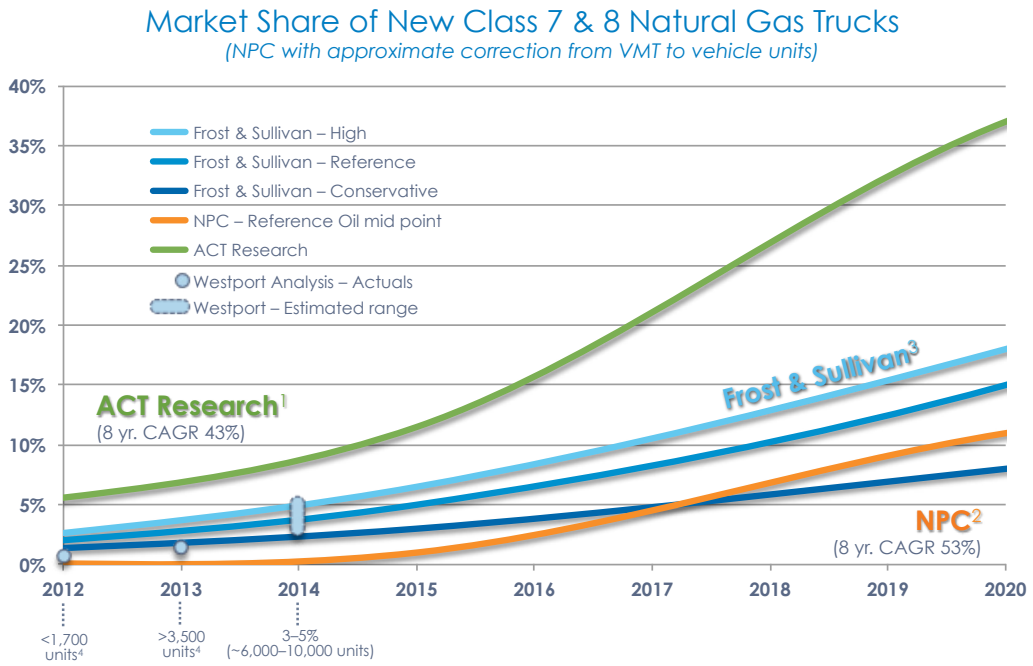
Westport Innovations is one of North America's leading medium- and heavy-duty engine developers that offer a full line of natural gas engines for customers that include Volvo, Cummins, Caterpillar, General Motors, and Ford. Karen Hamburg provided information on a range of studies showing that North American natural gas truck sales could grow from 3 to 5 percent of new Class 7 and 8 truck sales in 2014 to 7 to 35 percent of new sales in 2020. As shown in Figure 26, Westport's own projection ranges from 15 to 18 percent of new sales by 2020, a substantial increase from 2014 natural gas truck sales levels.[190]

Westport will soon offer a range of three natural gas engines from the pending 6.7 litre ISB 6.7 G model intended for school buses to the currently available 8.9 litre ISL G that can pull 66,000 pounds of gross vehicle weight (GVW) to the 11.9 litre ISX 12 that can pull Class 8 payloads of 80,000 pounds of GVW. Westport is also developing a heavy-duty LNG engine with Volvo that should be

189 Todd Campbell, Clean Energy Fuels, presentation at the June 23, 2014, *Integrated Energy Policy Report Update* workshop.

190 Karen Hamberg, Westport Innovations, presentation at the June 23, 2014, *Integrated Energy Policy Report Update* workshop.

Figure 26: Estimated Market Share of New Class 7 and 8 Natural Gas Trucks Through 2020



Source: Westport 1. Act Research Future of Natural Gas Engines, August 2012, 2. NPC Advancing Technology, Reference Case, August 2012, 3. Frost & Sullivan Strategic Outlook Truck Market 2013, 4. Westport Analysis

available in 2015. This range of natural gas engine sizes is intended to satisfy most North American truck duty cycles for medium- and heavy-duty trucks. Ms. Hamberg stated that further price reductions in natural gas engines are needed that could be obtained through market growth and increased economies of scale. Additional industry investments are needed to further reduce NO_x emissions and increase near-zero emission miles.

Erik Neandross of GNA also provided information on the potential market growth for natural gas fuels and trucks.[191] He said that in addition to the substantial fuel cost savings from the price differential between diesel and natural gas, many corporate fleet operations with green policy goals are seeing an opportunity to integrate environmental benefits with fuel cost savings, including Proctor and Gamble, Pepsico, and General Mills. Results from GNA's own study estimate market penetration rates of 50 to 60 percent for natural gas trucks in the 2027 to 2030 time frame.[192] Mr. Neandross also provided information on the interest of high-volume, off-road transportation and mining companies to begin a transition to natural gas fuels, stating that a line-haul locomotive uses about 250,000 gallons of diesel per year, a mine hauling truck uses 500,000 dge per year, and that small container ships use 35 million dge per year.

The trucking industry would be willing to adopt cleaner, low-emission natural gas vehicles into its fleets

The California Trucking Association (CTA) is an industry trade association representing the interests of California trucking fleets. Chris Shimoda provided information to the

191 Erik Neandross, Gladstein, Neandross and Associates, presentation at the June 23, 2014, Integrated Energy Policy Report workshop.

192 Gladstein, Neandross and Associates, *Pathways to Near-Zero Emission Natural Gas Heavy Duty Vehicles*, May 2014.

Energy Commission on how California fleet operators view the potential for natural gas fuels and trucks from a survey CTA conducted of 91 member organizations.[193] CTA asked the member organizations to identify the factors that would help and hinder the adoption of natural gas fuels and trucks into their fleets. The primary factors that would foster adoption were 1) fuel price savings, 2) better public perception of the trucking industry by using fuels that avoid public health concerns with diesel emission constituents, and 3) ongoing availability of incentive funding to compensate for higher incremental costs. The primary factors that would hinder the adoption of natural gas fuels and vehicles were 1) perceived lack of available fueling infrastructure, 2) lack of engine availability with sufficient power and torque, and 3) associated costs with training and the retrofit of maintenance bays.

Mr. Shimoda reported that another key survey finding was that the availability of incentive funding and vouchers was an important factor in evaluating a transition to natural gas fuels and engines. He reported that 17 percent of respondents would buy natural gas trucks without incentives, 27 percent would prefer incentives because it would allow them to expand their natural gas truck fleets more quickly, but that 55 percent of respondents would not buy natural gas trucks without public incentive funding. Mr. Shimoda noted that the Energy Commission's natural gas truck funding through ARFVTP was the only source of public incentive funding currently available to offset the incremental cost differential of $30,000 to $40,000 per truck, but that it is too small to provide incentives for large-scale shifts to natural gas.

A Vision for a Decarbonized Natural Gas Supply System

During the 2014 IEPR workshops, Southern California Gas Company (SoCalGas) representatives offered a vision and strategy for how natural gas pathways can play a key role in meeting California's near-term air quality goals and long-term carbon reduction goals from the transportation sector.[194,195] One representative proposed a parallel policy consideration for electricity and natural gas, stating that as California has a policy goal for decarbonizing electricity supplies and electrifying major portions of the transportation sector, the state should develop a similar policy goal for decarbonizing the natural gas supply chain and developing near-zero-emission natural gas vehicles. Dr. Jeffrey Reed described a mix of low-emission engine technology developments and a natural gas supply chain that integrates biogas and then green hydrogen as blendstocks to achieve AB 32 carbon reduction goals and federal Air Quality Act NO_x reduction goals. SoCalGas projects that natural gas vehicles may comprise 25 percent of the total heavy-duty truck market in California by 2030. The projected low and stable costs of natural gas will be a natural economic driver for this transition. SoCalGas provided information showing the comparative retail price differentials between diesel and natural gas through June 2014, with diesel fuel retailing at $4.01 per gallon and natural gas retail fuel retailing at $2.35 per dge. Dr. Reed added that even if the commodity price of natural gas were to double, the effect on retail fuel prices would be only a $0.50 per dge increase.

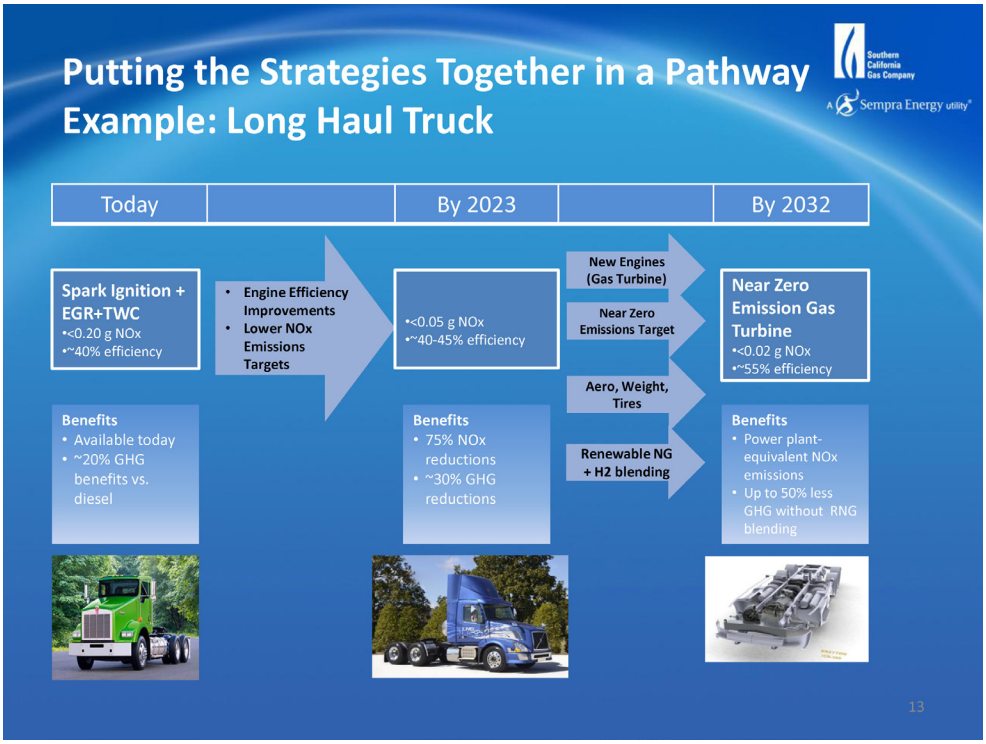
For criteria emissions reductions, Dr. Reed stated that current natural gas engine technologies could reduce NO_x emissions by 50 percent to 0.05 grams if sufficient incentive funding were available, and then down to the 0.02 gram standard by 2023 with a combination of incentive funding and regulatory drivers. Over the long-term from 2023 to 2032, natural gas engines would be capable of zero-emission miles by using hydrogen-methane fuel blends coupled with ultra-lean ignition and air-fuel control technologies.

193 Chris Shimoda, California Trucking Association, presentation at the June 23, 2014, Integrated Energy Policy Report workshop.

194 George Minter, Southern California Gas Company, *Natural Gas Pathways: Natural Gas Vehicles in California*, presentation at the June 23, 2014, Integrated Energy Policy Report workshop.

195 Dr. Jeffrey Reed, Southern California Gas Company, *Natural Gas Pathways to Achieve Air Quality Goals*, presentation at the April 10, 2014, Integrated Energy Policy Report workshop.

Figure 27: NO_x and Carbon Emission Reduction Strategies for a Long-Haul Truck



Source: Southern California Gas Company

For carbon emission reductions, Dr. Reed described a pathway where the initial 50 percent of carbon emissions reductions are achieved through the engine and truck efficiency measures that are in development for diesel-powered heavy-duty trucks. The next increments in carbon emissions reductions would occur through increasing the blend of renewable natural gas or biogas into the supply chain, followed by blends of green hydrogen derived from large-scale electrolysis, renewable power conversion to hydrogen, and ultimately, artificial photosynthesis. Figure 27 illustrates this technology evolution for long-haul trucks. Dr. Reed stated that this technology and fuel supply chain strategy could be scaled up further to include the marine and rail sectors that use very heavy-duty engines.

Dr. Reed shared a list of recommended technology development priorities:

» Natural gas engine and turbine development

» Next-generation engine after-treatment

» Mild hybrids for accessories and fuel economy

» Low-cost storage and fuel tanks

» Low-cost compression systems for fueling

» Renewable natural gas pathways

Julia Levin of the Bioenergy Association of California and Mr. Campbell of Clean Energy provided alternate potential renewable natural gas pathways that could benefit the transportation sector in California. Ms. Levin indicated that California's wastewater treatment plants, landfills, and dairies generate organic wastes could generate 2.5 billion

dge[196] per year. Further, currently landfilled organic wastes could produce 684 million gge[197] of carbon-negative transportation fuels if diverted to anaerobic digestion facilities. Citing the need to create access for biogas into the state's natural gas pipeline system, Ms. Levin identified access into the state's natural gas pipeline system as a potential hurdle for biogas and suggested using the natural gas utilities' cap-and-trade revenues to help offset testing and clean-up costs for in-state biogas producers.[198]

Mr. Campbell described Clean Energy's renewable natural gas pathway which imports 100 percent landfill gas from Texas at a capacity of 94,000 dge per day. Clean Energy sold 14 million gallons of this product in California in 2013 and expects strong growth in sales.

Energy Commission Natural Gas Fueling and Vehicle Funding

Through ARFVTP, the Energy Commission has invested nearly $90 million in natural gas fueling infrastructure and medium- and heavy-duty truck vouchers, about 15 percent of the current ARFVTP portfolio. The Commission has funded 58 CNG or LNG stations and 5 renewable natural gas stations for a total of $17.5 million. Nearly half these awards have gone to school districts or municipal government, with 14 awards to school districts and 14 awards to municipal or regional governments. Natural gas fueling stations at school district fleet yards enable the continuing displacement of pre-2010-compliant school buses, which means reducing the risks to young children of exposure to diesel particulates and toxics.

As shown in Chapter 4, this modest $17.5 million investment in natural gas fueling infrastructure creates greenhouse gas reduction benefits cost-effectively. Natural gas fueling infrastructure accounts for 65 percent of total expected carbon reduction benefits out of all the ARFVTP fueling infrastructure benefits and 17 percent of total expected carbon reduction benefits from the entire ARFVTP portfolio.

On the vehicle side, the Commission has distributed $54.4 million, which has resulted in about 2,735 new medium- and heavy-duty natural gas trucks in California.[199]

Natural gas fuels and engines have the potential to cost-effectively reduce carbon and criteria emissions from the on-road, heavy-duty trucking sector. To achieve this goal, however, biogas and green hydrogen will need to be blended with natural gas at industrial scales, and many significant technical, cost, and regulatory barriers must be overcome. With respect to vehicle technology, industry has indicated that low-NO_x natural gas engines that can achieve near-zero emissions profiles are technically viable. Government and industry will need to collaborate to accelerate development and market acceptance of the next generation of natural gas engines. As discussed further in Chapter 6, a policy concern is that methane leakage at well heads and along pipeline networks could compromise the air quality and greenhouse gas reduction benefits of natural gas as a transportation fuel, depending on the magnitude of the leakage.

196 Bioenergy Association of America. *Decarbonizing the Gas Sector: Why California Needs A Renewable Gas Standard*, November 2014.

197 Bioenergy Association of America, Comments on the Draft 2014 IEPR Update, http://www.energy.ca.gov/2014_energypolicy/documents/2014-11-24_workshop/comments/Bioenergy_Association_of_California_Comments_2014-12-05_TN-74117.pdf.

198 Julia Levin, Bioenergy Association of California, presentation at June 23, 2014, Integrated Energy Policy Report workshop.

199 An additional $7.3 million funded about 600 propane-fueled trucks, but this funding has ceased due to the low carbon reduction benefit of just 10 percent for propane.

Recommendations

Hydrogen

» **Help reduce hydrogen station development costs**. The Energy Commission should assist efforts to push down hydrogen station development costs while maintaining operational and market viability for this emerging alternative fueling sector. For hydrogen stations that the Energy Commission has awarded funding, the Energy Commission should monitor the costs of the stations and use the information to help inform future investments. Also, the Energy Commission staff should work closely with the H2 First partnership to maintain awareness of innovations in hydrogen station storage and dispensing equipment that can reduce equipment costs.

» **Encourage innovative funding and cost-sharing to help attract private investment in hydrogen fueling infrastructure**. The Energy Commission, in collaboration with state and federal government partners, the California Fuel Cell Partnership, and other stakeholders, should work to encourage innovative funding and cost-sharing initiatives that can increase private sector investment in hydrogen fueling infrastructure development. Specifically, the Energy Commission should:

- » Encourage additional automaker investments in fueling infrastructure.
- » Work with retail gas station owners and oil marketing companies to identify and attract additional station sites and investments.
- » Examine the funding arrangements in use in Europe and Asia between government and industry for hydrogen station development for possible use in California.

» **Advance renewable hydrogen fuel**. The Energy Commission should continue to support development of renewable hydrogen supplies and increase the renewable content of hydrogen fuels sold in California.

Near-Zero/Zero-Emission Vehicles

» **Provide targeted incentives to help bring down the cost of medium- and heavy-duty electric vehicles**. The Energy Commission should collaborate with other state and federal agencies to provide incentive funding targeted to help bring down the costs of medium- and heavy-duty vehicles over the next 10 years. The Energy Commission anticipates working in close collaboration with the California Air Resources Board (ARB) and California Department of Transportation on strategies to reduce pollution from the freight and goods movement sector. State incentives could go toward large-scale demonstration projects using 10 to 50 vehicles, continued funding of manufacturing facilities and assembly lines, and continued small scale, early commercial phase demonstrations of 1 to 5 vehicles.

» **Collaborate with state agencies to focus funding on transformative, advanced technology medium- and heavy-duty vehicles**. In the signing statement for Senate Bill 1204 (Lara, Chapter 524, Statutes of 2014), Governor Brown notes the importance of "reduc[ing] emissions from the highest polluting vehicles in the State." As called for in the signing statement, the Energy Commission should work in partnership with its sister state agencies, and with federal or local agencies to focus funding on providing incentives for the development and use of vehicles that "can meet the objectives of AB 32 by reducing emissions of both harmful criteria pollutants and greenhouse gases" and "are certified to meet the cleanest standards and run on renewable fuels."

Biofuels

» **Provide data to the U.S. Environmental Protection Agency on the potential for very low-carbon biofuels.** The Energy Commission should continue to provide information to the U.S. EPA so that very low-carbon biofuels are appropriately recognized and categorized in the annual Renewable Fuel Standard volumetric targets.

Renewable Natural Gas

» **Provide funding for research and precommercial technologies that can advance integrating biogas into fuel supplies**. The Energy Commission should continue to fund biogas production projects to increase the supply of biogas that can be integrated into natural gas fuel stocks and fund research and precommercial technologies that can more efficiently and economically convert waste-based feedstocks to renewable natural gas.

» **Assist in ensuring that biogas can be safely and economically injected into pipelines**. The Energy Commission should work with the California Public Utilities Commission and the ARB to overcome potential barriers impeding commercial biogas projects and explore the availability of potential funding or incentive programs to help bring additional low-carbon biogas projects online.

CHAPTER 6:
Transportation Integration Trend with Electricity and Natural Gas Systems

A trend toward diversifying California's transportation fuels has an effect on the state's efforts to increase renewable electricity sources and de-carbonize natural gas use. Linkages among the electricity, transportation, and natural gas systems are growing and creating opportunities for mutual benefits and new challenges.

California is on a path to achieve the Governor's Zero-Emission Vehicle (ZEV) goal of 1.5 million electric vehicles by 2025, and this success would contribute to electric vehicles becoming equal in cost or lower than gasoline and diesel cars by 2030.[200] Greater attention to vehicle and electric grid integration will be needed as California experiences growth of electric vehicles with average loads of 6 kilowatts per vehicle. The Energy Commission's *2013 Integrated Energy Policy Report* concluded that three- to sixfold growth of alternative fuels by 2020 in California is plausible based on sustained government incentives, regulations, and policies.[201] Other studies confirm the growth potential and note that growth of natural gas transportation should be enhanced as an option for medium- and heavy-duty trucks as greater amounts of low-carbon-intensity biomethane are cleaned up and inserted into natural gas pipelines.[202] The initial success of the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) (see Chapter 4) also signals growth of alternative fuels and the potential to substantially shift from a predominant dependence on petroleum fuels to a more diverse transportation system to include greater contributions from biofuels, electricity, natural gas, biomethane, and hydrogen fuels. As a consequence, the state will benefit by a reduction in greenhouse gas emissions and vehicle tailpipe air pollutants and the development of jobs from a new industry.

California is well on its way toward achieving a goal of 33 percent renewable electricity sources by 2020, spurred by the Renewables Portfolio Standard, the California Solar Initiative and other programs.[203] Further, Governor Brown has proposed increasing "from one-third to 50 percent

200 David Greene, Baker Institute, University of Tennessee and Oakridge National Lab study using National Research Council report, *Transportation Transitions to the Future*, March 2013.

201 California Energy Commission. 2013. *2013 Integrated Energy Policy Report.* Publication Number: CEC-100-2013-001-CMF, p. 215.

202 California Alternative Fuel Growth, Bloomberg New Energy Finance, February 2013; Low Carbon Fuel Standard Compliance Curves, California Air Resources Board, October 2014.

203 http://www.cpuc.ca.gov/NR/rdonlyres/64D1619C-1CA5-4DD9-9D90-5FD76A03E2B8/0/2014Q2RPSReportFINAL.pdf.

[California's] electricity derived from renewable sources" within the next 15 years.[204] Solar and wind energy are intermittent sources—solar energy supply is greatest during daytime hours, and wind energy tends to be gustiest during evening hours on a seasonal basis. The state's growth in renewable electricity is expected to be dominated by solar energy sources, which will result in surplus electricity for daytime consumption. Biomass and geothermal energy provide baseload power sources, and new natural gas power plants are increasingly deployed to fill gaps when intermittent renewable electricity is not available.

The transportation fuel shift has begun to cross into the electricity and natural gas industries to build on similar market changes in these sectors, resulting in mutual benefits and unique challenges for the statewide energy system. The successful growth of renewable electricity offers substantial potential to lower the carbon intensity and decrease total greenhouse gas emissions throughout the state. Renewable electricity use for electric transportation, such as passenger vehicles, transit, freight trucks, and high-speed rail also lowers carbon intensity of these zero-emission options. Battery electric passenger vehicles are 3.4 times more energy-efficient than cars with internal combustion engines fueled by gasoline because of more efficient power-trains and propulsion systems. The average mix of electricity (hydroelectric, nuclear, natural gas, coal, and renewables) used in California today combined with vehicle efficiency results in roughly a 70 percent reduction in carbon intensity for battery electric cars compared to gasoline vehicles. As California achieves the 33 percent Renewables Portfolio Standard, the marginal mix of electricity will lower the carbon intensity of battery electric vehicles an additional 20 percent.[205]

Electric transportation growth presents both opportunities and challenges to manage and deploy the intermittent nature of solar and wind energy supply. The electricity consumption profiles of each California electric utility vary throughout the state, and the definition of peak and off-peak demand for electricity differ and are likely to evolve depending on the available amount and type of intermittent supply of renewable electricity, expected demand for daily and seasonal household and business electricity use, the growth of electric vehicle use and charging, and time-of-use pricing signals established by utility tariffs to influence the timing of electricity consumption. Utilities will seek to balance the amounts and intermittency of electricity supply with the amount and timing of electricity consumption to minimize capital investment needed for new power plant construction and transmission lines.

Utilities will also seek to optimize electricity distribution to ensure grid safety and account for likely growth of decentralized solar energy supply and home charging of electric vehicles. Electric vehicles may offer a benefit to the grid through battery storage and sending electricity back to the electric grid when vehicles are not in use to help manage electricity loads or during periods of regional high electricity demand. Electric vehicle charging during some daytime hours may use expected surplus of solar energy as both options grow. As a consequence, smart charging technology incorporating flexibility to communicate with customers and electric utilities becomes an essential component of electric vehicle operation for owners to respond to pricing signals and utilities to maintain management of an increasingly complex electric utility system.

A complex network of pipelines delivers natural gas to most of California's 38 million residents for home appliances and heating, and to industries and power plants. Eighty-five percent of the state's natural gas is delivered to California from out-of-state sources in the Rocky Mountains.[206] Natural gas consumption in vehicles represents about 1 percent of the total statewide transportation fuel

204 Edmund G. Brown Jr. inaugural address, remarks as prepared, January 5, 2015.

205 Low Carbon Fuel Standard, Carbon Intensity Look Up Tables, California Air Resources Board, November 2012.

206 California Energy Commission. 2013. *2013 Integrated Energy Policy Report.* Publication Number: CEC-100-2013-001-LCF.

use in compressed natural gas (CNG) and liquefied natural gas (LNG) forms. As noted in chapter 5, natural gas in North America cost $1.00 to $1.50 per gallon less than diesel fuel on an energy-equivalent basis until the petroleum price drop began in September 2014, when the differential fell to $0.60 per dge. Natural gas prices are expected to sustain their current levels for 7 to 10 years, which should continue to make natural gas an economic option as a transportation fuel.[207] However, the duration of the current price slump for petroleum is unknown, nor is it known if the reduced price differential will affect the current long-term trends towards natural gas in the medium-, heavy-duty, and off-road transportation sectors.

On a greenhouse gas, carbon-intensity, life-cycle basis, natural gas used in vehicles offers a small-to-modest benefit compared to gasoline and diesel fuels, but renewable natural gas, or biomethane derived from organic waste residues, offers the potential to reduce carbon intensity 70 to 90 percent below levels of petroleum fuels but costs 30 to 50 percent more than conventional natural gas.[208] As a consequence, California has seen an upsurge in the development of plants producing biomethane from organic wastes separated at landfills, wastewater treatment facilities, and dairy farms—several cofunded by the ARFVTP. Biomethane production has also been stimulated by a state law and policy to separate 75 percent of organic material from landfills by 2020.[209] Two new statutes in 2014 will also affect the diversion of organic wastes in California and increase the feedstocks available for biogas production. Assembly Bill 1826 (Chesbro, Chapter 727, Statutes of 2014) will require recycling of commercial organic wastes and Assembly Bill 1594 (Williams, Chapter 719, Statutes of 2014) will phase out the recycling credit for greenwaste used as landfill cover. The Low Carbon Fuel Standard also spurs the development of biomethane projects in California and from out-of-state sources injected into natural gas pipelines.[210] Natural gas utilities and fuel providers have begun to blend renewable natural gas with conventional natural gas at levels to maintain a price advantage over diesel fuel, but lower than the carbon intensity of conventional natural gas. This is possible because biomethane has the same chemical makeup as natural gas once impurities are removed. Greater amounts of biomethane injected into the natural gas pipeline system have the net effect of lowering the carbon intensity of natural gas fuel for transportation, electricity, and home heating and appliance use.

Challenges involve controlling the costs of biomethane clean-up to remove impurities to match the quality standards of natural gas transported in pipelines. The California Public Utilities Commission (CPUC) is conducting a proceeding to establish the standard for biomethane sources.[211] Another challenge is reducing methane leakage in natural gas and biomethane production, transport, and consumption, as discussed later in this chapter.

This chapter first describes linkages with the electricity sector and then the natural gas sector. It also includes a discussion of methane leakage from the natural gas system and recommendations for future work.

Electric Vehicle Charging Offers an Opportunity to Help Integrate Renewable Resources Into the Electricity Grid

Electricity demand in California will continue to exhibit daily peaks, which vary in timing and intensity throughout the year, also seasonally and locationally, reflecting weather changes. Generally, electricity demand peaks in late afternoon and early evening as Californians return home from jobs during workdays. In some months, morning

207 Ibid.

208 California Air Resources Board, Low Carbon Fuel Standard, Carbon Intensity Analysis, 2010 and 2014.

209 Assembly Bill 341 (Chesbro, Chapter 476, Statutes of 2011).

210 California Air Resources Board, quarterly LCFS reports and October 27, 2014. Compliance Trends workshop.

211 http://www.dra.ca.gov/general.aspx?id=2269.

and evening peaks occur. During the June 23, 2014, IEPR workshop on electric vehicle integration, staff from the California Independent System Operator (California ISO) noted that a portfolio of resources with flexible capabilities is needed to address daily and seasonal peaks to maintain a reliable electricity grid. As the state realizes its 2020 Renewables Portfolio Standard objectives for 33 percent of energy consumed to be supplied from renewable sources, an overabundance of midday generation will exceed demand by customers for this energy. The California ISO notes this circumstance is already occurring in 2014 in times of low loads and high renewable production.

Moreover, locational studies (such as those conducted for southern California) define where critical resources are needed to support grid operations and where they can most effectively be applied. The California ISO and utilities face challenges in balancing fluctuating demand with supply sources that require flexible capabilities to ensure system reliability. The portfolio of resources needs to include ramping capability to increase or supply quickly for the needed duration as demand and variable renewable supply change during the day. These resources also need to be able to start and stop quickly and operate at zero or low minimum output levels. These capabilities combine to maximize renewable output and minimize curtailment of renewable electricity sources.

In addition to using flexible resources with capabilities to follow the net load, utilities can also influence the timing of electricity consumption with time-of-use tariffs, targeted energy efficiency, demand response programs, and other incentive mechanisms that result in changes in customer consumption.

Efficient integration of electric vehicles has the potential to serve as a grid resource that can help address the challenges. The timing of when electric vehicles are charged can reduce the need for ramping capacity to integrate renewable resources. At the June 23, 2014, workshop, Stephen Berberich, chief executive officer of the California ISO, stated that "electric vehicles have tremendous promise for grid operators and the ability to provide ancillary services, as well as soak up generation that may otherwise have to be … disposed of, that we would get from … solar and wind. …Electric vehicles can be a great boon to the grid, but they could also be quite detrimental to the grid if the polices are not closely aligned."[212]

Opportunities in Vehicle-to-Grid Integration and Electric Vehicles as Storage

Electric vehicles also offer opportunities to store electricity and help reduce the impact of local and systemwide power supply fluctuations and reduce the magnitude of fast ramping needed from baseload electricity sources.

Vehicle-to-grid integration (VGI) technologies such as smart charging and vehicle-to-grid (V2G)—bidirectional flow of electricity between the vehicle and the grid—include real-time communication signals between electric vehicles and utilities or the California ISO. This communication allows electric vehicles to optimize charging to times when energy demand is low, such as during off-peak hours or when electricity supply is abundant. During any normal workweek, electric vehicles are driven 4 percent of the time, charged 10 percent of the time, and parked at home or elsewhere for the remainder.[213] Storage of electricity in electric vehicle batteries can shift large amounts of energy. Fast dispatching of this stored energy and the bidirectional flow of power will allow the vehicles to help level out peak ramping and provide ancillary grid services, reducing the need to call on additional baseload conventional generation. Furthermore, stationary storage is a key component of vehicle-to-grid

212 June 23, 2014, Integrated Energy Policy Report workshop transcript, pp. 11-12.

213 Mark Higgins, California Energy Storage Association, June 23, 2014, Integrated Energy Policy Report workshop.

integration and, when coordinated with electric vehicle battery storage, can maximize the availability of resources for grid benefits.[214]

Another concern for grid operators as the market share of electric vehicles in California continues to grow is the potential impact these vehicles will have on electric grid distribution infrastructure. Today, California's distribution systems are not sized to handle excessive loads associated with electric vehicles; however, real-time communication will allow the charging of these vehicles to be controlled and coordinated with other vehicle charging, but also managed with other loads within the distribution system, reducing the need to perform expensive infrastructure upgrades. Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013) requires investor-owned utilities to submit a distributed energy resources plan to the CPUC by July 1, 2015, that identifies optimal deployment of distributed resources, including electric vehicles. The CPUC's Rulemaking 14-08-013 will evaluate the existing and future electric distribution infrastructure and planning procedures with respect to incorporating distributed energy resources into utilities' electric distribution systems.[215]

The CPUC also opened rulemakings on energy storage and alternative fuel vehicles.[216] The proceeding on energy storage is assessing whether controlled charging should be included in the definition of energy storage to meet the state's storage procurement targets. The CPUC's Alternative Fuel Vehicle Rulemaking will evaluate the potential and value of VGI, including the use of vehicle batteries for demand response and energy storage. Furthermore, the rulemaking will focus on developing new alternative fuel vehicle tariffs in each of the three largest investor-owned utility service territories. As part of this proceeding, the CPUC approved a decision on December 18, 2014, that lifts the prohibition against utility ownership of electric vehicle charging infrastructure, which is expected to encourage the expansion of charging infrastructure and widespread deployment of plug-in electric vehicles.[217]

Technology Demonstration Projects to Advance Vehicle Grid Integration

Research, development, and deployment will also be key to help ease implementation of VGI and VTG technologies. California has several ongoing research and demonstration activities geared at addressing many of the key challenges. Demonstration projects funded by the state, utilities, and the federal government are addressing areas such as residential plug-in electric vehicles (PEVs), submetering to better understand the electricity charging needs of the consumer, and employee workplace charging demand response projects to better understand the value of offering workplace charging to employees.[218]

In 2013, the U.S. Department of Defense initiated demonstrations to validate the performance of vehicle-to-grid technology at five military bases, including the Mountain View ARC and Los Angeles Air Force Base. The projects will help the military determine the feasibility of a broad-scale vehicle-to-grid program at different locations, utility systems, and climates for a variety of electric vans, pickup and utility trucks, shuttle buses, and passenger cars. The Energy Commission cofunded the project in Los

214 Steve Davis, KnGrid, June 23, 2014, Integrated Energy Policy Report workshop.

215 CPUC, Order Instituting Rulemaking, *Order Instituting Rulemaking Regarding Policies, Procedures and Rules for Development of Distribution Resources Plans Pursuant to Public Utilities Code Section 769,* Issued August 20, 2014, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M103/K223/103223470.pdf.

216 CPUC's Alternative Fueled Vehicles Order Instituting Rulemaking (R.13-11-007) (2013)

CPUC's Energy Storage Order Instituting Rulemaking (R. 10-12-007) (2010).

217 California Public Utilities Commission, *Proposed Decision of Commissioner Peterman – Phase 1 Decision in Establishing Policy to Expand the Utilities' Role in Development of Electric Vehicle Infrastructure, Application 14-04-014, Rulemaking 13-11-007*, November 14, 2014. Available at http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M140/K045/140045368.PDF.

218 Felix Oduyemi, Southern California Edison, June 23, 2014, Integrated Energy Policy Report workshop.

Angeles and includes Southern California Edison (SCE) and UC Berkeley/Lawrence Berkeley National Laboratory as partners. The project involves use of PEVs, a bidirectional charging station, and software architecture to communicate with SCE and the California ISO. The Los Angeles Air Force Base demonstration, one of the first in the nation, explores how bidirectional charging provides ancillary service benefits to help SCE manage system-wide electric load balancing, address local distribution constraints, and respond to tariffs affecting the air force base costs. The project will help the military determine how well bidirectional charging and communication and aggregator software works to support the base functions and help compare cost parity of electric vehicles to gasoline vehicles.

