

DOCKETED

Docket Number:	17-IEPR-01
Project Title:	General/Scope
TN #:	222377
Document Title:	Proposed Final 2017 Integrated Energy Policy Report- Clean Version
Description:	2017 IEPR Report
Filer:	Raquel Kravitz
Organization:	California Energy Commission
Submitter Role:	Commission Staff
Submission Date:	1/26/2018 2:43:13 PM
Docketed Date:	1/26/2018

California Energy Commission
COMMISSION REPORT

2017 Integrated Energy Policy Report



January 2018 | CEC-100-2017-001-CMF

The 2017 Integrated Energy Policy Report is dedicated to

JACKALYNE PFANNENSTIEL

**Former California Energy Commissioner and Chair
April 2004 – December 2008**

With gratitude for her leadership as the first female Chair of the Energy Commission and for her distinguished and pioneering career, during which she led advances in energy policy, including energy efficiency, demand response, and renewables.

California Energy Commission

Robert B. Weisenmiller, Ph.D.

Chair

Commissioners

Karen Douglas, J.D.

J. Andrew McAllister, Ph.D.

David Hochschild

Janea A. Scott, J.D.

Aniss Bahreinian

Stephanie Bailey

Jim Bartridge

Leon Brathwaite

Jennifer Campagna

Noel Crisostomo

Pamela Doughman

Tom Flynn

Guido Franco

Judy Grau

Mike Gravely

Eli Harland

Elizabeth John

Melissa Jones

Chris Kavalec

Matthew Ong

Charles Smith

Michael Sokol

Lana Wong

Primary Authors

Raquel Kravitz

Project Manager

Heather Raitt

Program Manager

Drew Bohan

Executive Director

DISCLAIMER

Staff members of the California Energy Commission prepared this report. As such, it does not necessarily represent the views of the Energy Commission, its employees, or the State of California. The Energy Commission, the State of California, its employees, contractors and subcontractors make no warrant, express or implied, and assume no legal liability for the information in this report; nor does any party represent that the uses of this information will not infringe upon privately owned rights. This report has not been approved or disapproved by the Energy Commission nor has the Commission passed upon the accuracy or adequacy of the information in this report.

ACKNOWLEDGEMENTS

Manjit Ahuja	Aleecia Gutierrez	Silvia Palma-Roxas
Rizaldo Aldas	Lea Haro	Mark Palmere
Meredith Alexander	Mark Hesters	George Piantka
Eileen Allen	Caryn Holmes	Fernando Piña
Al Alvarado	Yu Hou	Shawn Pittard
Grace Anderson	David Hungerford	Kiel Pratt
Dave Ashuckian	John Kato	Anitha Rednam
Kevin Barker	Michael Kenney	Ken Rider
Sylvia Bender	Sudhakar Konala	Robert Ridgley
Martha Brook	Eric Knops	Carol Robinson
Noah Silber Coats	Katharine Larson	Cynthia Rogers
Matt Coldwell	Emily Lemei	Jana Romero
Christine Collopy	Galen Lemei	Brian Samuelson
Denise Costa	Rachel MacDonald	Linda Schrupp
Rhetta DeMesa	Lynn Marshall	Sedina Sinanovic
William Dietrich	Pat McAuliffe	Courtney Smith
Bryan Early	Bob McBride	David Stoms
Ryan Eggers	Christopher McLean	Gabriel Taylor
Catherine Elder	Joseph Merrill	Laurie ten Hope
Scott Flint	Michael Murza	Chi-Chung Tsao
Sandra Fromm	Jennifer Nelson	Ysbrand van der Werf
Matthew Fung	Le-Huy Nguyen	Kourtney Vaccaro
Jesse Gage	Le-Quyen Nguyen	David Vidaver
Asish Gautam	Michael Nyberg	Misa Werner
Chuck Gentry	Tim Olson	Susan Wilhelm
Elena Giyenko	Garry O'Neill-Mariscal	Bailey Wobschall
Angela Gould	Jacob Orenberg	Angela Wuerth
Siva Gunda	Jason Orta	Sonya Ziaja

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 § 25301[a]). The Energy Commission prepares updates to these assessments and associated policy recommendations in alternate years, (Public Resources Code § 25302[d]). 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.

ABSTRACT

The *2017 Integrated Energy Policy Report* provides the results of the California Energy Commission's assessments of a variety of energy issues facing California. Many of these issues will require action if the state is to meet its climate, energy, air quality, and other environmental goals while maintaining energy reliability and controlling costs.

The *2017 Integrated Energy Policy Report* covers a broad range of topics, including implementation of Senate Bill 350, integrated resource planning, distributed energy resources, transportation electrification, solutions to increase resiliency in the electricity sector, energy efficiency, transportation electrification, barriers faced by disadvantaged communities, demand response, transmission and landscape-scale planning, the *California Energy Demand Preliminary Forecast*, the preliminary transportation energy demand forecast, renewable gas (in response to Senate Bill 1383), updates on Southern California electricity reliability, natural gas outlook, and climate adaptation and resiliency.

Keywords: California Energy Commission, Senate Bill 350, integrated resource plans, electricity demand forecast, climate adaptation and resiliency, renewable gas, energy efficiency, Southern California reliability, Aliso Canyon, integration of distributed energy resources, strategic transmission investment plan, transportation energy demand forecast, natural gas outlook, nuclear, energy storage, Alternative and Renewable Fuel and Vehicle Technology Program, resiliency

Please use the following citation for this report:

California Energy Commission staff. 2017. *2017 Integrated Energy Policy Report*. California Energy Commission. Publication Number: CEC-100-2017-001-CMF.

TABLE OF CONTENTS

	Page
Executive Summary	1
CHAPTER 1: Primary Policy Drivers	14
Climate Change	14
Air Quality	21
Access to Clean Technologies	23
Energy Reliability.....	24
Resource Conservation and Environmental Protection	24
Economic Growth	25
Electricity Sector Policy Drivers.....	28
Transportation Sector Policy Drivers	36
Conclusion.....	41
Recommendations	41
CHAPTER 2: Implementing the Clean Energy and Pollution Reduction Act, Senate Bill 350	42
Integrated Resource Planning for the Electric Sector.....	43
Encouraging Widespread Transportation Electrification	48
Doubling Energy Efficiency Savings	58
Renewables Portfolio Standard.....	68
Addressing Barriers Faced by Low-Income Residents and Disadvantaged Communities.....	75
Recommendations	90
CHAPTER 3: Increasing the Resiliency of the Electricity Sector	97
Operational Changes.....	98
Solutions to Increase Flexibility in the Electricity System	106
Conclusion.....	134
Recommendations	135
CHAPTER 4: Accelerating the Use of Distributed Energy Resources on the California Grid	137
Demand Response	140
Electricity Storage Systems	144
Vehicle-Grid Integration	147
Microgrids	150
Costs.....	154
Expanding DER Income and Savings	155
Transmission and Distribution Implications of the Growth in Distributed Energy Resources.....	157
Recommendations	160

CHAPTER 5: Strategic Transmission Plan and Landscape-Scale Planning.....	162
Introduction	162
Transmission Needed to Support the State’s Clean Energy and GHG Reduction Goals.....	164
Opportunities to Support the State’s Clean Energy and GHG Reduction Goals Through Efficient Use of Existing Transmission Grid	170
Landscape-Scale Planning to Reduce GHG Emissions	174
Use of Data Platforms and Analytical Tools in Landscape-Scale Planning.....	180
Recommendations	183
CHAPTER 6: Electricity and Natural Gas Demand Forecast.....	184
Background	184
2017 IEPR Forecast and Beyond.....	184
Data and Analytical Needs	186
Economic/Demographic Outlook for California	188
Trends in Energy Consumption	190
California Energy Demand Revised Forecast, 2018–2030	192
Climate Change Impacts on Temperatures and Load.....	199
Managed Forecasts	200
Choice of Managed Single Forecast Set	202
Recommendations	204
CHAPTER 7: Transportation Energy.....	205
Introduction	205
Transportation Fuel Supply	207
Transportation Energy Demand Forecast	224
Recommendations	244
CHAPTER 8: Natural Gas Trends and Outlook.....	245
California Overview	246
Natural Gas Price Projections	250
Natural Gas Sources and Production.....	251
Natural Gas Demand	254
Power Generation Sector in California and the Western Electric Coordinating Council	257
Natural Gas Infrastructure	258
Natural Gas-Electricity Coordination.....	269
Liquefied Natural Gas.....	272
First Steps in Transforming the Natural Gas Sector.....	273
Recommendations	274
CHAPTER 9: Renewable Gas.....	276
Cost-Effective Strategies.....	277

Priority End Uses for Renewable Gas	294
Economic Assessment of Renewable Gas End Uses	306
Long-Term and Alternative Pathways for Renewable Gas	316
Conclusions	320
Recommendations	321
CHAPTER 10: Climate Adaptation and Resiliency.....	326
Introduction	326
Policy Context for Adaptation in California’s Energy Sector.....	328
Actionable Science	335
Climate Projections for California and New Scientific Developments.....	344
New Scientific Developments Relevant to Planning and Research for Adaptation in the Energy Sector	347
Increasing Climate Resilience in Disadvantaged Communities.....	357
Recommendations	361
CHAPTER 11: Update on Energy Reliability Issues in Southern California	363
2017 Aliso Canyon Natural Gas Storage Facility Energy Reliability Issues.....	363
Update on Southern California Electricity Reliability	379
Recommendations	391
Acronyms	394
Glossary	400
APPENDIX A: 2017 Lead Commissioner Request for Data Related to California’s Nuclear Power Plants.....	A-1
APPENDIX B: Publicly Owned Utility Storage Goals Update	B-1
APPENDIX C: Publicly Owned Utility Energy Efficiency Savings.....	C-1
APPENDIX D: Benefits Report for the Alternative and Renewable Fuel and Vehicle Technology Program.....	D-1
APPENDIX E: Western Reliability and Planning Coordination.....	E-1
APPENDIX F: Status of Major California and Western Transmission Projects	F-1
APPENDIX G: June 2017 Heat Event in Southern California	G-1
APPENDIX H: Vehicle-Grid Integration Roadmap.....	H-1
APPENDIX I: Energy Commission Senate Bill 350 Implementation Progress	I-1
APPENDIX J: Energy Storage and Demand Response Roadmap Accomplishments	J-1