At the June 23, 2014, workshop, Paul Stith of EV Grid provided information on a "grid-to-wheels" project demonstrating deployment of electric school buses. The project seeks to measure and optimize bidirectional charging, electric grid benefits, power dispatch performance, vehicle battery wear, bus travel range, and revenue generation for power sales. Electric school buses require and can accommodate larger batteries (100-125 kilowatts) than cars and offer researchers an opportunity to evaluate greater amounts of storage and electricity sent to the grid. Initial results indicate that vehicle-to-grid revenue produced by the project could range from $5,000 to $20,000 per year and provide insights about duplicating this benefit in other "short-haul" vehicles.

San Diego Gas & Electric Company has proposed a VGI pilot project to the CPUC to advance-dynamic load management at 550 multifamily housing communities and workplace sites (10 chargers at each location) that offer long-duration vehicle parking. The project would introduce vehicle charging at hourly rates to efficiently integrate and manage charging loads with the electric grid and give electric vehicle customers electricity they need at the best price available. Approval of the pilot project has been incorporated into the CPUC's December 2014 decision in a broader proceeding related to alternative fuel infrastructure.

Other Vehicle Grid Integration Challenges

During the June 23, 2014, workshop, experts also discussed whether standards or regulations are necessary to ensure that all plug-in electric vehicles have VGI capabilities, and if so, what appropriate scope for those standards might be. Smart charging systems with communication capabilities need to be simple and convenient for customers but are significantly more expensive than simple chargers. Most technology is based on proprietary communication software and control networks. Utilities must ensure customer interface with the grid as V2G, VGI, storage, and other battery discharging technologies develop. Adam Langton of the CPUC identified a need to examine different communication pathways, including a standardized way for electric vehicles to communicate with charging stations, and to explore technology allowing electric vehicle drivers to communicate with charging stations. Mr. Langton noted that an interoperability standard "may depend on where the resource gets defined."[219] Steve Davis of KnGrid stated that 70 percent of electric vehicle charging occurs at home and this is the biggest opportunity for intelligent charging. He noted that initial results from an NRG study of V2G power for ancillary services produced $5 per day per car. Mr. Davis also stated that automakers need five to six years to make fundamental changes to vehicles and optimize the cost of communication technology. He urged the development of a common interoperability standard for all vehicles to take advantage of the opportunity.[220] Felix Oduyemi from Southern California Edison noted that the absence of standards could be a costly value proposition for the state as "we will be stranding a lot of investments if we do not come up with standards that will inform the technology that we deploy. There is a cost associated, for example,

219 Adam Langton, CPUC, June 23, 2014, Integrated Energy Policy Report workshop.

220 Stephen Davis, KnGrid, June 23, 2014, Integrated Energy Policy Report workshop.

with control technologies and communications technologies…..Those costs need to be factored into the equation before we proceed with VGI."[221]

During the workshop, industry representatives encouraged the Commission to consider moving forward with VGI standards since European original equipment manufacturers are already selecting standards and selling cars that are equipped to accept these standards.[222] However, other automakers want to see how the electric vehicle market grows and have proceeded at different levels of effort to explore bidirectional technology to improve communication between vehicles, chargers, and utility or California ISO electricity dispatchers. The workshop discussions illustrated the current lack of consensus VGI standards in California.

While there are clear benefits in increasing market penetration of electric vehicles through rate design and other mechanisms, there are still many unknowns as to the complexities, costs, and benefits of V2G, VGI, and storage that must be evaluated carefully. The Energy Commission is considering hosting a series of workshops to encourage issue identification and resolution and further dialogue on these important topics.

Transportation Linkages with Natural Gas Infrastructure

As discussed further in Chapter 5, efforts are underway to decarbonize natural gas. Similar to the need for electricity grid planning as a result of increased penetration of PEVs and EVs, effects on natural gas infrastructure need to be considered as a result of the increased use of biogas, renewable natural gas, and natural gas in the transportation sector. Advances and increased penetration of these new and emerging technologies have impacts on natural gas infrastructure. As the production of biogas and renewable natural gas increases, this gas may be transmitted through the existing natural gas pipeline infrastructure. The quality of the gas introduced to the pipeline system must meet minimum standards that are being developed at the CPUC.

Moreover, decisions concerning new and emerging natural gas technologies have the potential to affect the overall electric grid. The production and use of biogas and renewable natural gas in distributed generation resources, such as combined heat and power systems or natural gas-powered generators have the potential to replace systems that are supplying electricity to the grid today. One area where these many interrelated factors will be discussed and reported on is the required actions under Assembly Bill 1257.

Transportation is an Element of the Analysis Underway for Assembly Bill 1257

Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013) requires the Energy Commission to complete a report that identifies "strategies to maximize the benefits obtained from natural gas, including biomethane, as an energy source, helping the state realize the environmental and cost benefits afforded by natural gas." The bill identifies a number of topics related to natural gas and biogas use that should be explored in the report. Those topics include natural gas as a transportation fuel, as a part of the resource portfolio, as a fuel for combined heat and power, as a low-emission resource, as a fuel for end-use efficiency and efficient use of appliances, and as a fuel for zero-net-energy homes. AB 1257 also stipulates that the report should address natural gas infrastructure,

221 Felix Oduyemi, Southern California Edison, June 23, 2014, Integrated Energy Policy Report workshop.

222 Stephen Davis, KnGrid, June 23, 2014, Integrated Energy Policy Report workshop.

storage and pipeline safety, state and federal policies that promote the use of natural gas, and ways in which the electric and natural gas industries can promote the use of natural gas. Furthermore, the bill identifies the environmental and economic costs and benefits of natural gas, including life-cycle greenhouse gas emissions, fugitive methane emissions, and jobs development as primary topics to be covered in the report. The AB 1257 report is scheduled to be published by November 1, 2015, and will be reported on in the *2015 IEPR*.

The June 23, 2014, IEPR workshop provided an overview of natural gas used as a transportation fuel in the form of compressed natural gas (CNG) and liquefied natural gas (LNG). George Minter of Southern California Gas Company provided an outlook for significant growth of natural gas use in the transportation sector, primarily in medium- and heavy-duty trucks, and noted that the natural gas price advantage compared to diesel fuel may compel many fleet owners to shift to this fuel. The workshop also highlighted the prospect for biomethane blended with conventional gas to offer a low-carbon-intensity fuel that also reduces nitrogen oxides and particulate matter to offer a near-zero-emission fuel needed in areas such as the South Coast Air Quality Management District. The workshop included a robust discussion about methane leakage in the natural gas system and ways to reduce impacts.

In the final AB 1257 report, the Energy Commission expects to provide a full chapter on natural gas as a transportation fuel in California. The analysis will not only address the Energy Commission's funding to support advanced, near-zero emission natural gas vehicles and infrastructure, but all additional policies and programs that determine how natural gas is used in the transportation sector in California. In this manner, the discussion will provide a comprehensive overview of the role of natural gas as a transportation fuel in California and will be updated with any new developments that arise between this *2014 IEPR Update* and the final version of the AB 1257 report.

Evaluation of Methane Emissions From the Natural Gas System and Implications for the Transportation System

Even as the natural gas utilities work to decarbonize the natural gas system, researchers are raising awareness of methane leakage issues from the natural gas system. Since methane, the primary component of natural gas, is a very potent but short-lived greenhouse gas, the benefits of natural gas as a cleaner fuel in comparison to diesel or gasoline depend upon how much of that methane is emitted into the atmosphere. Estimates of methane emissions from the natural gas system are evolving. Emissions can take place anywhere in the natural gas system, from the wells where natural gas is extracted, to the processing facilities where raw natural gas is treated and fed into transmission pipelines, to the distribution networks that deliver natural gas to homes and businesses.

Estimating Fugitive Methane Emissions

Methane emissions from California's energy infrastructure have been estimated to be less than 1 percent of throughput.[223] However, new evidence suggests that these

223 California Air Resources Board. 2014. *Transportation Fuels: ARB Technology Assessment*. Paper presented at the Technology Assessment Workshop, available at http://www.arb.ca.gov/msprog/tech/presentation/fuels.pdf.

"fugitive emissions" may be underestimated.[224] Moreover, there is uncertainty regarding where the leaks are located within the natural gas system.

Researchers and technical staff estimate emissions using bottom-up, top-down, and hybrid methods. The "bottom-up" method applies emission factors (for example, grams of methane emitted per mile of transmission line) to each of the components of the natural gas system (for example, miles of pipeline). Estimating emissions is then a straightforward summing of emissions from all components of the natural gas system. "Top-down" estimates use ambient measurements of methane and other compounds to estimate emissions. For example, measurements can be taken with a research airplane upstream and downstream of a potential source, and, using information such as wind velocity and the enhanced concentration of methane downwind of the source, emissions can be estimated. Hybrid methods try to take advantage of both methods by reconciling the estimates from the top-down and bottom-up methods as much as possible.

A recent study published in the journal *Science*[225] performed a meta-analysis of all available studies. The authors concluded that, nationally, actual emissions are about 1.5 times greater than are reported in the U.S. Environmental Protection Agency (U.S. EPA) inventory. A similar study by researchers at Harvard University and other institutions such as Lawrence Berkeley National Laboratory (LBNL) suggests that actual emissions from the natural gas system are about 1.5 times the U.S. EPA inventory.[226] The researchers used ambient measurements of methane and other compounds from tall towers and aircraft campaigns. In California, they used the ambient measurements taken at a tower in Walnut Grove (Sacramento County). The Energy Commission initiated LBNL's research in 2006, and ARB and others have continued to fund this work.

In California, there have been several attempts to estimate emissions from the natural gas system, but again, emission estimates are highly uncertain. For example, the greenhouse gas inventory maintained by the ARB[227] indicates that emissions were about 2.4 million metric tons of carbon dioxide equivalent (MMTCO_2eq) in 2011. However, at a recent workshop, ARB staff reported that the inventory is being updated to include additional fugitive emission sources and it anticipates emissions will rise to about 5.2 MMTCO_2eq, according to initial estimates

224 For example, Jeong, S., Millstein, D., and Fischer. M.L., 2014. "Spatially Explicit Methane Emissions from Petroleum Production and the Natural Gas System in California." *Environmental Science & Technology. 48*(10), 5982-5990; Peischl, J., Ryerson, T.B., Brioude, J., Aikin, K.C., Andrews, A.E., Atlas, E., Blake, D., Daube, B.C., de Gouw, J.A., Dlugokencky, E., Frost, G.J., Gentner, D.R., Gilman, J.B., Goldstein, A.H., Harley, R. A., Holloway, J. S., Kofler, J., Kuster, W.C., Lang, P.M., Novelli, P.C., Santoni, G.W., Trainer,M., Wofsy, S.C., and Parrish, D.D., 2013. "Quantifying sources of methane using light alkanes in the Los Angeles basin, California." *Journal of Geophysical Research: Atmospheres.* 118(10): 4974-4990; Wennberg, P.O., Mui, W., Wunch, D., Kort, E.A., Blake, D.R., Atlas, E.L., Santoni, G.W., Wofsy, S.C., Diskin, G.S., Jeong, S., and Fischer, M.L., 2012. "On the sources of methane to the Los Angeles atmosphere." *Environmental science & technology.* 46(17): 9282-9289.

225 Brandt, A., Heath, G., Kort, E., O'Sullivan, F., Pétron, G., Jordaan, S., Tans, P., Wilcox, J., Gopstein, A.M., Arent, D., Wofsy, S., Brown, N.J., Bradley, R., Stucky, G.D., Eardley, D., Harriss, R. 2014. "Methane Leaks From North American Natural Gas Systems." *Science.* 343(6172), 733-735.

226 Miller, S.M., Wofsy, S.C., Michalak, A.M., Kort, E.A., Andrews, A.E., Biraud, S.C., Dlugokencky, E.J., Eluszkiewicz, J., Fischer, M.L., Janssens-Maenhout, G., Miller, B.R., Miller, J.B., Montzka, S.A., Nehrkorn, T., and Sweeney, C. 2013. "Anthropogenic emissions of methane in the United States." *Proceedings of the National Academy of Sciences*. 110(50): 20018-20022.

227 California Air Resources Board. 2014. *California Greenhouse Gas Emission Inventory: 2000-2012 (2014 Edition*), available at http://www.arb.ca.gov/cc/inventory/inventory.htm.

based on detailed surveys.[228] Other top-down and hybrid estimations of emissions suggest that emissions may be even higher than 5.2 $MMTCO_2eq$, though they are regional studies with significant uncertainties.[229]

Uncertainty in Fugitive Methane Emission Estimates

Emission estimates are uncertain because emissions can vary significantly from location to location and across periods. Thus, it can be very difficult to generate accurate estimates of total emissions. For example:

» As suggested by Brandt,[230] and a 2011 study prepared for the Energy Commission,[231] it appears that total emissions are dominated by super emitters[232] and that it is impossible to identify these super emitters *a priori*. For example, in one study of natural gas infrastructure, 58 percent of emissions came from 0.06 percent of possible sources.[233] Since only a small fraction of leaks likely represent a high percentage of total emissions, this creates huge challenges for bottom-up inventories because it almost requires testing all components of the natural gas system to ensure that all super emitters are identified.[234] For practical reasons, bottom-up inventories rely on testing done on a small sample of components that most likely does not capture a representative sample of super emitters.

» Emissions can be sporadic, and testing done at discrete times may or may not capture these emissions.[235]

» It is very difficult to compare different studies because they use a variety of metrics and boundaries in the estimates.[236] For example, emissions in the South Coast

228 California Air Resources Board. 2014. *Transportation Fuels: ARB Technology Assessment*. Paper presented at the Technology Assessment Workshop, available at http://www.arb.ca.gov/msprog/tech/presentation/fuels.pdf.

229 Jeong, S., Millstein, D., and Fischer, M.L. 2014. "Spatially Explicit Methane Emissions from Petroleum Production and the Natural Gas System in California." *Environmental Science & Technology. 48*(10), 5982-5990; Peischl, J., Ryerson, T.B., Brioude, J., Aikin, K.C., Andrews, A.E., Atlas, E., Blake, D., Daube, B.C., de Gouw, J.A., Dlugokencky, E., Frost, G.J., Gentner, D.R., Gilman, J.B., Goldstein, A.H., Harley, R.A., Holloway, J.S., Kofler, J., Kuster, W.C., Lang, P.M., Novelli, P.C., Santoni, G.W., Trainer, M., Wofsy, S.C., and Parrish, D.D.2013. "Quantifying Sources of Methane Using Light Alkanes in the Los Angeles Basin, California." *Journal of Geophysical Research: Atmospheres.* 118(10): 4974-4990; Wennberg, P.O., Mui, W., Wunch, D., Kort, E.A., Blake, D.R., Atlas, E.L., Santoni, G.W., Wofsy, S.C., Diskin, G.S., Jeong, S., and Fischer, M.L. 2012. "On the Sources of Methane to the Los Angeles Atmosphere." *Environmental Science & Technology.* 46(17): 9282-9289.

230 Brandt, A., Heath, G., Kort, E., O'Sullivan, F., Pétron, G., Jordaan, S., Tans, P., Wilcox, J., Gopstein, A.M., Arent, D., Wofsy, S., Brown, N.J., Bradley, R., Stucky, G.D., Eardley, D., Harriss, R. 2014. "Methane Leaks From North American Natural Gas Systems." *Science.* 343(6172), 733-735.

231 Kuo, J. 2012. *Estimation of Methane Emission from the California Natural Gas System*. California Energy Commission. Publication number: CEC-500-2014-072.

232 Methane leaks are not distributed evenly. Rather, most components or facilities have very low or no leaks while a few big leaks comprise a high percentage of methane emissions. The few facilities with high emissions are considered *super emitters*.

233 National Gas Machinery Laboratory. 2006, Clearstone Engineering, Innovative Environmental Solutions (2006). *Cost-Effective Directed Inspection and Maintenance Control Opportunities at Five Gas Processing Plants and Upstream Gathering Compressor Stations and Well Sites.* U.S. EPA March 2006; Brandt, A., Heath, G., Kort, E., O'Sullivan, F., Pétron, G., Jordaan, S., Tans, P., Wilcox, J., Gopstein, A.M., Arent, D., Wofsy, S., Brown, N.J., Bradley, R., Stucky, G.D., Eardley, D., Harriss, R. 2014. "Methane Leaks From North American Natural Gas Systems." *Science.* 343(6172), 733-735.

234 Allen, D. 2014. "Methane Emissions From Natural Gas Production and Use: Reconciling Bottom-Up and Top-Down Measurements." *Current Opinion in Chemical Engineering*. 5:78-83.

235 Tratt, D.M., Buckland, K.N., Hall, J.L., Johnson, P.D., Keim, E.R., Leifer, I., Westberg, K., and Young, S.J. 2014. "Airborne Visualization and Quantification of Discrete Methane Sources in the Environment." *Remote Sensing of Environment.* 154: 74-88.

236 California Air Resources Board. 2014. *Transportation Fuels: ARB Technology Assessment*. Paper presented at the Technology Assessment Workshop, available at http://www.arb.ca.gov/msprog/tech/presentation/fuels.pdf.

region of California may be reported per unit of natural gas coming into the region (from local extraction and from out-of-state imports). This is very difficult to compare with national level emission estimates that include emissions from all the sectors of the natural gas system.

» Emissions estimates for California exclude emissions that occur at fuel stages, such as extraction and fuel processing, that take place outside the state. From an energy policy perspective, however, all emissions from "well-to-wheel" are important. This is particularly true in California where roughly 90 percent of natural gas consumed is imported from other regions.[237]

» Some studies report emissions from associated gas (gas from wells that produce both crude oil and natural gas) as being part of the natural gas system. In the national U.S. EPA inventory,[238] these emissions are assigned to the petroleum sector. In practice, emissions from associated gas should somehow be apportioned to both the petroleum and natural gas sectors considering, for example, the proportion energy content of the products. However, there is currently no accepted method for systematically allocating emissions to reflect association with both petroleum and natural gas sector activities.

» It is difficult to estimate emissions per unit of natural gas produced or consumed for certain types of emissions. For example, before a well enters into full operation, some high emissions may take place during "well completion" when a well is prepared for production. To estimate emissions per unit of natural gas extracted from a well, it is necessary to know beforehand the amount of gas that will be extracted from the well during the lifetime of the well, which is at best an uncertain estimation.[239]

» Top-down emission estimates have some drawbacks. For example, it can be difficult to partition ambient measurements into emissions from a variety of sources such as landfills, dairies, natural seeps, and wetlands in a region. Chemical fingerprints (for example, ethane is associated mostly with methane from petroleum-based sources such as well and natural seeps) can be used to differentiate emissions sources, but some uncertainty in source attribution will remain. Ambient measurements can also rely on complex computations of weather conditions to link measured ambient concentrations to potential sources. These computations often have relatively high levels of uncertainty.[240]

Estimating life cycle emissions is also a challenge because of super emitters, the potential sporadic nature of some of the emissions, and the potential differences of the emission profiles of gas imported from different regions. It is possible, for example, that natural gas coming into California from Colorado may have a significantly different emission profile than natural gas originating in Texas. Dynamic natural gas flows through the network of transmission pipelines that cover the country further complicate the calculation of life-cycle emissions. The recently reported presence of natural gas "hot spots"

237 California Energy Commission. 2014. *Energy Almanac*. Available at http://energyalmanac.ca.gov/naturalgas/.

238 US Environmental Protection Agency. 2013. "Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990–2011," *Technical Report EPA 430-R-13-001*. Environmental Protection Agency,Washington, available at http://www.epa.gov/climatechange/ghgemissions/usinventoryreport.html.

239 Heath, G.A., O'Donoughue, P., Arent, D.J., and Brazilian, M. 2014. "Harmonization of Initial Estimates of Shale Gas Life Cycle Greenhouse Gas Emissions for Electric Power Generation." *Proceedings of the National Academy of Sciences*. 111(31):E3167-E3176.

240 Allen, D. 2014. "Methane Emissions From Natural Gas Production and Use: Reconciling Bottom-Up and Top-Down Measurements." *Current Opinion in Chemical Engineering*. 5:78-83.

support the idea of nonuniform emissions in the United States, which implies that generic life cycle emissions are not viable.[241]

The Energy Commission staff has been, and will continue to be, mindful of methane leakage issues and concerns. To stay well-informed about the changing landscape on methane leakage and the most current research, the Energy Commission will continue to participate in discussions with the ARB and other experts. As discussed below, the Energy Commission is funding studies to help advance the state of knowledge.

Efforts to Improve Estimates of Fugitive Emissions

At the national level, the U.S. EPA and other federal agencies such as DOE are supporting research on methane emissions from the natural gas system, while natural gas utilities are funding work coordinated by the Environmental Defense Fund (EDF), and the Gas Technology Institute is sponsoring research. The EDF program is the most comprehensive set of studies trying to improve the characterization of emissions from the natural gas system. It includes 16 studies covering all the parts of the natural gas system.[242] One of the EDF studies of particular importance to the transportation system is a West Virginia University study measuring "pump-to-wheels" emissions. This study involves measuring emissions from compressed and liquefied natural gas refueling and maintenance facilities as well as testing emissions from the operation of natural gas fueled medium- and heavy-duty vehicles.[243]

In California, the following institutions are involved in methane research: the Energy Commission with LBNL and UC Davis, ARB, NASA, UC Santa Barbara, Sandia National Laboratory, National Oceanic and Atmospheric Administration, and UC Irvine. These organizations, to one degree or another, are collaborating and sharing information. It is expected that these efforts will result in a much improved estimation of emissions in the next few years.

The Energy Commission is supporting research to reduce uncertainties regarding how much methane is being emitted from the natural gas system and where leaks are located. One project is surveying methane emissions from key subsectors of the natural gas system, including production and processing, transmission and distribution, and end uses in buildings. It is expected that this work will identify the main sources of emissions from the natural gas system, but further work will be required to fully quantify total emissions. A complementary project is improving capabilities of air-based identification of methane leaks from transmission pipelines. A third project assessing residential methane emissions started in early December 2014.

Opportunities to Reduce Fugitive Emissions

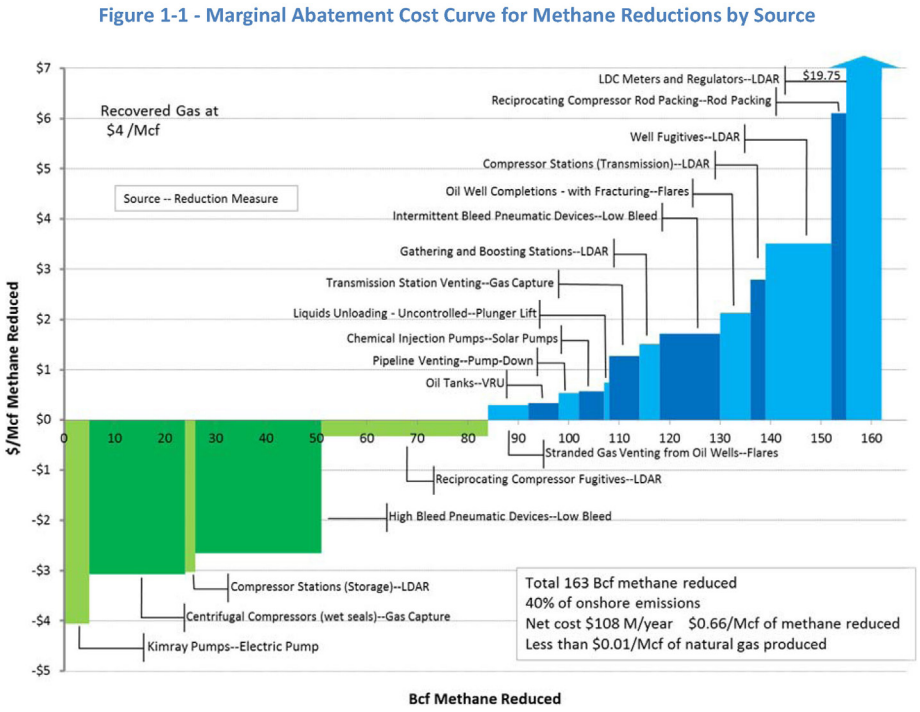
Utilities are already taking steps to reduce emissions. For example, Pacific Gas and Electric is using a mobile platform to detect leaks in the distribution system and immediately implementing measures to eliminate these emissions. This moving target creates additional challenges for researchers trying to characterize emissions. Several new technologies under development have the

241 Kort, E.A., Frankenberg, C., CostiganK.R., Lindenmaier, R., Dubey, M.K., and Wunch, D. 2014. "Four Corners: The Largest U.S. Methane Anomaly Viewed From Space." *Geophysical Research Letters*. doi:10.1002/2014GL061503; Schneising, O., Burrows, J.P., Dickerson, R.R., Buchwitz, M., Reuter, M., and Bovensmann, H. 2014. "Remote Sensing of Fugitive Methane Emissions From Oil and Gas Production in North American Tight Geologic Formations." *Earth's Future*. doi: 10.1002/2014EF000265.

242 EDF is not covering emissions that may occur after the meters that may be an important source of emissions, such as emissions in homes and buildings. The Energy Commission has a research project covering this area.

243 Timothy O'Connor's presentation at the June 23, 2014, Integrated Energy Policy Report workshop, http://www.energy.ca.gov/2014_energypolicy/documents/2014-06-23_workshop/presentations/13_O_Connor_EDF_IEPR-Presentation.pdf.

Figure 28: Methane Reductions are Cost-Effective



Source: ICF. 2014. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*, available at https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

potential for utilities to identify and measure leaks from the natural gas system.[244]

EDF commissioned an economic analysis of methane emission reduction opportunities for the oil and gas industries.[245] The study estimated that a 40 percent reduction in onshore methane emissions was possible with existing technologies and techniques at a net total cost of $0.66/Mcf of methane reduced, or less than $0.01/Mcf of gas produced. This analysis takes into account savings that accrue directly to the companies implementing methane reduction measures. Figure 28 presents the marginal cost of each measure examined. Reduction measures with green bars have negative costs due to significant gas savings.

From a climate policy perspective, it is important to know at what methane emission levels the advantages of using natural gas as a transportation fuel, in comparison, for example, to diesel engines, are substantially eroded.[246]

244 Tratt, D.M., Buckland, K.N., Hall, J.L., Johnson, P.D., Keim, E.R., I.Leifer, K.Westberg, and Young, S.J. 2014. "Airborne Visualization and Quantification of Discrete Methane Sources in the Environment." *Remote Sensing of Environment.* 154: 74-88.

245 ICF. 2014. *Economic Analysis of Methane Emission Reduction Opportunities in the U.S. Onshore Oil and Natural Gas Industries*, available at https://www.edf.org/sites/default/files/methane_cost_curve_report.pdf.

246 At the June 23, 2014, Integrated Energy Policy Report workshop, Rosa Dominguez-Faus from UC Davis presented information on the "breakeven leakage rate for transportation"(slide 26). *Breakeven leakage rates* are the rates at which using natural gas in cars or heavy trucks have the same climate impacts as gas or diesel vehicles. If actual methane emission rates are higher than the breakeven leakage rates, using natural gas will have higher climate impacts than using cars and trucks burning gasoline and diesel.

There is a growing body of literature suggesting alternate approaches to compare natural gas with other transportation fuels (for example, R.A. Alvarez, S. W. Pacala, J. J. Winebrake, W. L. Chameides, and S. P. Hamburg. 2012. "Greater Focus Needed on Methane Leakage From Natural Gas Infrastructure." *Proceedings of the National Academy of Sciences.*109 (17), 6435–6440; M. R. Edwards and J. E. Trancik. 2014. "Climate Impacts of Energy Technologies Depend on Emissions Timing." *Nature Climate Change*. 4(5), 347-352

Recommendations

Transportation Nexus with the Electricity Sector

» **Conduct workshops to explore connections between the transportation and electricity sectors, including smart charging options and opportunities for integration across vehicle technologies**. The Energy Commission, in coordination with the California Public Utilities Commission (CPUC), the California Independent System Operator (California ISO), and California Air Resources Board (ARB), should host one or more open workshops to:

- » Discuss opportunities for smart charging, time-of-use rates, and targeted efficiency and demand response programs to help balance electric vehicle charging and hydrogen production and fueling with incorporation into the grid.
- » Explore ways that stakeholders can work together to accelerate the market in the near-term to help meet state goals and improve the business case for VGI.
- » Explore how smart charging can potentially add value to PEV ownership and be incorporated into the *Statewide PEV Infrastructure Plan* to optimize benefits to PEV drivers and the electricity distribution system.
- » Consider opportunities for hydrogen production, storage and use to help balance the electricity system and integrate renewable electricity resources.
- » Collect information on potential pilot or demonstration projects that are cross-cutting ways of connecting renewable energy, transportation electrification, (using batteries and fuel cells), and natural gas systems that can accelerate the state's greenhouse gas and criteria pollutant reduction goals.
- » Explore potential incentives or rate structures to encourage the beneficial and economic electrification of other transportation modes, including heavy-duty vehicles, rail, electric port equipment, and the use of shore power by ocean-going vessels.

» **Assist in the implementation of the California Independent System Operator's Vehicle-Grid Integration Roadmap**. The Energy Commission, in coordination with the CPUC and California ISO, should implement activities highlighted in the California ISO's Vehicle-Grid Integration (VGI) Roadmap, including:

- » Scheduling annual workshops beginning in 2014 to review progress on research and demonstration projects related to VGI, soliciting stakeholder feedback on the direction of research, and integrating the role of publicly owned utilities in VGI development.
- » Discussing VGI activities in workshops for the *Statewide Plug-In Electric Vehicle Infrastructure Plan*, and integrating findings related to VGI into the Plan.
- » Reaching out to California publicly owned utilities to ensure that they are aware of the VGI activities.
- » Continuing demonstration projects on VGI, such as the Los Angeles Air Force Base Vehicle-to-Grid Demonstration project, the

high-power Vehicle-to-Grid energy module being developed by TransPower, and the plug-in electric vehicle load simulator with San Diego Gas and Electric, and assessing the implications of their results.

» Understanding the benefits and costs of different VGI options (for example, time-of-use rates, demand charges, dynamic smart charging rates, demand response, vehicle-to-grid, smart charging to provide ancillary services, other smart charging technologies such as power capping, sharing and/or sequencing).

» **Conduct timely implementation of research, development, and demonstration projects on VGI funded through the Electric Program Investment Charge (EPIC)**. The Energy Commission's proposed EPIC Investment Plan for 2015-2017 identifies research, development, and demonstration projects on VGI activities that address:

» Standards for consistent communication pathways (that is, interoperability) for electric vehicles to communicate with charging stations and vice versa.

» Control and communications technologies that incorporate smart charging systems.

» Pathways and strategies to lower the costs of VGI to the consumer.

» Research to understand the opportunities to increase the benefits of VGI to the grid.

If the CPUC approves the *2015–2017 EPIC Investment Plan* as proposed, then the Energy Commission should implement these projects in a timely fashion.

» **Assist in developing updates to the VGI Roadmap as needed**. The California ISO, in consultation with the CPUC and the Energy Commission, should review the results of implementation of the VGI Roadmap and identify necessary updates to the VGI Roadmap, particularly as it develops the roadmap on energy storage. As part of this update, the Energy Commission should work with the CPUC and the California ISO to address additional VGI issues that require cross-agency coordination, such as delays in interconnection, costs of deployment, and development of technical standards.

» **Identify challenges and solutions for potential impacts to the utility distribution system from electric vehicle deployment, as part of its distributed energy resource plans**. Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013) requires investor-owned utilities to submit a Distributed Energy Resources plan to the CPUC that identifies optimal deployment locations for all distributed energy resources, including electric vehicles. These plans should consider all the policies for distributed resources, including the Governor's *ZEV Action Plan* and VGI development as tools to address some of these impacts.

» **Identify and support opportunities to encourage VGI development as state agencies implement the Governor's ZEV Action Plan**. State agencies should reach out to transit officials, fleet owners, and fleet managers, such as the military, to identify opportunities for pilot programs and efforts to deploy charging stations with VGI capabilities that can help with both demand response and storage, to engage new entities in helping to achieve the goals in the Governor's *ZEV Action Plan* while adding grid benefits, including in publicly owned utility service territory.

Transportation Nexus with Natural Gas Sector

» **Collect and report information on methane leakage from the natural gas system**. As part of its Natural Gas Act Report under AB 1257, the Energy Commission should continue to collect information from the ARB, the Environmental Defense Fund (EDF), and other institutions researching methane leakage (fugitive methane emissions), to inform its analysis related to strategies that maximize the beneficial use of natural gas as an energy source. The Energy Commission should conduct a workshop on methane leakage, after the EDF and other institutions complete their studies on methane leakage, to gather additional stakeholder input on the issue. This may be coordinated with the ARB as a joint workshop. The Energy Commission will take this information into account as it drafts its Natural Gas Act Report in response to AB 1257. The Energy Commission should maintain flexibility within its programs and plans to incorporate relevant data, when appropriate, as they become available. Finally, the Energy Commission should continue supporting scientific research to quantify methane emissions from the natural gas system and contribute with research looking at cost-effective options to reduce these emissions.

CHAPTER 7:
Changing Trends in California's Sources of Crude Oil

California's crude oil sources appear to be shifting from foreign, Alaskan, and instate supplies to new sources in the Midwest and Canada, spurred by a dramatic increase of domestic oil production enabled by more widespread use of hydraulic fracturing and other extraction advances. Shipments of these new resources by rail or by barge are increasing and could represent up to 23 percent of California's crude oil within a few years, depending on the economics of the extraction, transport, and development and approval of receiving/storage terminals in California. Greater use of transport of oil by rail is also a trend nationally, and industry is investing in increased infrastructure to support transport by rail. The federal government has primary oversight of rail safety, with roles also played by state and local agencies.

To better understand this changing landscape in the supply of crude oil and how it is regulated, the Energy Commission hosted an Integrated Energy Policy Report (IEPR) workshop in Berkeley on June 25, 2014. The workshop focused on the changing trends in California's sources of crude oil with emphasis on the growth of crude oil delivered by rail (CBR) and the effects of these trends on the transportation energy market and existing government policies. The discussions also focused on existing and possible new roles of federal, state, and local government to address market changes.

Chair Robert Weisenmiller and Commissioners Janea Scott and Karen Douglas presided over the meeting, along with California Public Utilities Commissioner (CPUC) President Michael Peevey and Cliff Rechtschaffen and Ken Alex from the Governor's Office. The workshop featured presentations on near-term trends and long-term policy goals, crude oil distribution logistics, government responsibilities within that distribution process, government responsibilities regarding safety requirements and oversight for CBR, environmental and oil industry perspectives, and the relationship of crude oil trends to environmental and energy policies.

This workshop brought together, for the first time, a broad set of stakeholders involved in changing trends in the sources of California's crude oil and represented one step in the state's efforts to proactively address it. Mr. Rechtschaffen from the Governor's Office briefly spoke about the Governor's Office Interagency Rail Safety Working Group formed in January 2014, explaining, "California is on the cusp of dramatic changes in the sources of our oil and increasing transportation. We wanted to be ahead of the problem. …We wanted to be proactive and deal with the

risks as they are in a sensible and thoughtful way."[247] The Governor's Office Interagency Rail Safety Working Group published *Oil by Rail Safety in California: Preliminary Findings and Recommendations*[248] in June 2014, highlighting actions state agencies and the federal government should consider in light of project increases of CBR. Recommendations included a call to increase the number of CPUC Rail Inspectors to improve emergency preparedness and response programs, to request more information from railroads regarding shipments and routes, to request that the U.S. Department of Transportation expedite phasing out older DOT-111 tank cars, and to take action to ensure railroads complete agreed-upon voluntary safety improvements.

State Assemblymember Nancy Skinner thanked the Energy Commission for hosting the workshop in one of the primary affected corridors and highlighted some of the bills introduced in the second year of the 2013-2014 Legislative Session that were moving through the legislature that pertain to CBR. She also noted that the recently adopted state budget included funding for seven additional safety inspectors at the CPUC and 38 new positions for prevention, emergency response, cleanup, and enforcement at the Office of Spill Prevention and Response (OSPR).

This chapter highlights changes to the trends in crude oil sources for California refineries, in particular the more recent increases in rail car deliveries that have developed in response to discounted oil sources in Canada and domestic shale oil production regions of North Dakota, Colorado, and Texas. Federal and state activities associated with improving the safety of transporting flammable liquids via rail cars is also explained, along with the status of recent regulatory activity for rail operations and tank car construction standards.

247 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 187.

248 The full report can be found at http://www.caloes.ca.gov/HazardousMaterials/Documents/Oil%20By%20Rail%20Safety%20in%20California.pdf.

Agency Roles and Responsibility

One purpose of the June 25, 2014, workshop was to help clarify roles various agencies play. There are several entities that oversee railroad safety and rail tank car standards.

Federal Government

The Pipeline and Hazardous Materials Safety Administration within the U.S. Department of Transportation is responsible for developing regulations to help ensure and improve the safe transportation of hazardous materials. In addition, this agency is also responsible for responding to any safety-related recommendations issued by the National Transportation Safety Board in the wake of a major accident investigation. The Federal Railroad Administration employs inspectors who enforce rail safety regulations.

State of California

The federal government has primary authority over railroad safety. In California, the Rail Safety Division within the CPUC works in conjunction with federal inspectors to help ensure the safe operations of rail movement for goods and people. Table 12 provides more detail on specific state agency roles and responsibilities.

Local Governments

California local governments normally have lead responsibility under the California Environmental Quality Act regulations for the review of environmental impacts that new construction of crude oil storage and delivery terminals might have in the jurisdictions. For example, the permit process for a project to allow crude-by-rail receipts at a refinery could be overseen by a county or city planning commission. In addition, local agencies, such as the Certified Unified Program Agencies, play critical roles in emergency preparedness and response, alongside local first responders.

Table 12: Crude Oil Movement—California State Agency Primary Roles and Responsibilities

State Agency	Information Collection	Planning	Inspection	Enforcement	Emergency Response
Governor's Office of Emergency Services (Cal OES)	Counties traversed within California by CBR shipments of Bakken crude oil greater than 1 million gallons	Review plans and training on emergency preparedness– hazmat team gap analysis work			Incident command on regional or statewide level, provide mutual aid support (if necessary) in response to an incident
Office of Spill Prevention & Response		Oversight and approval of spill response plans, local government training, and contingency planning development	Investigate all spills and releases	Surprise inspections, unannounced drills, verification of proof of financial responsibility by crude oil shippers	Oil spill prevention and response, coastal waters and inland areas– restoration of habitat and oiled wildlife care
California Public Utilities Commission	Crude oil projects and rail activity related to crude oil	Perform statewide and localized risk assessments and analysis	Inspect rail tracks, bridges, crossings, train control, and rail equipment– investigate all rail-related accidents	Enforce federal and state rail safety requirements	
California State Lands Commission	Marine vessel receipts and loading of crude oil and other petroleum products by terminal - monthly	Oversight of marine oil terminal modifications and new projects	Annual and spot inspections of marine oil terminals	Enforce Marine Oil Terminal Engineering and Maintenance Standards (MOTEMS)	
Office of State Fire Marshal - Office of Pipeline Safety	Location of hazardous liquids pipelines	Emergency response planning and training for hazardous materials spills	Inspect and pressure test hazardous liquids pipelines	Intrastate hazardous liquids pipeline standards and operations	Contacted by Cal OES for each hazardous liquids pipeline leak and train derailment, respond to site if necessary
California Energy Commission	CBR shipments from BNSF and UP, volume & source state/province– monthly				
California Air Resources Board	Crude oil types used by each refinery– annual				

Source: California Energy Commission

Class 1 Railroads

There are two Class 1 railroads operating in California: Burlington Northern Santa Fe and Union Pacific. These companies have invested in their infrastructure and modified operating procedures to decrease the number of derailments and minimize the consequences of a hazardous release of flammable liquids.[249]

Canada

The Transportation Safety Board of Canada is responsible for developing regulations to improve the safe operations of rail activity in Canada. Transport Canada employs Railroad Safety Inspectors who enforce these regulations. In July 2013, Canada witnessed the most notable CBR accident in recent history as 63 tank cars of crude oil exploded, killing 47 people in Lac Mégantic, Quebec.[250]

Safety-related activities (see Appendix G for a chronology of key milestones) associated with rail transport of flammable liquids have included new practices and proposed regulations designed to reduce the probability of derailments and reduce the possibility of any explosion and fire if such a derailment were to occur for a train transporting crude oil or other flammable liquids. These international, federal, and individual state activities have intensified following the tragic loss of life associated with the crude train derailment in Lac Mégantic, Quebec.[251]

249 Each of these companies provided an overview of their operations, including details of improvements and operational changes for their systems, during the California Energy Commission's public workshop on June 25, 2014. The BNSF presentation can be found at http://www.energy.ca.gov/2014_energypolicy/documents/2014-06-25_workshop/presentations/06_DiCamillo_CBR_Safety_Presentation_June_24.pdf and the UP presentation at http://www.energy.ca.gov/2014_energypolicy/documents/2014-06-25_workshop/presentations/Stark_Union_Pacific_Railroad_IEPR_Workshop_v1.pdf.

250 Congressional Research Service, "U.S. Rail Transportation of Crude Oil: Background and Issues for Congress," May 5, 2014, http://www.fas.org/sgp/crs/misc/R43390.pdf.

251 *Railway Investigation Report R13D0054*, Transportation Safety Board of Canada, August 2014, http://www.tsb.gc.ca/eng/rapports-reports/rail/2013/R13D0054/R13D0054.pdf.

Changing Trends in California's Crude Oil Production

The decline of California crude oil production has persisted since 1985, when production peaked at 424 million barrels per year. Most of California's crude oil-producing fields are mature, such as those in Kern County, and have been producing oil for more than 100 years. Over time, the drilling and extraction of crude oil result in diminishing output from wells. As Figure 29 illustrates, the production of California crude oil has peaked and has been declining for the majority of the years since 1985 through 2013. For the first time since a brief uptick during 1994 and 1995, oil production in California showed a modest increase during 2013. However, the consequence of the long-term declining trend has been a growing shift to alternative sources of crude oil from foreign sources.

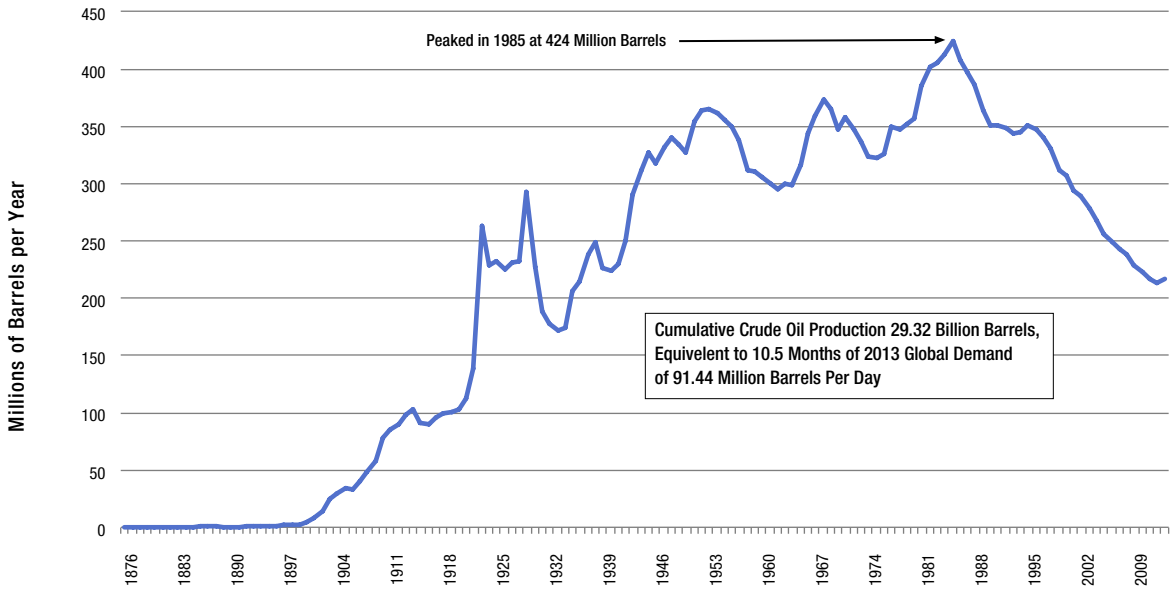
Crude Oil Pricing Trends

Crude oil prices had been relatively stable from January 2011 through June 2014, fluctuating between $96 and $126 per barrel for Brent North Sea crude oil (an international benchmark for crude oil prices) for an average of $110.29 per barrel.[252] Over this period the production of crude oil in the United States increased from 5.5 million barrels per day (BPD) in January 2011 to 8.7 million BPD by June 2014, an increase of 3.2 million BPD.[253] Despite

252 Europe Brent daily crude oil spot prices, Energy Information Administration. See http://www.eia.gov/dnav/pet/xls/PET_PRI_SPT_S1_D.xls.

253 Monthly crude oil production for the United States, Energy Information Administration. See http://www.eia.gov/dnav/pet/pet_crd_crpdn_adc_mbblpd_m.htm.

Figure 29: California Oil Production (1876 to 2013)



Source: California Division of Oil, Gas, and Geothermal Resources (DOGGR) and the California Energy Commission

this dramatic rebound in domestic oil production there was little discernible impact on international crude oil prices because global demand for crude oil had continued to increase from 88.4 million BPD[254] during the first quarter of 2011 to 91.5 million BPD by the second quarter of 2014.[255] The 3.1 million BPD increase in global oil demand was nearly identical to the rise of U.S. oil production over the same period.

During the second half of 2014, however, the dynamics between supply and demand trends for crude oil began to shift. Brent oil price declined from an average of $111.80 during June 2014 to an average of $58.31 per barrel on December 22, 2014, a decrease of nearly 48 percent.[256] U.S. oil production also continued to surge, increasing by an additional 600 thousand BPD between June and December 2014.[257] Over this same period, the International Energy Agency lowered its forecast for crude oil demand in the fourth quarter of 2014 from 94 million BPD in the June report[258] to 93.5 million BPD by its November report,[259] a decrease of 500,000 barrels each day.

The resurgence of U.S. oil production initially redi-

254 Oil Market Report, International Energy Agency, June 2013, Table 1. See https://www.iea.org/media/omrreports/tables/2013-06-12.pdf.

255 Oil Market Report, International Energy Agency, November 2014, Table 1. See https://www.iea.org/media/omrreports/tables/2014-11-14.pdf.

256 The Energy Information Administration has Brent North Sea oil prices available on a daily basis going back to May 20, 1987. See http://www.eia.gov/dnav/pet/pet_pri_spt_s1_d.htm.

257 Drilling Productivity Report, Energy Information Administration, December 2014, http://www.eia.gov/petroleum/drilling/xls/dpr-data.xlsx.

258 Oil Market Report, International Energy Agency, June 2014, Table 1. See https://www.iea.org/media/omrreports/fullissues/2014-06-13.pdf.

259 Oil Market Report, International Energy Agency, November 2014, Table 1. See https://www.iea.org/media/omrreports/tables/2014-11-14.pdf.

rected crude oil imports to other destinations experiencing continued demand growth. As global oil demand began to ease with the lower-than-anticipated growth for China, the rest of Southeast Asia, and Europe, this created an increasing challenge for various oil-exporting countries to continue selling the same quantity of crude oil in a market beginning to experience excess supply. Organization of the Petroleum Exporting Countries (OPEC) members met in November 2014 but were unable to reach consensus to voluntarily decrease their output in an effort to keep oil prices from declining to even lower levels. To retain market share in Southeast Asia and the United States, Saudi Arabia and other OPEC members have been willing to discount their oil prices, leading to downward pressure on international oil prices. Oil prices are now expected to continue easing at least through the first half of 2015.

A recovery of international oil prices could not begin until incremental supply from the United States begins to slow in conjunction with a rebound in global oil demand. The continued drop in oil prices has reduced the profitability of some higher-cost producers, deferred an increasing number of oil field development projects, decreased the number of new drilling permits, and may possibly result in the shut-down of more expensive oil well operations. All of these actions are expected to dampen the continued increase of U.S. oil production and possibly lead to a leveling or slight decline some time during 2015. This potential outcome would place upward pressure on international oil prices. On the demand side, global demand for oil is forecast to rise on a seasonal basis by about 1.8 million BPD between the first and second halves of 2015.[260] If this typical seasonal pattern develops, this reversal would also place upward pressure on international crude oil prices during the latter months of 2015.

260 Oil Market Report, International Energy Agency, November 2014, Table 1. Global crude oil demand is forecast by IEA to rise from an average of 92.65 million BPD during the first half of 2015 to an average of 94.45 million BPD during the second half of 2015.

Sources of Crude Oil for California Refiners

Crude oil used by California refineries is imported from foreign and domestic sources. This crude oil is delivered to California primarily via marine vessels, in-state pipelines, and more recently via rail tank cars. There are no crude oil pipelines that deliver crude oil to California refineries from outside the state. Figure 30 illustrates how sources of crude oil to California refineries have shifted to become more dependent on foreign sources as supplies from Alaska and California have declined.[261] During 2013, California refiners received a total of 623.7 million barrels of crude oil for an average of 1.7 million BPD. About 51 percent came from foreign sources, 37 percent came from California and other domestic lower-48 state sources, and about 12 percent was from Alaska.

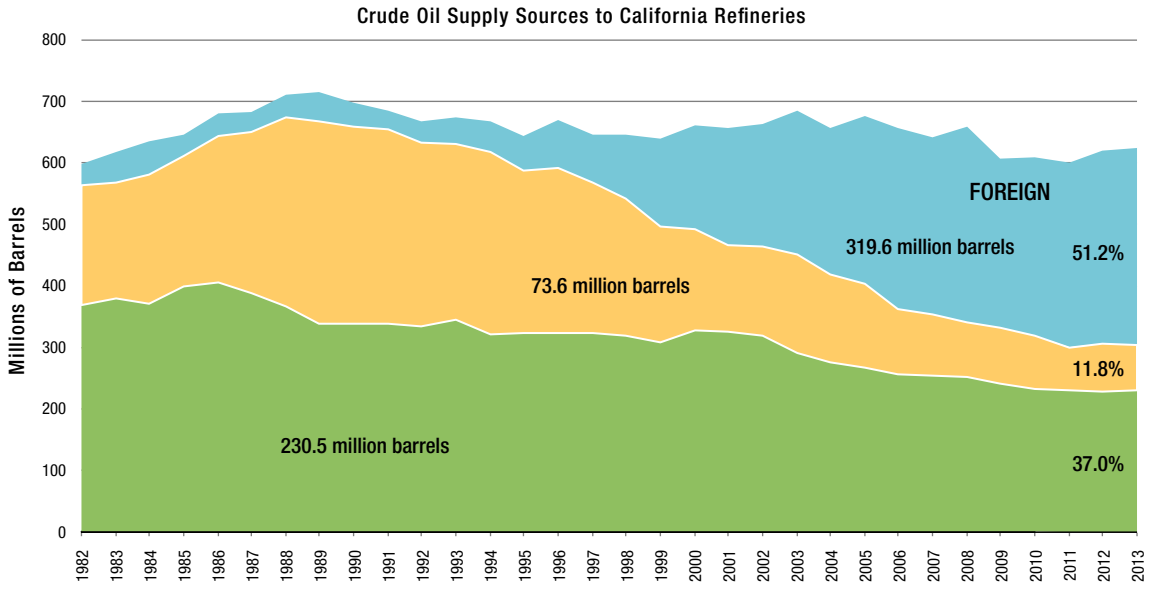
All of the crude oil from Alaska was delivered via marine tanker, as was the vast majority of foreign crude oil. A smaller portion (0.7 percent) of the domestic (California plus lower-48 states) crude oil was imported by marine vessel.

Crude oil imports from foreign sources are obtained from diverse countries. During 2013, Saudi Arabia was the largest source of foreign crude oil imports with 29.5 percent of total, followed by Ecuador (22.3 percent) and Iraq (18.5 percent). Figure 31 depicts the top 12 source countries' share of foreign crude oil imports.[262]

261 California Energy Commission. This chart and detailed monthly data can be found at http://energyalmanac.ca.gov/petroleum/statistics/crude_oil_receipts.html.

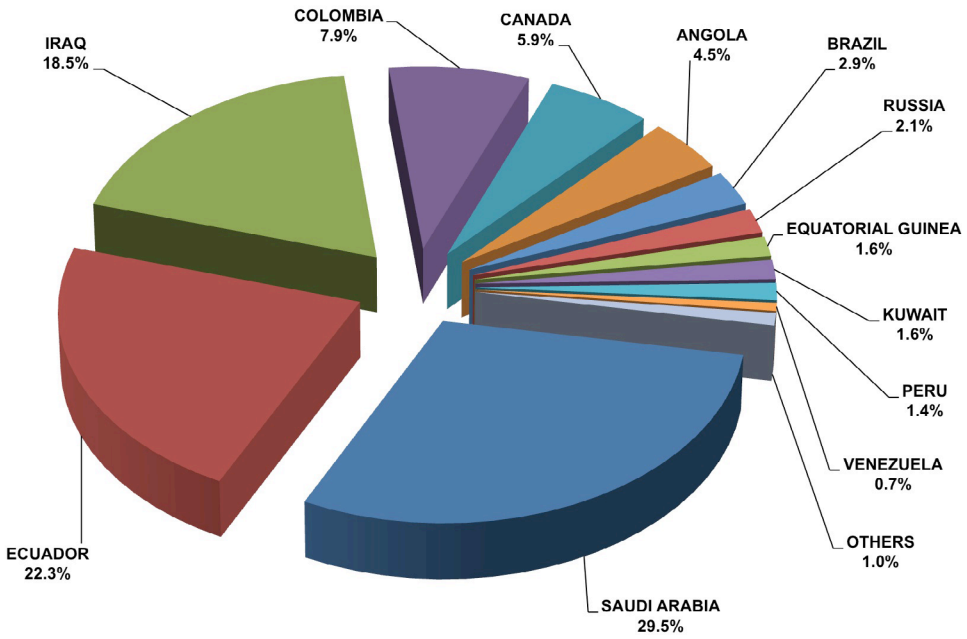
262 California Energy Commission. This chart and individual country totals are at http://energyalmanac.ca.gov/petroleum/statistics/2013_foreign_crude_sources.html.

Figure 30: California Oil Sources (1982 to 2013)



Source: DOGGR and the California Energy Commission

Figure 31: Foreign Oil Sources (2013)



Source: Energy Information Administration, Company-Level Imports

U.S. Crude Oil Extraction Developments and Resulting Increased Output

Although crude oil production has been generally declining in California, production is increasing in the rest of the United States. Domestic crude oil production has dramatically rebounded in the United States due to the extensive use of horizontal drilling techniques and unconventional well stimulation treatments, like hydraulic fracturing.

Hydraulic fracturing or "fracking" is a technique used by the petroleum industry to obtain crude oil and natural gas from geological formations that require additional effort to increase the volume of petroleum that can be removed from an existing field. These "tight oil and gas" formations require the rock to be fractured to enable the crude oil and natural gas to flow though the fissures to well bores and on to the surface. Hydraulic fracturing is not a new procedure and is estimated to have been used in more than 1 million wells worldwide. At the June 25, 2014, IEPR workshop, Steven Bohlen from the California Division of Oil, Gas, and Geothermal Resources (DOGGR) explained how hydraulic fracturing, or fracking, in California differs from techniques used in the Marcellus Shale or other places. He noted that a substantial portion of California's wells "do require some kind of well stimulation in order to enhance recovery," but that the water used for well stimulations in California is much more restricted than in other parts of the country, by virtue of the vertical style of wells used here.[263] Mr. Bohlen also spoke about Senate Bill 4 (Pavley, Chapter 313, Statutes of 2013)—which requires oil and gas companies to apply for permits to conduct hydraulic fracturing in-state, publicly disclose the chemicals used, and monitor ground water and air quality—noting that draft regulations had been released by DOGGR for public comment.

Continued improvement in technology, operating procedures, and understanding of subsurface petroleum deposit structures has allowed companies to deploy fracking in conjunction with horizontal drilling. This type of activity has been used with great success in tight oil formations in North Dakota (Bakken) and southern Texas (Eagle Ford). Production of oil in the United States stood at 9.05 million barrels per day during October 2014, the highest level of output since February 1986. It is forecasted that production could continue increasing and eventually exceed the all-time record output of 10.04 million barrels per day achieved during November 1970.[264]

The surge in domestic crude oil production is centered on the shale oil regions of the United States, such as the Eagle Ford formation in Texas and Bakken formation in North Dakota. Figure 32 shows how much oil production in those respective states has increased since January 2010 compared to California and Alaska.

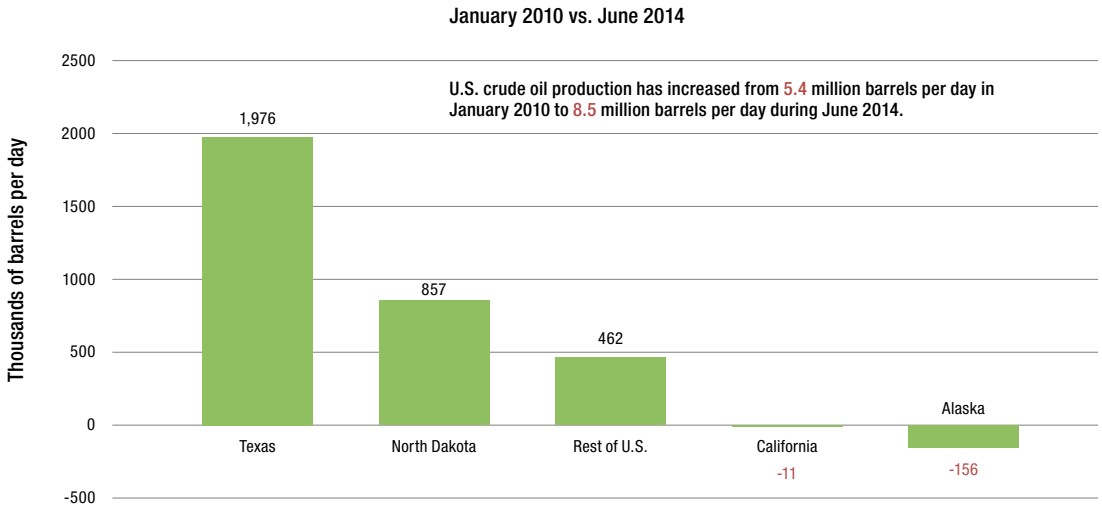
While crude oil production in California has been generally declining, several presenters at the June 25, 2014, workshop spoke about the potential development of the Monterey Shale. In response to a question from Mr. Rechtschaffen regarding how to gauge the potential of the Monterey Shale play, Michael Schaal from the Energy Information Administration suggested that "…research would unlock the potential…and…additional technological innovation would have to occur before it could be considered a commercial success."[265]

263 June 25, 2014, Integrated Energy Policy Report workshop transcript, pp. 65-66.

264 According to the Energy Information Administration's latest *Annual Energy Outlook* publication, crude oil production in the United States could reach 11.41 million barrels per day by 2020 under the "High Oil and Gas Resource" scenario. *Annual Energy Outlook 2014 with Projections to 2040*, Energy Information Administration, April 2014, Table D8, page D-16, http://www.eia.gov/forecasts/aeo/pdf/0383(2014).pdf.

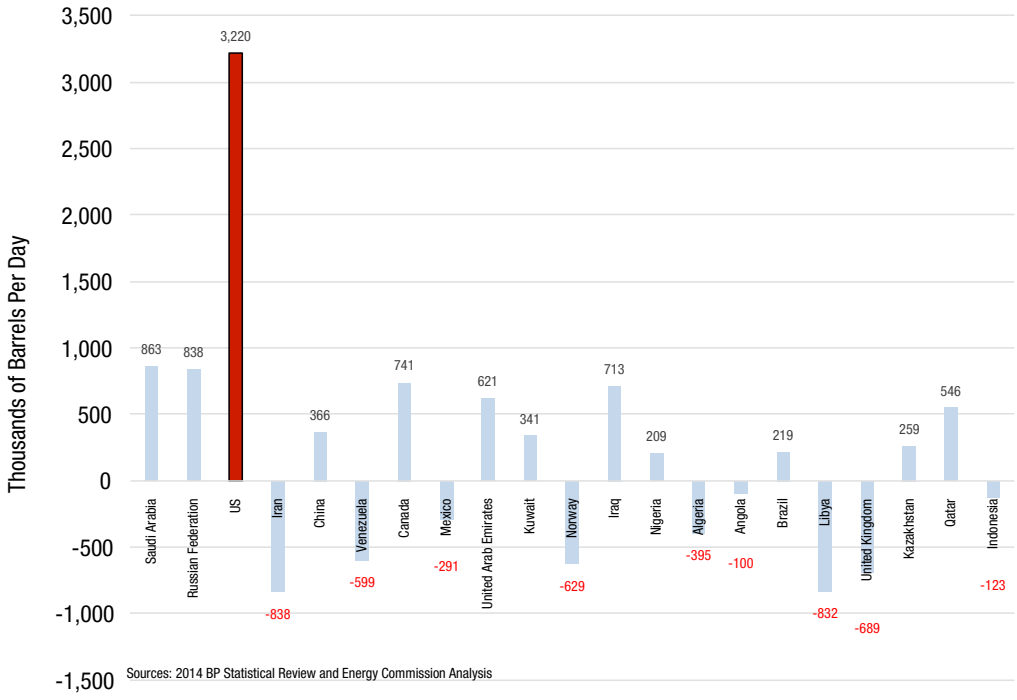
265 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 69.

Figure 32: Crude Oil Production Change



Source: Energy Information Administration

Figure 33: Crude Oil Production Change 2013 vs. 2008



Source: 2014 BP Statistical Review and Energy Commission analysis

Figure 34: Crude Oil Pipeline Infrastructure

Source: CAPP, Raymond James Ltd.

Global Crude Oil Production Decline

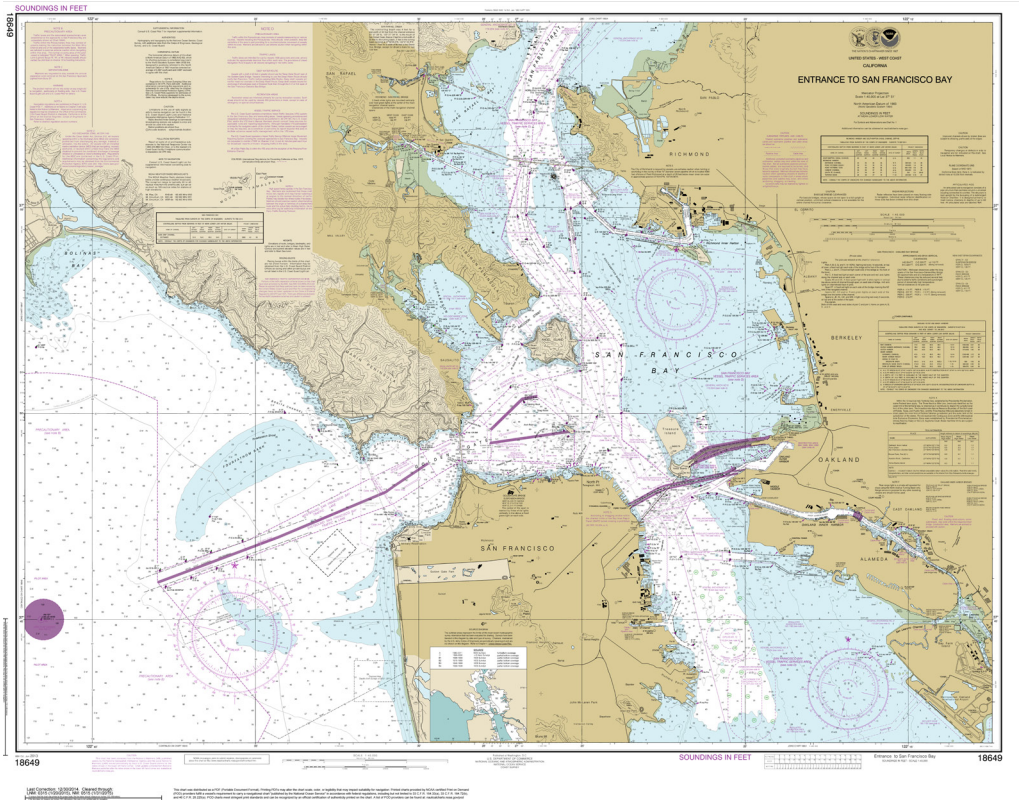
Although the decline in crude oil production has reversed in the United States over the last several years, the trend in several other oil-producing countries is the opposite. During 2008, there were 21 countries that produced at least 1 million BPD of crude oil with the United States ranking third.[266] By 2013, nearly half (nine) of those countries experienced a decline in oil production, as shown in Figure 33. The aggregate change for these 21 countries amounted to an increase of 4.44 million BPD. However, if the United States' contribution is removed, the increase between 2008 and 2013 drops to 1.22 million BPD.

Crude Oil Distribution Trends Toward Rail Transportation

The dramatic increase of crude oil production has outpaced the ability of the crude oil pipeline gathering and distribution infrastructure to keep pace. Consequently, producers have sufficiently discounted their oil prices to make the more expensive means of rail transportation an economically viable option for refiners outside these shale oil regions. As Figure 34 shows, there are no crude oil pipelines providing oil to California from outside the state. California refiners have not had a need to import

266 *BP Statistical Review of World Energy*, BP, June 2014, p. 8, http://www.bp.com/content/dam/bp/pdf/Energy-economics/statistical-review-2014/BP-statistical-review-of-world-energy-2014-full-report.pdf.

Figure 35: San Francisco Bay Entrance—Marine Tanker Lanes



Source: National Oceanic and Atmospheric Administration – San Francisco Bay entrance chart number 18649

domestic crude oil from other states via pipeline due to local sources of oil production and access to waterborne deliveries from Alaska and foreign sources.

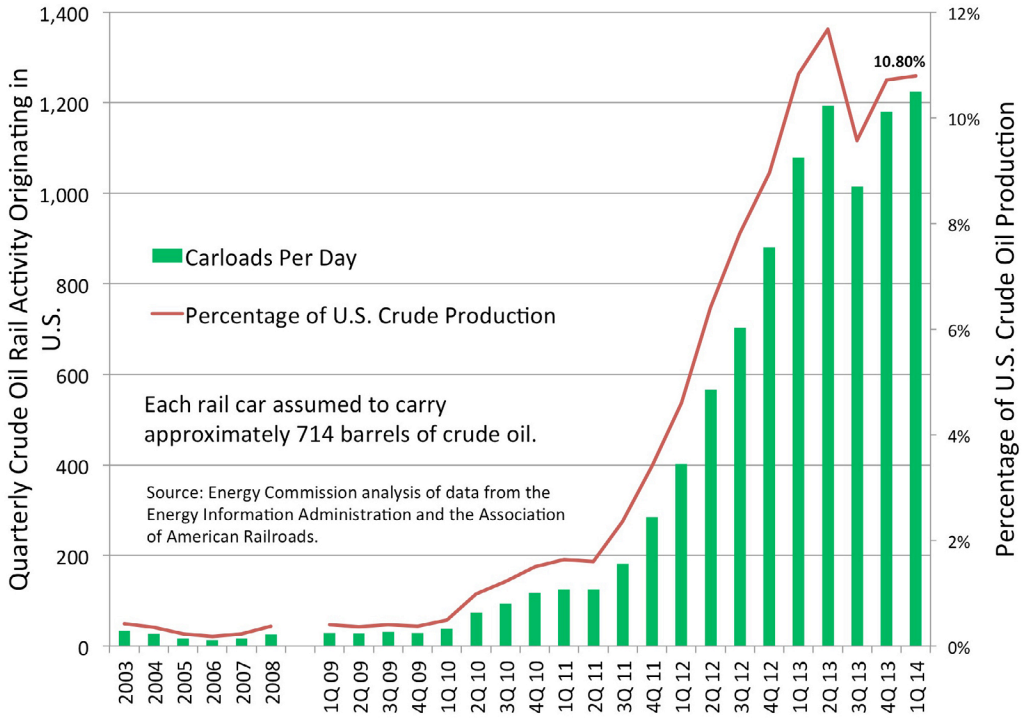
Marine terminals allow California refiners the flexibility to import crude oil from a variety of locations that meet their quality needs. However, the emergence of discounted crude oil prices and development of rail loading capability in shale oil states have provided an opportunity for refiners to take advantage of these discounted domestic crude oil sources. Refiners inside and outside the state are pursuing crude-by-rail (CBR) receiving terminal projects not because they are running out of crude oil supplies from existing sources; rather they are trying to obtain discounted crude oil to reduce their operating costs and improve profitability.

California Crude Oil Routes for Marine Tankers

Crude oil deliveries via marine vessel from South American countries usually follow a southern coastal route through designated shipping lanes before being escorted to individual refinery marine berths in the ports of Long Beach, Los Angeles, and the San Francisco Bay Area. Canadian crude oil deliveries via marine vessel follow in coastal shipping lanes from the north, while marine vessels delivering crude oil from the Middle East and Russia traverse the Pacific Ocean. The figure below provides an example of these designated marine vessel routes for the approach to San Francisco Bay.

Crude oil deliveries via marine vessels can also include the discharge of a partial cargo at one refinery in one portion of the state before moving to another refinery marine terminal to discharge the remainder of the crude

Figure 36: Crude Oil Transportation by Rail Tank Car



Source: Energy Commission analysis of data from the Energy Information Administration and the Association of American Railroads

oil cargo. In such instances, these marine vessels follow designated coastal shipping lanes running north to south before being escorted to refinery marine terminals.