LIST OF FIGURES

	Page
Figure ES-1: The Largest, Most Destructive, and Deadliest California Wildfires.....	1
Figure ES-2: California Has Reduced Its Greenhouse Gas Emissions While Growing Its Economy	3
Figure ES-3: California Air Quality Emissions per Sector (2012 Estimated Annual Average)	4
Figure ES-4: Duck Curve, Electricity Demand Minus Wind and Solar Generation on a Typical Spring Day.....	8
Figure ES-5: Existing and Future Western EIM Entities	10
Figure 1: California's GHG Emissions in 2015	19
Figure 2: Relative Contribution of GHGs in California in 2015	20
Figure 3: Emissions of SLCPs and Other Non-CO ₂ GHGs (2015)	21
Figure 4: Air Quality Emissions per Sector (2012 Estimated Annual Average).....	22
Figure 5: California Has Reduced Its GHG Emissions While Growing Its Economy.....	25
Figure 6: Per Capita Electricity Use Stays Flat in California While Increasing Nationwide	26
Figure 7: GHG Reductions in the California ISO System Since 2014.....	28
Figure 8: Cost Reductions in Five Clean Energy Technologies (2008–2015)	29
Figure 9: Annual Additional Installed Solar Self-Generation Capacity.....	30
Figure 10: Operational, Pending, and Potential CCAs.....	33
Figure 11: 2017 IOU Transportation Electrification Portfolios	55
Figure 12: Proposed SB 350 Doubling Target for Electricity (GWh).....	60
Figure 13: Proposed SB 350 Doubling Target for Natural Gas (MM Therms)	61
Figure 14: California Renewable Energy Generation by Resource Type (In-State and Out-of-State)*	73
Figure 15: Growth in RPS Facilities With Approved Certification.....	75
Figure 16: California Disadvantaged Communities, Low-Income Communities, and Tribal Lands	84
Figure 17: Hourly Average Breakdown of Renewable Resources	99
Figure 18: Duck Curve, Electricity Demand Minus Wind and Solar Generation on a Typical Spring Day.....	100
Figure 19: Actual and Projected Maximum Three-Hour Ramps, California ISO, Years 2016 (Actual), and the Projection to 2017, 2018, and 2020 (MW)	102
Figure 20: Frequency of Negative 5-Minute Prices by Month in 2016 and 2017	103

Figure 21: Total Annual Wholesale Costs per MWh of Load Served, 2012–2016	104
Figure 22: Existing and Future Western EIM Entities.....	110
Figure 23: Changes in the Capacity Factor of Various Types of Natural Gas Power Plants in California (2001–2016)	119
Figure 24: Plug-In Times and Locations of Battery Electric Vehicles for Personal Use.....	133
Figure 25: Energy Storage Technologies by Discharge Time, Size, and Use.....	145
Figure 26: Examples of Battery Storage Used on the California Grid	146
Figure 27: Microgrid	151
Figure 28: China and United States Lead Growth in Electric Vehicles (2010–2016)	155
Figure 29: Map of Approved Transmission Projects in California to Help Integrate Renewable Energy.....	167
Figure 30: Areas of Data Collection for Statewide Energy Planning	175
Figure 30: Statewide Electricity Consumption by Sector Since 2000.....	191
Figure 31: Statewide Electricity Consumption.....	193
Figure 32: Statewide Light-Duty Electric Vehicle Electricity Consumption	194
Figure 33: Statewide PV Installed Capacity	195
Figure 34: Historical and Projected Statewide Electricity Sales.....	196
Figure 35: Statewide Noncoincident Peak Demand	197
Figure 36: Peak Shift Impact on Statewide Noncoincident Net Peak, <i>CED 2017 Revised</i> Mid Case	198
Figure 37: Statewide Baseline Natural Gas Consumption Demand	199
Figure 38: Statewide AAEE and PV Savings.....	202
Figure 39: California Gasoline and Ethanol Consumption (2003–2016)	208
Figure 40: California Diesel Fuel, Biodiesel, and Renewable Diesel Consumption	209
Figure 41: California Jet Fuels and Aviation Gasoline Consumption (2004–2016).....	209
Figure 42: California Transportation Electricity Consumption (2003–2016).....	211
Figure 43: California LCFS Credit Portion by Fuel Type (2011–2016)	211
Figure 44: California Refinery Crude Oil Sources (1982–2016).....	212
Figure 45: Crude Oil Production Change 2015 vs. 2008.....	213
Figure 46: Daily Brent Crude Oil Prices (2012 Through April 18, 2017).....	214
Figure 47: California Crude Oil Imports via Rail Tank Cars	215
Figure 48: Product Slate of California Refineries (2016)	216

Figure 49: California Gasoline Inventories Lower Than Normal (Early 2015).....	217
Figure 50: Monthly Foreign Imported Gasoline and Gasoline Blendstocks by Country of Origin, 2015	219
Figure 51: Monthly Net Gasoline and Gasoline Blendstocks Regional Imports (2014–2016).....	220
Figure 52: U.S. Ethanol Concentration in Finished Gasoline (January 2005 to January 2007) ..	222
Figure 53: U.S. Biodiesel Blending Levels (January 2005 to December 2016)	223
Figure 54: California Regular Gasoline Price Cases (2015 Dollars per Gallon)	227
Figure 55: Fuel Cost per Mile Trends for Light-Duty Vehicles (Midsize Cars), Mid Case.....	229
Figure 56: Fuel Cost per Mile Trends for Medium-Duty (Classes 4–6) Trucks, Mid Case	230
Figure 57: Projected BEV Range by Light-Duty Vehicle Class, Mid Case	235
Figure 58: Projected BEV Price by Light-Duty Vehicle Class, Mid Case	236
Figure 59: ZEV and PHEV Forecast Compared to CARB’s Midterm Review Scenarios	237
Figure 60: FCEV Population From Energy Commission Forecast and CARB Automaker Survey Projections.....	238
Figure 61: Historical and Forecasted Sales-Weighted Average LDV Fuel Economy	239
Figure 62: Medium-Duty New Truck Sales by Fuel or Technology, High Case	240
Figure 63: Heavy-Duty New Truck Sales by Fuel or Technology, High Case.....	240
Figure 64: Revised Forecast of 2030 Total Energy Consumption by Transportation Segment ...	241
Figure 65: Revised Conventional Fuel Demand Forecast (Mid Case)	242
Figure 66: Revised Alternative Fuel Demand Forecast, Mid Case	243
Figure 67: Percentage Usage of Natural Gas by Sector in California (2016).....	246
Figure 68: California Natural Gas Production Versus Rest of the United States	247
Figure 69: Western North American Natural Gas Pipelines.....	249
Figure 70: Mid Demand Case Prices for Henry, Topock, and Malin Hubs (2016\$/MCF).....	251
Figure 71: Proved Reserves in the United States	253
Figure 72: California’s Proved Reserves (2000–2015).....	254
Figure 73: U.S. Energy Demand by Fuel	255
Figure 74: U.S. Natural Gas Demand by Sector.....	256
Figure 75: Annual Daily Average Natural Gas Demand by Sector in California.....	256
Figure 76: California Annual Natural Gas Use for Power Generation for All Cases	258
Figure 77: Monthly Profile of Natural Gas Usage in California in 2016	260

Figure 78: 2015 California Methane Emissions Inventory (100-Year GWP)	279
Figure 79: California Potential Supply of Renewable Natural Gas (RNG)	289
Figure 80: California Potential Supply of Renewable Natural Gas (RNG) Derived From Anaerobic Digestion, Overall and by Feedstock Source	290
Figure 81: Supply Curve and Component Cost for (A) Dairies, (B) WWTPs, (C) MSW, and (D) Landfills.....	291
Figure 82: Map of Waste Resources and Disadvantaged Communities.....	293
Figure 83: Renewable Gas Project Development Time Frames.....	296
Figure 84: Dairy Cost Curves by Pathway	310
Figure 85: Historical RIN and LCFS Credits per MMBtu Produced for Four Major Renewable Gas Production Pathways.....	313
Figure 86: The Largest, Most Destructive, and Deadliest California Wildfires in the Last Century	326
Figure 87: Statewide Summer Average Temperatures: June, July, and August.....	327
Figure 88: Smoke Plumes From the Sonoma-Napa Cluster of Wildfires (October 9, 2017)	340
Figure 89: CPUC Fire-Threat Map, Draft (January 19, 2018)	342
Figure 90: Annual Average Temperature in California	350
Figure 91: Thirty-Year 90th and 95th Percentiles of Maximum Daily Temperatures for Stockton	355
Figure 92: Potential Increases in CDDs and Decreases in HDDs in Stockton, California	356
Figure 93: Potential Regionwide Heat Waves: Arizona, California, Utah, and Nevada.....	357
Figure 94: Climate-Linked Impacts to Vulnerable Populations	358
Figure 95: Geographical Distribution of NO _x Emissions in the South Coast Air Basin.....	359
Figure 96: SoCalGas System Map Highlighting Outages Affecting Northern Zone Receipts (Needles, Topock, and Newberry)	372
Figure 97: POU 2006–2016 Reported Electricity Savings.....	C-1
Figure 98: POU 2006–2016 Reported Program Expenditures	C-2
Figure 99: POU 10-Year ELRAM Projections (Cumulative)	C-3
Figure 100: POU 2018–2027 Incremental Electricity Savings From Codes and Standards.....	C-5
Figure 101: POU 2018–2027 Annual Incremental Electricity Savings Targets	C-6
Figure 102: Annual GHG Reduction From ARFVTP-Funded Projects	D-10
Figure 103: Major WECC Transmission Paths in California.....	F-2

Figure 104: Map of California ISO and Outside California ISO Grid-Approved Transmission Projects.....	F-3
Figure 105: Western Transmission Projects Accessing Out-of-State Resources	F-23

LIST OF TABLES

	Page
Table 1: California Transportation Policy Drivers	37
Table 2: Nonutility Energy Efficiency Programs	64
Table 3: RPS Targets.....	72
Table 4: IOU Renewable Procurement Status	74
Table 5: Energy Commission Low-Income Barriers Study Recommendations	77
Table 6: CARB Low-Income Barriers Study Priority Recommendations.....	78
Table 7: Western EIM Reduced Curtailment of Renewable Energy, Associated Reductions in CO ₂ , and Participant Gross Benefits by Quarter.....	109
Table 8: Once-Through Colling Phase-Out Implementation Schedule– Adopted and Owner Proposed.....	117
Table 9: IOU Proposed or Adopted Base Time-of-Use Periods	125
Table 10: DER in California 2013 Compared to 2017 (Percentage Change)	139
Table 11: Top California Microgrids in the Navigant Research Q2 2017 Microgrid Tracker	152
Table 12: Status of California Transmission Projects to Integrate Renewable Energy	165
Table 13: California Gaseous Fuel Consumption (2003–2016).....	210
Table 14: Energy Commission Transportation Forecasting Models.....	225
Table 15: Common Electricity Demand Cases Main Inputs.....	226
Table 16: Recent Trends in Consumer Preferences for Light-Duty Vehicles	231
Table 17: Inputs and Assumptions for PEV Scenarios.....	234
Table 18: Main Pipeline Systems Serving California (Bcf/day)	259
Table 19: Natural Gas Storage in California.....	262
Table 20: Annual Technically Available and Economically Feasible Biomethane Renewable Gas Production Potential From California Biomass Resources	288
Table 21: Non-levelized Production Facility Capital Cost Ranges by Type	292
Table 22: Number of On-Road Medium-Duty/Heavy-Duty Natural Gas Vehicles Operating in California by Key Market Sectors and Vehicle Class	298