The morning session of the June 25, 2014, workshop outlined marine oil terminals and the crude oil pipeline network. Laura Kovary from the California State Lands Commission's Marine Facilities Division spoke about maritime disasters aboard the Sansinena at the Los Angeles Harbor and the Betelgeuse in Ireland and about the lessons learned as a result of these disasters. "…The International Maritime community made changes in the way that crude oil is transported by water. A couple of these changes were to require closed loading and discharging operations and for the use of inert gas to replace ambient air, therefore keeping oxygen away from flammable vapors. … More recently the oil industry has been developing safety management systems for marine oil terminals through the Oil Companies International Marine Forum…including a baseline criteria auditing process." She encouraged those in the rail industry to "take some of these lessons learned from the maritime industry and look towards safety management systems and prevention first."[267]

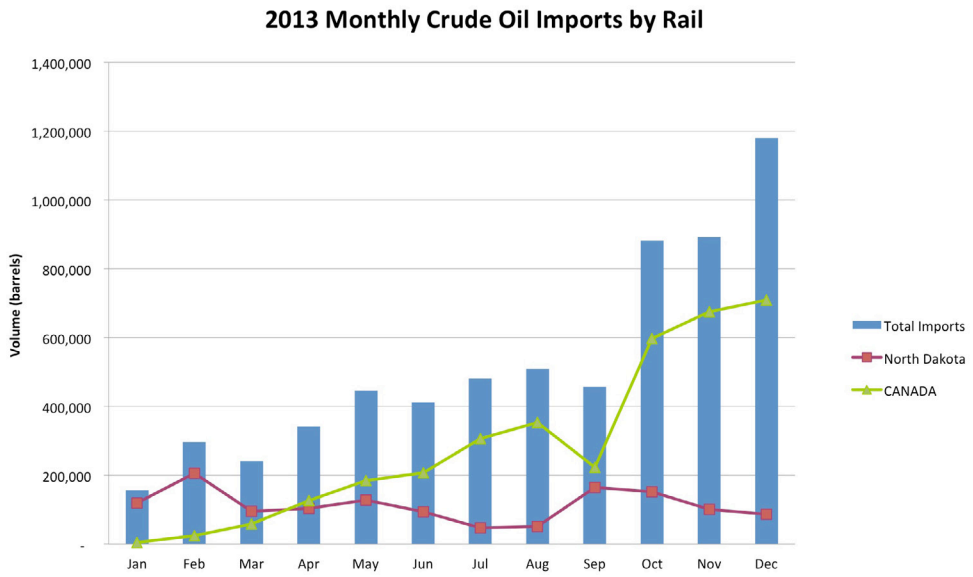
Crude Oil Export Restrictions

In addition to the rapid increase of crude oil production temporarily outpacing the ability of oil pipeline transportation capacity, there are federal restrictions in place that severely limit the quantity of domestic crude oil that can be exported from the United States. Domestically produced crude oil exports to foreign destinations are allowed under specific "license exceptions" identified under federal statute.[268] These restrictions on exports es-

267 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 154.

268 *U.S. Crude Oil Export Policy: Background and Considerations*, Congressional Research Service, March 26, 2014, http://www.energy.senate.gov/public/index.cfm/files/serve?File_id=dfe108c9-cef6-43d0-9f01-dc16e6ded6b4.

Figure 37: California CBR Receipts



Source: Petroleum Industry Information Reporting Act data, Energy Commission analysis

sentially mean that crude oil that is produced in the United States has to be used in the United States. No heavy crude oil is exported from California nor has any been exported for several years.

Shift to Crude-By-Rail Increases and Expands to West Coast

CBR is a somewhat recent phenomenon. Figure 36 shows the rapid increase over the last three years as logistical providers have ramped up the capability to load crude oil into rail cars at production locations in Canada, North Dakota, Texas, Colorado, and New Mexico. These projects have been recently completed to take advantage of crude oil price discounts for Canadian and domestic crude oil, for which rapid increase in output has overwhelmed the capacity of crude oil pipelines to transport to refineries. As a consequence, crude oil prices at these new tight oil (or shale oil) producing regions (such as Bakken in North Dakota) have been sufficiently discounted by producers to enable the costlier rail transportation economics to work for refining customers on the West, East, and Gulf coasts of the United States. The American Association of Railroads said 874,000 barrels per day (BPD)—about 10.8 percent of U.S. output of 8.09 million BPD—moved by rail during the first quarter of 2014.

Crude-by-Rail in California

California refiners received 1.1 million barrels of crude oil via rail during 2012. During 2013, California refiners received 6.3 million barrels, a nearly six-fold increase within one year. Figure 37 shows how quickly the monthly CBR deliveries increased throughout 2013.

The 2013 deliveries of CBR to California originated from Canada and 10 other states. Canada was the largest source of CBR cargoes, accounting for slightly more than 55 percent of statewide totals, followed by North Dakota at 21.4 percent and Colorado at 7.9 percent. CBR deliveries for the first seven months of 2014 have totaled 3.65 million barrels, roughly 53.8 percent greater than the same period during 2013 (2.37 million barrels). Canada's share has

Table 13: California CBR Sources and Destinations (2013–July 2014)

Country or State of Origin for Railcars	2013 Totals	2013 Percentage	2014 Totals	2014 Percentage
California Totals				
Canada	3,472,050	55.15%	1,520,288	41.69%
Colorado	500,706	7.95%	125,755	3.45%
New Mexico	411,725	6.54%	485,482	13.31%
North Dakota	1,348,681	21.42%	825,557	22.64%
Utah	59,004	0.94%	411,933	11.30%
Wyoming	441,398	7.01%	203,833	5.59%
Other States*	62,621	0.99%	76,417	2.10%
Subtotals	**6,296,185**	**100%**	**3,646,265**	**100%**
Northern California				
Canada				
Colorado	157,836	12.54%	68,622	7.52%
New Mexico			15,268	1.67%
North Dakota	1,075,861	85.45%	825,557	90.50%
Utah				
Wyoming				
Other States*	25,366	2.01%	2,764	0.30%
Subtotals	**1,259,063**	**100%**	**912,211**	**100%**
Bakersfield & Southern California				
Canada	3,472,050	68.93%	1,520,288	55.54%
Colorado	342,870	6.81%	57,133	2.09%
New Mexico	411,725	8.17%	470,214	17.18%
North Dakota	272,820	5.42%		
Utah	59,004	1.17%	411,933	15.05%
Wyoming	441,398	8.76%	203,833	7.45%
Other States*	37,255	0.74%	73,653	2.69%
Subtotals	**5,037,122**	**100%**	**2,737,054**	**100%**

*Other states include Illinois, Louisiana, Missouri, and Nebraska

Source: California Energy Commission

dropped to 41.7 percent of total, followed by North Dakota at 22.6 percent (similar to 2013 share) and New Mexico at 13.3 percent. Table 13 depicts the totals from the other states and the regional breakdown within California of these CBR deliveries for 2013 through July 2014.

Rail deliveries of crude oil to California refiners represent the smallest source, about 1 percent of the 625 million barrels of crude oil received during 2013. Foreign crude via marine tankers accounted for 316.1 million barrels (50.6 percent), followed by 228.9 million barrels (36.6 percent) from California crude oil received via pipeline and 73.6 million barrels (11.8 percent) from Alaska via marine tankers.

CBR deliveries for the first seven months of 2014 (see Table 14) have totaled 3.65 million barrels, about 53.8 percent greater than the same period during 2013 (2.37 million barrels). Canada's share has dropped to 41.7 percent of total, followed by North Dakota at 22.6 percent (similar to 2013 share) and New Mexico at 13.3 percent.

Going forward, the outlook is for a continued increase that will continue into 2015. Assuming the Plains All American CBR receiving facility (which became operational during late November 2014) operates at or near capacity, California CBR deliveries could reach at least 4 percent of total crude oil supply—roughly four times greater than the average for 2013. Further, if Alon (which recently received permits for its Bakersfield project) begins construction by early 2015, CBR imports could jump to just more than 10 percent of total crude oil supply by the end of 2015.[269]

Delivery Logistics for CBR in California

CBR projects are designed to receive shipments of roughly 100 rail tanker cars at a time, referred to as "unit trains." Unlike the more expensive manifest rail car transportation means used by a couple of California refiners, unit train shipments are granted top priority for rail line access and normally do not stop until reaching the CBR receiving facility destination. CBR rail deliveries in California are a combination of unit trains and manifest cars intermingled with other types of rail cars in mixed freight train deliveries. Rail tank cars carrying crude oil are then dropped off at different rail yards (such as Bakersfield), where they are grouped together for transport to the final refinery destination. In other instances, the rail cars are delivered to locations that unload the crude oil into storage tanks connected to a refinery. Some CBR tank cars directly transfer crude oil from rail tank cars to tanker trucks that are then driven to a refinery.

CBR imports were transferred to tanker trucks at two locations in California during 2013. The Kinder Morgan rail yard in Richmond (Contra Costa County, Northern California) receives between one and two unit trains of crude oil per month. That crude oil is then transferred directly from the rail tank cars to tanker trucks through a process referred to as *transloading*. About three to four tanker trucks are required to transfer the crude oil from a single rail tank car. The other rail terminal that was used to transload crude oil is located in Sacramento and operated by the SAV Patriot Rail Company. However, the Sacramento CBR operation has recently ceased activity during early November 2014 after the permit from the Sacramento Air Quality Management District was revoked by that agency.

CBR Safety Concerns

At the June 25, 2014, IEPR workshop, the afternoon presentations covered recent derailments of hazardous materials and current and proposed standards. Ernie Simotek from the U.S. Department of Transportation Federal Railroad Administration noted that in response to the catastrophic derailment of a runaway train in Lac-Mégantic, Quebec, his agency had come out with Emergency Order 28. The Order "requires…railroads to…develop a security plan for leaving unattended trains, develop a process for securing trains outside of yards and terminals, review and update existing procedures, and implement

269 For additional information on California CBR projects, see Appendix F.

operating rules requiring the discussion of the securement of any train or vehicle."[270]

After discussion surrounding the potential safety issues with existing rail tank cars in the event of a derailment, Commissioner Scott asked what time frame the presenters would propose for the phasing out of legacy DOT-111 tank cars. Liisa Lawson Stark from Union Pacific answered that "…as part of the rail industry we have already called on the federal government to make those changes and recommendations, keeping in mind that those legacy tank cars meet all federal standards for transportation. We would like to see that…happen…as soon as possible and we've encouraged the federal government to do so."[271] Public feedback received both at the workshop and via written comments reflected concern over legacy tank car safety, with several commenters recommending a phaseout or immediate ban of DOT-111 tank cars.

Similarly, the state Interagency Rail Safety Working Group recommended that the federal government expedite phaseout of these older, riskier tank cars. This request, among many related, was conveyed to the federal government by California Public Utilities Commission (CPUC) President Michael Peevey in his letter to U.S. Department of Transportation Secretary Anthony Foxx in July 2014.

In general, Class 1 railroads have adopted operating practices that are designed to reduce the risk of hazardous materials release from rail tank cars. A more recent example directly related to the rail transportation of crude oil is the voluntary agreement between BNSF and other Class 1 railroads with the Department of Transportation to adopt additional operating measures including speed restrictions, risk-based routing, derailment prevention, distributed power, and emergency response.[272]

Public comments also expressed concern over the integrity of tracks being used for CBR through populated areas. Commenters pointed out that running CBR trains on damaged tracks can be dangerous. At the workshop, David Wickersham from Union Pacific underscored the potential safety improvements that could be brought about through greater use of concrete railroad ties. While he acknowledged the big upfront capital investment that would be needed, he explained that "…if you have a really strong track structure, you can eliminate mechanical derailments. …if a train engineer is not handling his train right, concrete ties will prevent that car from derailing at that moment."[273]

Since the IEPR workshop, the CPUC and the California Governor's Office of Emergency Services (Cal OES) submitted comments to the U.S. Pipeline and Hazardous Materials Safety Administration regarding the proposed federal regulations for transportation of hazardous materials by rail.[274] The comments highlight the importance of finalizing these national regulations with sufficient detail and clarity to protect communities and natural resources along rail lines. In the comment letter, state agencies recommend adopting proposed regulations for:

» Classification of mined gas and liquids to enhance safety before shipping and ensure proper classification.

270 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 175.

271 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 134.

272 Specific examples of actions taken by Class 1 railroads are detailed in the comment letter submitted by BNSF on December 8, 2014. A link to that document is as follows: http://energy.ca.gov/2014_energypolicy/documents/2014-11-24_workshop/comments/BNSF_Railway_IEPR_Update_Comments_2014-12-08_TN-74132.pdf.

273 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 138.

274 Docket No. PHMSA-2012-0082 (HM-251), Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains, Comments of California State Agencies, September 30, 2014.

» Rail routing, clarifying that state railroad safety and emergency response personnel should have ready access to analyses.

» A notification system for CBR shipments and ensuring the data can provide accurate projections of *future* shipments.

» Speed restrictions and enhanced breaking requirements, including electronically controlled pneumatic brakes.

» Phasing out DOT-111 tank cars according to the proposed schedule or sooner.

New Risks Require Additional Funding

The risks posed by transportation of CBR are new and unique, as outlined above. With transportation of CBR expected to increase up to a maximum of 22 percent in the next couple of years, adequate preparation for CBR and other incidents involving hazardous materials will require additional funding for local emergency responders.[275] Despite recent actions taken by the federal government, CBR still poses fundamental risks at the local level that have yet to be addressed. In California, Cal OES reported that numerous local emergency response agencies lack resources to respond to a CBR incident. The state should take steps to ensure local emergency responders have the equipment, training, and support they need to take on additional responsibility for CBR incidents and reduce risks for communities along rail lines for years to come.

CBR Data Gaps

Timely data on CBR activities are necessary to address safety concerns; provide thorough, accurate information to local emergency responders; and enable the state to plan for future incidents. To date, some progress has been made on notification of shipments, pursuant to the federal Emergency Order, but several data gaps in other areas remain:

» Information on the source of imported crude by month, year and country/state (provided upfront in a timely manner)

» Profile/composition of the crude

» Routes of entry to California (rail, barge, pipeline) and in what quantities

» Types and quantities of crude (and refined product) exported and final destination

» Transfer points from trains and other modes of transportation

» Information on refinery replacements, expansions, or equipment changes

California and West Coast CBR Potential for Increased Imports

CBR imports to California are expected to increase over the next couple of years. The California Energy Commission is tracking five CBR projects that are either under construction or undergoing permit review. If the four projects seeking permits obtain all the necessary approvals and begin operating at full capacity, the contribution of CBR for California refiners could significantly increase from 1 percent in 2013. Assuming that California refiners process

275 If the project developers seeking permits obtain all the necessary environmental approvals, sign up a sufficient number of customers, receive full funding, complete construction by 2016, and operate at full capacity, the contribution of CBR for California refiners could significantly increase from 1.0 percent in 2013. Assuming that California refiners process the same quantity of crude oil during 2016 that they did during 2013 (625 million barrels or about 1.71 million barrels per day), the 376,000 barrels per day for maximum throughput of the five California CBR projects would amount to 22.0 percent of the crude oil processed during 2016.

the same quantity of crude oil during 2016 that they did during 2013 (625 million barrels or about 1.71 million BPD), the 376,000 BPD for maximum throughput of the five California CBR projects would amount to 22 percent of the crude oil processed during 2016. Please see Appendix F for more information on California CBR projects.

At the June 25, 2014, workshop, San Luis Obispo County Supervisor Caren Ray spoke about her concerns with increased CBR as a local official, saying, "I am the one who is perceived as responsible here, and yet I have very little decision-making authority. …we have no regulatory authority to restrict what's coming into our county."[276] Providing another local perspective, Diane Bailey from the Natural Resources Defense Council spoke about the concerns her organization is hearing from the communities they work with. "As far as we know, every refinery in the Bay Area right now is proposing a new project, and we have some additional oil terminals on top of that, and these seem to overlap almost perfectly with areas already identified by our air district as health vulnerable and vulnerable to air pollution, so we have some very serious environmental justice considerations with these new terminals that I think bear extra consideration."[277]

It is possible that not all proposed projects will receive financing and be constructed. Those that eventually do become operational will receive CBR deliveries that will most likely displace imports of Alaska crude oil (about 201,721 BPD in 2013), followed by imports of foreign crude oil via marine tanker that are of similar quality to the properties of the CBR oil.

Oil refiners in Washington state began initiating CBR projects before California refiners due to lower rail transportation costs. Washington state refiners are also the biggest consumers of Alaska crude oil, which continues to

Changing Crude Oil Quality- Potential Refinery Impacts

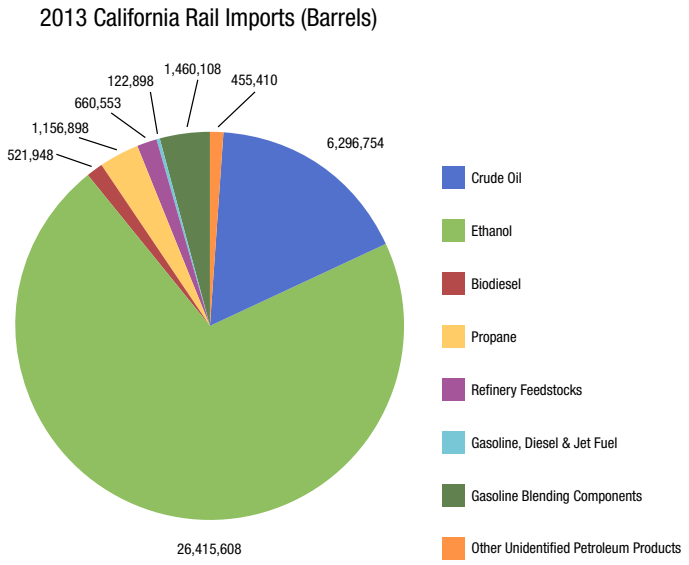
Given the similar properties to crude oil imported by marine vessel, CBR oil could be used by California refineries without construction of new processing equipment. If all CBR project proposals in California receive permits and become operational at the rated capacities, the combined volume of CBR will be about 22 percent of total crude oil receipts by 2016.

Refiners may have to make some adjustments to their operating procedures to accommodate the higher paraffinic (wax) and hydrogen sulfide nature of Bakken crude oil. The higher paraffinic content can cause increased development of waxy coatings in storage tanks and combining Bakken with other typical crude oil can result in the development of more solids and sludges. Both issues require operational changes and increased attention to coating and sludge removal. Changes in atmospheric distillation tower operations are also needed to avoid the development of chloride salts, which could increase the risk of corrosion if left untreated.

276 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 245-246.

277 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 264.

Figure 38: Other Fuel-Related Products Imported via Rail Into California



Source: California Energy Commission

decline in output, compelling refiners to seek alternative sources of crude oil to replace the declining Alaska source. The light crude oil from Bakken (North Dakota) is similar in quality to Alaska crude oil, reducing the need to make additional refinery modifications to accommodate the new source of domestic crude oil. Several CBR facilities are operating in Washington state, and more planned. Please see Appendix F for more information on individual projects.

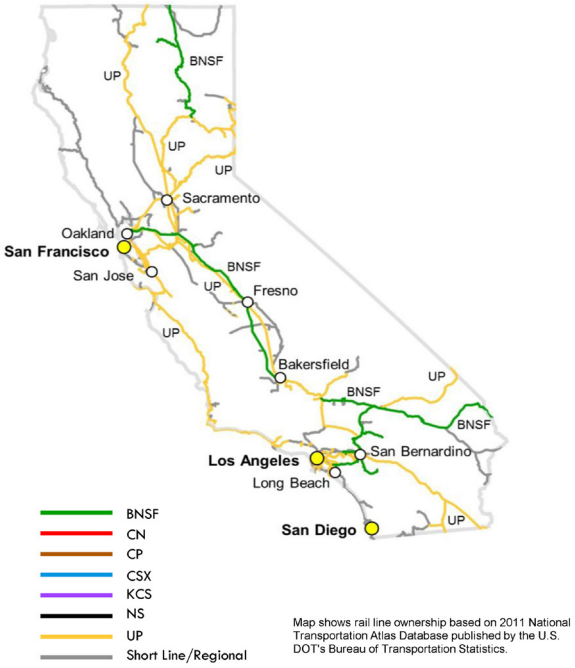
California Rail Imports of Other Fuel-Related Products

Rail is also used to import renewable fuels (ethanol and biodiesel), liquefied petroleum gases (propane), gasoline blending components (such as alkylate and butane), and refined petroleum products. Ethanol deliveries to California via rail tanker cars amounted to 26.42 million barrels (1.11 billion gallons) during 2013, or about 72.37 thousand BPD. During that same year, there were 0.52 million barrels (21.92 million gallons) of biodiesel delivered to California via rail tanker cars. Propane imports via rail cars amounted to 1.16 million barrels (48.59 million gallons), followed by 1.46 million barrels (61.32 million gallons) of gasoline-blending components, while rail imports of refined petroleum products (gasoline, diesel and jet fuel) were only 0.12 million barrels (5.16 million gallons) during 2013. Figure 38 depicts their relative contribution of each.

California CBR Routes

Union Pacific and Burlington Northern Santa Fe are the only two railroad companies that transport rail tank cars into California, using portions of their tracks or tracks owned by other companies. Figure 39 depicts the rail route options for these companies. The exact routes used

Figure 39: Rail Routes Into and Within California



Source: U.S. Department of Transportation's Bureau of Transportation Statistics

by these companies to move rail tank cars containing crude oil into California is not precisely known since the rail companies have multiple routes to take, especially for CBR imports from Canada, North Dakota, Colorado, New Mexico, and Wyoming. It is likely that shipments of crude oil from Canada, North Dakota, and Wyoming enter California through southern Oregon and northwestern Nevada, while the balance of crude oil imports from other states enters California through western Arizona and southwestern Nevada. Although information regarding the volume of crude oil delivered by rail cars to each specific destination is collected from the rail companies and refiners through the California Energy Commission confidential Petroleum Industry Information Reporting Act (PIIRA) monthly data collection, the routing of these shipments is not required to be reported to the Energy Commission.

Safety of transporting flammable liquids by rail is a concern for regulators, rail operators, and community members along rail corridors. At the workshop, Gina Solomon, Deputy Secretary for Science and Health for the California Environmental Protection Agency, previewed a public interactive map as a tool to view local vulnerabilities related to rail risks and to view local response capabilities.[278] The mapping tool allows users to zoom down to street intersections to identify areas that have potentially higher levels of vulnerability. It was designed to help focus state and local efforts toward preventing incidents and enhancing and improving emergency response capabilities.[279] Many of the public comments received centered on concerns over CBR routing and contingency planning. Commenters requested additional studies be conducted on populations in the immediate vicinity of CBR railways, safer speed limits through populated areas, and additional data on CBR. These issues were also raised by the Interagency Rail Safety Working Group and the federal comment letter submitted by state agencies.

Please see Appendix G for a detailed timeline of safety-related CBR events since 2011.

Moving Forward

Representatives from the federal government presented at the June 25, 2014, IEPR workshop, including the Energy Information Administration, the U.S. Department of Transportation Federal Railroad Administration, and the U.S. Department of Transportation Pipeline and Hazardous Materials Safety Administration. They were joined by state and local government presenters from the California Environmental Protection Agency, DOGGR, Cal OES, CPUC, California Air Resources Board, OSPR, California State Lands Commission, Office of the State Fire Marshal, Bay Area Air Quality Management District, West Sacra-

278 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 195.

279 http://www.caloes.ca.gov/HazardousMaterials/Pages/Oil-By-Rail.aspx.

mento Fire Department, and San Luis Obispo County. Workshop presenters also included representatives from rail operators, including Railway Supply Institute, Union Pacific, and Burlington Northern Santa Fe, as well as from stakeholders including the International Council on Clean Transportation, Communities for a Better Environment, Natural Resources Defense Council, and Western States Petroleum Association. This level of coordination among agencies and stakeholders is important going forward. As Mr. Rechtschaffen from the Governor's Office noted in his opening remarks, "There haven't been very many forums where we've brought together all the stakeholders at federal, local, NGO, community, industry and so forth, so that's very valuable here."[280]

In her closing comments, Commissioner Scott noted that the workshop had helped clarify different agency roles and responsibilities and said she had "learned a lot about the data that we do have, the data that we don't have, the data that we do need to be able to do our jobs well." While the focus of much of the workshop was on the logistics of CBR and general trends in the state's sourcing of its crude oil, the overall message of needing to work toward reducing California's dependence on fossil fuels was also highlighted. During his presentation at the close of the workshop, Dr. Alan Lloyd with the International Council on Clean Transportation concluded, "[P]ublic health, the air quality, (and) climate concerns demand the ultimate elimination of carbon in most combustion. … So while the transition will require time and investment, it is viable, necessary, and benefits are about ten times the investment. …California is well ahead of everybody else. And you can expect that leadership to continue."[281] And in his closing remarks, Ken Alex from the Governor's Office reminded those present that he "continue[s] to be concerned that California has a huge usage of oil that we have to come to grips with and cannot snap our fingers and simply be done with. So how we work our way out of that usage is essential. And it's also part of both our strategy and our obligation to deal with climate change."[282]

Recommendations

» **State agencies should continue to work together to implement the recommendations in the Oil by Rail Safety in California: Preliminary Findings and Recommendations**. The state should be vigilant in protecting its ability to proactively address safety concerns.

» **Monitor the status of federal rulemakings and proceedings to ensure they capture recommendations made by the state**. Since the IEPR workshop, the California Public Utilities Commission and the California Governor's Office of Emergency Services (Cal OES) submitted comments to the U.S. Pipeline and Hazardous Materials Safety Administration regarding the proposed federal regulations for transportation of hazardous materials by rail. The comments highlight the importance of finalizing these national regulations with sufficient detail and clarity to protect communities and natural resources along rail lines. As directed by the Governor's Office, the California Public Utilities Commission and Cal OES should monitor progress on the federal regulations to ensure California's concerns are addressed.

280 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 16.

281 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 317-318.

282 June 25, 2014, Integrated Energy Policy Report workshop transcript, p. 347.

» **Provide additional funding for local emergency response agencies**. As highlighted in this chapter, the risks posed by the transportation of crude oil by rail are unique. The Cal OES identified that numerous local emergency response agencies lack resources to respond to a crude-by-rail (CBR) incident. The Legislature should take steps to ensure local emergency responders have the resources, equipment, training, and support they need to take on additional responsibility for CBR incidents and reduce risks for communities along rail lines for years to come.

» **Acquire the data needed to fill identified information gaps**. Timely data on CBR activities are necessary to address safety concerns, provide useful information to local emergency responders and enable the state to plan for future incidents. To date, some progress has been made, but data gaps remain. State agencies should work together to collect, or request from other entities, the data needed to fill these gaps.

CHAPTER 8:
Integrating Environmental Information in Renewable Energy Planning Processes

In addition to being a clean energy leader in transportation, California is a leader in renewable energy development. The state has one of the most aggressive renewables portfolio standards (RPS) in the nation with a requirement that its utilities serve 33 percent of retail electricity sales with renewable resources by 2020. However, to meet the state's long-term goal of reducing greenhouse gas emissions 80 percent below 1990 levels by 2050, the state will likely need to expand its use of renewable energy beyond 33 percent. As Governor Brown said, "While reaching a 33 percent renewables portfolio standard will be an important milestone, it is really just a starting point—a floor, not a ceiling."[283] Moving forward, California needs to build on best practices to help ensure that efforts to advance renewable energy development are made thoughtfully and with careful stewardship of the state's natural resources. This chapter discusses how environmental information has been used in renewable generation and transmission planning and explores how it could be used to inform planning in the post-2020 time frame.

Introduction

The environmental impacts of constructing new electric generation and transmission projects vary depending on geographic location and may affect requirements for securing permits as well as the overall costs of building energy infrastructure. For that reason, environmental information can be very important in generation and transmission planning. Landscape-scale environmental information or plans can be particularly valuable in helping generation and transmission developers select geographic locations that may be preferable from an environmental perspective, and have the potential to lower risk of project failure and reduce delays for project development.

Landscapes are geographical regions that have similar environmental characteristics and may span across multiple regulatory jurisdictions. A landscape-scale approach examines large areas to more fully recognize important ecological values and patterns of change that may not be evident through smaller scale, project-by-project evaluations.[284] Such a comprehensive planning process

283 Governor Edmund G. Brown Jr.'s April 12, 2011 Senate Bill X1 2 signing message, available at http://gov.ca.gov/docs/SBX1_0002_Signing_Message.pdf.

284 For more information, see the BLM's Landscape Approach for Managing Public Lands website, available at http://www.blm.gov/wo/st/en/prog/more/Landscape_Approach.html.

can help protect and conserve sensitive species and their habitats, while allowing for the appropriate development of renewable energy and transmission projects with reduced risk of project delays or failure. Such information and plans could also help inform long-term procurement and transmission planning. The move away from project specific planning assessments, as summarized in the Department of Interior's *A Strategy for Improving the Mitigation Policies and Practices of the Department of the Interior*,[285] will promote certainty, transparency, and collaboration for all stakeholders.

The Energy Commission has been involved in several efforts to identify areas with high renewable energy resource potential and relatively low environmental conflicts, as well as sensitive environmental areas where permitting costs and challenges are likely to be high. The Renewable Energy Transmission Initiative was a multiple-agency, public process to identify the transmission projects needed to accommodate California's renewable energy goals. This stakeholder process resulted in the identification of Competitive Renewable Energy Zones. The *Desert Renewable Energy Conservation Plan* (DRECP) is an ongoing project of state, federal and local agencies to identify appropriate areas in the Mojave and Colorado Deserts where endangered species permitting for renewable energy and transmission projects can be streamlined in the context of a landscape-scale conservation plan. On July 13, 2012, Energy Commission Chair Robert Weisenmiller and Commissioner Karen Douglas conducted a public DRECP workshop to gather information, perspectives, and high-level principles on how the DRECP can be most effective as a long-term energy infrastructure plan.

The *2011 Integrated Energy Policy Report (IEPR)* noted that many of the challenges to renewable development relate to energy infrastructure needs, including addressing land-use issues and fragmented and overlapping permitting processes associated with building new renewable utility-scale generation facilities and building sufficient transmission needed to interconnect and deliver renewable generation.

The Renewable Action Plan that was presented in the *2012 IEPR Update* identified several challenges and opportunities associated with the interconnection and integration of renewable generation at the transmission level. The Energy Commission recommended that environmental and land-use information developed through the DRECP and other relevant sources be incorporated into the renewable resource scenarios used in the California Public Utilities Commission's (CPUC) Long Term Procurement Plan (LTPP) proceeding and the California ISO's Transmission Planning Process (TPP).

The *2013 IEPR* provides a list of the projects but also discusses other transmission issues, such as the need to better synchronize generation and transmission planning and permitting, which typically have very different timelines; coordinating land use and transmission planning through the DRECP and the potential of using that plan as a model for other regions; opportunities to designate appropriate transmission corridors in advance of need, particularly in Southern California; and emerging trends in the Western Interconnection that could affect California.

Energy Commission staff worked with the CPUC to develop an environmental scoring metric that was used in the 2013 LTPP proceeding. The environmental scores are one of several screening metrics to develop different scenarios of renewable project portfolios that would be needed to meet the 33 percent of electric retail sales RPS target. The renewable project portfolios were then transmitted to the California ISO and used in the 2013-2014 TPP to evaluate the need for new transmission lines.

285 Clement, J.P. et al., *A Strategy for Improving the Mitigation Policies and Practices of the Department of the Interior. A Report to The Secretary of the Interior From The Energy and Climate Change Task Force,* Washington, D.C., April 2014, http://www.doi.gov/news/upload/Mitigation-Report-to-the-Secretary_FINAL_04_08_14.pdf.

Collaborative Initiatives for Renewable Energy and Transmission Permitting Issues

California was among the first states to enact a RPS and has one of the most aggressive portfolio requirements in the country. Meeting these RPS goals requires a substantial amount of new transmission development, as most of the state's high-value renewable energy resources are located in remote areas, rather than near the state's major load centers. The Energy Commission recognizes that the state's transmission planning processes must be made more efficient and coordinated to ensure the siting of the most appropriate transmission projects that also consider land-use and environmental issues. In addition, the last several IEPRs have identified environmental issues associated with new energy projects and proposed actions to minimize the risk for permit delays and cost increases. The Energy Commission has been involved in a number of analytical efforts to identify areas most appropriate for renewable energy and transmission development, so as to better coordinate and expedite the permitting of renewable energy projects that are critical to meeting the established RPS.

The Renewable Energy Transmission Initiative

The Renewable Energy Transmission Initiative (RETI) was created in June 2007 as a statewide initiative designed to identify and quantify the renewable resources that could provide cost-effective, environmentally responsible energy to meet the RPS requirements, and to identify the transmission investments necessary to ensure delivery of that energy to California consumers. RETI established the precedent for incorporating land-use planning into the statewide transmission planning process by bringing together state, federal, and local agencies and entities responsible for permitting transmission projects, as well as representatives from the environmental community, developers of renewable technologies, investor- and publicly owned utilities, Native American tribes, U.S. military, and consumers. The primary goals of RETI were to (1) help identify the transmission projects needed to accommodate California's renewable energy goals; (2) ease the designation of corridors for future transmission line development; and (3) expedite transmission line and renewable generation siting and permitting.[286]

The RETI collaborative analytical effort resulted in the identification of 30 Competitive Renewable Energy Zones (CREZs) throughout the state that were most favorable for cost-effective and environmentally responsible generation development with corresponding transmission interconnections and lines. The CREZs included about 80,000 MW of potential statewide renewable resource development, including nearly 66,000 MW in California's Mojave and Colorado Deserts.

Desert Renewable Energy Conservation Plan (DRECP)

The Mojave and Colorado Deserts of California are home to some of the world's strongest renewable energy resources. They also support extraordinary biological and other natural resources of great value, including numerous threatened and endangered plant and animal species. Thus, development of renewable generation and transmission projects within these desert regions presents complicated permitting challenges.

While the RETI process was underway, California Governor Arnold Schwarzenegger issued Executive Order

286 For more information on RETI see http://www.energy.ca.gov/reti/.

S-14-08 on November 17, 2008,[287] requiring 33 percent of the electricity sold in California to come from renewable energy resources by 2020. The Order further directed the California Natural Resources Agency to lead a joint collaboration between the Energy Commission and the California Department of Fish and Wildlife to expedite the development of RPS-eligible renewable energy resources. To implement the executive order, the Energy Commission, California Department of Fish and Wildlife, the Bureau of Land Management, and the U. S. Fish and Wildlife Service signed a Memorandum of Understanding (MOU)[288] formalizing the Renewable Energy Action Team (REAT) to address permitting issues associated with specific renewable energy projects. Federal participation was supported by Secretarial Order 3285 (March 2009),[289] the directive of Secretary of the Interior Kenneth Salazar to all Department of the Interior agencies and departments (which include the Bureau of Land Management and the U.S. Fish and Wildlife Service) encouraging the timely and responsible development of renewable energy, while protecting and enhancing the nation's water, wildlife, and other natural resources.

The MOU among the REAT agencies became the foundation for the DRECP process. The RETI activity established the concept for incorporating land-use planning into the statewide transmission planning process and led directly to the collaborative land use planning occurring in the DRECP. While the state and federal governments are committed to facilitating development of compatible renewable energy generation facilities and related transmission infrastructure to achieve these requirements and goals, the agencies are also committed to conserving biological and natural resources within the state. The DRECP is intended to advance state and federal conservation goals in these desert regions, while promoting the timely permitting of renewable energy projects under applicable state and federal laws, and providing certainty for biological mitigation obligations.

The DRECP is focused on the desert regions and adjacent lands of seven California counties – Imperial, Inyo, Kern, Los Angeles, Riverside, San Bernardino, and San Diego—totaling roughly 22.5 million acres of California desert land. The DRECP will delineate renewable energy development focus areas (DFAs) that are located where large-scale renewable energy development is commercially viable and that are sufficient to help meet California's long-term climate and renewable energy goals. DFAs identified in the DRECP may include areas of immediate commercial interest, as well as areas that could be viable for future development. The DRECP's conservation framework is designed to provide comprehensive conservation for desert ecosystems and species that are covered by the plan. The DFAs are also compatible with this conservation framework.

Implementation of the DRECP is intended to provide regulatory certainty for developers that propose projects in DFAs. Certainty will come from implementation of an integrated and coordinated multiagency permitting process, with clear terms and conditions for permits and clear requirements for permit application from DRECP participating agencies. The extensive habitat and species information and the landscape-scale mapping tools developed under the DRECP process will help advance efforts to integrate environmental information into statewide renewable generation and transmission planning.

The REAT agencies released the Draft DRECP and EIR/EIS for public review and comment on September 26, 2014.[290]

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287 Governor Schwarzenegger's November 17, 2008 Executive Order S-14-08, available at http://www.drecp.org/documents/docs/2008-11-17_Exec_Order_S-14-08.pdf.

288 *Memorandum of Understanding Between the California Department of Fish and Game, the California Energy Commission, the Bureau of Land Management, and the U.S. Fish and Wildlife Service Regarding the Establishment of the California Renewable Energy Permit Team*, available at http://www.energy.ca.gov/siting/2008-11-17_MOU_BLM_FWS_DFG_CEC.PDF.

289 Secretary of the Interior Ken Salazar Order no. 3285, March 11, 2009, *Renewable Energy Development by the Department of the* Interior, available at http://www.blm.gov/or/energy/opportunity/files/order_3285.pdf.

290 The Draft DRECP report is available at http://www.drecp.org/draftdrecp/.

Local Government Planning Activities

California county governments are the permitting authority for most nonthermal power plants, such as wind and solar photovoltaic, located on private lands in California. Projects approved by counties are subject to applicable federal and state law, as well as local governments land use rules and policies. Counties, especially those rich with renewable energy resources, play an integral role in siting projects and helping California meet its energy and environmental goals.

Local governments often face staffing and other resource challenges that affect their ability to plan adequately for renewable development in their jurisdictions. To help address these challenges, Governor Brown signed Assembly Bill X1 13 (V. Manuel Pérez, Chapter 10, Statutes of 2011) which authorized the Energy Commission to award up to $7 million in grants to "qualified counties" to develop or revise rules and policies that promote the development of eligible renewable energy resources, the associated transmission facilities, and the processing of permits for eligible renewable energy resources. "Qualified counties" identified in AB X1 13 are Fresno, Imperial, Inyo, Kern, Kings, Los Angeles, Madera, Merced, Riverside, San Bernardino, San Diego, San Joaquin, Stanislaus, and Tulare. In 2012, Assembly Bill 2161 (Achadjian, Chapter 250, Statutes of 2012) added San Luis Obispo county as a qualified county.

To implement AB X1 13, the Energy Commission established the Renewable Energy and Conservation Planning Grants (RECPG) in 2012 and has awarded more than $5 million out of the available $7 million.[291] RECPG helps qualified counties update their general plans and zoning codes, complete environmental studies and mitigation plans, and engage the public. Grants also help ensure that county land use plans are consistent with federal and state goals for renewable resource development and natural resource conservation.

In addition to providing assistance to local jurisdictions, RECPG also helps California achieve long-term energy goals like the DRECP. The legislature specified that the Energy Commission may award grant funds to a qualified county in the DRECP area only if that county is a "plan participant" or enters into a MOU with the Energy Commission in which a county agrees to participate in the development of the DRECP. As of June 2014, five of the seven counties with land in the DRECP planning area have executed MOUs with the Energy Commission, including the Counties of Imperial, Inyo, Los Angeles, Riverside, and San Bernardino.

The Energy Commission held competitive solicitations to award RECPG funding in February 2013, January 2014, and February 2014 and approved grant awards to Imperial, Inyo, Los Angeles, Riverside, San Bernardino, and San Luis Obispo counties.[292] Activities funded by the grants include development of renewable energy elements as part of counties' general plan updates; preparation and certification of Environmental Impact Reports; identification of areas within a county where renewable resources will be given priority and be eligible for streamlined permitting; collection and development of geospatial data; and engagement of public, private, and tribal partners to

291 The remainder of the $7 million reverts to the Renewable Resources Trust Fund. The 2012 Budget Act (AB 1464, Blumenfield, Chapter 21, Statutes of 2012) appropriated funding from the Renewable Resource Trust Fund for the 2012-2013 fiscal year, and AB 1060 (Fox, Chapter 621, Statutes of 2013) reappropriated the unencumbered funds from the 2012 Budget Act for encumbrance or expenditure until June 30, 2014.

292 Information about each grant award is available at http://www.energy.ca.gov/renewables/planning_grants/.

plan for renewable energy development.

The work funded by RECPG grants represents important steps toward achieving California's long-term energy and natural resource conservation goals, including the successful implementation of the DRECP.

Advances in Landscape-Scale Analytical Capabilities

A critical aspect of broad, collaborative initiatives based upon landscape-scale environmental information is a solid platform upon which analyses can be effectively shared and information can be efficiently communicated. Historically, geographic information system (GIS) platforms tended to be expensive to implement and maintain, especially for multi-user environments. Increasingly, open source software and online geospatial resources are combined to offer sophisticated social platforms for geographic analyses. These resources should prove to be effective platforms for growing the collaborative efforts required of diverse stakeholder groups with the common goal of a successful landscape-scale approach to planning.

The assessment and advancement process would survey state-of-the-art geographic analytical techniques with the goal of transparently integrating diverse data across many layers. The surveyed techniques and applications should include, but are not limited to:

» Mapping tools to represent both generation and transmission project classes.

» Diverse landscape-scale data on proposed projects and environmental information.

» Methods to identify locations with low environmental risks, including predictions of how regions could be affected by climate change.

Increasingly, software packages offer tools that can be leveraged for complex spatial analyses. Various third-party vendors make available for license modules that extend or enhance these tools. Further, several publicly available online geo-spatial resources operate feature rich platforms based upon open source software that can readily incorporate analyses on environmental information.

The assessment and advancement process would also focus on available regional environmental databases to evaluate out-of-state projects serving California. There are many data resources for out-of-state areas that have developed since the Energy Commission's initial environmental scoring process:

Data Basin

A team of scientists, software engineers, and educators at the Conservation Biology Institute in Corvallis, Oregon, built Data Basin, a mapping and analysis tool designed to support participatory conservation planning. Data Basin is a web-based platform that provides user access and ability to share conservation science data, with tools to analyze and map landscape-level information. Data Basin is the foundation for the Desert Renewable Energy Conservation Plan (DRECP) Gateway, which provides a means to assist public review. The Gateway will be used to engage and inform all interested parties about ongoing planning and management issues in the California desert and, equally important, to provide the means for anyone interested to contribute to ongoing planning and management in meaningful ways. For more information on the DRECP Gateway, please see: http://drecp.databasin.org/pages/what-is-drecp-gateway

» The Western Electricity Coordinating Council Environmental Data Task Force (WECC EDTF) was formed in June 2010 to develop recommendations on the type, quality, and sources of data on land, wildlife, cultural, historical, archaeological, and water resources. The EDTF was purposed with exploring ways to transform those data into a form usable in WECC's Transmission Expansion Planning study cases, 10-year, and long-term planning models.

» The Western Governors Association's Crucial Habitat Assessment Tool is a cooperative effort of 16 western states to provide the public and industry a high-level overview of "crucial habitat" across the West.

The WECC and Western Governors Association environmental databases also include California, which can be used to verify and supplement the statewide representation of environmental information. Other state and federal agency efforts can also be incorporated so that the best available data are applied in the decision-making process for out-of-state resources.

Electric Infrastructure Planning Processes

Even before the formation of RETI and DRECP, the Energy Commission, CPUC, and California ISO have recognized the need to work together to reach the California renewable energy policy mandates and environmental goals. The agencies are engaged in long-term electric planning processes that cover a range of jurisdictional responsibilities. (See sidebar.)

More recently with the adoption of new energy and environmental policy goals and the emergence of diverse supply and demand-side technologies, closer collabora-

Aligning Infrastructure Planning

Three cyclical processes conducted by the Energy Commission, CPUC, and California ISO form the core of electric infrastructure planning:

Integrated Energy Policy Report

The Energy Commission's IEPR 10-year demand forecast is the essential first step in infrastructure planning. A new feature in 2014 is an even-year forecast update based on the newest economic-demographic data and another year of historical peak and consumption data (See Chapter 9).

Long-term procurement plan (LTPP)

Biennially in an even-numbered year, the CPUC begins a new two-year, two-phase LTPP to determine how much system, local, and flexible generation or non-generation alternatives are needed for jurisdictional utilities, how the investor-owned utilities may best procure these, and that culminate in a decision authorizing procurement.

Transmission planning process (TPP)

The California ISO annually develops the TPP to identify transmission system upgrades needed to maintain reliability of the California ISO-controlled grid, transmission projects that could bring economic benefits to consumers, and public policy-driven projects needed to meet California's 33 percent renewables target by 2020.

tion among the agencies and alignment of these processes are needed. (Process alignment is also discussed in Chapter 9.) Improved alignment will ensure studies are based on consistent and up-to-date inputs, clarify expectations for timing of information flows, and encourage effective and strategic actions toward goals. A new interagency annual process, performed each fall, develops assumptions, study scenarios, and renewable resource portfolios for infrastructure planning in the coming year. This work is coordinated through a Joint Agency Steering Committee, composed of a senior manager from each of the three agencies. Should unforeseen events occur to force plans out of alignment, the agencies commit to work with each other to readjust coordination most effectively.

The agency collaborative process is reflected in the CPUC December 2013 order establishing the structure for the 2014–2015 LTPP cycle.[293] The LTPP, as described in the order, is a two-year, two-phase process that begins in an even-numbered year and thus aligns with the regular IEPR cycle. Phase 1 of the LTPP assesses needs for system, local, and flexible capacity, including generation and nongeneration alternatives, like demand response. This phase also includes the utility obligations to procure renewable generation to comply with the RPS goals. The California ISO performs studies to assess needs for system, flexible, and local generation capacity to help inform the need for new procurement. Phase 2 determines how best to meet the needs identified in Phase 1 and culminates in a CPUC decision—authorizing procurement at the end of the odd-numbered year of the cycle. The latest available transmission plan from California ISO will be an input to Phase 2 of the LTPP so that approved transmission upgrades can contribute to meeting some of the needs identified in LTPP Phase 1.

RPS portfolio calculation and renewable project information come mainly from a tool called the RPS Calculator, a screening tool that was developed by E3 Consulting to sort the expected renewable generation projects identified by the CPUC and the Energy Commission into supply curves using different evaluation criteria (project costs and environmental scores, for example). The tool was then used to identify a set of resource planning scenarios for procurement evaluations and identification of generation project scenarios that can best meet the 33 percent RPS target, which are transmitted to the California ISO for the TPP studies.

The Energy Commission collaborated with the CPUC to develop the environmental scoring metric that is an implicit input to the RPS Calculator for screening renewable generation projects. The Energy Commission staff compiled environmental information to develop a scoring metric that reflects the land-use sensitivities considered under DRECP. Since the DRECP is limited to the Colorado and Mojave deserts, it was necessary to develop a broader statewide scoring method so that the metric would not disadvantage projects located outside the desert region. The projects located within the DRECP region covered three environmental scoring categories, with variations depending on the location of the projects. There are two other categories for projects outside the DRECP, distinguished by whether they are located on "disturbed lands." Multiple data sources were used to distinguish which locations are considered to be "disturbed," including salt-affected land that can no longer be used for agriculture. Out-of-state projects located in remote locations throughout the west are given a neutral score since there was limited information readily available to evaluate these regions.

Further work is needed to better characterize the environmental implications of proposed renewable generation and transmission projects throughout California and in other western regions that are intended for electricity imports. The Energy Commission will continue to investigate environmental information sources developed for different landscape-scale studies and consider GIS mapping tools for energy stakeholder planning evaluations.

293 The CPUC Administrative Law Judge's Order Instituting Rulemaking is available at http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M084/K241/84241040.PDF.

The RPS Calculator is being re-designed and updated within the RPS proceeding at the CPUC. Agency staff is engaged in discussions as the calculator is being redesigned to better reflect the maturing market for renewable generation, changing project economics, and the effects on system operations and infrastructure.

The agencies are committed to continuing to collaborate and align their electricity infrastructure planning with a primary goal of ensuring that California's energy and environmental policy goals are met in a coordinated, transparent, and effective manner. As part of that effort, the Energy Commission expects to continue supporting the inclusion of environmental information in the interagency planning processes.[294] However, the Energy Commission also recognizes the need for continued interagency and stakeholder dialogue to promote transparency and establish an analytical link among the different infrastructure studies, leading to better informed policy development and investment decisions. These studies are essential to determine what infrastructure investments are needed to secure California's energy future, strengthen the economy, and protect the environment.

294 Joint Energy Commission and CPUC letter to Stephen Berberich, President and Chief Executive Officer of the California Independent System Operator, Base Case and Alternative Renewable Resource Portfolios for the CAISO 2014-2015 Transmission Planning Process, February 27, 2014.

Stakeholder Perspectives on Integrating Environmental Information in Planning Processes

At a public workshop for the *2014 IEPR Update*, government, utility, environmental, and developer stakeholders participated in a roundtable panel discussion moderated by Commissioner Karen Douglas that sought input on how best to integrate environmental information into renewable energy planning. The discussion was guided by questions provided in the agenda[295] and information presented during the earlier panel sessions.

The panel discussion built off the *2012 IEPR* recommendations that the state identify preferred geographic areas for both renewable utility-scale and distributed generation development. This strategy is a response to direction in Governor Brown's plan for the Energy Commission to prepare a plan to "expedite permitting of the highest priority [renewable] generation and transmission projects." The intent was to support investments in renewable energy that will create new jobs and business, increase energy independence, and protect public health.[296] The panel also built off a July 13, 2012, Roundtable Discussion on Infrastructure Planning, Cost, and Market Implications of the DRECP.[297]

295 August 5, 2014, Integrated Energy Policy Report workshop agenda is available at http://www.energy.ca.gov/2014_energypolicy/documents/2014-08-05_workshop/2014-08-05_agenda.pdf.

296 California Energy Commission, 2012. *2012 Integrated Energy Policy Report Update*. Publication Number: CEC-100-2012-001-CMF.

297 July 13, 2012 DRECP workshop, http://drecp.org/meetings/2012-07-13_workshop/2012-07-13_Workshop_summary.pdf.

Workshop panelists and public commenters broadly expressed interest in having better environmental information available to guide decisions and support for the use of this information for landscape planning for renewable energy development, especially as the state plans for higher penetration levels of renewable generation to meet greenhouse gas emission targets. Panelists identified several potential challenges to using this information effectively and appropriately in energy infrastructure planning. One challenge identified by multiple panelists is the need for a post-2020 goal to guide planning at the energy agencies. V. John White of the Center for Energy Efficiency and Renewable Technologies urged the agencies to start now to coordinate their processes, data, and planning assumptions but noted that it will be necessary to clarify what goal beyond 2020 we are seeking to meet.[298] Commissioner Carla Peterman expressed appreciation to the Energy Commission for its leadership role on this issue, noting that, as the assigned Commissioner for the RPS at the CPUC, she is "keenly interested in how we can scale our renewable energy beyond 33 percent in a sustainable way."[299]

Benefits of landscape planning include the opportunity to drive development to areas with less environmental conflict and avoiding impacts in the first place by identifying places in the landscape where it really makes sense for the development to go.[300] Another important benefit is that a broader suite of mitigation options becomes available when taking a landscape approach rather than just looking at a project-specific level.[301] For example, Matt Stucky with Abengoa Solar expressed interest in opportunities the DRECP raises for developers to work with the environmental community to find the best and most

August 5, 2014, IEPR Workshop Panelists

National Park Service
U.S. Bureau of Land Management
U.S. Department of Defense
California Department of Conservation
California Department of Food and Agriculture
California Energy Commission
California Public Utilities Commission
Imperial County
California Farm Bureau Association
Imperial Irrigation District
Pacific Gas and Electric
San Diego Gas & Electric
Southern California Edison
Defenders of Wildlife
Natural Resources Defense Council
The Nature Conservancy
Sierra Club
Abengoa Solar
EDF Renewable Energy
Iberdrola Renewables
NRG
Westlands Solar Park
California Wind Energy Association
Center for Energy Efficiency and Renewable Technologies
Large-scale Solar Association

298 August 5, 2014, Integrated Energy Policy Report workshop, pp. 208–210.

299 August 5, 2014, Integrated Energy Policy Report workshop, p. 16.

300 August 5, 2014, Integrated Energy Policy Report workshop, p. 77.

301 August 5, 2014, Integrated Energy Policy Report workshop, p. 190.

cost-effective use of limited mitigation funds.[302] Ray Kelly with NRG suggested that state and federal agencies get together to create mitigation programs that combine high-value properties that developers can help fund as part of required mitigation for their projects.[303]

The panelists agreed that valuable predictability and certainty can be gained through landscape planning and consideration of environmental information early in the process. Steve Chung, representing the Department of Defense, stated that there is a great deal of support from the military for landscape planning because it adds predictability, is proactive, and collectively helps planners minimize surprises.[304]

County representatives expressed a desire for improved coordination among and within agencies and better alignment of state and regional renewable energy development and environmental protection policies.[305] They also expressed interest in access to environmental information that can help guide the preparation of renewable energy development elements for county general plans.[306] County representatives emphasized that local jurisdictions are charged with implementing land use on private land and that any regional plans need to contain a certain amount of flexibility as well.[307] Bruce Wilcox, with Imperial Irrigation District, noted that Imperial County is developing an overlay plan, and that the DRECP makes sense if it is able to set up a permitting system, and maybe even a mitigation system, that counties and cities can use in some of their plans.[308]

Workshop panelists also expressed important cautions regarding the appropriate uses of landscape-scale information. For example, while new tools for compiling and analyzing environmental data have greatly expanded the possibilities for landscape level analysis, it is essential to have good underlying data to use these tools effectively. Furthermore, panelists cautioned against using landscape-level environmental information and tools for project-level analysis except to the extent that the plans are specifically designed and scaled to address permitting, as in the DRECP. Rachel Gold with the Large-Scale Solar Association observed that while environmental information provided through the DRECP is a great resource, "we have to somehow account for the fact that we do not have the same level of information outside the DRECP area."[309]

Karen Mills with the California Farm Bureau Federation pointed out the importance of recognizing that impacts will be different, and the way the impacts are viewed will be different, in different parts of the state.[310] Further, Ms. Mills argued, it is important to clarify definitions and to recognize, for example, that the term "disturbed land" means different things to different people. Similarly, Andy Horne with the County of Imperial noted that it would be a mistake to assume that solar projects or other energy projects can be developed on disturbed agricultural land with no environmental impact. In Imperial County, taking farmland out of production reduces inflows to the IID drain system, which ends up reducing inflows to the Salton Sea.[311]

302 August 5, 2014, Integrated Energy Policy Report workshop, p. 296.

303 August 5, 2014, Integrated Energy Policy Report workshop, pp. 297–298.

304 August 5, 2014, Integrated Energy Policy Report workshop, p. 283.

305 August 5, 2014, Integrated Energy Policy Report workshop, pp. 133-135, 139, 152, 157, and 161.

306 August 5, 2014, Integrated Energy Policy Report workshop, pp. 128-129, 143, 149, and 160-161.

307 August 5, 2014, Integrated Energy Policy Report workshop, pp. 155–156.

308 August 5, 2014, Integrated Energy Policy Report workshop, p. 203.

309 August 5, 2014, Integrated Energy Policy Report workshop, pp. 194–195.

310 August 5, 2014, Integrated Energy Policy Report workshop, p. 200.

311 August 5, 2014, Integrated Energy Policy Report workshop, pp. 228–229.

Procurement

The question of whether and how environmental information should factor into procurement generated a lot of discussion. Some panelists expressed the view that the types of incentives that can be provided to developers in plans such as the DRECP, including certainty and predictability of mitigation and reasonable environmental costs, will be sufficient to drive projects to these areas[312] Other panelists expressed the need for both transmission and generation incentives to promote development in low-conflict areas[313] In public comment, Michael Wheeler of Recurrent Energy stated that transmission is the most important factor and, along with streamlined permitting, will absolutely drive siting decisions to low conflict areas. However, he stated, the procurement process is the test to see if these incentives are working.[314]

Overall, there was little support for an approach where the CPUC would use project-level environmental information to score or screen projects in the procurement process. CPUC Commissioner Michael Picker (Governor Brown subsequently appointed Commissioner Picker to become CPUC President on December 23, 2014) stated that screening processes pre-litigate CEQA and do not meet the tests of CEQA and CEQA-functionally equivalent programs of having public review, comment, and an actual decision maker. This kind of overlay does not meet the test of good public policy and is an implicit criticism of CEQA and CEQA functionally equivalent programs as not having been effective.[315] In contrast, Commissioner Picker stated that the DRECP does have this level of analysis, and is a good model for how government agencies can pursue landscape-level planning. Commissioner Picker emphasized the need for agencies to work together between state and local government, among state agencies, and between the state and federal government to be able to provide the kind of very effective, efficient, and equitable analysis that meets the test of public policy and honors the intention of CEQA and the National Environmental Policy Act (NEPA).[316]

Panelists did express interest in better understanding the linkages among planning, procurement, and the interconnection process. The Large-scale Solar Association expressed serious concerns about any use of environmental scoring in the procurement process, they expressed openness to using environmental information to think through long-term goals.[317] The Nature Conservancy argued that there needed to be some kind of connection between planning and procurement, such that planning informs procurement, and procurement informs planning.[318] Jesse Gronner with Iberdrola Renewables suggested that there was value in putting more thought into where in the development process a power purchase agreement (PPA) is appropriate, and how that PPA can or should affect the interconnection or permitting process.[319]

Craig Murphy of Kern County provided two examples of how state actions cause challenges for local government permitting and land-use authority. First, he described a situation where the county might wish to reduce the size of a proposed project to address environmental and land-use compatibility concerns, only to be told that such action would be inconsistent with the PPA of the project and would kill the project. In his second example, the consequence of requiring a project applicant to change the project location was that it would lose its place in the interconnection queue at the

312 August 5, 2014, Integrated Energy Policy Report workshop, p. 192 and 194.

313 August 5, 2014, Integrated Energy Policy Report workshop, p. 249.

314 August 5, 2014, Integrated Energy Policy Report workshop, p. 315.

315 August 5, 2014, Integrated Energy Policy Report workshop, p. 18.

316 August 5, 2014, Integrated Energy Policy Report workshop, pp. 19–20.

317 August 5, 2014, Integrated Energy Policy Report workshop, p. 257 and 259.

318 August 5, 2014, Integrated Energy Policy Report workshop, p. 255.

319 August 5, 2014, Integrated Energy Policy Report workshop, p. 253.

California ISO. This lack of flexibility puts local officials in a very difficult position.[320]

Commissioner Peterman responded that there is some flexibility with amendments in contracts, and that sometimes a developer or a utility may be overstating the difficulty of getting an amendment.[321] Utility panelists also emphasized that amendments can be made to PPAs to address environmental issues that arise in permitting.[322] However, Mark Tholke with the Environmental Defense Fund noted that while some flexibility can be beneficial, the failure to hold developers to the milestones in their PPAs effectively penalizes those who have a more methodical approach to selecting sites.[323]

Workshop panelists expressed overall support for having environmental factors included in the viability process in utility procurement.[324] Katie Sloan with Southern California Edison argued that procurement is both too late in the process and also too early in the process to effectively use this information. It is too late because projects must already have a Phase II interconnection study to come into the solicitation process, so the developers have already put a lot of time and effort into them. It is too early because the projects have not gone through a full CEQA and NEPA review. Nevertheless, Ms. Sloan stated, SCE is starting to use some of the available environmental tools to inform procurement decisions, not as a screening tool or a way of prejudging the permitting process, but rather as a starting point for conversations with developers and a way to go into a procurement decision with eyes wide open.[325]

Jim Detmers with Westlands Solar Park emphasized the need to close the gap between planning and decision-making to ensure planners actually make use of the information they have. While planning is a great thing, especially with the new tools that are available for planning, Mr. Detmers stated that we already know that there are places in this state where it makes more sense to locate solar projects today, but it is not happening.[326]

Panelists welcomed the CPUC initiative to redesign and update the RPS Calculator during 2014 and 2015 to better reflect the maturing market for renewable generation, project economics, and the impacts on system operations and infrastructure. Panelists expressed strong interest in using this opportunity to look at the quality of the renewable energy product overall, including cost, environment, and the actual attributes of the electricity being generated.[327] The panelists broadly acknowledged the need to strike a balance between cost and environmental considerations.[328] Mr. V. John White stated that it is important to delve more carefully into the RPS calculator and consider all the values and attributes that are important with long-term GHG reductions in mind because this is where the planning process is going.[329]

Transmission

As discussed in the *2011 IEPR,* the project development process identifies routing issues and constraints but does not begin until after the "wires" planning process is complete. This lengthens the transmission development process, and the conclusion that some of the proposed projects may not be feasible due to significant environmental issues does not occur until late in the development

320 August 5, 2014, Integrated Energy Policy Report workshop, pp. 155–156.

321 August 5, 2014, Integrated Energy Policy Report workshop, p. 165.

322 August 5, 2014, Integrated Energy Policy Report workshop, p. 240.

323 August 5, 2014, Integrated Energy Policy Report workshop, p. 245.

324 August 5, 2014, Integrated Energy Policy Report workshop, pp. 263-264.

325 August 5, 2014, Integrated Energy Policy Report workshop, pp. 238–239.

326 August 5, 2014, Integrated Energy Policy Report workshop, p. 231.

327 August 5, 2014, Integrated Energy Policy Report workshop, pp. 276 and 295.

328 August 5, 2014, Integrated Energy Policy Report workshop, pp. 274 and 287.

329 August 5, 2014, Integrated Energy Policy Report workshop, pp. 293–294.

process. Consideration of environmental information early in transmission planning helps identify those corridors that have a higher likelihood of containing routes for specific transmission projects that can be permitted successfully.

As discussed in Chapter 9, the California ISO in its *2013-2014 Transmission Plan* identified several transmission projects that could alleviate the transfer limitations and reliability problems caused by the shutdown of the San Onofre Nuclear Generating Station (San Onofre). The Energy Commission funded a consultant report[330] that provides a high-level assessment of the environmental feasibility several electric transmission alternatives under consideration by the California ISO to address reliability and other system challenges resulting from the San Onofre closure.[331] Following a July 2014 California ISO Imperial County consultation stakeholder meeting, an addendum to the consultant report was prepared in September 2014 that evaluates two additional transmission alternatives proposed by IID and SCE.[332] A second addendum is being prepared that includes additional transmission alternatives suggested in the consultation workshop. One or more of the alternatives may be considered by Energy Commission staff in the state's electric transmission corridor designation process. While the alternatives examined may provide electrical solutions for addressing challenges arising from the closure of San Onofre, that report and the addendum present and examine the likely siting constraints that may have to be considered during the environmental permitting process for each potential alternative.

Panelists voiced strong agreement that landscape scale information can be extremely valuable in transmission planning. For example, Nancy Rader of the California Wind Energy Association stated that landscape-scale information is well suited to transmission planning and offers opportunities to weigh environmental and economic factors early in the process rather than being driven by projects that happen to have deliverability status.[333] Ms. Rader suggested that the agencies consider adopting a long-term transmission plan instead of continuing the existing process of screening projects on environmental grounds for transmission planning.[334]

This approach may also provide a basis for the energy regulatory agencies to encourage utilities to proposed transmission projects that are "right sized" to meet current and future needs. Also, the risk of stranding assets can be avoided when transmission is approved for projects that conform to Garamendi principles of being located near or in existing corridors.[335] This issue of "right-sizing"[336] was first identified in the *2011 IEPR* proceeding, where the Energy Commission considered ways to make better use of the existing grid by allowing projects to be upsized beyond what is needed to provide unused capacity for future use. Upsizing could maximize the value of land associated with already necessary transmission investment while avoiding future costlier upgrades to accommodate

330 *Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generation Station (SONGS) – Environmental Feasibility Analysis*, May 2014, http://www.energy.ca.gov/2014publications/CEC-700-2014-002/CEC-700-2014-002.pdf.

331 Since its May 2014 publication, the California ISO found that the closure significantly reduced the capability of the transmission system to deliver future renewable generation from the Imperial Irrigation District (IID) due to changes in electricity flow patterns.

332 *Addendum to Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generation Station (SONGS) – Environmental Feasibility Analysis*, September 2014, http://www.energy.ca.gov/2014publications/CEC-700-2014-002/CEC-700-2014-002-AD.pdf.

333 August 5, 2014, Integrated Energy Policy Report workshop, p. 193.

334 August 5, 2014, Integrated Energy Policy Report workshop, p. 301.

335 Comments from the August 5, 2014, Integrated Energy Policy Report workshop, p. 2.

336 In this context, *right-sizing* refers to building transmission facilities that have greater capacity than needed over the short-term planning period (10 years) to accommodate longer term electricity demand growth and/or connect new generation development for the future. For example, building transmission infrastructure (towers) that can accommodate a future 500 kV transmission line that is energized initially at 230 kV.

additional needed (for example, reliability, renewable, economic, public policy-driven) development.[337]

Panelists also discussed right-sizing transmission within the context of the DRECP planning area in the July 13, 2012 Energy Roundtable Discussion on Infrastructure Planning, Cost, and Market Implications of the DRECP. Jonathan Weisgall of Mid-American Energy Holdings Company suggested that the long-term perspective provided by the DRECP makes the case for upsizing new transmission lines with extra capacity where it looks like the line will be fully subscribed with renewable energy projects. Dennis Peters from the California ISO noted that some of this is already occurring with projects that are being built or in the permitting process. Carl Zichella, with the Natural Resources Defense Council (NRDC), stated that the DRECP is a great model for thinking about which areas can be developed, and using that information to understand the scale and capacity of transmission that will be needed.[338]

At the August 5, 2014, IEPR workshop, Kevin Richardson of Southern California Edison agreed that landscape-scale planning is good for transmission planning, but cautioned that planners need to look beyond the boundaries of the DRECP so that future generation can be delivered outside the DRECP area into other areas of California.[339] Mr. Richardson suggested that transmission planners from utilities could be in a better position to suggest upgrades that would have an easier time going through NEPA/CEQA and help the generators meet RPS goals if they had better environmental information up front.[340]

Landscape-scale information can be particularly valuable in addressing the lack of synchronization between land-use and transmission planning that was identified in the *2013 IEPR*.[341] For example, in written comments, the Joint Commenters (The Nature Conservancy, Natural Resources Defense Council, Defenders of Wildlife, and Sierra Club) stated, "Our organizations underscore the importance of a California energy future that uses landscape-scale planning to *first* identify preferred areas of least-impact for generation development, including areas near transmission with capacity or potential to upgrade existing transmission with least impacts."[342]

Conclusion

There are several areas of consensus that emerged from the public workshop discussion. The first area of consensus was a broad support for landscape-level planning for renewable and transmission infrastructure development. Panelists and commenters also agree that valuable lessons have been learned from both the RETI and DRECP efforts, especially with respect to bringing stakeholders together in collaborative long-term planning forums to address state policy goals and for identifying environmentally appropriate, cost-effective renewable resource locations.

The DRECP is currently in draft form and going through the public comment process. It stands as a model of a landscape-scale approach for energy infrastructure planning and development, using extensive habitat and species information and the landscape-scale mapping tools to integrate environmental information into statewide renewable generation and transmission planning activities and to facilitate public engagement and dialogue on the draft. Once finalized, the DRECP will greatly

337 California Energy Commission. 2011. *2011 Integrated Energy Policy Report.* Publication Number: CEC-100-2011-001-CMF, p. 38.

338 Meeting Summary entitled *Energy Commission Workshop entitled Energy Roundtable Discussion: Infrastructure Planning, Cost & Market Implications of the Desert Renewable Energy Conservation Plan*, July 13, 2012 pp. 7-8.

339 August 5, 2014, Integrated Energy Policy Report workshop, pp. 198–199.

340 August 5, 2014, Integrated Energy Policy Report workshop, pp. 289–290.

341 August 5, 2014, Integrated Energy Policy Report workshop, p. 196.

342 Comments from the August 5, 2014, Integrated Energy Policy Report workshop, p. 3.

increase certainty and predictability for developers within development focus areas.

There is also wide support for using landscape-level analytical tools such as the Conservation Biology Institute Data Basin platform to perform landscape scale analysis in other regions of the state beyond the DRECP area and also, potentially, within the western United States and/or potential international partners in the western interconnected grid, such as Baja California.[343] Further work is needed to identify these opportunities for bringing improved environmental information into energy infrastructure decisions.

The Energy Commission is committed to working with other agencies, permitting jurisdictions, and stakeholders to advance renewable generation and transmission planning. The goal for these actions is to compile and share relevant landscape-scale environmental information, promote transparency in resource planning, and encourage energy infrastructure development in a manner that ensures system reliability while safeguarding California's sensitive environmental resources.

Recommendations

» **Finalize and implement the Desert Renewable Energy Conservation Plan (DRECP).** The DRECP serves as a model for the conservation and protection of the environmental and cultural values of the Mojave and Colorado Deserts, while at the same time, identifying the best places for energy infrastructure development. DRECP will ultimately promote the timely permitting of renewable generation and transmission projects in the most appropriate areas in the region. The Energy Commission should, together with the other Renewable Energy Action Team (REAT) agencies, work to ensure that the DRECP is completed and the findings implemented in a timely fashion.

» **Collaborate and improve agency energy infrastructure planning**. The Energy Commission and the California Public Utilities Commission (CPUC) should use their experiences from recent planning efforts, including the DRECP, the CPUC Long Term Procurement Planning (LTPP) and the California Independent System Operator (California ISO) Transmission Planning Process (TPP) processes, to shape the current process and improve the overall consistency of future energy planning.

» **Advance the current capabilities of the state in performing landscape-scale analysis**. The Energy Commission should lead an effort with local, state, and federal partners and other stakeholders to assess the data and tools available for performing landscape-scale analysis, identify gaps, and move forward to advance these analytical capabilities. This effort should focus outside the DRECP area, including the western United States and potential international partners in the western interconnected grid. The effort should identify how environmental information should be used in energy resource decisions and support the CPUC LTPP and California ISO TPP processes.

» **Evaluate how to best apply landscape considerations in statewide transmission plans**. The Energy Commission should lead an effort to bring stakeholders together and further explore how DRECP and other landscape-level analysis can be incorporated into the 2015 Strategic Transmission Investment Plan.