Table 23: Non-levelized Capital Cost Ranges for Biomethane Renewable Gas End Uses.....	307
Table 24: Economic Analysis for Projects at an Example Flush Dairy With 2,000 Milking Cows Over a 10-year Period (44,410 MMBtu/yr, all Costs and Revenues in Million Dollars)	309
Table 25: Renewable Gas Facility Revenue Ranges by End Use.....	311
Table 26: BioMAT Program Information for Three Major IOUs.....	315
Table 27: Gasification Facility Capital Cost Ranges	317
Table 28: LFG Utilization – Most Stringent Emission Limits and Estimated Net Revenue.....	320
Table 29: Summary of Results for Six Scenarios of Gas Receipt Point and Transmission Use, Assuming a Hotter-Than-Average Summer in 2017 (1-in-10, 2017 Peak Summer Case)	367
Table 30: System Capacity and Maximum Supported Demand (MMcfd)	375
Table 31: 1-in-10 Winter Peak Day Demand, Normal and Minimum Electric Generation (MMcfd)	376
Table 32: Shortfall on a 1-in-10 Peak Day With Minimum Electric Generation and an N-1 Contingency	376
Table 33: Conventional Generation Projects in San Onofre Area.....	381
Table 34: Procurement of Preferred Resources in San Onofre Area	383
Table 35: Transmission Projects in San Onofre Area	386
Table 36: Onsite Spent Nuclear Fuel Capacity.....	A-3
Table 38: POU Energy Efficiency Targets (GWh).....	C-7
Table 39: POU Demand Reduction Goals (MW)	C-8
Table 40: ARFVTP Awards as of September 1, 2017	D-2
Table 41: Funding Analyzed by NREL by Project Type Through June 2017.....	D-4
Table 42: Annual Petroleum Fuel and GHG Reductions (Expected Benefits).....	D-6
Table 43: Annual Air Pollutant Reductions (Expected Benefits).....	D-7
Table 44: Market Transformation Benefits Description	D-8
Table 45: Annual Market Transformation Benefits in 2025	D-9
Table 46: Kilograms CO _{2e} Reduced Through 2025 per ARFVTP Dollar	D-11
Table 47: ARFVTP Funding per Metric Ton CO _{2e} Reduced Through 2025.....	D-11
Table 48: ARFVTP Investments in Workforce Training and Development.....	D-13
Table 49: SoCalGas Daily Operations Summary.....	G-1
Table 50: SoCalGas Forecast and Actual Composite Weighted Average Temperatures	G-2
Table 51: Reported Daily High and Nighttime Low Temperatures at Select Locations	G-2

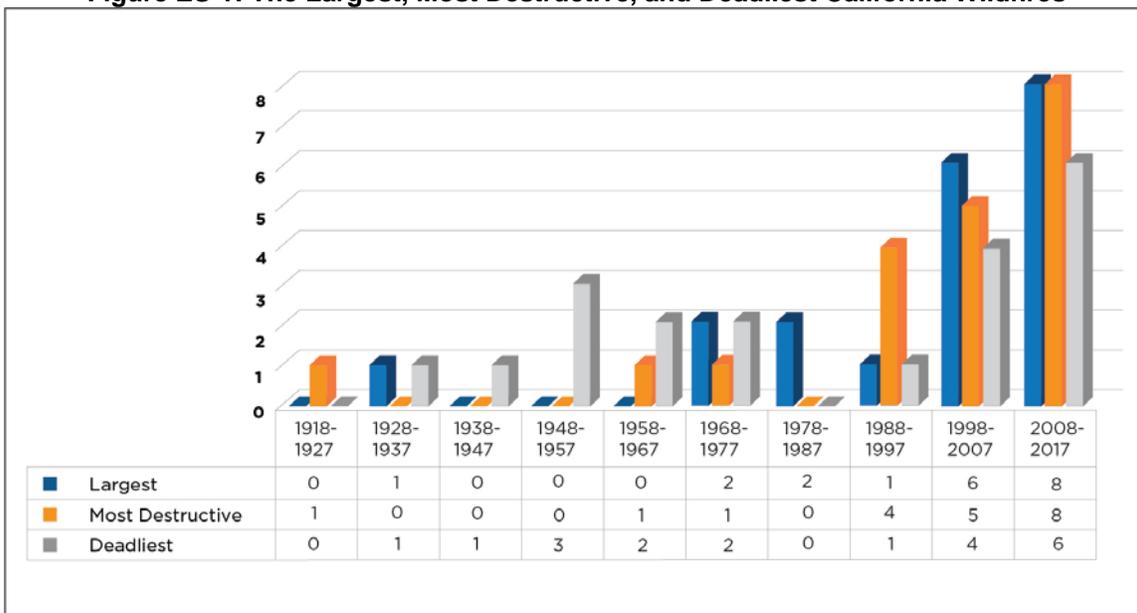
Table 52: SoCalGas Operations Summary June/July 2015 Curtailment Event.....G-4
Table 53: Fires with Potential Impact on Electric Facilities During Heat Wave G-5
Table 54: Energy Storage Roadmap (ESR) J-1
Table 55: Goals and Key Activities outlined in the Demand Response and Energy
Efficiency Roadmap (DR&EE)J-5

EXECUTIVE SUMMARY

More than ever, critical action is needed to drastically reduce greenhouse gas emissions from California’s energy system. The state must further transform its energy system away from fossil fuels while maintaining the services Californians rely on at a reasonable price, including energy for lighting, heat on a cold day, air conditioning during a heat wave, and fuel to get to school, work, or vacation. California has made great progress, but the energy sector, when transportation is included, is the state’s biggest source of greenhouse gas emissions.

California must continue to lower its greenhouse gas emissions to help reduce the risk of the most dangerous impacts of climate change. Because many greenhouse gases remain in circulation for decades, past emissions have already created climate change and more is unavoidable. If emissions continue on the current path, more destructive impacts are anticipated – such as continued large wildfires, additional sea-level rise, reduced snowpack, increased subsidence due to groundwater withdrawal, and more frequent heat waves, major storms, and drought. Californians are already facing the impacts of climate change. For example, about half of the 20 largest wildfires in California burned in the last decade with seven of the state’s largest, deadliest, and most destructive wildfires in 2017 alone. (See Figure ES-1.)

Figure ES-1: The Largest, Most Destructive, and Deadliest California Wildfires



Source: California Energy Commission using data from http://cdfdata.fire.ca.gov/incidents/incidents_statsevents.

An open letter by prominent scientists and cosigned by Governor Edmund G. Brown Jr. in June 2017 argues that a rapid downward trend in greenhouse gas emissions must be initiated in the next three years to avoid the most extreme impacts of this unfolding global calamity. While a large task, transforming the energy sector also offers opportunity for innovation and economic growth. Governor Brown said, “It’s up to you, and it’s up to me and tens of millions of other

people ... to roll back the forces of carbonization and join together to combat the existential threat of climate change.”

California’s Leadership in Addressing Climate Change

Recognizing that California’s actions alone won’t be enough, Governor Brown continues to lead international and coordinated subnational efforts to address climate change, despite efforts by the federal administration to the contrary. Governor Brown championed the Subnational Global Climate Leadership Memorandum of Understanding (the “Under-2 MOU”), a commitment by cities, states, and countries to help limit the rise in global average temperature to below 2 degrees Celsius. He was also a leader in achieving the Paris Agreement at the 2015 United Nations Climate Change Conference and was appointed the special advisor for States and Regions ahead of the 2017 conference.

In the Paris Agreement, nations worldwide agree to sufficiently reduce greenhouse gas emissions to avoid catastrophic climate change – but President Donald Trump has stated he intends to pull the United States out of it. The week after the President’s announcement, Governor Brown was in China discussing ways to collaborate to reduce emissions and help California’s clean technology industry grow there. The clean tech market in China is orders of magnitudes larger than the market in California and can help drive technology advancements and global greenhouse gas reductions. Partnerships with China and other nations and subnational governments committed to safeguarding their people from the challenges posed by climate can make a difference.

Governor Brown and the California Legislature remain resolute in addressing climate change. Executive Order B-30-15 set a greenhouse gas emissions reduction goal of 40 percent below 1990 levels by 2030 and established guiding principles for climate planning and funding. Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) codified the 2030 goal, and the companion bill, Assembly Bill 197 (Garcia, Chapter 250, Statutes of 2016), emphasized equitably implementing state climate change policies such that the benefits reach disadvantaged communities. The 2030 goal builds on the landmark California Global Warming Solutions Act (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006) requiring a 20 percent reduction in greenhouse gas emissions by 2020.

In Governor Brown’s 2015 inaugural address, he said that California must “transform our electrical grid, our transportation system, and even our communities” to reduce greenhouse gas emissions. He set the following goals for 2030:

- Increase from one-third to 50 percent the state’s 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.

He further called on the state to:

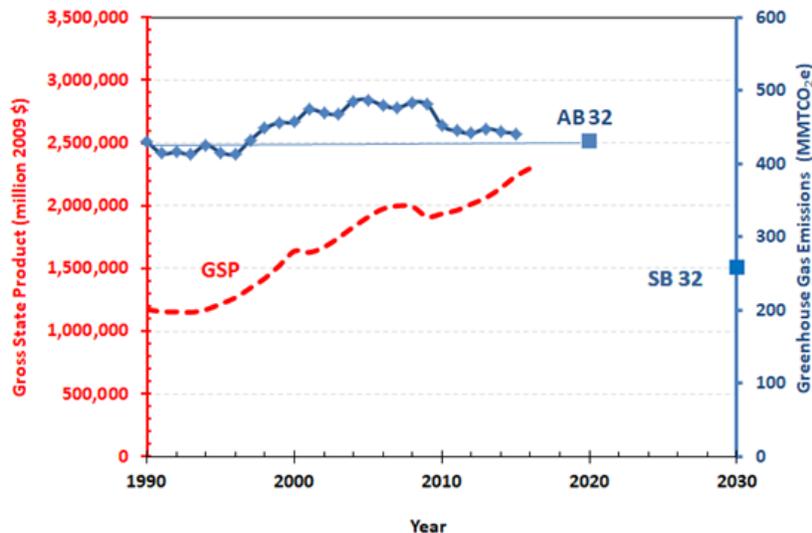
- Reduce the relentless release of methane, black carbon, and other potent pollutants across industries.
- Manage farm and rangelands, forests, and wetlands so they can store carbon.

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) codifies the goals for the electricity and natural gas sectors from the Governor’s inaugural address. Implementation of SB 350 is a central topic of this *Integrated Energy Policy Report*.

Reducing Greenhouse Gas Emissions While Growing the Economy

Economywide, California’s 2015 carbon dioxide emissions were 1.5 million metric tons below 2014 levels – a 10 percent reduction from 2004. Since the peak in 2001, greenhouse gas emissions per gross state product have steadily declined by 33 percent, and the economy grew 37 percent. While California is making progress, this is no time to rest. Achieving a 40 percent reduction below 1990 levels by 2030 requires unprecedented reductions, as evident in Figure ES-2.