343 Memorandum of Understanding for Cooperation in Clean Energies Between the Ministry of Energy of the United Mexican States and the State of California of the United States of America, July 29, 2014, available at http://gov.ca.gov/docs/7.29.14_energy_mou_eng.pdf.

CHAPTER 9:
Updates From the 2013 Integrated Energy Policy Report

This chapter provides updates on two topics discussed in the *2013 Integrated Energy Policy Report* (IEPR): electricity infrastructure in Southern California and the electricity demand forecast. The Energy Commission's *2014 IEPR Update Scoping Order*[344] envisioned also providing an update on the energy efficiency program for existing buildings, but that topic is being deferred to the *2015 IEPR*.

Update on Electricity Infrastructure in Southern California

Background

Efforts to ensure the reliability of Southern California's electricity system have been challenged in recent years as result of the closure of the San Onofre Nuclear Generating Station (San Onofre) and the impending retirement of several fossil-generating units using once-through cooling (OTC)[345] technologies. This issue has been discussed in the *2011 IEPR*, the *2012 IEPR Update*, and the *2013 IEPR*.

Aging Natural Gas Fleet in Southern California

Southern California relies upon a large number of old, natural gas-fired steam boiler facilities that have long outlived the original design life and purpose. Originally built as oil-fired units with extensive storage tank farms, these facilities were converted to natural gas in the 1980s once the federal Power Plant and Industrial Fuel Use Act of 1978 restrictions were lifted.[346] Most have been retrofitted to improve criteria pollutant emissions and to operate at much lower minimum generation levels than originally intended to allow for seasonal and peaking usage. Nonetheless, they have very long-start-up times, relatively low

344 http://www.energy.ca.gov/2014_energypolicy/2014-04-03_2014_IEPR_Update_Scoping_Order.pdf.

345 *Once-through cooling* technologies intake ocean water to cool the steam that is used to spin turbines for electricity generation. They allow the steam to be reused, and the ocean water that was used for cooling becomes warmer and is then discharged back into the ocean. Both the intake and discharge processes have negative impacts on marine and estuarine environments.

346 The federal Power Plant and Industrial Fuel Use Act of 1978 forbad the use of natural gas in utility steam boilers. See http://www.beg.utexas.edu/energyecon/thinkcorner/Natural_Gas.pdf.

efficiency, and high emissions factors.[347] Also, most use OTC technologies that state and federal policies seek to eliminate. Within the aging OTC fleet there is considerable variation in how flexible units are—decades after they were constructed. Units built for baseload operations are the least flexible and are likely to be retired before older units that are more flexible, since flexibility is now the most prized quality.

Planning for Phaseout of Once-Through-Cooling Technologies

In May 2010, the State Water Resources Control Board (SWRCB) adopted its OTC policy to phase out the use of this technology and established December 31, 2020, as the compliance date for most facilities still using once-through cooling.[348] The SWRCB assigned earlier compliance dates for facilities that had replacement infrastructure already in the delivery pipeline.[349] The policy also recognizes that some facilities using OTC technologies are critical for system and local reliability, and provides a specific advisory role to the energy agencies in recommending compliance date changes if necessary to avoid reliability issues.[350] In response to the SWRCB's adoption of the OTC policy, the California Public Utilities Commission (CPUC) began a decision-making process to identify what share of the capacity ought to be replaced with conventional generation versus various types of preferred resources.

San Onofre Closure Adds to Concerns About Maintaining Reliability in Southern California

The outage of the two San Onofre units in January 2012 and the decision to retire San Onofre in June 2013 greatly complicated the situation because California Independent System Operator (California ISO) studies had revealed the extent to which the entire Los Angeles Basin/San Diego region was vulnerable to low-voltage and posttransient voltage instability concerns.[351] The San Onofre outage also changed planning from how to replace fossil OTC units given the existence of San Onofre, to what must be done to replace San Onofre given the OTC compliance dates.

With the closure of San Onofre, the concerns about electricity reliability in Southern California became operational issues rather than planning exercises. Also, the focus of planning concerns shifted from localized thermal overload concerns into regionwide low-voltage and posttransient voltage instability issues. The immediate problem was resolved by numerous short-term transmission system fixes that replaced reactive power supplied from San Onofre with nongeneration electrical components (shunt capacitors, static var compensators, synchronous condensers, and so forth) that could be used to control voltage. (See sidebar for definitions.) Installation of these transmission elements reduced the need for new generating capacity that needed to be located close to load and thus increased the flexibility in locating replacement resources.[352]

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347 http://autl.assembly.ca.gov/sites/autl.assembly.ca.gov/files/hearings/6%2017%2013%20FINAL%20PRESENTATION%20%5BRead-Only%5D.pdf.

348 http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/policy.shtml

349 Although Los Angeles Department of Water and Power (LADWP) fossil OTC units were originally required to comply by December 31, 2020, LADWP requested delays for many units. A principal argument in LADWP's request was the likely rate burden on its customers of simultaneously replacing OTC units, backing out of coal power contracts and ownership shares, and developing a renewable fleet to satisfy the Renewables Portfolio Standard requirements. To lessen some of the effects of the delay, LADWP accelerated the retirement of other plants that were committed to move toward dry-cooled technologies going forward.

350 SWRCB OTC policy, Section 1.I.

351 Addendum-2013LCTA Report, http://www.caiso.com/Documents/Addendum-Final2013LocalCapacityTechnicalStudyReportAug20_2012.pdf.

352 Control of the electrical grid using reactive power maintains the necessary balance among the phases of alternating current systems. However, reactive power devices do not generate real power or energy; thus, actual resources (either preferred or conventional) needed to supply load must be developed to replace the generating capacity and energy provided by San Onofre and the fossil OTC facilities.

The Agencies Collaborate to Maintain Reliability With Preferred Resources, Conventional Generation, and Transmission Upgrades

Immediately following Southern California Edison's (SCE's) June 7, 2013, announcement to close San Onofre, Governor Brown requested that energy agencies, utilities, and air districts develop a plan for its replacement and the assurance of reliability in Southern California. A preliminary plan[353] was developed by the staff of the organizations and presented at a September 9, 2013, workshop as part of the *2013 IEPR* proceeding.

The preliminary plan was a multipronged effort to satisfy California ISO estimates of resource requirements needed to assure reliability, as measured by local capacity area requirements, using a rough replacement target of 50 percent preferred resources and 50 percent conventional generation. The preliminary plan was not finalized or adopted by any agency, but both the CPUC and California ISO examined the issue in their respective proceedings. In February 2013, before SCE permanently retired San Onofre, the CPUC issued a decision authorizing SCE to procure capacity to replace the fossil OTC units scheduled for retirement in 2015 and 2020. Since the long-term fate of San Onofre was unknown at the time, the California ISO studies and the CPUC decision relying upon them assumed San Onofre was operational in the tenth year forward. Of the total capacity authorized by the CPUC, separate amounts were authorized for conventional gas-fired capacity and for storage and preferred resources.[354] The California ISO conducted further studies of local capacity requirements without San Onofre and submitted the results to the CPUC. In March 2014, the CPUC issued a second decision to authorize incremental preferred resource and conventional generation development to address the retirement of San Onofre for both SCE and San Diego Gas and Electric (SDG&E). In that same month, the California ISO approved transmission system upgrades for the two utilities. The CPUC resource decisions direct the investor-owned utilities (IOUs) to develop both preferred and conventional resources, albeit in somewhat less than the amounts that California ISO studies indicated were needed.[355] The California ISO Board approved transmission system upgrades that greatly increase reactive power

Key Power Engineering Terms

Reactive power is a byproduct of alternating current (AC) systems when voltage and current are not in phase. It is produced when the current leads voltage and consumed when the current lags voltage. Reactive power (vars) is required to maintain the voltage to deliver active power (watts) through transmission lines. Several devices (rated in MVars) can be used to control reactive power in addition to traditional generating facilities.

Shunt capacitors—mechanically switched or fixed capacitor banks installed at substations or near loads that control voltage by charging and discharging capacitors

Static VAR compensators—combine capacitors and inductors with fast switching time frame capability

Synchronous condensors—synchronous machines are designed exclusively to provide continuously variable reactive power support

Source: Oak Ridge National Laboratory, http://web.ornl.gov/sci/decc/RP%20Definitions/Reactive%20Power%20Overview_jpeg.pdf

353 *Preliminary Reliability Plan for LA Basin and San Diego*, August 30, 2013. See http://www.energy.ca.gov/2013_energypolicy/documents/2013-09-09_workshop/2013-08-30_prelim_plan.pdf.

354 CPUC,D.13-02-015, Ordering Paragraphs 1 and 2.

355 CPUC, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements Due To Permanent Retirement Of The San Onofre Nuclear Generations Stations,* Decision14-03-004 issued March 14, 2014, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF.

supplied by transmission and enabled more electricity to flow to the constrained areas.[356]

Both SDG&E and SCE have submitted power purchase agreements (PPA) to the CPUC in response to direction from the CPUC. SDG&E submitted a PPA for a reconfigured Carlsbad facility that uses six LMS100 combustion turbines rather than the combined cycle facility that was permitted by the Energy Commission.[357] NRG has submitted a permit amendment for this new configuration to the Energy Commission for review. SDG&E intends to submit an additional PPA to the CPUC for preferred resource projects once it completes its all-source request for offers process and negotiates terms and conditions with winning projects. In late November 2014, SCE submitted a large package of PPAs to the CPUC for review and approval. In two applications, one each for the Los Angeles Basin and Moorpark (Ventura County), SCE submitted PPAs for both conventional generating facilities and preferred resources. For the Los Angeles Basin, SCE submitted two combined cycle gas-fired PPAs, one gas turbine project, and about 50 PPAs that encompass a wide range of preferred resources and storage facilities. For the Moorpark area, SCE submitted one PPA for a gas-fired peaker and several PPAs for preferred resources.[358] The Huntington Beach gas-fired combined cycle project reflects a different technology and slightly different location than that permitted in October 2014 by the Energy Commission, so AES will need to undergo a permit amendment for this reconfigured project. For the Alamitos PPA, the specific technology configuration submitted in the PPA for this combined cycle facility is not the same as that proposed in the ongoing Application for Certification, so AES will need to revise its proposal. The CPUC review of the SDG&E PPA with Carlsbad is well underway, while the many SCE PPAs are at the beginning of the CPUC's review.

Current Interagency Collaboration to Ensure Reliability in Southern California

The normal processes of the energy agencies are underway to develop a mixture of preferred resources, conventional generating capacity additions, and transmission system upgrades. The CPUC approved D.14-03-004,[359] directing SCE and SDG&E to target preferred resource development in the geographic areas where they are most useful for system reliability. Also, the CPUC is overseeing SCE's and SDG&E's development of PPAs aimed at constructing new generation in desired locations. The Energy Commission is processing permits for a variety of proposed generation projects, some of which may be built if the CPUC approves a PPA.[360] The California ISO is studying, and in some cases authorizing, transmission system upgrades that address the voltage instability concerns created by the retirement of San Onofre.

The California ISO performed a reliability assessment of Southern California (Los Angeles Basin and San Diego) in light of the retirement of San Onofre and the potential retirement of gas-fired generation as part of its *2013-2014 Transmission Plan*. The California ISO organized the potential transmission solutions into three groups: I) those optimizing existing transmission lines to address local area needs, II) major new transmission that reinforces the area and addresses reliability needs, and III) major new transmission that would increase import capability to the area and address future state policy objectives, such as promoting renewable energy

356 California ISO, 2013-14 Board-Approved Transmission Plan. See http://www.caiso.com/Documents/Board-Approved2013-2014TransmissionPlan.pdf.

357 A.14-07-009.

358 A.14-11.012 encompasses the Los Angeles Basin PPAs, while A.14-11-016 encompasses the Moorpark PPAs.

359 CPUC, *Decision Authorizing Long-Term Procurement for Local Capacity Requirements Due To Permanent Retirement Of The San Onofre Nuclear Generations Stations,* Decision14-03-004, issued March 14, 2014, http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF.

360 Energy Commission, http://www.energy.ca.gov/sitingcases/alphabetical.html.

development in certain areas of the state. To expedite the California ISO's review of potential transmission solutions, the Energy Commission funded a consultant report[361] that provided a preliminary, high-level assessment of the environmental feasibility for several electric transmission alternatives that the California ISO was considering in Groups II and III.

The California ISO identified three Group I transmission projects: an additional 450 MVAR of dynamic reactor support at San Luis Rey, an Imperial Valley flow controller-phase shifter, and the Mesa Loop-in Project. These mitigations provide material reductions in local capacity requirements without adding new transmission rights of way. These projects provide the best use of existing transmission lines and minimize the risk of permitting to meet projected on-line dates.[362] For the *2013-2014 Transmission Plan*, the California ISO recommended and approved the Group I projects as track 1 of a three-track strategy. The second track involves initiation of longer-term analysis (10- to 20-year) in the 2014-2015 or 2015-2016 transmission planning cycle to assess the need for potential Los Angeles Basin/San Diego connector projects (Group II) in light of evolving load forecasts and the potential for preferred resources and storage. The third track will address potential transmission lines that increase import capability into the Los Angeles Basin/San Diego areas and/or address future state policy objectives (Group III), recognizing that these may obviate the need to advance a future Group II project.

Figure 40 provides a map view of the location for the cumulative set of transmission system upgrades authorized by the California ISO that will be operational by 2020.

Contingency Planning if Development of Preferred Resources, Conventional Generation, and Transmission do not Advance as Planned

If all this resource development continues as planned (preferred resources, conventional generation, and transmission), reliability in Southern California would likely be assured. The ongoing planning processes would continue to look ahead and augment the major round of resource additions that are now approved. Resource margins, however, are tight in Southern California, and reliability rests upon close coordination between large amounts of fossil OTC retirement and the development of appropriate resources in locations needed to assure local capacity requirements are satisfied. Accordingly, the energy agencies and the California Air Resources Board (ARB) have been working cooperatively to develop a contingency plan. This plan is being developed as an interagency effort, but if it becomes necessary to trigger mitigation measures, the implementation would occur through the authority and processes of the individual agencies.

Three core activities are under development among the agencies.

» **Tracking all types of resource development**. This includes preferred resources (energy efficiency, demand response, fuel cells, renewable distributed generation, combined heat and power, and so forth),[363] conventional power plants, and transmission. For preferred resources the CPUC will separately track "business-as-usual"

361 *Transmission Options and Potential Corridor Designations in Southern California in Response to Closure of San Onofre Nuclear Generation Station (SONGS) – Environmental Feasibility Analysis*, http://www.energy.ca.gov/2014publications/CEC-700-2014-002/.

362 In addition to California ISO Board approval, these projects will require authorization from the CPUC via either the Permit to Construct or Certificate of Public Convenience and Necessity processes as outlined in the CPUC General Order 131-D, *Rules Relating to the Planning and Construction of Electric Generation, Transmission/Power/Distribution Line Facilities and Substations Located In California*, available at http://docs.cpuc.ca.gov/PUBLISHED/Graphics/589.PDF.

363 Fuel cells and combined heat and power facilities can be environmentally desirable resources under some but not all circumstances. These technologies are preferred in situations where fuel source and efficiency characteristics of the facility have a lower environmental impact than conventional power plants.

Figure 40: Authorized Transmission System Upgrades Intended to Assure Reliability in Southern California Operational by 2020

Source: California ISO

program efforts from incremental preferred resources authorized by D.14-03-004. For conventional power plants, the agencies track the selection and preparation of proposed PPAs, the CPUC's review and approval of such agreements, the Energy Commission's permitting of such facilities, and ultimately the construction of authorized projects. For transmission, the agencies track system upgrades, especially installation of reactive power control devices. Tracking includes understanding the current status of resource development and reviewing and refining expectations about the development schedule.

» **Development of contingency mitigation measures that can be triggered if resource expectations do not match requirements**. These include (1) a possible request to SWRCB to defer compliance dates for specific OTC facilities for which a specific new power plant would allow retirement, and (2) conventional power plant proposals taken as far through the permitting and procurement processes as practicable, but then held in reserve to receive final approval and begin construction only if triggered. In addition to developing the measures themselves, the agencies would need to modify normal approval processes to accelerate review and approval should the mitigation measures ever need to be triggered.

» **Creation of an analytic process for the early detection of any projected shortfall of resources needed to meet local capacity requirements**. A protocol would be developed to determine whether a projected shortfall justifies a recommendation to trigger mitigation measures. If the leadership from the energy agencies recommends triggering mitigation measures, then the applicable agencies overseeing a specific mitigation measure

approval would implement proposed actions according to approval processes established in advance.

The energy agencies, utilities, and air districts staffs continue to refine the contingency plan that seeks to assure reliability for the Southern California region. In particular, tracking preferred resource development—both conventional programs assumed to continue in California ISO power flow modeling studies to establish local capacity requirements and additional preferred resource development specifically ordered in D.14-03-004—and sharing such data among the energy agencies are a new undertaking. Energy Commission staff will continue to develop an annual accounting tool for tracking data and for compiling data on substation loads.[364] The tool will be used to develop projections of expected resources versus local capacity requirements. Mitigation measure development, still largely at the conceptual stage, needs to be fleshed out, agreed to, and made ready for implementation. In particular, the generation mitigation options will require close coordination among the energy agencies and air districts legally charged with issuing local permits.

Finally, close attention to local reliability issues with respect to local capacity area requirements must be expanded to address reliability of the broader South of Path 26 region.[365] Also, electricity planners must pay attention to the establishment of 2030 greenhouse gas emission reduction targets in support of achieving the state's long-term goal of reducing emissions 80 percent below 1990 levels by 2050.[366]

August 20, 2014, Workshop Comments

On August 20, 2014, the Energy Commission hosted a public workshop on the UCLA campus to review the progress since the September 2013 workshop (for the *2013 IEPR*) to implement the preliminary reliability plan and help assure electricity reliability in Southern California. The management of the Energy Commission, the ARB, the California ISO, the South Coast Air Quality Management District (AQMD), the SWRCB, and the CPUC actively participated in the workshop. Staff of the agencies, utilities, and air permitting districts provided updates on progress implementing the CPUC's D.14-03-004 and on transmission projects approved by the California ISO Board in the 2012-2013 and 2013-2014 *Transmission Plans*.[367] Energy Commission staff, ARB staff, the senior director of the SWRCB, and senior representatives of the South Coast AQMD and San Diego Air Pollution Control District (APCD) provided an overview of contingency plan efforts, OTC retirement extensions, and some key air permitting issues.

Stakeholders provided a range of feedback, including the following:

» The City of Carlsbad suggested that the energy agencies should not contemplate a scenario in which both Encina and Carlsbad operate simultaneously.[368]

364 SCE and SDG&E are now providing substation hourly loads to the Energy Commission for use in comparing actual load patterns with assumptions used to develop Energy Commission demand forecasts.

365 Path 26 is a Western Electricity Coordinating Council designation for power flows from Northern California to Southern California. The cut plane defining this path is essentially through the lower San Joaquin Valley. All of the loads of SCE and SDG&E transmission access charge areas are included as well as a small portion of PG&E loads at the extreme southern portion of their distribution service area.

366 http://gov.ca.gov/news.php?id=17463.

367 Energy Commission, http://www.energy.ca.gov/2014_energypolicy/documents/#08202014.

368 http://www.energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/comments/City_of_Carlsbad_Comments_2014-08-25_TN-73715.pdf

» Sempra Utilities pointed out that Southern California Gas Company is taking steps to further support reliable natural gas service for electric generation.[369]

» EarthJustice, a non-profit public interest law organization dedicated to environmental issues, suggested that developing a contingency plan is wasting time and resources that could be devoted to actually obtaining preferred resources in the region.[370]

» The San Diego and Los Angeles Chambers of Commerce and Orange County Business Council suggested that the energy agencies have not sought the input of the business community and the process may be dominated by advocacy groups committed to opposing conventional generating resources.[371]

» The Bay Area Municipal Transmission Group commented that the energy and environmental agencies and the California ISO should be commended for visibly cooperating in assuring reliability.[372]

» Bay Area Municipal Transmission Group also suggested that although distributed generation apparently is being counted upon as an assumption in planning studies and considered as a contingency mitigation option, it is not clear that distributed generation facilities are actually receiving resource adequacy credit when developers propose them. It suggested that this is a disincentive to actually achieve planning assumptions.[373]

» Wärtsilä, a Finnish corporation which manufactures and services power sources and other equipment in the energy market, commented that flexible generation, whether simple-cycle combustion turbines or internal combustion engines, can improve overall system efficiency by helping to address renewable intermittency and allow combined cycles to operate at higher capacity factors where they are more efficient and more reliable.[374]

Following the November 24, 2014, workshop on the draft *2014 IEPR Update*, four entities submitted comments on the scope and design of the contingency planning process.

» Sierra Club noted that the description of the resource mitigation options differed between the August 20, 2014, workshop presentation and the text of the draft *2014 IEPR Update.* In particular, Sierra Club noted that a preferred resource option no longer appeared as a mitigation option.[375]

Energy Commission response: The mitigation options are designed for a failure of a gas-fired resource addition, a substantial shortfall in the collective impacts of preferred resources, or inability to bring the transmission system upgrades on-line. Such options need to be designed and permitted/approved (where feasible), so that they are capable of providing effective capacity with a short lead time. Currently, it is not clear whether preferred resources

369 http://energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/comments/Sempra_Energy_Comments-Aug_20_2014-09-03_TN-73736.pdf.

370 http://energy.ca.gov/2014_energypolicy/documents/2014-08-05_workshop/2014-08-05_transcript.pdf, p. 191.

371 http://energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/comments/Southern_California_Business_Community_Comments_2014-08-21_TN-73699.pdf.

372 http://energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/comments/BAMx_Comments_Electricity_Infrastructure_Reliability_Planning_2014-09-03_TN-73737.pdf.

373 http://energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/comments/BAMx_Comments_Electricity_Infrastructure_Reliability_Planning_2014-09-03_TN-73737.pdf.

374 http://energy.ca.gov/2014_energypolicy/documents/2014-08-20_workshop/comments/WARTSILA_Comments_to_CEC_Workshop_on_Southern_California_Electricity_Reliability_2014-09-02_TN-73734.pdf.

375 http://www.energy.ca.gov/2014_energypolicy/documents/2014-11-24_workshop/comments/Sierra_Club_Comments_2014-12-08_TN-74118.pdf.

that build up slowly through voluntary participation by end users can readily satisfy this requirement.[376] Further, if gas-fired resource additions fail to develop, or are delayed, then generating resources with comparable flexibility and dispatch characteristics should be able to substitute.

» Sierra Club and the Independent Energy Producers Association (IEP) expressed concerns about developing and implementing a contingency plan outside the CPUC procurement process. IEP suggested that if a distinct contingency planning effort was needed it should be developed within the CPUC's Long Term Procurement Planning (LTPP) proceeding. Sierra Club suggested that this contingency planning effort needed to be better documented and its results made more transparent to stakeholders, thus enabling public comment.[377], [378]

Energy Commission response: The effort initiated with the San Onofre retirement revealed that there are a large number of agencies with a critical role in assuring the resource development needed to assure reliability. CPUC, California ISO, Energy Commission, and ARB are the four agencies collectively developing the contingency plan. Its implementation, however, relies directly upon cooperation from SWRCB and the air permitting agencies in Southern California – South Coast AQMD and San Diego APCD. Collaborative development of the contingency plan is important for assuring support from each agency. If contingency measures require specific action from any agency, the agency will do so through its public review process.

» Sierra Club proposed that rather than looking to develop additional gas-fired generation, even as mitigation measures, no additional gas-fired peakers should be approved because storage and demand response were sufficient to satisfy the requirements.[379] The Environmental Defense Fund made similar recommendations.[380]

Energy Commission response: The original preliminary reliability plan of September 2013 proposed a balanced portfolio of gas-fired generation and preferred resources. In its more indepth examination of the options in Track 4 of the 2012 LTPP rulemaking, the CPUC weighed testimony from many parties and ultimately authorized specific amounts of gas-fired generation to satisfy reliability needs in three load pockets—San Diego, Los Angeles Basin, and the Moorpark subarea of the Ventura/Big Creek load pocket. There is no assurance that storage facilities or an aggregation of end-users willing to engage in demand response can substitute for a peaker and meet the availability requirements of the California ISO for local capacity.[381] The Sierra Club and Environ-

376 As noted in the Energy Commission staff presentation at the August 20, 2014, workshop, a renewable distributed generation option was being developed, but was subsequently dropped. Rather than creating a contingency option, the CPUC by D14-11-042 added an increment of procurement authorization in the Renewable Auction Mechanism for distributed generation facility developers in the SCE and SDG&E service areas. The mechanics of identifying appropriate sites, acquiring end-user consent, and then deferring actual development of these projects for years at a time have not been demonstrated to be workable.

377 http://www.energy.ca.gov/2014_energypolicy/documents/2014-11-24_workshop/comments/Sierra_Club_Comments_2014-12-08_TN-74118.pdf.

378 http://www.energy.ca.gov/2014_energypolicy/documents/2014-11-24_workshop/comments/Independent_Energy_Producers_Association_Comment_Letter_2014-12-08_TN-74125.pdf.

379 http://www.energy.ca.gov/2014_energypolicy/documents/2014-11-24_workshop/comments/Sierra_Club_Comments_2014-12-08_TN-74118.pdf.

380 http://www.energy.ca.gov/2014_energypolicy/documents/2014-11-24_workshop/comments/EDF_IEPR_Update_Comments_2014-12-08_TN-74134.pdf.

381 The current resource adequacy program requires that resources satisfying local capacity requirements be provided year round at the level determined through California ISO studies of stressed summer peak conditions (1:10 weather peak load) with Category C outages (CPUC D.06-06-064 pages 41-42). The California ISO tariff and CPUC decisions limit the amount of demand response that can be counted to satisfy resource adequacy requirements (California ISO Tariff Section 40.8.1.9) if its performance is too limited. In December 2014, the CPUC adopted a new framework that will promote the evolution of DR programs over the next several years.

mental Defense Fund raise concerns about greenhouse gas consequences; however, California's Cap-and-Trade program ensures that greenhouse gas emissions will not increase in California. Further, installing sufficient peakers to assure reliability can allow preferred resources with high energy benefits (and greenhouse gas reduction qualities) to be pursued even more vigorously. To the extent preferred resources are successful at demonstrating load reduction capabilities covering a wide range of generation and transmission outage conditions, then peakers will run even less.

As evident from the August 20, 2014, workshop, the Energy Commission and the collaborating agencies in the Southern California Reliability Project are committed to assuring electrical reliability for the region. The coordinated planning discussed at the workshop promotes this assurance. Implementing actions that are part of this multiagency effort requires actions from each agency. All of the procedural opportunities to participate in the decision-making processes of the agencies continue to exist and will allow stakeholders to provide input if specific projects are proposed. The Energy Commission anticipates a similar update from the staff of the key agencies next summer in the *2015 IEPR* proceeding at a workshop in Southern California.

Electricity Demand Forecast Update

Background

The Energy Commission provides full forecasts for electricity and natural gas demand every two years (in odd-numbered years) as part of the IEPR process. The forecasts are used in various proceedings, including the CPUC's LTPP process and the California ISO's Transmission Planning Process (TPP). In addition, the Energy Commission provides annual year-ahead peak demand forecasts for the California ISO's Resource Adequacy (RA) proceedings. In its current form, the IEPR forecast consists of two parts: a baseline forecast, which includes energy efficiency savings from initiatives already in place or approved, and a forecast for savings from future energy efficiency initiatives, referred to as additional achievable energy efficiency (AAEE) savings. Combinations of the two parts yield a "managed" forecast for resource planning.

Energy Commission, CPUC, and California ISO Commit to Process Alignment

The Energy Commission, CPUC, and California ISO have committed to collaborative planning for the IEPR demand forecast, the LTPP, the TPP, and the CPUC energy efficiency proceedings. This commitment was formalized in a joint letter to Senators Alex Padilla and Jean Fuller on February 25, 2013,[382] as well as a follow-up letter on January 31, 2014,[383] reporting on progress. The commitment was in response to a hearing by the Senate Committee on Energy, Utilities, and Communications that raised questions about the consistency of energy efficiency impacts applied in the three proceedings. As recommended in the *2013 IEPR*, the three agencies will "…continue discussions… about the timing and alignment of the demand forecast, energy efficiency funding cycles, measurement and evaluation, and agency planning cycles."[384]

Energy Commission Commits to Refreshing the Demand Forecast in Off Years

During the *2013 IEPR* process, staffs from the Energy Commission, the CPUC, and the California ISO met frequently to develop a "process alignment" calendar. The effort was "…structured around a two phased, biennial

382 California Public Utilities Commission, California Independent System Operator, California Energy Commission, letter, addressed to Senators Padilla and Fuller, February 25, 2013.

383 California Public Utilities Commission, California Independent System Operator, California Energy Commission, letter, addressed to Senators Padilla and Fuller, January 31, 2014.

384 California Energy Commission. 2013. *2013 Integrated Energy Policy Report*. Publication Number: CEC-100-2013-001-LCF, p. 157.

Long-Term Procurement Planning (LTPP) proceeding, with the [Energy Commission] and [California ISO] providing critical annual inputs to the procurement proceeding out of their IEPR demand forecasting and Transmission Planning Processes, respectively." With respect to the demand forecast, the agencies agreed that the Energy Commission would "…update the demand forecast in even-numbered years using the most recent economic/demographic assumptions and an additional year of actual data. Even-year forecasts will not include demand-side program updates, such as additional achievable efficiency."[385] The Energy Commission also committed to "maintain timely decisions with regard to adoption of the demand forecast and IEPR."[386]

The Energy Commission's full demand forecast requires a great deal of time to develop. In addition, Energy Commission staff relies on IEPR off-years (even-numbered years) to update and improve input data and modeling methods. For these reasons, the Energy Commission agreed to a smaller-scale forecast update in even-numbered years to meet the CPUC and California ISO requests, rather than a full new demand forecast. More specifically, the update replaces the economic and demographic drivers used in the previous full IEPR forecast with the most current projections and adds one more year of historical electricity consumption and peak demand data, used to recalibrate the forecast. Other factors that affect the forecast, including results of energy efficiency programs, projected rates, and projected photovoltaic system adoptions, will not be updated. In addition, projections for AAEE will remain the same. The forecast horizon was extended one year, to 2025, to meet the needs of the TPP.

385 California Public Utilities Commission, California Independent System Operator, California Energy Commission, letter, addressed to Senators Padilla and Fuller, January 31, 2014.

386 Weisenmiller, Robert, B., California Energy Commission, letter, addressed to President Michael Peevey and Commissioners, California Public Utilities Commission, Support of Alignment with New LTPP Structure, December 17, 2013.

Updates to the Economic and Demographic Drivers Lead to Slightly Lower Statewide Forecast Than in 2013

The econometric models used to develop the *California Energy Demand Updated Forecast, 2015 – 2025* (*CEDU 2014)* require a variety of economic and demographic variables, including gross product by region, population, number of occupied homes, and industrial output. These drivers come from Moody's Analytics, IHS Global Insight, and the California Department of Finance (for population). As in the *California Energy Demand 2014 – 2024 Final Forecast*[387] (*CED 2013*), the forecast developed for the *2013 IEPR*, the "baseline" case from Moody's was used for the mid baseline forecast update, the demand forecast to be used (in conjunction with AAEE projections) for planning.

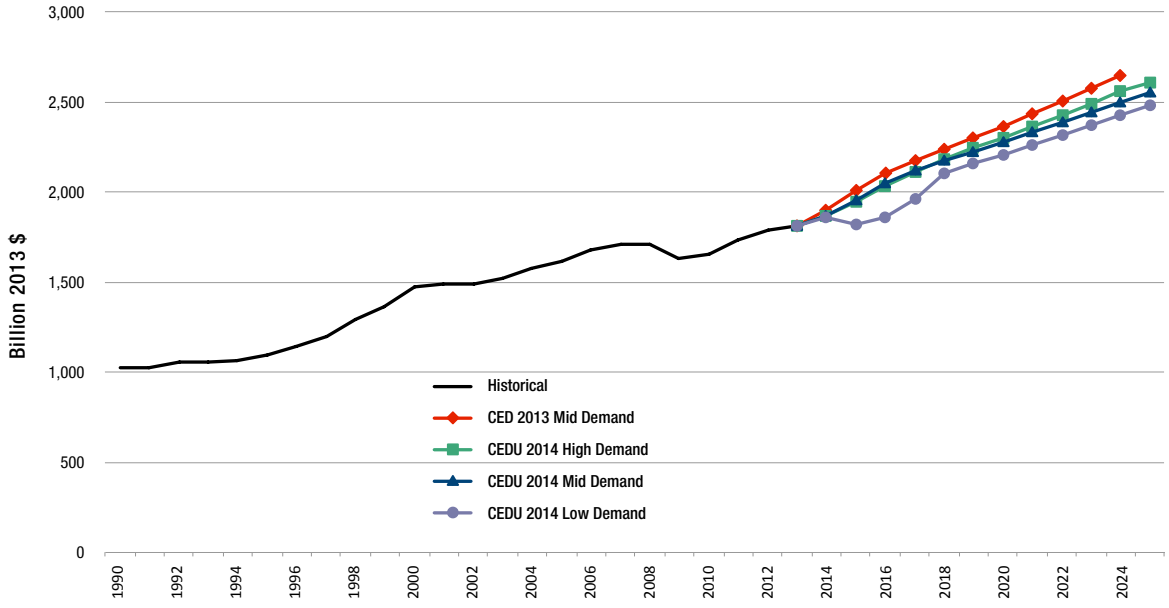
In general, the projections for economic growth in California from August 2014 are more pessimistic compared to those used in *CED 2013*, resulting in lower forecasts for electricity sales, consumption, and peak demand. Both Moody's and Global Insight project slower growth for key economic variables such as personal income and employment at the national level which translates, all else equal, to slower growth at the state level. According to Moody's, "structural damage" (less long-term investment, skilled labor, and so on) "…inflicted by the recession will be greater than initially anticipated."[388] Lower economic growth also yields slightly slower growth in population (and therefore number of households) for California in the high and mid scenarios.

Figure 41 shows historical and projected personal income at the statewide level for the three *CEDU 2014* scenari-

387 Kavalec, Chris, Nicholas Fugate, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Kate Sullivan, and Malachi Weng-Gutierrez. 2014. *California Energy Demand 2014-2024 Final Forecast, Volumes 1 and 2.* Publication Number: CEC-200-2013-004-V1-CMF. Available at http://www.energy.ca.gov/2013_energypolicy/documents/#adoptedforecast

388 Email communication with Chris Lafakis, California Analyst at Moody's Analytics, October 2014.

Figure 41: Comparison of Projected Statewide Personal Income



Source: Moody's Analytics and HIS Global Insight, 2013–2014

os and the *CED 2013* mid demand case.[389] By 2024, income is around 5.5 percent lower in the *CEDU 2014* mid case compared to *CED 2013*. Annual growth rates from 2013-2024 average 3.19 percent, 2.97 percent, and 2.68 percent in the *CEDU 2014* high, mid, and low scenarios, respectively, compared to 3.50 percent in the *CED 2013* mid case.