Figure ES-2: California Has Reduced Its Greenhouse Gas Emissions While Growing Its Economy

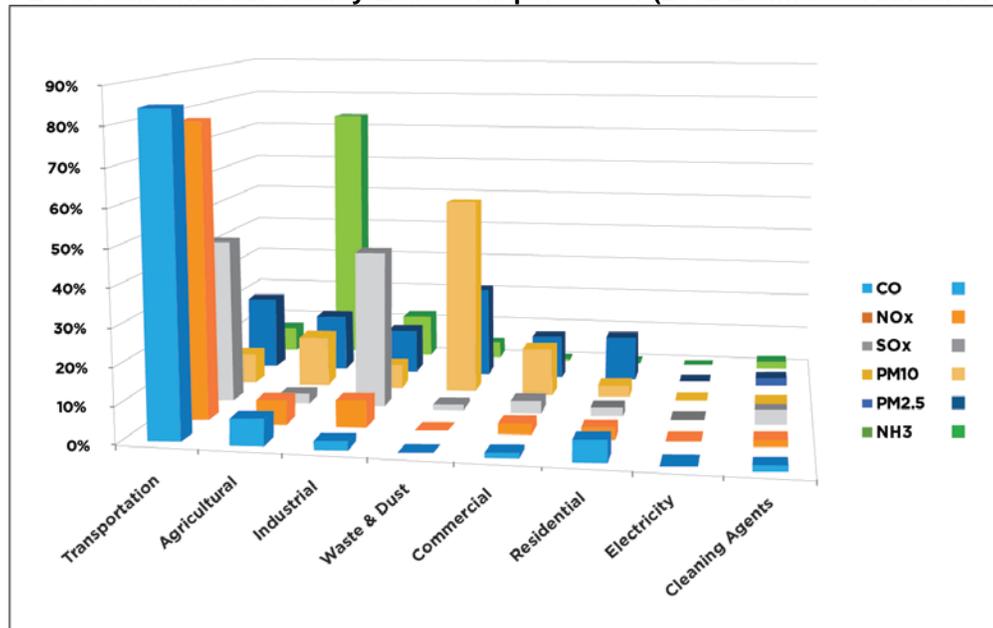


Source: California Energy Commission staff using data from the CARB Greenhouse Gas Inventories and gross state product data from the Bureau of Economic Analysis of the U.S. Department of Commerce. Note: Not shown is California’s 2050 goal to reduce greenhouse gas emissions 80 percent below 1990 levels (Executive Order B-30-15).

Trends in Greenhouse Gas Emissions in the Transportation and Electricity Sectors

The transportation sector continues to dominate greenhouse gas emissions in California, accounting for 38.5 percent of the state’s emissions in 2015 (the most recent data available), not including emissions from refineries that produce gasoline, which increase transportation sector emissions to about 50 percent of the statewide total. Further, motor vehicles are the largest source of air pollution that harms human health, overshadowing all other sectors and accounting for nearly 80 percent of nitrogen oxide emissions and 90 percent of diesel particulate matter emissions. (See Figure ES-3.)

Figure ES-3: California Air Quality Emissions per Sector (2012 Estimated Annual Average)



Source: California Energy Commission using California Air Resources Board data

Because of these high emissions, a major push in California’s energy policy is to shift from gasoline to zero-emission and near-zero-emission vehicles (ZEVs) that run on electricity from plug-in electric batteries, hydrogen fuel cells, or a combination of the two.

The electricity sector accounted for about 19 percent of the state’s greenhouse gas emissions in 2015, with greenhouse gas emissions about 24 percent *below* 1990 levels in 2015. This reduction has been achieved even with the closure of the zero- greenhouse-gas-emitting San Onofre Nuclear Generating Station in 2013 and low hydroelectricity production in 2015 due to drought. The reduced emissions in the electricity sector are in part attributable to an increase in renewable energy resources and a reduction in coal-fired electricity. Since California’s Renewables Performance Standard was established in 2002, renewable-based electricity has increased by about 2.5 times. Since California’s Emissions Performance Standard was enacted by Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006), coal-fired electricity consumed in California has declined about 75 percent and is expected to be zero by 2026.

Transforming California’s Energy System to Meet the 2030 Greenhouse Gas Reduction Goal

As part of SB 350 requirements, the California Air Resources Board (CARB) will establish a greenhouse gas emission reduction target for the electricity sector share of economy-wide emission reductions. Through the *2017 IEPR* proceeding, the Energy Commission and California Public Utilities Commission (CPUC) worked with CARB to split the target between the load-serving entities (LSEs) regulated by the CPUC (such as investor-owned utilities [IOUs] and community choice aggregators [CCAs]) and the publicly owned utilities (POUs).

SB 350 also requires a more comprehensive approach to energy planning specifically focused on meeting the 2030 greenhouse gas target. Through integrated resource plans, LSEs will identify

the most cost-effective way to meet greenhouse gas reduction goals and other SB 350 goals, taking resources and customer base characteristics into account. Sixteen POU's (those that meet the threshold size requirements) will file their integrated resource plans with the Energy Commission, and the IOUs and other LSEs will file with the CPUC. In August 2017, the Energy Commission adopted guidelines for the POU's' integrated resource plans.

Double Energy Efficiency Savings by 2030

The Energy Commission, working with the CPUC and POU's, is setting the path for doubling energy efficiency savings by 2030. SB 350 directs the Energy Commission to establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a statewide cumulative doubling of energy efficiency savings in electricity and natural gas end uses by January 1, 2030. In November 2017, the Energy Commission adopted a doubling target and framework for achieving the goal. The framework includes:

- Utility-funded activities (ranging from incentives aimed at directly influencing consumer choices to those that target efficiency improvements in supply chains including manufacturers, contractors, and builders) and
- Nonutility-funded activities (such as advancing building and appliance codes, emerging technologies, innovative market solutions, progressive program designs, and public awareness).

In tandem with this work, the Energy Commission is improving its analytical capabilities to track and account for the doubling energy efficiency savings goal (as well as the increase in electric vehicles, rooftop solar, and other factors) into its 10-year electricity and natural gas forecast. The forecast is used in energy planning efforts such as the CPUC's long-term procurement planning and the California Independent System Operator's (California ISO's) transmission planning.

Achieve 50 Percent RPS by 2030

The Energy Commission and CPUC have established rules for the 50 percent Renewables Portfolio Standard, and the IOUs are confident they will meet it.

As discussed in this and previous *IEPRs*, California is working to minimize the environmental and land-use impacts of new renewable energy and transmission projects needed to support its greenhouse gas goals. The Renewable Energy Transmission Initiative 2.0 (RETI 2.0), initiated in September 2015 and concluded in March 2017, brought together state and federal partners to identify constraints and opportunities for new transmission that may be needed to access and integrate new renewable energy resources to meet California's goals. As noted by Energy Commission Chair Robert B. Weisenmiller, California is "...pursuing an integrated strategy, and looking ahead at least 15 years to make sure we're doing the right things now to develop the options we'll need then. The RETI 2.0 process is helping the state's energy agencies, utilities, renewable industry, and residents narrow down our focus on where we might need new transmission." Building on the RETI 2.0 process and supporting the needs outlined in utilities' integrated resource plans, the Energy Commission continues to develop landscape-scale planning

applications that can be used by state and local planners as they consider renewable generation and infrastructure development.

Advance Transportation Electrification

SB 350 also emphasizes transportation electrification as a key part of California's low-carbon energy future. This emphasis builds on policies such as Governor Brown's Executive Order B-16-12, which set a target for California to have 1.5 million ZEVs on the road by 2025. In 2014, Senate Bill 1275 (De León, Chapter 530, Statutes of 2014) established the goal of placing 1 million zero-emission and near-zero-emission vehicles in service by January 1, 2023, while providing increased access to these vehicles for disadvantaged, low-income, and moderate-income communities and consumers. In 2017, CARB's proposed *Climate Change Scoping Plan Update* included a goal of 4.2 million ZEVs by 2030.

Planning for the growth in plug-in electric vehicles to advance "smart charging" (charging with internal controls that adjust to customer and grid needs) can help make the grid more resilient to variations in renewable generation and help reduce emissions, provided that pricing and charging infrastructure encourage charging at midday. Continued strategic investments are needed to ensure low-income customers, especially those living near heavily used freeways, also have access to the use of plug-in electric and fuel cell electric buses and vehicles and related economic and environmental benefits.

Address Low-Income Barriers to Clean Energy

Across the energy sector, the Energy Commission is working to ensure all Californians have an opportunity to participate in and benefit from Energy Commission programs that can lead to job creation and training, improved air quality, and energy efficiency and environmental gains. In coordination with other state agencies, the Commission is focusing on issues highlighted in the following SB 350 studies:

- Low-income barriers to energy efficiency and weatherization investments, photovoltaic energy generation investments, and small business contracting opportunities identified in the Energy Commission's 2016 *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities* (Barriers Study).
- Low-income barriers to access to clean transportation technologies addressed in the companion study under development by CARB. A draft of CARB's *Low-Income Barriers, Study Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents* was released on April 12, 2017.

In developing these studies, community meetings and public workshops provided opportunities for low-income customers and disadvantaged communities to highlight local priorities, concerns, and recommendations. Climate change and air pollution disproportionately impact low-income and disadvantaged communities. Local knowledge is a critical component of efforts to ensure clean energy investment enhances resilience to climate change.

The recommendations in the Energy Commission's Barriers Study broadly address three key objectives: expand access (to products, good jobs, small business contracting opportunities, and nondebt financing); increase investment (such as in buildings, research demonstrations, infrastructure, and emergency preparedness); and improve resilience (including improving energy reliability, energy affordability, and health and safety) for California's low income communities and disadvantaged communities. The Energy Commission is developing indicators to measure progress implementing the recommendations in the Barriers Study and to help identify locations where further resources need to be directed.

California's Evolving Electricity Sector

As the state moves forward to achieve the goals identified in SB 350, the basic structure in which programs in the electricity sector have been implemented for decades is fundamentally changing. Traditionally, the IOUs have served about 75 percent of Californians, with POU's serving most of the rest. Energy planning has been fairly centralized; most of California's electricity planning needs have been addressed for the IOUs with CPUC oversight.

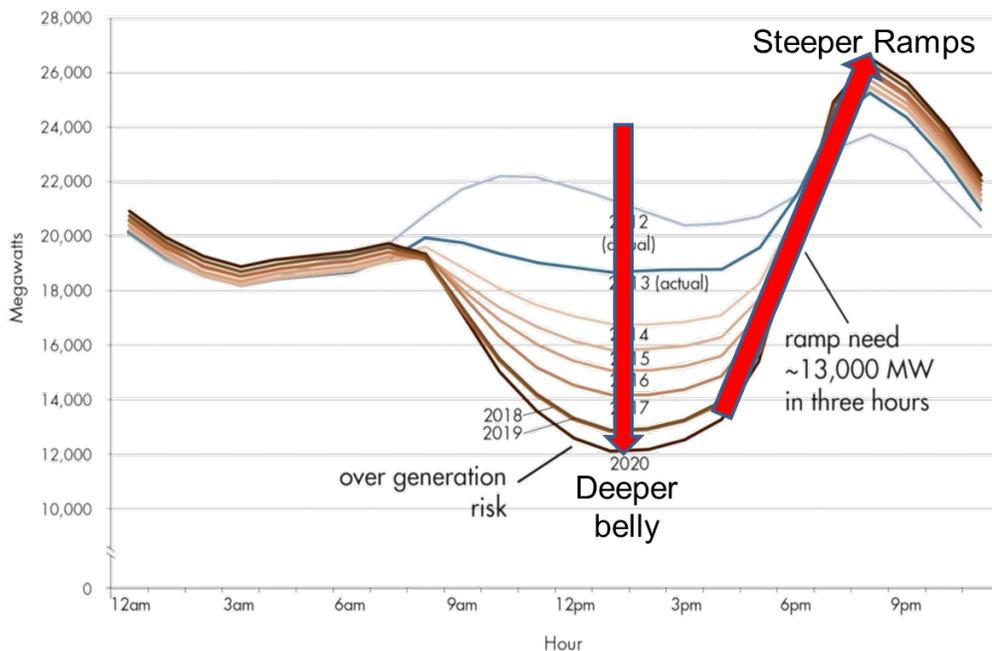
This structure is changing as consumer choice affecting both generation and consumption is proliferating, spurred by market developments, technological innovations, and policy actions. Californians are installing their own rooftop solar, numerous companies are contracting for renewable resources, and local government agencies are forming CCAs that can develop and buy electricity on behalf of their customers with relatively limited state oversight. IOU retail electric load could drop by 85 percent in the next decade.

As a result, the IOUs are not entering into long-term contracts for renewable generation or other energy products. However, there is considerable uncertainty about the ability of CCAs to secure the financing needed for long-term investments, because they are thinly capitalized shell companies. This uncertainty raises important questions about how roles traditionally filled by the IOUs will be met, including making needed investments in energy infrastructure, energy efficiency, energy services for low-income consumers, and research and development. While markets and technology innovations evolve quickly, regulatory mechanisms do not. Policy makers and regulators need to think ahead about how to ensure California's policy implementation successfully evolves with changing market conditions for IOUs and CCAs.

Increasing Resiliency in the Electricity Sector

Amid this changing market structure, California's electricity grid must quickly make needed adjustments to support a low-carbon future. Unlike natural gas-fired generation, wind and solar vary depending on when the wind is blowing and the sun is shining. Integrating increasing amounts of solar and wind energy into the grid requires a greater emphasis on flexibility and resiliency. This is illustrated by the "duck curve" developed by the California ISO that shows the net load (load minus solar and wind generation) on a typical spring day. (See Figure ES-4.) When solar electricity generation peaks at midday, the net load is low and is described as the "belly of the duck."

Figure ES-4: Duck Curve, Electricity Demand Minus Wind and Solar Generation on a Typical Spring Day
 Typical Spring Day



Source: California ISO, presentation by Mark Rothleder at May 12, 2017, IEPR workshop

When net load is lowest, the system operator works to get as many resources off the system as possible to make room for renewable generation, and sometimes has to curtail renewables. The state continues to explore beneficial uses of excess renewable energy, however, such as through storage for later use or to power desalination plants. As the system operator manages the deep drops in net load some resources need to be available to ramp up in anticipation of the evening drop in solar production while demand remains high. The late-afternoon ramp from the belly of the duck up is approaching 13,000 MW in a three-hour period on some of the most extreme days. The duck curve illustrates the operational challenges for the California ISO but also presents opportunities for better managing the grid to maximize the benefits of renewables.

The Role for Responsive and Strategically Located Natural Gas-Fired Power Plants

Natural gas-fired power plants historically have been the workhorses of the grid and are capable of being turned up or down as needed in response to variations in energy supply or demand. With the increase in renewables, natural gas power plants are operating less and less, and many have ceased operation or have gone bankrupt. In one sense, this is a success story in reducing greenhouse gas emissions, but some natural gas-fired power plants are important for the reliable operation of the grid, either by virtue of location or their ability to rapidly ramp up and down. The Energy Commission, CPUC, and California ISO need to work together to address how to ensure the availability of those plants that are needed to maintain the reliability and resiliency of the grid.

Zero-Greenhouse Gas Emission Solutions

California needs to increasingly develop solutions to help integrate renewables that do not emit greenhouse gases, such as improving the operational flexibility and reliability of renewable power plants. With advanced controls, a test by the California ISO found that a utility-scale solar power plant could provide more resiliency to the grid than natural gas power plants. Improving short-term weather forecasting capabilities to better anticipate changes in renewable generation is also important. For example, monsoonal cloud cover over large solar facilities in the desert can quickly cause rapid drops of hundreds of megawatts and is difficult to predict.

Expanding the use and integration of distributed energy resources is a high priority for California to provide customers low-greenhouse gas opportunities for meeting electricity demand, especially in the Southern California areas affected by the closure of the San Onofre Nuclear Generation Station in 2012 and the massive leakage of methane at the Aliso Canyon natural gas storage facility in 2016. Distributed energy resources include:

- Demand response, which has been used traditionally to shed load in emergencies. It also has the potential to be used as a low-greenhouse-gas, low-cost, price-responsive option to help integrate renewable energy and provide grid-stabilizing services, but California has a serious demand response underperformance problem. Solutions are available but require proactive leadership in the policy and ratemaking realms.
- Distributed renewable energy generation, primarily rooftop photovoltaic systems and also fuel cells.
- “Vehicle grid integration,” or all the ways plug-in electric vehicles can provide services to the grid, including coordinating the timing of vehicle charging with grid conditions.
- Energy storage in the electric power sector to capture electricity or heat for use at a later time to help manage fluctuations in supply and demand.

Microgrids combine distributed energy resources with a controller to manage energy use. A key feature of many microgrids is the ability to continue operating even if the surrounding electricity grid experiences an outage. Further work is needed to make microgrids available on a commercial scale, especially in areas with vulnerable populations, disadvantaged communities, and tribes.

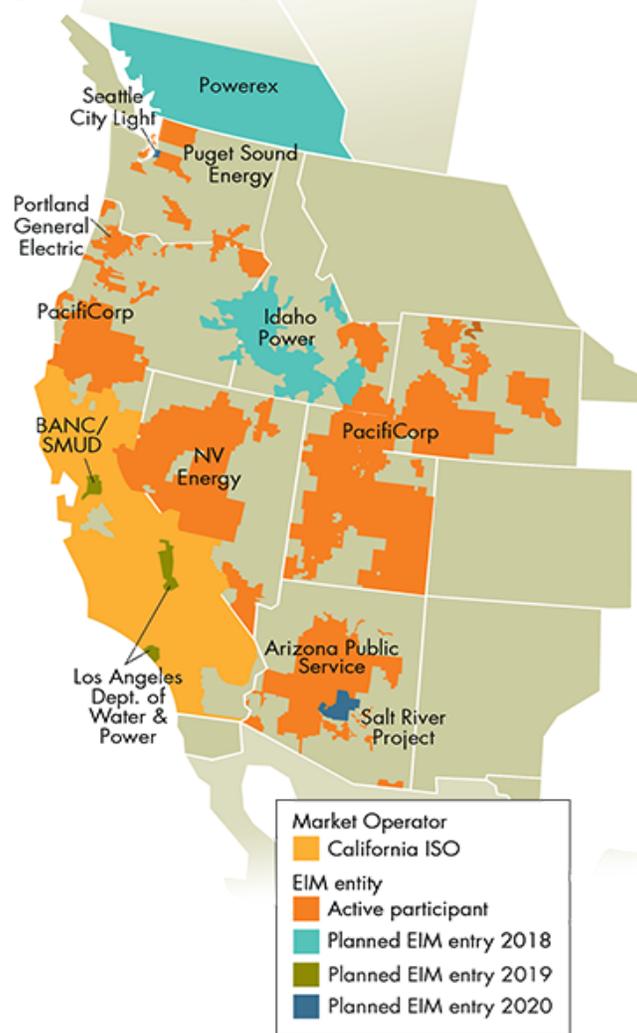
Increasing Resiliency Through Geographic Resource Diversity

Among the suite of tools available to increase the resiliency of a low-greenhouse-gas electricity system, increasing the regional scale of the electricity system provides the clearest benefits in terms of reducing costs and greenhouse gas emissions. Trading with partners across a larger footprint allows for purchases and sales between renewable power plants with differing seasonal and daily operating profiles. For example, when California has excess renewable generation, a regional electricity market can allow the generation to be sold instead of potentially curtailing operations, and when California needs more energy to meet ramping needs, more resources are available.

Initiated in 2014, the Western Energy Imbalance Market is a wholesale energy market that allows participants to buy and sell energy in real time. Its benefits have grown as more entities join and

increase access to more generation and transmission. (See Figure ES-5.) Through the third quarter of 2017, the Western Energy Imbalance Market has provided gross benefits of \$255 million, avoided curtailment of more than 502 gigawatt-hours of renewable energy, and reduced greenhouse gas emissions by almost 215,000 tons of carbon dioxide equivalent emissions. In response to the Western Energy Imbalance Market, innovative market opportunities are evolving.

Figure ES-5: Existing and Future Western EIM Entities



Source: Western Energy Imbalance Market, <https://www.westerneim.com/Pages/About/default.aspx>, accessed January 2018

While carbon dioxide accounts for more than 80 percent of greenhouse gas emissions and is created when fuel is combusted, methane is more potent at trapping heat. It is a “short-lived climate pollutant” that accounts for about 9 percent of the state’s greenhouse gas emissions and is one of the greenhouse gases that Governor Brown called out in his 2015 inaugural address. Cattle, manure management, and landfills generate most of California’s methane emissions and emissions from California’s natural gas infrastructure account for about 10 percent.

In response to Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016), CARB approved and began implementing a comprehensive short-lived climate pollutant (SLCP) strategy in March 2017 that

includes strategies to reduce statewide methane emissions 40 percent below 2013 levels by 2030. SB 1383 also requires the Energy Commission, in consultation with CARB and the CPUC, to “develop recommendations for the development and use of renewable gas, including biomethane and biogas as part of its *2017 Integrated Energy Policy Report*.” Renewable gas has been used, or proposed for use, as a substitute for conventional natural gas in a variety of applications and can be used to make hydrogen. Consistent with SB 1383, the *2017 IEPR* identifies “cost-effective strategies that are consistent with existing state policies and climate change goals by considering priority end uses of renewable gas.” In this context, cost-effective strategies yield the lowest cost per SLCP reduction benefit in terms of greenhouse gas emissions reduced.

Two independent studies carried out by the University of California, Davis, and ICF International concluded that existing government policies (with some modifications) could support the substantial growth of renewable gas, particularly as a transportation fuel. Both studies noted that renewable gas production can generate up to four times the revenue for transportation fuel use compared to electricity from the same renewable gas sources because of the monetary value of credits generated from the federal Renewable Fuels Standard and California Low Carbon Fuel Standard for renewable transportation fuels. Renewable gas use in the medium- and heavy-duty vehicle sectors is an important strategy for improving air quality, and the Energy Commission’s transportation forecast anticipates the growth of renewable gas use within those transportation sectors. Still, the market is constrained by a limited number of models and production volume of natural gas vehicles.

Additional policies may be needed, and agencies may also need to modify, reconfigure, and enhance existing regulations, policies, and programs to fully enable cost-effective commercialization of renewable gas and maximize methane emission reductions.