As shown in Figure 42, the projection for statewide commercial employment[390] in the *CEDU 2014* mid case is lower than in *CED 2013*, but the difference is less than for personal income. By 2024, commercial employment is around 0.8 percent lower in the new mid case compared to *CED 2013*. Annual growth rates from 2013-2024 average 1.34 percent, 1.14 percent, and 1.04 percent in the *CEDU 2014* high, mid, and low scenarios, respectively, compared to 1.21 percent in the *CED 2013* mid case.

389 To account for periodic revisions to the historical data by Moody's and Global Insight, the *CED 2013* scenarios in this section are scaled so that levels matches those used in *CEDU 2014* in 2013.

390 Total employment minus employment in the industrial and agricultural sectors.

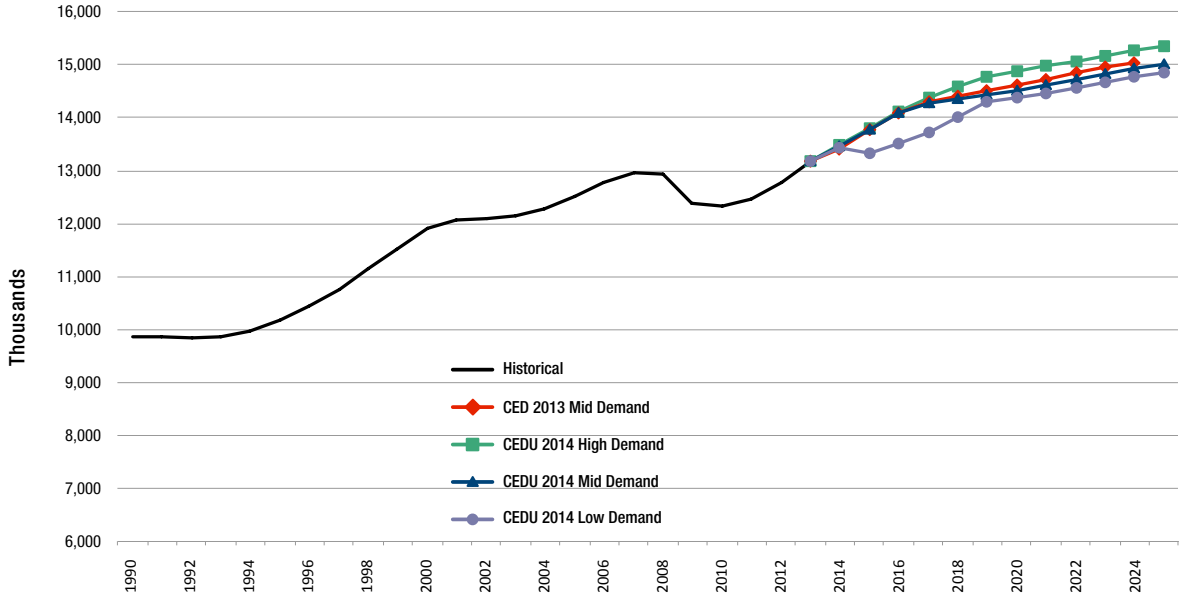
Method

The Energy Commission uses detailed models for each sector (residential, commercial, and so on) to project electricity consumption and demand for the full IEPR forecast. Staff also estimates simpler, single-equation econometric models for each sector and compares the forecast results with those from the more complex models. Typically, both types of models yield similar results at an aggregate level.[391] For *CEDU 2014*, staff relied upon the econometric models, re-estimated to incorporate historical data for 2013. The explanatory variables and estimation results for each econometric model are provided in the *CEDU 2014* report.[392]

391 See Appendix A in Kavalec, Chris, Nicholas Fugate, Bryan Alcorn, Mark Ciminelli, Asish Gautam, Kate Sullivan, and Malachi Weng-Gutierrez. 2014. *California Energy Demand 2014-2024 Final Forecast, Volume 1: Statewide Electricity Demand, End-User Natural Gas Demand, and Energy Efficiency.* California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2013-004-V1-CMF.

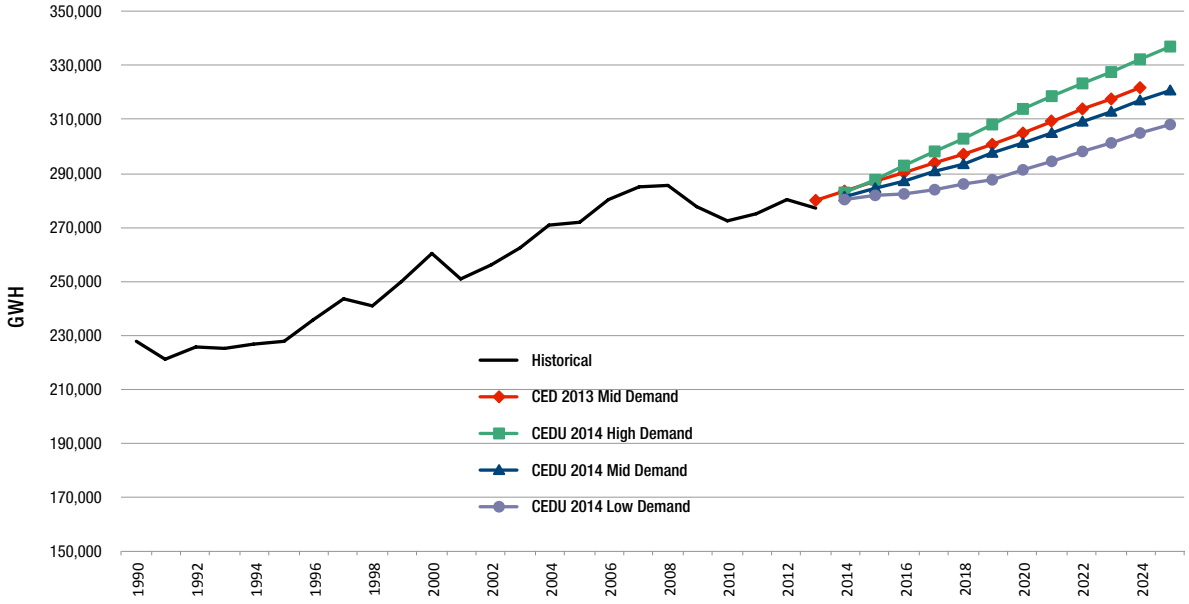
392 http://www.energy.ca.gov/2014publications/CEC-200-2014-009/CEC-200-2014-009-SF-REV.pdf.

Figure 42: Comparison of Projected Statewide Commercial Employment



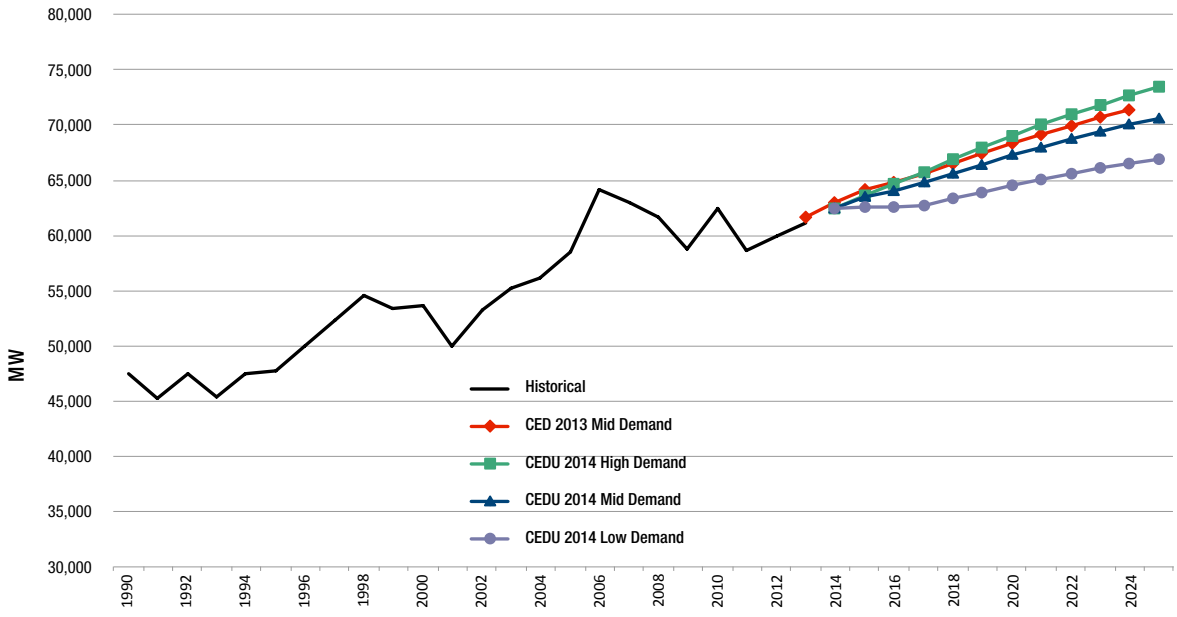
Source: Moody's Analytics and HIS Global Insight, 2013–2014

Figure 43: Statewide Baseline Annual Electricity Consumption



Source: California Energy Commission, Demand Analysis Office, 2014.

Figure 44: Statewide Baseline Annual Noncoincident Peak Demand



Source: California Energy Commission, Demand Analysis Office, 2014.

To ensure a proper comparison to the *2013 IEPR* forecast, results from the econometric models were benchmarked to the earlier forecast to isolate the effects from the revised set of economic and demographic drivers. In other words, percentage changes in electricity demand caused by the updated drivers using the econometric models were applied to the adopted *2013 IEPR* demand forecast.

Results

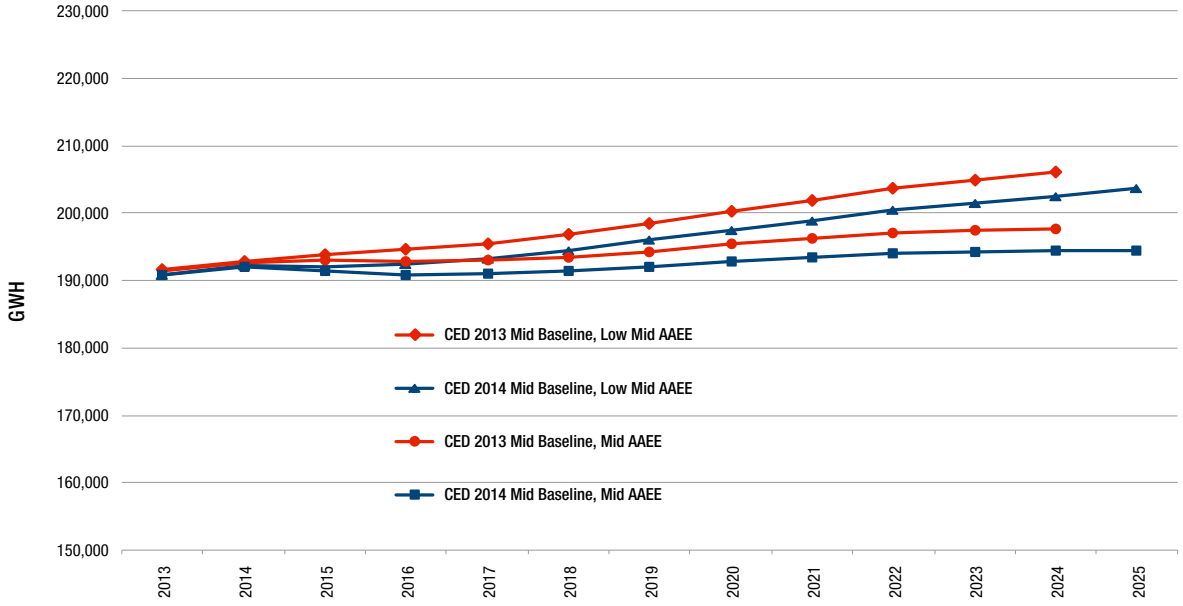
Figure 43 shows projected *CEDU 2014* electricity consumption for the three baseline scenarios and the *CED 2013* mid demand forecast. By 2024, consumption in the updated mid scenario is projected to be 1.5 percent lower than the *CED 2013* mid case. Annual growth rates from 2013-2024 for the *CEDU 2014* scenarios average 1.66 percent, 1.23 percent, and 0.87 percent in the high, mid, and low scenarios, respectively, compared to 1.27 percent in the *CED 2013* mid case.

Figure 44 shows projected *CEDU 2014* noncoincident peak demand for the three baseline scenarios and the *CED 2013* mid demand peak forecast. By 2024, statewide peak demand in the updated mid scenario is projected to be 1.8 percent lower than the *CED 2013* mid case. Annual growth rates from 2013-2024 for the *CEDU 2014* scenarios average 1.52 percent, 1.15 percent, and 0.63 percent in the high, mid, and low scenarios, respectively, compared to 1.26 percent in the *CED 2013* mid case.

Updated forecast results for individual planning areas are generally similar, reflecting more pessimistic economic growth projections at a regional level. The largest reductions relative to *CED 2013* occur in planning areas covering the Los Angeles region, as assumed economic growth is affected more adversely than in other part of the state.

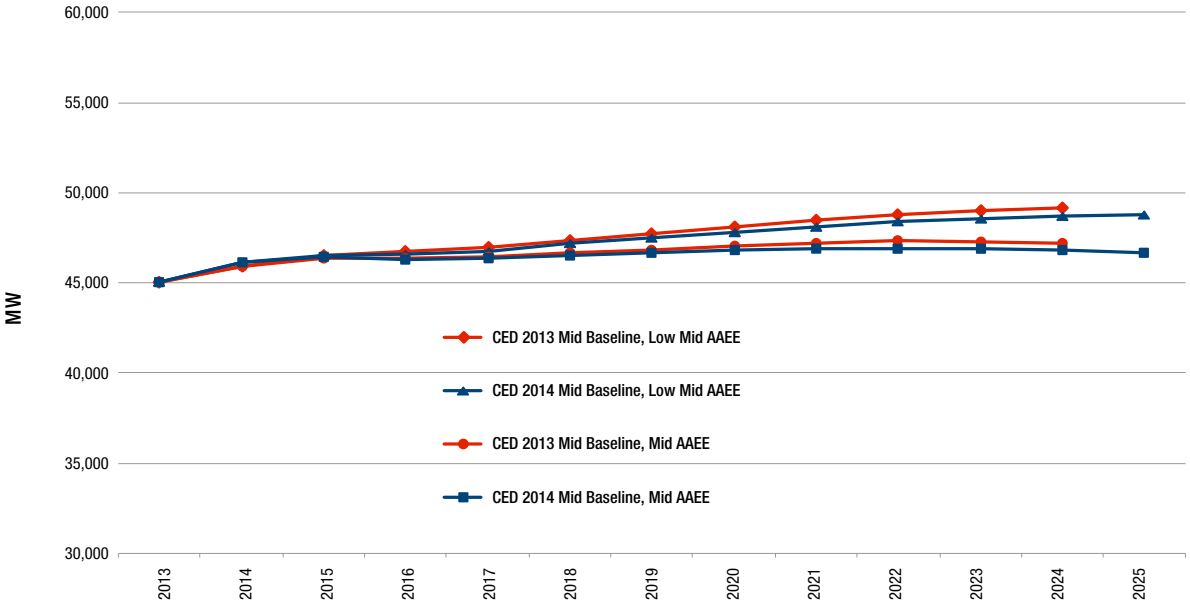
Updated managed forecasts for the IOU service territories, which incorporate AAEE savings, are also lower relative to *CED 2013*. Figure 45 and Figure 46 compare *CEDU 2014* managed forecasts with *CED 2013* for electricity sales and peak demand, respectively, for the combined IOUs. By 2024, managed sales in the updated forecast are around 1.6 percent lower than *CED 2013* assuming either the mid or low mid scenario for AAEE. For

Figure 45: Managed Forecasts for Sales, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2014.

Figure 46: Managed Forecasts for Peak Demand, Combined IOUs



Source: California Energy Commission, Demand Analysis Office, 2014.

managed peak demand, the reductions are around 0.9 percent for both mid and low-mid AAEE scenarios.

The IEPR Lead Commissioner conducted a workshop on December 8, 2014, to receive public comments on a preliminary version of this forecast, with comments incorporated into a final version described in this chapter. The Energy Commission adopted the *California Energy Demand Updated Forecast 2015–2025* at a business meeting on January 14, 2015.

December 8, 2014, Workshop Comments

This section summarizes comments submitted by stakeholders during the December 8, 2014, workshop as well as written comments submitted afterward, along with the Energy Commission response.

» PG&E and SDG&E recommended that load modifying demand response should be updated using the April 2014 utility filings (*CEDU 2014* uses estimated impacts from *CED 2013*).

Energy Commission Response: The Energy Commission's position is that the forecast update be restricted to changes in economic and demographic growth projections and updates to the historical load data. An update to demand response raises the question about updates to other factors affecting demand (e.g., electric vehicles). The Energy Commission wants to avoid "scope creep" in the forecast update.

» PG&E expects system-level energy sales in 2024 to be approximately 4 percent lower than the proposed Energy Commission forecast update. A higher forecast of distributed generation primarily drives the difference. For example, PG&E expects that by 2024, customer-owned rooftop solar will generate over twice as much energy than currently assumed in the Energy Commission demand forecast.

Energy Commission Response: For the forecast update, the Energy Commission did not develop new projections for rooftop solar. As PG&E acknowledges, this is an issue for the next demand forecast, for the *2015 IEPR*. Staff will consider PG&E's results when developing a new distributed generation forecast for the *2015 IEPR* forecast.

» PG&E expects bundled sales to drop 18 percent by 2024 due to a large transfer of customers from PG&E's bundled service to community choice aggregation (CCA). The Energy Commission forecast does not currently address expected CCA departures outside of Marin Clean Energy. PG&E feels it is critical to take a hard look at this issue in the *2015 IEPR* forecast. PG&E looks forward to working collaboratively to develop a probabilistic forecasting approach to CCA departure similar to the approach they took in the bundled procurement plan.

Energy Commission Response: The Energy Commission agrees that this is an emerging issue that requires increased attention in the *2015 IEPR* forecast.

» California ISO staff suggested that the 2014 weather-normalized coincident peak appears to be high given actual loads in 2014 and California ISO's own estimate.

Energy Commission Response: Staff estimates a coincident peak for the California ISO by adding individual transmission access charge area peaks and applying a coincident factor. In response to California ISO's comments, staff reexamined this coincidence factor and found that more recent historical data yield a lower factor (0.927) than had been used previously (0.976). Applying the updated coincidence factor gives a California ISO coincident peak in 2014 very close to California ISO's estimate.

» While NRDC appreciates the use of AAEE in the forecast, they recommend that the Energy Commission work quickly with the California ISO, the CPUC, and the utilities to improve the efficiency data used, such that the most accurate levels of efficiency can be relied upon in local planning processes—instead of just conservatively estimating a lesser amount of savings.

Energy Commission Response: Currently, geographic granularity for AAEE is constrained by the CPUC's efficiency potential studies, which provide results down to the climate zone level only. The Energy Commission has had numerous discussions with the California ISO and the CPUC about further geographic disaggregation of future efficiency impacts, but it is not yet clear how soon the potential studies will be able to provide further granularity.

» NRDC recommends that the Commission work with its sister agencies to improve energy efficiency temporal data, like estimated aggregate daily load shapes of projected savings and peak capacity savings forecasts that vary by month and season.

Energy Commission Response: In 2015, the Energy Commission will begin a major effort to update load shapes used in the IEPR forecasts. This effort will include development of daily load shapes specifically for AAEE savings.

» According to Sacramento Municipal Utilities District (SMUD), the Energy Commission's forecast for SMUD seems high, and they believe this is due to the absence of additional achievable energy efficiency that SMUD expects and incorporates in its forecasts.

Energy Commission Response: The Energy Commission agrees with this assessment. The Energy Commission publicly owned utility forecasts do not currently include AAEE. Staff is planning to develop AAEE impacts for the publicly owned utilities and incorporate these effects in the forecast for the *2015 IEPR*.

» The Environmental Defense Fund (EDF) believes that the scenario analysis is incomplete because it does not forecast transformational roles for distributed energy resources (particularly photovoltaics) and electric vehicles at scales of significance.

Energy Commission Response: The Energy Commission recognizes the potential growing significance of distributed energy resources and electric vehicles. However, the 2014 forecast update is meant only to account for changes in economic growth projections over the last year. Staff did not develop new forecasts for distributed generation, electric vehicles, energy efficiency, and so on, for the forecast update. Distributed energy and electric vehicles will be topics of focus in the *2015 IEPR* forecast, with new forecasts developed for each, using the latest available information, expectations, and trends.

» EDF strongly supports the ongoing efforts of the Demand Analysis Working Group to develop a demand forecast incorporating high penetration of residential time variant rates and that this scenario be amongst the managed forecasts developed for the IEPR. Of particular interest to EDF is the development of a demand forecast that anticipates broad adoption of time-variant rates and associated education, outreach, and enablement campaigns for customers (and their energy using cars, appliances, and homes).

Energy Commission Response: The Energy Commission is happy to hear of EDF's interest in time-of-use pricing, and hopes that EDF can provide comments and input as the Energy Commission, the CPUC, and the California ISO begin to develop analyses of the impacts of time-variant rates during the *2015 IEPR* cycle.

» Frank Brandt (private citizen) expressed concern that reported forecast numbers imply a precision that is unwarranted and the numbers should be rounded. For example, 123,456 MW should be reported as 123,000 MW.

Energy Commission Response: The Energy Commission has addressed this concern in the *CEDU 2014* report as follows: "Note that all numerical forecast results presented in this report and associated spreadsheets represent expected values derived from model output that have associated uncertainty. The results should therefore be considered in this context rather than precise to the last digit."

Recommendations

Electricity Infrastructure in Southern California

» **Continue the multiagency Southern California Reliability Project as a framework for interagency coordination to assure reliability**. The special coordination efforts initiated in summer 2013 should continue until such time as reliability expectations for Southern California match those of the rest of the state. The Energy Commission will host another workshop in Southern California in the summer of 2015 as part of the *2015 Integrated Energy Policy Report (IEPR)* to review progress in developing preferred resources, conventional generation and transmission resources, and a contingency plan.

» **Enhance monitoring and data sharing among the agencies**. Close monitoring of key factors influencing expected reliability is necessary to assure a common understanding among the agencies, provide a basis for communicating to the public, and lay a foundation for recommendations to trigger contingency plans.

» **Develop contingency plans and potential mitigation measures that are credible solutions to specific risks**. The adverse economic consequences of actual or perceived threats to electrical reliability on California's largest region justify expenditures to create mitigation options. This is similar to investing in an insurance policy for traditional risks faced by individuals and businesses.

Electricity Demand Forecast Update

» **Continue efforts to align planning processes**. Energy Commission staff should continue to work closely with staffs from the California Public Utilities Commission (CPUC) and California Independent System Operator (California ISO) to ensure that the IEPR, long term procurement plan, and transmission planning process remain aligned properly and that the IEPR demand forecasts are meeting the needs of the CPUC and California ISO.

Acronyms

AAEE	—	additional achievable energy efficiency
AB	—	Assembly Bill
APCD	—	Air Pollution Control District
AQMD	—	Air Quality Management District
ARB	—	California Air Resources Board
ARFVTP	—	Alternative and Renewable Fuel and Vehicle Technology Program
ARRA	—	American Recovery and Reinvestment Act
BEV	—	battery-electric vehicle
BLM	—	Bureau of Land Management
BPD	—	barrels per day
CAEATFA	—	California Alternative Energy and Advanced Transportation Financing Authority
California ISO	—	California Independent System Operator
Cal OES	—	California Governor's Office of Emergency Services
CBR	—	crude-by-rail
CCCCO	—	California Community Colleges Chancellor's Office
CEQA	—	California Environmental Quality Act
CNG	—	compressed natural gas
CO_2e		carbon dioxide equivalent
CPC 1232	—	Casualty Prevention Circular 1232
CPCFA	—	California Pollution Control Financing Authority
CPUC	—	California Public Utilities Commission
CREZ	—	Competitive Renewable Energy Zone
CVRP	—	Clean Vehicle Rebate Project
DAWG	—	Demand Analysis Working Group
DCFC	—	direct current fast charging
DFA	—	Development Focus Area
DGE	—	diesel gallon equivalent
DOE	—	U.S. Department of Energy
DOGGR	—	Division of Oil, Gas, and Geothermal Resources
DOT	—	Department of Transportation
DRECP	—	*Desert Renewable Energy Conservation Plan*
E85	—	blend of 85 percent ethanol and 15 percent gasoline
EDD	—	Employment Development Department

EDTF	—	Environmental Data Task Force
EER	—	energy efficiency ratio
EIR	—	environmental impact report
EIS	—	environmental impact statement
EPIC	—	Electric Program Investment Charge
EPRI	—	Electric Power Research Institute
ERDD	—	Energy Research and Development Division
EV	—	electric vehicle
EVCS	—	electric vehicle charging station
EVI	—	Electric Vehicle International
EVSE	—	electric vehicle supply equipment
FCEV	—	fuel cell electric vehicle
GHG	—	greenhouse gas
GIS	—	geographic information system
GO-Biz	—	Governor's Office of Business and Economic Development
HEV	—	hybrid electric vehicle
HHFT	—	high hazard flammable train
IEPR	—	*Integrated Energy Policy Report*
ICE	—	internal combustion engine
IOU	—	investor-owned utility
LADWP	—	Los Angeles Department of Water and Power
LBNL	—	Lawrence Berkeley National Laboratory
LCFS	—	Low Carbon Fuel Standard
LLC	—	limited liability corporation
LNG	—	liquefied natural gas
LTPP	—	Long Term Procurement Plan
MM Bbls	—	million barrels
MOU	—	Memorandum of Understanding
MUD	—	multi-unit dwelling
MW	—	megawatt(s)
NEDO	—	New Energy and Industrial Technology Development Organization of Japan
NEPA	—	National Environmental Policy Act
NGO	—	nongovernmental organization
NO_x	—	oxides of nitrogen
NREL	—	National Renewable Energy Laboratory
OPEC	—	Organization of the Petroleum Exporting Countries
OSPR	—	Office of Spill Prevention and Response
OTC	—	once-through cooling
PACE	—	Property Assessed Clean Energy
PCC	—	Pacific Coast Collaborative

PEV	—	plug-in electric vehicle
PG&E	—	Pacific Gas and Electric Company
PHEV	—	plug-in hybrid electric vehicle
PIIRA	—	Petroleum Industry Information Reporting Act
PM	—	particulate matter
POU	—	publicly owned utility
PPA	—	power purchase agreement
ppb	—	parts per billion
R&D	—	research and development
RA	—	Resource Adequacy
REAT	—	Renewable Energy Action Team
RECLAIM	—	Regional Clean Air Incentives Market
RECPG	—	Renewable Energy and Conservation Planning Grants
RETI	—	Renewable Energy Transmission Initiative
RFS2	—	Renewable Fuel Standard Program
RPS	—	Renewables Portfolio Standard
San Onofre	—	San Onofre Nuclear Generating Station
SB	—	Senate Bill
SCAG	—	South Coast Association of Governments
SCAQMD	—	South Coast Air Quality Management District
SCE	—	Southern California Edison Company
SDG&E	—	San Diego Gas & Electric
SoCalGas	—	Southern California Gas Company
SWRCB	—	State Water Resources Control Board
TETAP	—	Transportation Energy Technology Advancement Program
TPP	—	Transmission Planning Process
UPS	—	United Parcel Service
U.S. EPA	—	United States Environmental Protection Agency
VGI	—	Vehicle-to-Grid integration
WECC	—	Western Electricity Coordinating Council
ZEV	—	zero-emission vehicle

APPENDIX A:
Climate References

Below are the references for the text boxes on climate change in Chapter 1.

Vulnerability of the Transportation System to Climate Change

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4. Ibid.

5. Ibid.

6. California Department of Transportation. (2013). *Caltrans Activities to Address Climate Change: Reducing Greenhouse Gas Emissions and Adapting to Impacts* (pp. 102).

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1. Biging, G. S., Radke, J. D., & Lee, J. H. (2012). *Impacts of Predicted Sea Level Rise and Extreme Storm Events on the Transportation Infrastructure in the San Francisco Bay Region*: California Energy Commission.

2. Ibid.

3. Lempert, R., Sriver, R. L., & Keller, K. (2012). *Characterizing Uncertain Sea Level Rise Projections to Support Investment Decisions*.

4. Radke, J., Biging, G., Foster, H., Roe, E., Schmidt-Poolman, M., Ju, Y., . . . Neuhausler, R. (2014). *Potential Impacts of Sea-Level Rise on Transportation and Fuel Infrastructure.* Paper presented at the IEPR Workshop on Climate Change and Transportation, Sacramento, CA.

APPENDIX B:
PEV Readiness Planning Regions and Elements of Readiness Plans

Highlights from the readiness plans are below. The full plans can be viewed online.[393]

Table 14: PEV Readiness Planning Regions and Elements of Readiness Plans

PEV READINESS PLANNING REGION	ELEMENTS OF READINESS PLAN
South Coast Association of Governments Region	PEV travel patterns and charging needs. Challenges associated with charging at homes, workplaces, and retail centers. Impacts of zoning, building codes, permitting, and parking regulations on the cost of charger installations. PEV atlas to project growth and daytime travel to employment and destinations.
Bay Area Region	Estimated amount and type of infrastructure needed over time. Public funds and incentives needed to grow the market. Consumer information and education. Opportunities to attract and retain related manufacturing and services. Integrating analysis with *Plan Bay Area* 2013 study.
Capital Area Region	PEV market forecasts. Integrating analysis with previously conducted Sacramento Area Council of Governments' studies for public charging infrastructure. Regional travel behavior. Land-use analysis. PEV readiness of regional jurisdictions.
San Diego Association of Governments Region	Barriers to PEV acceptance. Planning for new technology PEVs. Determining timing of charger deployment. Looking at lessons learned from previous studies and projects. Specific requirements for installing charging at multi-unit dwellings.

393 http://www.energy.ca.gov/2013-ALT-01/documents/Regional_Readiness_Grants.pdf.

PEV READINESS PLANNING REGION	ELEMENTS OF READINESS PLAN
Central Coast Region	Planning for PEV infrastructure deployment. Comprehensive network charging development. Streamlining the permitting, installation, and inspection process for charging infrastructure. Installation challenges and solutions for multi-unit dwellings. PEV marketing and outreach activities. Training and education for building inspectors, public works personnel, public safety officers, and first responders.
Monterey Bay Region	Charging network development including EV-ready buildings and parking lots, guidelines for workplace charging, and EV-friendly policies and practices. Purchase incentives to lower EV initial cost. PEV marketing and outreach. Best practices education for building inspectors and local government staff. EV charging permitting and inspection guide.
North Coast Region	Infrastructure deployment plan. Acquiring data on consumer charging behavior. Standardize method for estimating greenhouse gas reduction. Plan to mitigate on-peak PEV charging. Plan for streamlining charger permitting, installation, and inspection. PEV adoption in fleets. Incentives to promote PEVs. PEV education and outreach activities.
San Joaquin Region	Guide to PEVs and charging infrastructure. Specific conditions with single- and multifamily homes, retail and public locations, and workplaces. Homeowners guide on permitting, installation, and inspection of charging infrastructure. Zoning code provisions. Local utilities' programs. Best practices for local government action plans. Charging station guidelines for fleet, residential, and nonresidential installations. Considerations for public agencies that provide charging. Case studies.
Coachella Valley Region	Short-, medium-, and long-term actions. Plans, policies, and parking regulations. Building codes. Permitting and inspection. Economic development strategies. Integrating PEVs into regional plans. Training and education for public agencies. Barriers to PEV adoption. Consumer education and outreach.
Upstate (Shasta) Region	Infrastructure deployment plan at macro- and micrositing level. Consumer charging behavior data collection plan. Assessing and mitigating peak demand impacts. Streamlining charger permitting, installation, and inspection. PEV adoption in fleets. Municipal activities and incentives to promote PEVs PEV education and outreach plan. Plan for sharing project results.

Source: Energy Commission

APPENDIX C:
Full List of ARFVTP Projects Analyzed by NREL for 2014 IEPR Update

Table 15: Full List of ARFVTP Projects Analyzed by NREL

Project Categories	Fuel Class or Sub Class	Awards to 3/14 ($M)	Awards to 3/14 No. Awards	Projects Evaluated in Benefits Analysis ($M)	Projects Evaluated in Benefits Analysis No. Awards	Projects Evaluated in Benefits Analysis Number Units
Fuel Delivery Infrastructure						
Electric Drive Charging Infrastructure	Electric Drive	$40.3	68	$40.3	68	40 Level 1 9478 Level 2 116 DCFC
Hydrogen Fueling Infrastructure	Hydrogen	$83.5	17	$82.5	16	48 Stations
Natural Gas Fueling Infrastructure	Natural Gas	$17.3	48	$17.2	47	55 Stations
E85 Fueling Stations	Gasoline Substitute	$16.5	4	$16.5	4	100 Stations
Upstream Infrastructure	Diesel Substitute	$4.0	4	$4.0	4	5 Facilities or Expansions
Hydrogen Fuel Standards Development	Hydrogen	$4.0	1	-	-	-
Fuel Delivery Infrastructure Subtotal		**$165.8**	**142**	**$160.5**	**139**	
Vehicles						
Light-Duty Incentives, CVRP	Electric Drive	$44.1	3	$44.1	3	21,462 Rebates
Medium- Heavy-Duty Incentives, HVIP	Electric Drive	$4.0	1	$4.0	1	160 vehicles
Natural Gas Vehicle Deployment Incentives	Natural Gas	$33.4	4	$33.4	4	1038 vehicles
LPG Vehicle Deployment Incentives	Propane	$7.3	2	$2.3	2	515 vehicles

Project Categories	Fuel Class or Sub Class	Awards to 3/14 ($M)	Awards to 3/14 No. Awards	Projects Evaluated in Benefits Analysis ($M)	Projects Evaluated in Benefits Analysis No. Awards	Projects Evaluated in Benefits Analysis Number Units
Light-Duty Demonstration	Electric Drive	$0.6	1	$0.6	1	50 LDVs
Medium- and Heavy-Duty Vehicle Demonstration	Electric Drive	$33.9	10	$33.9	10	Various1
Fuel Cell Bus Demonstration	Hydrogen	$2.4	1	$2.4	1	1 bus
Medium- and Heavy-Duty Vehicle Demonstration	Natural Gas	$6.3	2	$6.3	2	2 natural gas engine demos
Medium- and Heavy-Duty Vehicle Demonstration	Gasoline Substitute	$2.7	1	$2.7	1	1 hybrid E85 powertrain
Component Demonstration	Hydrogen	$1.6	2	$1.6	2	6 vans, 1 bus
Component Demonstration	Electric Drive	$19.7	13	$19.7	13	Various2
Vehicle Manufacturing	Electric Drive	$25.4	6	$25.4	6	Various3
Vehicles Subtotal		**$192.1**	**46**	**$176.4**	**46**	
Fuel Production						
Diesel Substitute	Biodiesel	$30.89	10	$30.89	10	-
Diesel Substitute	FT Diesel	$5.00	1	$5.00	1	-
Diesel Substitute	Renewable Diesel	$12.38	5	$12.38	5	-
Natural Gas Substitute	Biomethane	$50.97	15	$50.97	15	-
Gasoline Substitute	Ethanol	$21.39	7	$21.39	7	-
Fuel Production Subtotal		$120.6	38	$120.60	38	
Other						
PEV Regional Readiness	Electric Drive	$3.7	16	-	-	-
Regional Readiness	Hydrogen	$0.3	1	-	-	-
Sustainability Research	Biofuels	$2.1	2			
Workforce Training and Development	Workforce Training/ Dev.	$23.3	30	-	-	-
Technical Assistance and Analysis	Program Support	$17.3	15	-	-	-
Other Subtotal		$46.7	64	-	-	
TOTAL		**$514.50**	**290**	**$457.50**	**223**	

Notes: (1) 4 HD hybrid hydraulic delivery trucks, 1 range-extender MD truck demo, 5 HD truck retrofits to PHEV, 1 class 8 hybrid natural gas truck, 1 all electric fleet at Air Force Base, 1 diverse fleet of 378 vehicles, 1 prototype class 4 all-electric, feasibility and testing for 1 truck manufacturing facility, 1 CLEAN Truck Demo Program, 8 HD truck retrofits to pantograph system; (2) 3 lithium battery production/assembly processes, 1 electric motorcycle powertrain, 2 battery management/communication systems, 3 electric drive manufacturing and assembly processes, and 4 electric drive demonstration projects including 14 MD trucks, 17 class 6 trucks, 6 schools buses, and 7 walk-in vans; (3) 1 new production line for electric motorcycle, 1 BEV manufacturing and assembly expansion, 1 new manufacturing facility for M/HD BEVs, 1 manufacturing expansion for range-extended MD trucks, 1 pilot production line for flexible all-electric platform, and 1 pilot production line for powertrain control systems.