First Steps in Transforming the Natural Gas Sector

California’s aggressive energy efficiency programs and increased renewable energy generation are reshaping its use of natural gas. In California, consumption has remained relatively flat over the last 10 years, while consumption in the United States has increased 2.4 percent per year. Although natural gas remains an important resource for heating, electricity production, and increasingly in transportation, the use of natural gas will need to decline dramatically for California to meet its long-term climate goals. In planning, utility executives are considering the use of renewable gas in the existing infrastructure, but concerns such as pipeline safety and leakage would need to be explored further and addressed.

Energy Reliability Concerns in Southern California

The evolving role of natural gas is unfolding in Southern California, where ongoing reliability issues heighten the need to accelerate deployment of integrated distributed energy resources. The ability to maintain reliable electricity service in the Greater Los Angeles Area was first tested by the unexpected closure of the San Onofre Nuclear Generation Station in 2013, compounded by plans for the phased retirement of older natural gas facilities in the region that used marine water for cooling in once-through cooling systems. The Energy Commission, CPUC, and California ISO continue to work closely and take corrective action as needed to maintain electricity system

reliability. Most recently, the State Water Resources Control Board approved a request initiated by the agencies to defer the retirement of the Encina power plant temporarily to allow more time to complete the replacement facility in Carlsbad (San Diego County).

California must also consider the long-term role of natural gas as California continues ratcheting down its greenhouse gas emissions. In a letter from Energy Commission Chair Robert B. Weisenmiller to CPUC President Michael Picker dated July 19, 2017, the Chair wrote, “With the state’s climate target in mind, Governor Brown has asked me to plan for the permanent closure of the Aliso Canyon natural gas storage facility, and I urge the CPUC to do the same.”

Preparing for Climate Change

While California works to transform its energy system, it must also prepare for the effects of climate change as discussed above including increases in wildfires (see Figure ES-1), sea-level rise, heat waves, and drought. Several actions are underway, for example:

- As directed by Assembly Bill 2800 (Quirk, Chapter 580, Statutes of 2016), the California Natural Resources Agency announced the formation of the Climate-Safe Infrastructure Working Group. The working group will report to the Legislature by July 2018 on engineering standards that should be updated considering future climatic conditions.
- As stated in the *General Plan Guidelines: 2017 Update*, published by the Governor’s Office of Planning and Research (OPR), Senate Bill 379 (Jackson, Chapter 608, Statutes of 2015) requires local governments to include a climate change vulnerability assessment, measures to address vulnerabilities, and a comprehensive hazard mitigation and emergency response strategy in the safety element of the general plan. OPR’s Integrated Climate Adaptation and Resiliency Program Adaptation Clearinghouse provides access to information on funding, case studies, and tools and research (such as Cal-Adapt) to support adaptation planning by local governments.
- California’s utilities are working with the Energy Commission and the CPUC to incorporate updated climate science research into utility risk assessment and infrastructure planning decisions.

Through science-based research, California is increasing its resilience to climate change. Through its implementation of SB 350, California is on a path to transform the electricity, natural gas, and transportation sectors to meet its 2030 greenhouse gas reduction goal. As Governor Brown said, “California, as it does in many areas, must show the way. We must demonstrate that reducing carbon is compatible with an abundant economy and human well-being. So far, we have been able to do that.”

CHAPTER 1:

Primary Policy Drivers

California’s energy system provides a vast array of services that people count on every day, including electricity for lighting, air conditioning, and manufacturing; natural gas for heating, cooking, and industrial processes; and transportation fuels for cars, freight, and airplanes. These services, while providing the underpinnings of the state’s economy and way of life, also have serious consequences that must be addressed. When including transportation, the energy sector is the largest source of greenhouse gas (GHG) emissions in California, accounting for about 83 percent of the state’s GHG emissions.¹ The transportation sector alone directly accounts for more than 38 percent of statewide GHG emissions and is the largest source of pollutants that harm human health. Reducing GHG emissions is a paramount focus of state energy policy. Further, efforts to reduce GHG emissions must assure that all Californians have access to clean technologies and that the benefits of reducing GHG emissions reach the poor and disadvantaged communities that bear a disproportionate share of the pollution from the energy sector.

The window for turning the tide on global carbon emissions and avoiding the potentially catastrophic impacts is closing fast. An open letter authored by prominent scientists and cosigned by Governor Edmund G. Brown Jr. argues that a rapid downward trend in GHG emissions must be initiated in the next three years to avoid the most extreme impacts of this unfolding global calamity.² (See Chapter 10, “Carbon Budget for 2 Degrees Celsius Ceiling” for more information.) In July 2017, Governor Brown said, “It’s up to you and it’s up to me and tens of millions of other people... to roll back the forces of carbonization and join together to combat the existential threat of climate change.”

The California Energy Commission is required to develop the Integrated Energy Policy Report (IEPR) every two years “to develop energy policies that conserve resources, protect the environment, ensure energy reliability, enhance the state’s economy, and protect public health and safety.”³ This year’s report focuses on the state’s efforts to reduce GHG emissions in the electricity and transportation sectors. The discussion below lays out the drivers shaping California’s energy policy and provides context for the issues explored in-depth in other chapters.

Climate Change

The potential effects of climate change in California are many. Rising sea levels threaten coastal settlements, infrastructure, and ecosystems. An increase in extreme heat and a growing risk of regional megadrought threaten the state’s water supply. A warming climate portends the spread

¹ California Air Resources Board, Energy Commission staff analysis based on data from the California Greenhouse Gas Inventory for 2000–2015 by IPCC [Intergovernmental Panel on Climate Change] Category.

² Figueres, Christiana, Hans Joachim Schellnhuber, Gail Whiteman, Johan Rockström, Anthony Hopley, Stefan Rahmstorf, Comment, “Three Years to Safeguard our Climate,” *Nature*, Volume 546, June 2017.

³ Public Resources Code Section 25301 (a).

of pests and diseases that threaten the state's agriculture, forests, and human health. Larger, more frequent, and more intense fires pose a growing threat to much of rural California. Each of these trends is already underway and may become more extreme without a global effort to drastically and quickly reduce carbon pollution.

Climate change threatens serious economic impacts in California. This threat is most striking for sectors that are directly linked to natural resources – agricultural production will be challenged by higher temperatures and drought; tourism, the ski industry, and forestry in the Sierra Nevada will face the challenges of reduced snowpack, forest die-off, and intense wildfires. Along the coast, natural resources and built infrastructure, including cities, ports, airports, and energy and water systems, will be severely impacted by sea-level rise. Ultimately, every sector of the state's economy – including the energy sector – will be affected by climate change as the natural systems that provide the basis for all economic activity are increasingly stressed.

As potentially devastating as the effects of climate change may be for California, less wealthy regions of the world are facing even greater risks. According to the Encyclical letter signed by Pope Francis:

“[Climate change] represents one of the principal challenges facing humanity in our day. Its worst impact will probably be felt by developing countries in coming decades. Many of the poor live in areas particularly affected by phenomena related to warming, and their means of subsistence are largely dependent on natural reserves and ecosystemic services such as agriculture, fishing, and forestry. They have no other financial activities or resources which can enable them to adapt to climate change or to face natural disasters, and their access to social services and protection is very limited. ... Sadly, there is widespread indifference to such suffering, which is even now taking place throughout our world.”⁴

Moreover, the most extreme effects of climate change will be borne by future generations. There is an ethical imperative to act now.

International and Subnational Leadership in Reducing GHG Emissions

California's role as an international leader in reducing GHG emissions has grown since the 2016 presidential election. Recognizing that climate change is the “existential threat of our time,” Governor Brown continues to spearhead international and coordinated subnational efforts to address climate change. California represents about 1 percent of global GHG emissions, and, consequently, even if California cut all its GHG emissions, it would not be enough to avoid catastrophic climate change. Global action is needed.

Governor Brown's leadership includes participating in an international call to action on climate change in a 2013 consensus document;⁵ signing accords with leaders from Mexico, China, Japan,

⁴ Encyclical Letter *Laudato Si'* of the Holy Father Francis on Care for Our Common Home, http://w2.vatican.va/content/francesco/en/encyclicals/documents/papa-francesco_20150524_enciclica-laudato-si.html.

⁵ *Scientific Consensus on Maintaining Humanity's Life Support Systems in the 21st Century: Information for Policy Makers*, May 21, 2013, <http://mahb.stanford.edu/consensus-statement-from-global-%20scientists>.

Israel, Peru, Chile, the Netherlands, and others to reduce GHG emissions;⁶ and championing the Subnational Global Climate Leadership Memorandum of Understanding (the “Under-2 MOU”), a commitment by cities, states, and countries to help limit the rise in global average temperature to below 2 degrees Celsius.⁷ As part of this effort, Governor Brown and the Chinese Minister of Science and Technology signed an agreement in 2017 to cooperate on research, innovation, and investment to develop low-carbon energy technologies via the California-China Clean Technology Partnership.⁸ He was also a leader at the 2015 United Nations Climate Change Conference in Paris that resulted in an agreement among nations worldwide to sufficiently reduce GHG emissions to avoid catastrophic climate change. In 2017, Governor Brown was appointed to be the Special Advisor for States and Regions ahead of the 2017 United Nations Climate Change Conference.

While President Trump has stated his intention to pull the United States from the Paris Agreement, Governor Brown and other California leaders have maintained their commitment to reducing GHG emissions. California sought climate mitigation partnerships with other states, founding the United States Climate Alliance with the governors of Washington and New York. In less than a month, the partnership quadrupled in size. In July 2017, Governor Brown announced that California will host a Climate Action Summit in San Francisco in September 2018. He said, “President Trump is trying to get out of the Paris Agreement, but he doesn't speak for the rest of America. We in California and in states all across America believe it's time to act, it's time to join together, and that's why at this Climate Action Summit we're going to get it done.”⁹

California Policy Directives to Reduce GHG Emissions

Reducing GHG emissions and improving air quality are primary drivers of California’s energy policy. In 2006, California enacted the groundbreaking California Global Warming Solutions Act (Assembly Bill 32, Núñez, Chapter 488, Statutes of 2006), requiring a 20 percent reduction in GHG emissions by 2020. The California Air Resources Board (CARB), with input from the Energy Commission, California Public Utilities Commission (CPUC), other agencies, and a broad array of stakeholders, developed the *AB 32 Scoping Plan*¹⁰ to lay out a framework for meeting the goal. Some of the key measures included expanding energy efficiency programs and building and appliance standards; using renewables to serve 33 percent of the state’s electricity needs; developing a Cap-and-Trade Program for GHGs; and reducing emissions from the transportation sector. Considerable progress has been made on each of these measures.

⁶ http://www.climatechange.ca.gov/climate_action_team/partnerships.html.

⁷ See <http://under2mou.org/>.

⁸ <https://www.gov.ca.gov/news.php?id=19832>.

⁹ <https://www.gov.ca.gov/news.php?id=19866>.

¹⁰ CARB, *The First Update to the Climate Change Scoping Plan: Building on the Framework*, May 2014, http://www.arb.ca.gov/cc/scopingplan/2013_update/first_update_climate_change_scoping_plan.pdf.

In 2015, Governor Brown called on California to do still more. In his inaugural address, he said that California must “continue to transform our electrical grid, our transportation system, and even our communities” to reduce GHG emissions. He set the following goals for 2030:¹¹

- Increase from one-third to 50 percent the state’s 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.
- Reduce the relentless release of methane, black carbon, and other potent pollutants across industries.
- Manage farm and rangelands, forests, and wetlands so they can store carbon.

Governor Brown also put forward Executive Order B-30-15, which set a GHG emissions reduction goal of 40 percent below 1990 levels by 2030, while establishing guiding principles for climate planning and funding.¹² Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) codifies the 2030 GHG emissions reduction goal, and Assembly Bill 197 (Garcia, Chapter 250, Statutes of 2016) focuses on equitably implementing state climate change policies such that the benefits reach disadvantaged communities.

Senate Bill 350 (De León, Chapter 547, Statutes of 2015) advances the focus of California’s energy policy on achieving GHG reductions. The state’s work to implement SB 350 is the focus of this *IEPR*.

Key provisions of SB 350 include putting the Governor’s goals for 50 percent renewable energy and doubling energy efficiency savings into statute as tools for achieving the 40 percent reduction in GHG emissions by 2030. It also advances transportation electrification, as discussed further in the section below on “Transportation Sector Policy Drivers” and in Chapter 2. In accordance with the statute, specified load-serving entities must develop integrated resource plans that reflect these goals as part of an overall framework to cost-effectively reduce GHG emissions. (For more information on integrated resource plans, see Chapter 2.) SB 350 also allows the voluntary transformation of the California Independent System Operator (California ISO) into a regional organization, an important strategy to reduce GHG emissions as well as provide cost savings and other benefits. (For more information, see Chapter 3, “Regional Coordination.”)

SB 350 also requires CARB, in coordination with the CPUC and the Energy Commission, to establish GHG emissions reduction targets for the electricity sector and load-serving entities as part of the statewide 2030 goal while ensuring that low-income and disadvantaged communities are not marginalized as the grid transitions. (For more information, see Chapter 2.) CARB

¹¹ Governor Brown’s 2015 inaugural address, January 5, 2015, <https://www.gov.ca.gov/news.php?id=18828>.

¹² It also set a long-term goal to reduce GHG emissions 80 percent below 1990 levels by 2050. <https://www.gov.ca.gov/news.php?id=18938>.

proposed an updated Scoping Plan to reflect Senate Bill 350 in January 2017,¹³ and work to set targets is ongoing.

In 2016, Governor Brown signed Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) into law, furthering actions to reduce emissions of methane, black carbon, and other potent GHGs termed “short-lived climate pollutants” (SLCP). Among other requirements, SB 1383 directs CARB to develop and begin implementing a comprehensive strategy to reduce emissions of SLCPs to achieve reductions in the emissions of these gases by 40 to 50 percent below 2013 levels by 2030.

More recently, in July 2017, California’s Cap-and-Trade Program was extended through 2030 (Assembly Bill 398, Garcia, Chapter 135, Statutes of 2017), reiterating SB 32 goals of reducing GHG emissions to 40 percent below 1990 levels by 2030. In addition, AB 398 requires CARB to establish price ceilings and containment measures while adding sales tax exemptions to encourage renewable electricity development. A companion bill (Assembly Bill 617, Garcia, Chapter 136, Statutes of 2017) requires reporting, monitoring, and reduction plans for criteria-pollutant emissions in disadvantaged communities. The Legislature also decided that money collected from the auction of allowances from the Cap-and-Trade Program shall be prioritized to include, among other factors, climate adaptation and resilience, as well as climate and clean energy research.¹⁴

California is also working to increase the resiliency of its energy system to climate change. This work is discussed in Chapter 10.

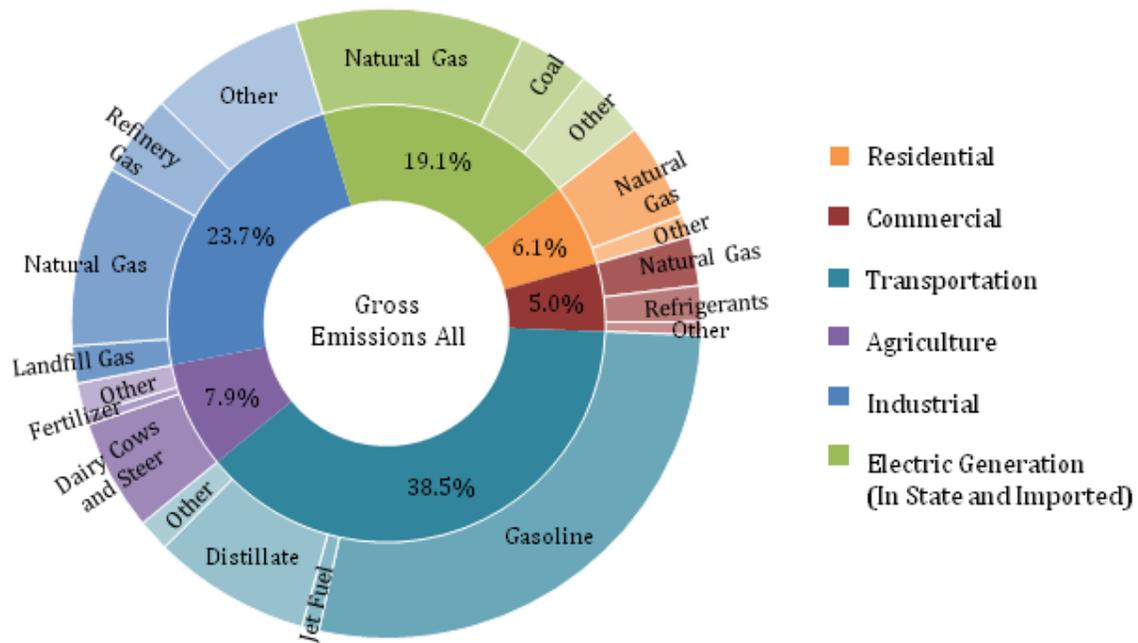
Sources of California GHG Emissions

Understanding the sources and tracking the amount of GHG emissions are critical to reducing them. The transportation sector dominates GHG emissions in California, accounting for 38.5 percent of the state’s emissions – almost double the emissions from the electricity sector, which is 19.1 percent. The industrial sector includes oil refineries and accounts for 23.7 percent, increasing the amount of emissions attributable to California’s transportation sector (although not included in the 38.5 percent noted above). The residential sector accounts for 11.1 percent, and agriculture accounts for 7.9 percent.

¹³ For additional information, see <https://www.arb.ca.gov/cc/scopingplan/scopingplan.htm>.

¹⁴ Health and Safety Code, Section 38590.1 (a).

Figure 1: California's GHG Emissions in 2015



Total = 440.4 MMTCO₂e

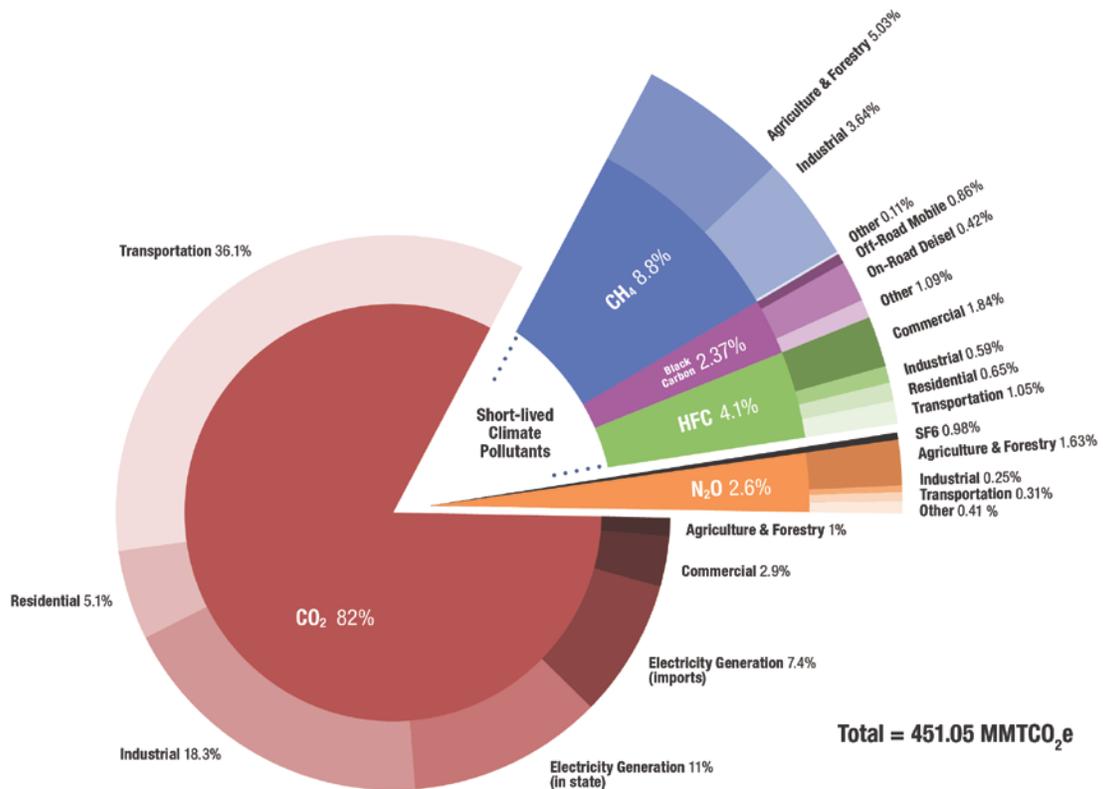
Source: California Energy Commission staff using data from CARB's 2017 Greenhouse Gas Emissions Inventory of 2015 emissions

If emissions from the electricity sector are attributed to end uses and not accounted for as a distinct category, then the 2015 California GHG emissions breakdown would be:

- Transportation – 38.5 percent.
- Industrial – 26.2 percent.
- Commercial – 13.8 percent.
- Residential – 12.3 percent.
- Agriculture and Forestry – 9.2 percent.

California's GHG emissions are primarily carbon dioxide (CO₂) released with the combustion of fossil fuels, accounting for 84.1 percent of GHG pollutants in 2015. Other pollutants that contribute to global climate change, as noted above, include methane (CH₄, primarily from agriculture and forestry), black carbon (soot, primarily from transportation), nitrous oxide (N₂O, primarily from agriculture), and fluorinated gases (HFC, primarily from the commercial sector). Figure 2 shows the relative contribution of carbon dioxide and SLCPs.