APPENDIX D:
Additional Information on NREL's Assessment of Expected and Market Transformation Benefits

Expected Benefits Methods

The National Renewable Energy Laboratory (NREL) research team constructed a model to estimate expected benefits in the form of reductions in petroleum use, greenhouse gas (GHG) emissions, and select air pollutants for projects supporting electric drive vehicles.[394] NREL tallied the estimated use levels for all of the commercial-scale projects that have been funded, and assumed that each project will be built and operated according to grant agreement specifications. These projects include all commercial-scale biorefineries; hydrogen, compressed natural gas (CNG), and E85 fueling stations; electric chargers; and commercial vehicle support vouchers for heavy-duty CNG or propane trucks and buses and light-duty CNG and electric vehicles. NREL then calculated the petroleum fuel and internal-combustion-engine vehicles and vehicle-miles that would be displaced through Alternative and Renewable Fuel and Vehicle Technology Program-funded (ARFVTP) alternative fuels, vehicles, and fueling stations.

394 Please refer to the *2014 Benefits Guidance Report* for full descriptions of the methods, models, and data used, http://www.energy.ca.gov/2014publications/CEC-600-2014-005/CEC-600-2014-005-D.pdf, updated with NREL's final analysis in December 2014.

Expected Benefits Results by Project Class and in Five-Year Increments from 2015 to 2025

In addition to the results shown in Chapter 4, Table 17 provides additional detail on expected benefits. Table 9 shows the progression of GHG and petroleum fuel reductions over time in five-year increments. Most categories reach peak production or throughput in 2020 and then operate at maximum design capacity through the end of the study period in 2025. The natural gas truck figures indicate a different life cycle typical for commercial trucks; the newest trucks are deployed in high-mileage duty cycles, and then the duty rotations and total mileage decrease over time.

For the fueling infrastructure and fuel production categories, first-generation alternative fuels such as natural gas and biodiesel provide the greatest portion of GHG and petroleum fuel reduction benefits due to the more developed commercialization, greater market share, and more competitive pricing of these fuels. Zero-emission fuels such as electricity and hydrogen provide lower benefit levels because they are earlier in commercialization and have relatively lower levels of market penetration.

Table 16: Summary of GHG Emission and Petroleum Fuel Reductions From Expected Benefits Through 2025

Benefit Category	Project Class	GHG Reductions (thousand tonnes CO_2e)			Petroleum Reductions (million GGE/DGE*)		
		2015	2020	2025	2015	2020	2025
Refueling Infrastructure	Biodiesel	5.0	70.5	70.5	0.5	8.5	8.5
	Natural and Renewable Gas	50.7	374	378.5	12.1	55.4	57.5
	Electric Chargers	25.9	56.9	61.7	3.3	6.7	7.8
	E85 Ethanol	1.6	10.1	10.1	3.9	24.1	24.8
	Hydrogen	1.2	19.8	19.8	0.2	3.1	3.1
Vehicle	Light Duty BEVs and PHEVs**	0.1	3.0	2.0	0.0	0.4	0.3
	Electric Commercial Trucks	0.0	3.0	1.4	0.0	0.4	0.2
	Gas Commercial Trucks	82.1	33.3	4.8	20.5	10.4	1.2
	Manufacturing	2.9	546.1	1104.9	0.4	49.3	139.5
Fuel Production	Biomethane	2.4	51.7	97.4	0.2	3.2	8.1
	Diesel Substitute	37.5	466.4	606.1	3.4	33	57.3
	Gasoline Substitute	0.0	1.6	1.6	0.0	0.2	0.2
Total		**209.3**	**1636.40**	**2358.8**	**44.4**	**188.8**	**308.4**

Source: NREL

*GGE/DGE= gasoline gallon equivalents/diesel gallon equivalents, **BEV= battery electric vehicle, PHEV=plug-in hybrid electric vehicle

Market Transformation

Markets are self-sustaining assemblages of willing producers, sellers, and buyers. Transforming California's fuels and vehicle markets requires the introduction of low-carbon fuels products, fueling infrastructure to dispense the new fuels, and vehicles that can use the new fuels. The manner in which these markets transform can be measured by quantifying the number of alternative fuel and vehicle products, the number of producers, the number or volume of fuels, fueling station and vehicles that are sold, and the rate of change in product sales and consumer response.

Another aspect of market transformation is the economic viability and durability of the new markets for low-carbon alternative fuels and vehicles. At what point can products be produced and sold without government incentives or subsidies? Tracking the reductions in production costs and sales prices is another metric of market transformation.

Market transformation benefits are associated with the effects that ARFVTP activities have on current and future market conditions for new technologies. Some may be *second-order* benefits that follow from successful deployment of technologies accounted for under expected benefits. For example, the goal in demonstrating a small-scale biofuel production process would be to validate the technology, production process, and production costs, all of which are critical to future market success. Yet this important technology validation would yield only a small volume of low-carbon fuel that is directly attributable to the initial ARFVTP project grant (expected benefit). The success of this demonstration project wouldincrease the likelihood that the technology will be deployed at a larger scale by the initial company and perhaps other companies as well. A successful demonstration would also provide the company with performance and potential market data to attract new private or public funding. This future commercial-scale production and sale of the biofuel cannot be fully attributed to the initial ARFVTP grant, but there is a direct link between the technology validation and future commercial-scale production. The magnitude of these future benefits is market transformation.

Some market transformation benefits are distinct from the corresponding expected benefits. For example, installing hydrogen stations provides the direct benefit of efficient fuel cell electric vehicles (FCEVs) driving on hydrogen fuel and displacing gasoline use (expected benefit), while an increase in the geographic availability and convenience of additional stations will influence future consumer purchase decisions, and, therefore, the future market conditions for FCEV adoption (market transformation benefit). This example indicates how market transformation benefits are more uncertain and theoretical than expected benefits.

Market Transformation Methods

Though there are many types of potential market transformation influences associated with ARFVTP activities, NREL quantified three types, each including multiple subcategories. The term *influence* is used here to refer to the functional mechanism through which a project or set of projects might change future market adoption rates. The resulting market transformation benefits accrue due to the resulting increase in market share. The three influences are:

1. Vehicle price reductions.

    A. Reduction in the perceived price of plug-in electric vehicles (PEVs) due to increased availability of public electric vehicle supply equipment (EVSE) stations.

    B. Reduction in the perceived price of FCEVs due to increased availability of hydrogen stations.

C. Reduction in the price of PEVs due to Clean Vehicle Rebate Program rebates.

2. Vehicle cost reductions.

   A. Reductions due to direct investments in production.

   B. Reductions due to increased experience or learning-by-doing associated with deploying additional units.

3. Next-generation technologies.

   A. Additional biofuel production facilities or advanced trucks deployed as a result of ARFVTP support for the current generation of the same (or similar) technology.

The method relied upon to estimate benefits associated with vehicle price reductions is based upon assumptions about consumer behavior and a demand elasticity calculation. Benefits due to vehicle and fuel component cost reductions are determined using an industry experience curve framework in which costs decline with increased cumulative output. Benefits associated with next-generation technologies are based upon project-specific data for fuel production processes and truck demonstrations supported by ARFVTP. As indicated, vehicle price reductions apply to EVSE and hydrogen fueling stations, vehicle production cost reductions apply to a select number of vehicle categories, and next-generation benefits are determined for three fuel production categories.

Market Transformation Results

In addition to the results shown in Chapter 4, table 18 provides additional detail on the total market transformation benefits in low- and high-case scenarios. The total additional GHG and petroleum reduction benefits range from 1.0 $MMTCO_2e$ and 132 million GGE/DGE to 2.9 $MMTCO_2e$ and 385 million GGE/DGE. Next-generation fuels, representing increased investment and development of biorefineries due to the initial public sector investment, demonstration, and pilot-scale facilities, provide the largest future GHG reduction potential and account for nearly half of the total benefit in the high case. Future vehicle price reductions from increased consumer awareness of zero-emission electricity and hydrogen fueling networks also provide large potential future market transformation benefits. For petroleum reduction, next-generation trucks provide the largest future potential reduction, and represent the future benefits from early public sector investment in demonstration-scale zero emission medium- and heavy-duty truck technologies.

Table 17: Market Transformation Benefits for GHG Emissions and Petroleum Fuel Reductions Through 2025

Market Transformation Influence	Case	GHG Reductions (thousand tonnes CO_2e)			Petroleum Reductions (million GGE/DGE)*		
		2015	2020	2025	2015	2020	2025
Vehicle Price Reductions	High	323.7	660.1	881.2	38.6	81.6	126.4
	Low	224.6	387.6	518.4	27.1	48.9	73.9
ZEV Industry Experience**	High	29.6	126.2	212.7	3.9	16.7	32
	Low	25.3	107.8	181.7	3.3	14.3	27.3
Next Generation Trucks	High	117.3	469	469	24.2	96.6	96.6
	Low	5.7	22.8	22.8	-	5	5
Next Generation Fuels	High	-	592.2	1381.2	-	55	129.6
	Low	-	27.9	277.3	-	2.6	26
Total	**High**	**470.6**	**1847.5**	**2944.1**	**66.6**	**250**	**384.6**
	Low	**255.6**	**546.1**	**1000.2**	**30.5**	**70.8**	**132.3**

Source: NREL *GGE= gasoline gallon equivalents, DGE= diesel gallon equivalents, **ZEV= zero-emission vehicle

APPENDIX E:
Carbon Intensity Values for Gasoline and Diesel Substitute Fuels

The following charts show current carbon intensity values for gasoline substitute and diesel substitute fuels. All carbon intensity values are drawn from the current Low Carbon Fuel Standard (LCFS) Look Up Tables, unless otherwise noted. Note that the California Air Resources Board is proposing modifications to several carbon intensity values as part of re-adoption proceeding for the LCFS, and that the values shown here are subject to modification.

Figure 47: Carbon Intensity for Diesel & Substitutes

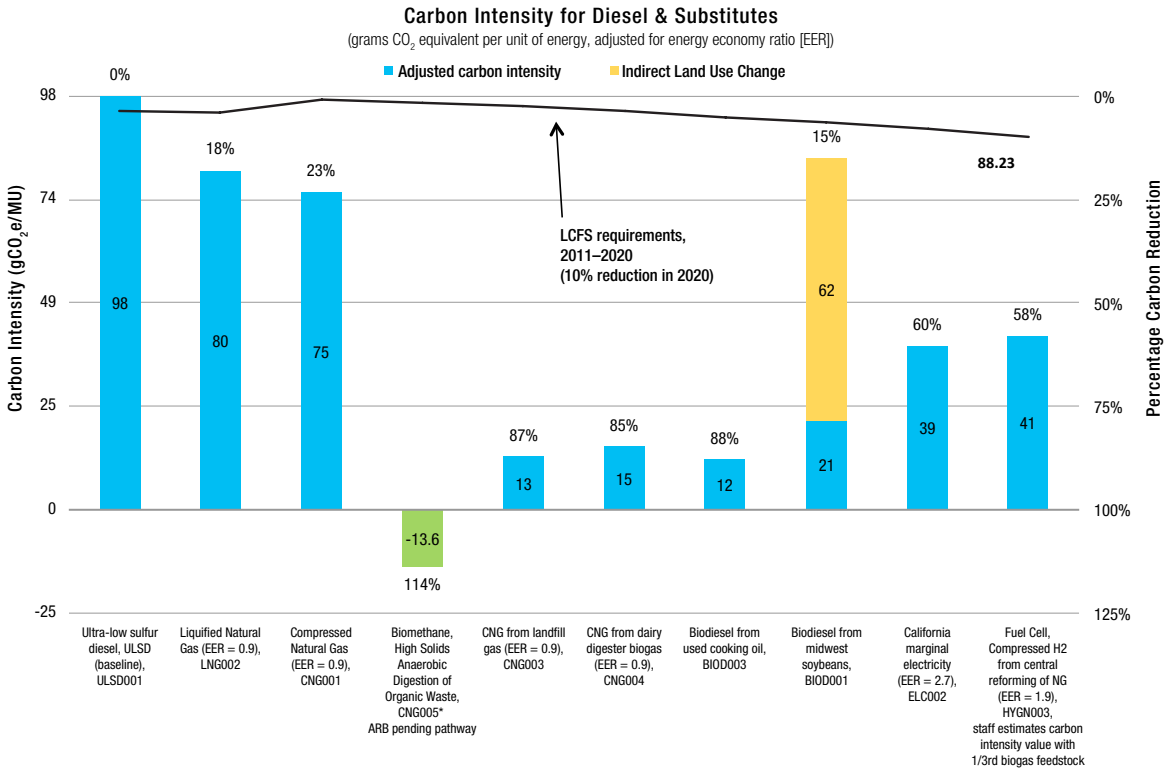


Figure 48: Carbon Intensity for Gasoline & Substitutes

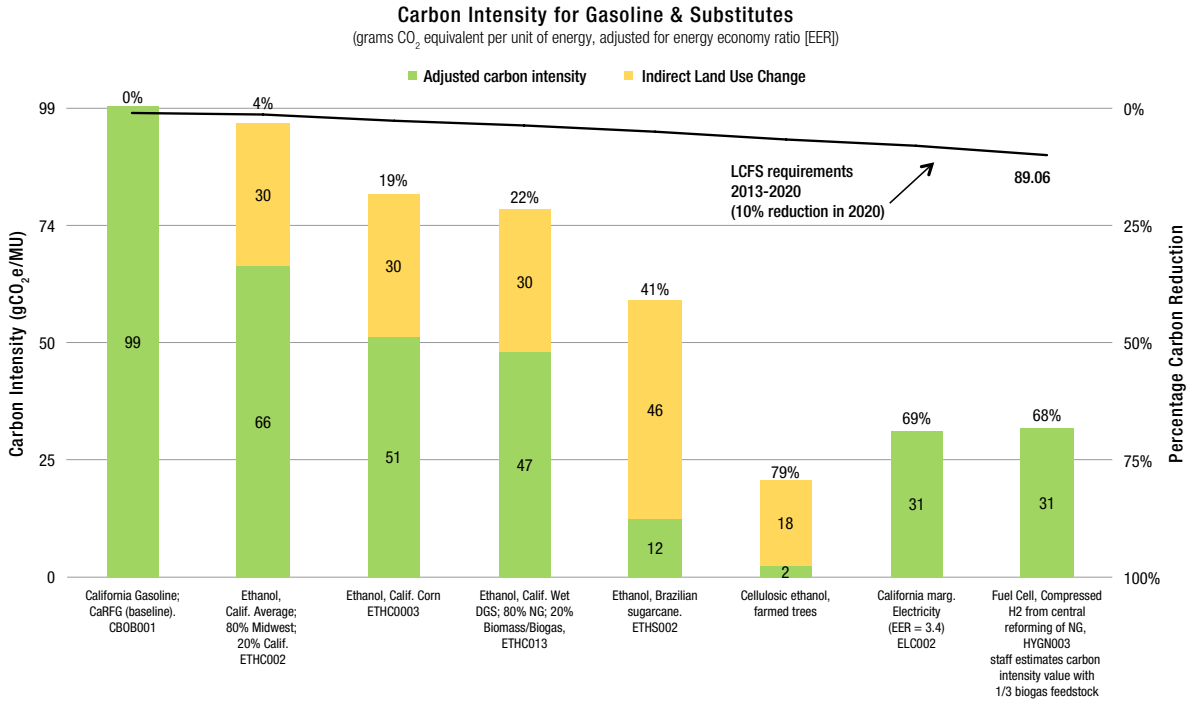
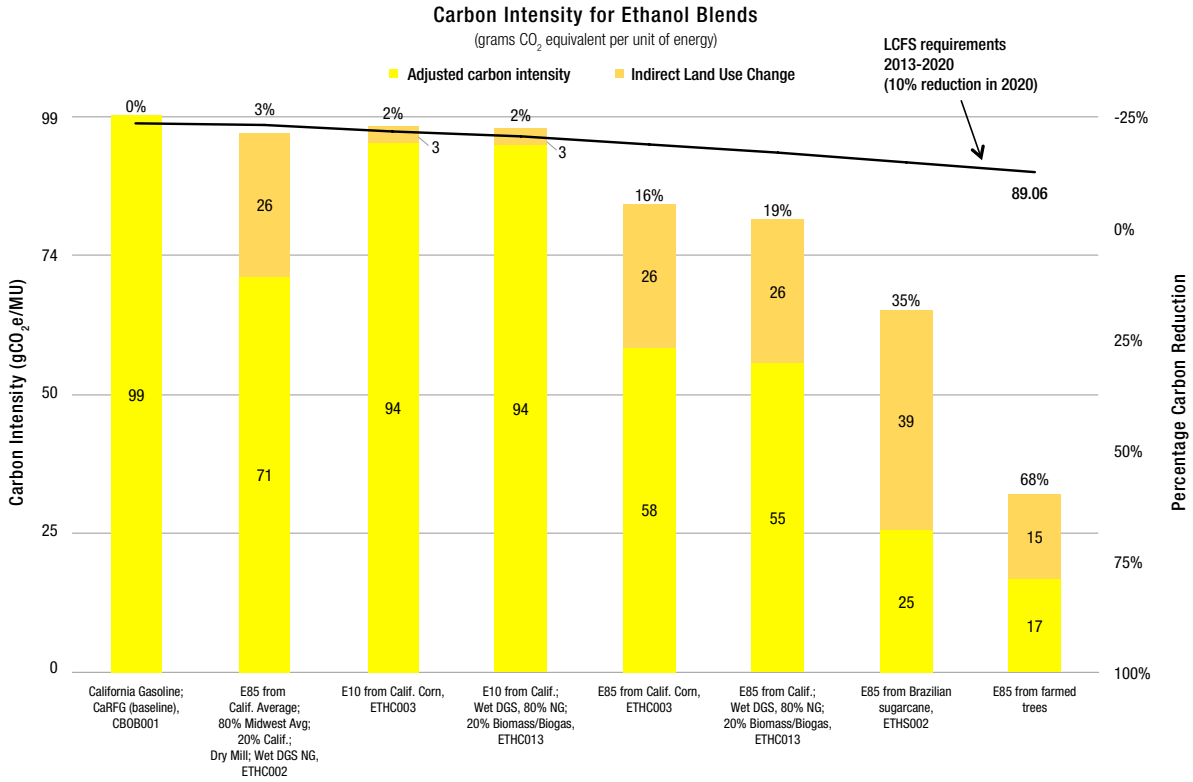


Figure 49: Carbon Intensity for Ethanol Blends



APPENDIX F:
California and Washington Crude-by-Rail Projects

California Crude-by-Rail (CBR) Projects

Northern California

WesPac Energy Project – Pittsburg – Undergoing Permit Approval

- Rail receipt average capability of 50,000 barrels per day (BPD)
- Also plan marine terminal for receipt and loading—average of 192,000 BPD
- Combined average receipt capability of 242,000 BPD
- Connection to KLM pipeline- access to Valero, Shell, Tesoro and Phillips 66 refineries
- Connection to idle San Pablo Bay Pipeline- access to Shell, Tesoro and Phillips 66 refineries
- There is currently no scheduled release date for the Recirculated Draft Environmental Impact Report (EIR) Construction could be completed within 18 months of receiving all permits
- Could be operational by 2016

Valero – Benicia Crude Oil by Rail Project – Undergoing Permit Approval

- Benicia refinery
- Up to 100 rail cars per day or 70,000 BPD
- Draft EIR released June 10, 2014
- Initial comment period closed by September 15, 2014
- Project will require approval of the City of Benicia
- Permit decision possible during January of 2015
- Construction would take 6 months
- Could be operational by 2015

Bakersfield Region

Alon Crude Flexibility Project – Permits Approved

» Alon-Bakersfield Refinery

» 2 unit trains per day—104 rail cars per unit train

» 150,000 BPD offloading capacity

» Will be able to receive heavy crude oil

» Oil tankage connected to main crude oil trunk lines—transfer to other refineries in Northern and Southern California

» Kern County Board of Supervisors approved permits for the project on September 9, 2014

» Construction has not commenced, but would take nine months to complete

» Could be operational by 2015

Plains All American – Bakersfield Crude Terminal – Operational

» Up to 65,000 BPD

» Construction on first phase (the rail and storage tanks portion) has been completed

» Phase 2 is a pipeline connection via new pipeline six miles in length to improve efficiencies of pipeline operations.

» Based on comments received on the mitigated negative declaration, Kern County has directed the applicant needs to prepare an EIR for the pipeline portion

» No specific timeline for release of the draft EIR

» Kern County's Planning and Community Development Department is lead agency

» Became operational November 2014

Southern California

Phillips 66 – Santa Maria Refinery – Undergoing Permit Approval

» Up to 41,000 BPD

» Revised draft EIR re-circulated during October 2014Project will require approval of the San Luis Obispo County Planning Commission

» Planning Commission hearing could occur during January 2015

» Construction expected to require 9–10 months to complete

» Could be operational by 2016

The Energy Commission is also monitoring the progress of two other potential CBR projects, one in Stockton (Northern California) and another in Riverside County (Southern California). The Targa project in the Port of Stockton is designed to receive CBR cargoes and transfer the oil to marine vessels for delivery to California refineries. The planned capacity of the facility is nearly 65,000 BPD. Another project being tracked by the Energy Commission is the Questar/Spectra CBR project that is designed to import up to 120,000 BPD of crude oil into

a yet-to-be-determined facility in Riverside County that would then be off-loaded into storage tanks before being shipped via a combination of existing and new pipelines to refineries in Southern California. These two CBR proposals have the potential to contribute an additional 185,000 BPD to California's CBR receiving capacity by the end of 2016.

Washington CBR Projects

Northwest Washington

BP – Cherry Point Refinery (1) – Operational

» Up to 60,000 BPD

» Permits received from Whatcom County, Washington, on April 13, 2013

» Operational December 26, 2013

Phillips 66 – Ferndale Refinery (2) – Operational & Planned Expansion

» Up to 20,000 BPD, mixed freight cars

» Permits for expansion to 40,000 BPD received from Whatcom County, Washington on April 13, 2013

» Expansion project anticipated to be operational by fall of 2014

Shell- Anacortes Refinery (3) – Planned

» Up to 50,000 BPD

» Will require permits from Army Corps of Engineers, Washington Department of Ecology, and Skagit County

» Could be operational by 2016

Tesoro – Anacortes Refinery (4) – Operational

» Up to 50,000 BPD

» 40 percent of refinery crude oil supply

» Operational September 2012

Southwest Washington and Northwest Oregon

Global Partners LP – Clatskanie, Oregon (5) – Operational

» Original crude oil transloading capability up to 28,600 BPD

» Revised permit issued August 19, 2014; increases capacity to 120,000 BPD

» 200,000 barrels of storage capacity

» Deepwater marine terminal

» Operational November 2012

Imperium Renewables, Port of Grays Harbor Project (6) – Planned

- Rail receipts of unit trains and loading of marine vessels
- Capacity up to 75,000 BPD
- Shoreline Substantial Development Permit was issued June 17, 2013
- SSDP remanded and SEPA determination invalidated by State Shorelines Hearing Board on November 12, 2013
- Environmental impact statements (EIS) being developed – Washington Department of Ecology and City of Hoquiam are co-lead agencies for the project permit review
- Start-up date uncertain

NusStar, Port of Vancouver (7) – Planned

- Rail receipts of unit trains & loading of marine vessels
- Capacity up to 41,000 BPD
- Permit review underway
- Initial start-up date uncertain

Targa Sound, Tacoma Terminal (8) – Planned

- Rail receipts of unit trains & loading of marine vessels
- Capacity up to 41,000 BPD
- Permit review underway
- Start-up date uncertain

Tesoro – Savages, Port of Vancouver Project (9) – Planned

- Rail receipts of unit trains and loading of marine vessels
- Initial capacity up to 120,000 BPD
- Tesoro will have offtake rights to 60,000 BPD
- Expansion capability of up to 280,000 BPD
- Port authority approved proposal on 7/24/13
- Washington State permit could be issued by 1Q 2015
- Start-up could occur by late 2015 or early 2016

U.S. Oil & Refining – Tacoma Refinery (10) – Operational and Planned Expansion

- Up to 6,900 BPD, mixed freight cars
- Operational April 2013
- Seeking permits to expand capacity to 48,000 BPD
- Construction could commence by late 2014

Westway Terminals, Port of Grays Harbor Project (11) – Planned

- Rail receipts of unit trains and loading of marine vessels
- Capacity up to 26,000 BPD for first phase of project, up to 48,900 BPD second phase
- Shoreline Substantial Development Permit issued on April 26, 2013
- SSDP remanded and SEPA determination invalidated by State Shorelines Hearing Board on November 12, 2013
- EIS being developed – Washington Department of Ecology and City of Hoquiam are lead agencies for the project permit review
- Start-Up date uncertain, construction would take 12–16 months to complete once all permits have been received.

APPENDIX G:
Crude-By-Rail Chronology of Safety-Related Actions

August 31, 2011	Association of America Railroads issues Casualty Prevention Circular 1232 (CPC 1232). Requires all manufacturers to construct rail tank cars to upgraded standards beginning October 10, 2011.[395]
August 7, 2013	Federal Railroad Administration issues Emergency Order No. 28. Primarily requires trains transporting crude oil and other flammable liquids to be manned at all times whether or not the train is temporarily idled on side tracks.[396] Intended to prevent an unattended train from rolling away from its idle position and derailing as was the case with the Lac Mégantic, Quebec, Canada, accident.
September 6, 2013	Pipeline and Hazardous Materials Safety Administration issues an Advance Notice of Proposed Rulemaking covering standards for rail tank cars and operations of trains transporting flammable liquids.[397]

395 *Crude Oil Tank Cars – Economics, Specification, Supply, Regulation, and Risk*: GATX, February 13, 2013, slide 17, http://www.crude-by-rail-destinations-summit.com/media/downloads/127-paul-titterton-vice-president-and-group-executive-fleet-management-marketing-and-government-affairs.pdf.

396 "Emergency Order Establishing Additional Requirements for Attendance and Securement of Certain Freight Trains and Vehicles on Mainline Track or Mainline Siding Outside of a Yard or Terminal," *Federal Register*, Vol. 78, No. 152, August 7, 2013, pages 48218-48224, http://www.fra.dot.gov/Elib/Document/3338.

397 "Hazardous Materials: Rail Petitions and Recommendations To Improve the Safety of Railroad Tank Car Transportation (RRR)," *Federal Register,* Vol. 78, No. 173, September 6, 2013, pages 54849-54861, http://www.gpo.gov/fdsys/pkg/FR-2013-09-06/pdf/2013-21621.pdf.

February 21, 2014 — Department of Transportation sends a letter to the Association of American Railroads requesting specific voluntary steps to be undertaken to reduce the risk of derailment and release of crude oil.[398] Actions include:

- Maximum speeds of 50 miles per hour
- Maximum speed reduced to 40 miles per hour for any trains shipping crude oil using pre-CPC 1232 rail tank cars
- Operational changes to improve emergency braking capability
- Increased inspections
- Installation of devices to detect defective bearings

May 7, 2014 — U.S. Department of Transportation issues an Emergency Order OST-2014-0067 requiring railroad companies to alert State Emergency Response Commission representatives of the specific counties that trains carrying Bakken crude oil in excess of one million gallons will traverse.[399] In the case of California that would be the Governor's Office of Emergency Services.

April 23, 2014 — Transport Canada issues a Protective Direction that prohibits older style rail tank cars from transporting Class 3 flammable liquids such as crude oil and ethanol. Further, pre-CPC 1232 rail tank cars are to be phased out of service within three years or retrofitted to meet stricter standards. In addition, Transport Minister issues an order limiting the speeds of trains transporting crude oil and ethanol to 50 miles per hour (MO 14-01).[400]

June 10, 2014 — California Interagency Rail Safety Working Group issues report on crude-by-rail activities that contain extensive recommendation to federal and state agencies directed at improving rail safety of flammable liquid transportation.[401]

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398 A copy of the letter can be found at http://www.dot.gov/briefing-room/letter-association-american-railroads.

399 A copy of the Emergency Order can be found at http://www.phmsa.dot.gov/pv_obj_cache/pv_obj_id_D9E224C13963CAF0AE4F15A8B-3C4465BAEAF0100/filename/Final_EO_on_Transport_of_Bakken_Crude_Oi_05_07_2014.pdf.

400 Minister of Transport Order Pursuant to Section 19 of the Railway Safety Act, April 23, 2014, http://www.tc.gc.ca/eng/mediaroom/ministerial-order-railway-7491.html.

401 *Oil by Rail Safety in California*, State of California Interagency Rail Safety Working Group, June 10, 2014, http://www.caloes.ca.gov/Hazardous-Materials/Documents/Oil%20By%20Rail%20Safety%20in%20California.pdf.

June 20, 2014 Governor Brown signs into law SB 861 (Corbett, Chapter 35, Statues of 2014) that, among other issues, expands the role of the California Office of Spill Prevention and Response from coastal responsibility to a statewide responsibility.[402] The Office of Spill Prevention and Response has initiated activities to develop new rules that will be used to enforce the legislation. A fee assessed for crude oil delivered to California refineries will be used to fund 38 permanent staff.[403]

June 25, 2014 California Energy Commission convenes a public workshop of various federal, state, private and public stakeholders to discuss emerging trends in crude oil transportation, recent developments of rail-related safety regulations, and expanded oversight of crude-by-rail activities by various state agencies.[404]

California Interagency Rail Safety Working Group unveils their interactive rail risk and response map tool. This software "…helps identify areas along rail routes in California with potential higher vulnerability and shows nearby emergency response capacity".[405]

August 1, 2014 Pipeline and Hazardous Materials Safety Administration issues Notice of Proposed Rulemaking covering standards for rail tank cars and operations of trains transporting flammable liquids.[406] Primary proposed regulatory changes:

- Designates trains transporting Class 3 flammable liquids (such as crude oil and ethanol) as High-Hazard Flammable Trains (HHFTs)
- Limits all HHFT to maximum speed of 50 miles per hour along all routes
- Seeks comments on proposed lower maximum speeds under various circumstances
- Requires railroads to undertake analysis of HHFT routes to identify the ones with the least risk
- Requires adoption of new operating procedures and/or equipment to improve braking responses to emergency stops

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402 http://www.leginfo.ca.gov/pub/13-14/bill/sen/sb_0851-0900/sb_861_bill_20140620_chaptered.pdf.

403 A description of OSPR responsibilities and new activities in response to SB 861 may be viewed at http://www.dfg.ca.gov/ospr/About/.

404 *Lead Commissioner Workshop on Trends in Sources of Crude Oil*, California Energy Commission, June 25, 2014. The workshop proceeding can be found at http://www.energy.ca.gov/2014_energypolicy/documents/#06252014.

405 The Rail Risk & Response Map is at http://california.maps.arcgis.com/apps/OnePane/basicviewer/index.html?appid=928033ed043148598f7e511a95072b89.

406 "Hazardous Materials: Enhanced Tank Car Standards and Operational Controls for High-Hazard Flammable Trains," *Federal Register,* Vol. 79, No. 148, August 1, 2014, pages 45016-45079. The presentation can be found at http://www.gpo.gov/fdsys/pkg/FR-2014-08-01/pdf/2014-17764.pdf.

» Requires new construction standards for all rail tank cars constructed after October 2015 that would be used to transport Class 3 flammable liquids – new Department of Transportation Specification 117[407]

Requires all noncomplying rail tank cars (legacy fleet) to be re-purposed, retired, or refurbished to meet the stricter standards by October 1, 2017, for the most flammable commodities (Packing Group I).

September 9, 2014 — Federal Railroad Administration issues a Notice of Proposed Rulemaking (NPRM) to codify many of the directives specified in Emergency Order 28 related to the securement of unattended locomotives.[408] These measures are designed to prevent trains carrying certain hazardous materials (such as crude oil) from being unmanned while on sidings or mainline track. Exceptions are allowed if various additional safety and securement protocols are followed by the train crews.

December 9, 2014 — The North Dakota Industrial Commission issues new standards related to the treatment of Bakken crude oil to ensure that the more volatile components are removed through application of heat or pressure prior to being loaded into rail tank cars. New standards go into effect on April 1, 2015, and limit the volatility of the treated crude oil to a maximum of 13.7 pounds per square inch (psi), lower than the ASTM standard of 14.7 psi.[409]

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407 According to William Finn of the Railway Supply Institute, there were 43,750 rail tank cars in crude oil service at the end of 2013 of which 14,350 rail tank cars were compliant with the more stringent CPC 1232 standards. In addition, there were 29,850 rail tank cars in ethanol service at that time of which 500 were compliant with the more stringent CPC 1232 standards. By the end of 2015, the number of rail tank cars meeting the CBC 1232 standards is expected to number 57,200 at the current rate of construction. Mr. Finn's presentation can be found at http://www.energy.ca.gov/2014_energypolicy/documents/2014-06-25_workshop/presentations/Finn_PPT_Updated.pdf.

408 "Securement of Unattended Equipment," *Federal Register,* Vol. 79, No. 174, September 9, 2014, pages 53356-53383. The document can be found at http://www.gpo.gov/fdsys/pkg/FR-2014-09-09/pdf/2014-21253.pdf.

409 North Dakota Industrial Commission Order Number 25417, December 9, 2014. The document can be found at https://www.dmr.nd.gov/oilgas/Approved-or25417.pdf.