Figure 2: Relative Contribution of GHGs in California in 2015

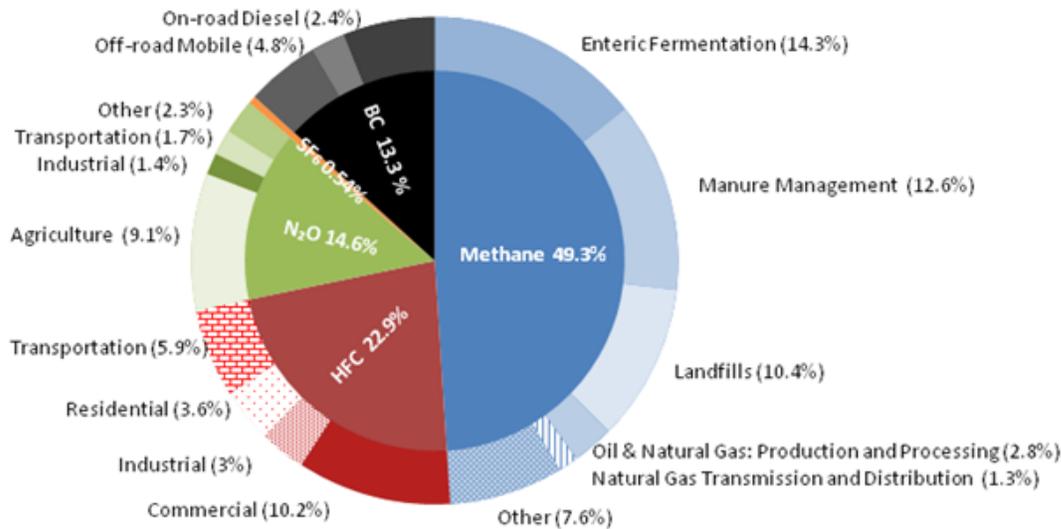


Source: California Energy Commission staff using data from CARB's 2017 Greenhouse Gas Emissions Inventory of 2015 emissions. The total million metric tons of carbon dioxide equivalent in Figure 2 is higher than in Figure 1 because Figure 2 accounts for black carbon emissions. Black carbon emissions data are from 2013, the most recent data available. Also, by including black carbon in total GHG emissions, the percentage emissions per sector differs from Figure 1. (For example, the transportation sector is 36.2 percent of total when including black carbon and 38.5 percent when black carbon is not included.)

Figure 3 shows the sources of SLCPs. Agriculture is the dominant source, accounting for more than 36 percent. Energy production and uses account for more than 35 percent.

Figure 3: Emissions of SLCPs and Other Non-CO₂ GHGs (2015)

Total = 81 MMTCO₂e



Source: California Energy Commission staff using data from CARB's 2017 Greenhouse Gas Emissions Inventory of 2015 emissions. Black carbon emissions data are for 2013, the most recent year of available data.

Reducing GHG emissions by 40 percent relative to 1990 levels by 2030 requires a dramatic and unprecedented cut in emissions. It requires fundamental changes to California's energy system, many of which are already underway.

Air Quality

California has made tremendous progress in improving air quality, but more work is needed. More than 90 percent of Californians breathe unhealthy levels of one or more air pollutants during some part of the year.¹⁵

Air pollutants that impact public health include criteria pollutants, such as particulate matter, ground-level ozone, carbon monoxide, oxides of nitrogen, oxides of sulfur, and toxic air pollutants. In its 2016 *State of the Air* report, the American Lung Association lists eight California metropolitan areas in the top-10 most polluted cities nationwide.¹⁶ CARB estimates that smog-forming emissions may need to be cut by 80 percent to attain federal air quality standards in 2023 and 2031 in parts of the state.¹⁷

Motor vehicles represent the largest source of air pollution in California,¹⁸ overshadowing all other sectors and accounting for nearly 80 percent of nitrogen oxide emissions and 90 percent of

¹⁵ <https://www.arb.ca.gov/research/health/fs/fs1/fs1.htm>.

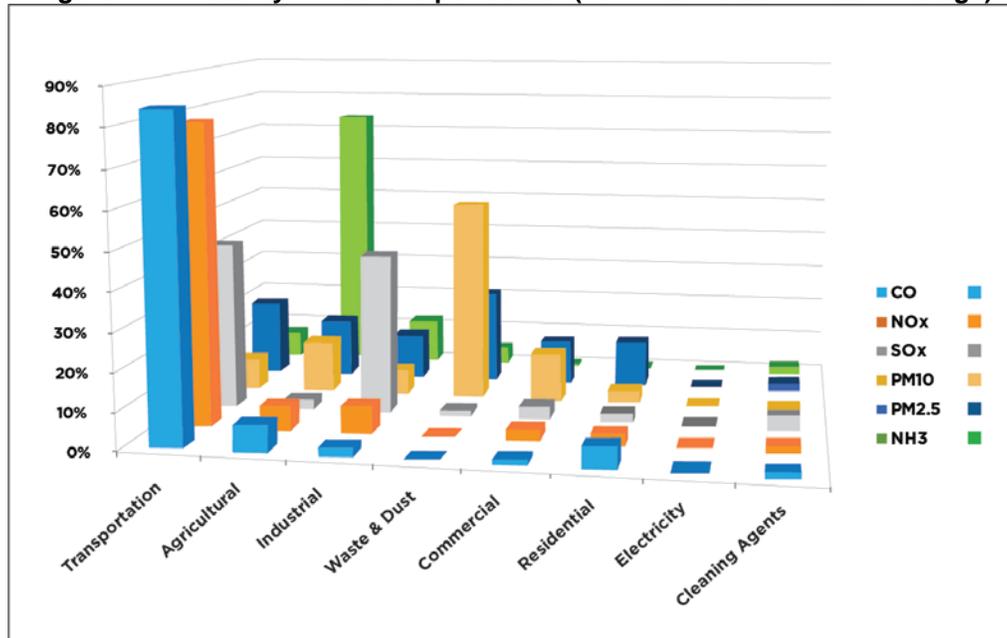
¹⁶ <http://www.lung.org/assets/documents/healthy-air/state-of-the-air/sota-2016-full.pdf>.

¹⁷ CARB. *Mobile Source Strategy*, May 2016, available at <https://www.arb.ca.gov/planning/sip/2016sip/2016mobsr.pdf>.

¹⁸ <https://www.arb.ca.gov/knowzone/history.htm>.

diesel particulate matter emissions in the state.¹⁹ (See Figure 4.) Transportation-related criteria pollutant emissions are associated with premature death and disease, as well as upper and lower respiratory symptoms, bronchitis, asthma, and cancer.²⁰ Electricity generation contributes a small percentage of California’s overall criteria pollutants (0.3 to 5.6 percent of statewide emissions in 2013),²¹ although emissions from power plants can raise local community concerns. Reducing criteria pollutant emissions from the transportation sector is an important part of California’s energy policy, as discussed further in the section below on Transportation sector “Regulations and Requirements.”

Figure 4: Air Quality Emissions per Sector (2012 Estimated Annual Average)



Source: California Energy Commission using CARB data at https://www.arb.ca.gov/app/emsinv/2017/emseic1_query.php?F_DIV=-4&F_YR=2012&F_SEASON=A&SP=SIP105ADJ&F_AREA=CA

Some communities face disproportionate air quality and other environmental burdens in California. To help focus investment to reduce such burdens, Senate Bill 535 (De León, Chapter 830, Statutes of 2012) directed the California Environmental Protection Agency to direct 25 percent of greenhouse gas reduction fund (GGRF) cap-and-trade allowance revenue to projects that provide economic and health benefits to disadvantaged communities, including 10 percent to projects located in disadvantaged communities.²² CalEnviroScreen 3.0 calculates a score for each

¹⁹ California Air Resources Board. *Mobile Source Strategy*. May 2016. Available at <https://www.arb.ca.gov/planning/sip/2016sip/2016mobsr.pdf>.

²⁰ California Energy Commission. 2015. *2014 Draft Integrated Energy Policy Report Update*. Publication Number: CEC-100-2014-001-CMF.

²¹ California Energy Commission Staff. 2016. *2016 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2016-003-CMF.

²² Disadvantaged Communities are defined as California census tracts facing the highest environmental burdens, as determined by a number of economic, environmental, and socioeconomic factors including low-income, high unemployment, poor health conditions, air and water pollution, and hazardous wastes. SB 535 directs the California Environmental Protection Agency (CalEPA) to identify disadvantaged communities for funding purposes, and as of April

census tract based on geographic, socioeconomic, public health, and environmental hazard criteria. The census tracts with the top 25 percent score are eligible to receive cap-and-trade funding consistent with SB 535 requirements. In 2016, Assembly Bill 1550 (Gomez, Chapter 369, Statutes of 2016) revised requirements for allocation of GGRF funding to specify that 25 percent of GGRF money must go to projects located within, and benefitting individuals living in, disadvantaged communities. Also, Assembly Bill 1550 added new requirements requiring 10 percent of GGRF money to fund projects located within, and benefitting individuals living in, low-income communities, as specified.

Access to Clean Technologies

The state is also working to ensure that all Californians have access to the clean energy resources critical to achieving the state's climate goals. As California continues down the path toward a low-carbon economy, it is critical the most vulnerable populations are not left behind. In addition to minimizing the impacts of fossil fuel generation and transportation on disadvantaged communities, it is equally important to create opportunities for this segment of the population to have access to cleaner alternatives, so they may play an active role in the fight against climate change and enjoy the numerous benefits that clean energy technologies provide.

Governor Brown and the Legislature have underscored this need by identifying a need for benefits to low-income residents and disadvantaged communities in SB 350 and other recent legislation. The full range of clean energy benefits extends beyond carbon reduction or bill savings to increasing public health and safety and enabling new workforce and small business opportunities for local residents.

SB 350 concluded that increasing low-income customers' access to weatherization, energy efficiency, renewable energy, and clean transportation options will allow communities across the state to begin realizing these benefits while providing meaningful contributions to overall GHG emissions reductions. Furthermore, increased investment in clean distributed energy resources will increase community resilience, or the ability to withstand difficult conditions. Conditions are expected to get only more difficult for residents of disadvantaged communities as climate change accelerates.

The SB 350 Low-Income Barriers Studies completed by the Energy Commission²³ and CARB²⁴ further supported this priority and put forth a range of potential solutions to overcome some of the difficulties faced by low-income residents and disadvantaged communities in accessing clean energy and low-emission transportation options. For more information on the identified barriers and potential solutions, refer to Chapter 2.

2017 CalEPA uses the top scoring 25 percent of communities using the CalEnviroScreen 3.0 tool to make this determination.

23 Scavo, Jordan, Suzanne Korosec, Esteban Guerrero, Bill Pennington, and Pamela Doughman. 2016. *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities*. California Energy Commission. Publication Number: CEC-300-2016-009-CMF.

24 <https://www.arb.ca.gov/msprog/transoptions/transoptions.htm>.

Energy Reliability

As California implements its climate goals, a major focus continues to be on maintaining the reliability of the energy system. Californians expect a reliable energy system, and any disruptions to energy services (such as energy for lighting, heating, water pumping, gasoline refining, or manufacturing) can have serious health and safety consequences, as well as negative economic repercussions.

In recent years, the energy infrastructure in California has suffered two major disruptions that have required ongoing efforts to assure energy reliability, as discussed in Chapter 11. Early manifestations of a changing climate (see Chapter 10), such as the early melting of the snowpack that reduces the availability of hydropower in the summer, increased peak electricity demand, and climate-induced wildfires contribute to reliability issues. Interagency work to maintain reliability following the unanticipated closure of the 2,200 MW San Onofre Nuclear Generating Station in 2012 and in the wake of the major leak at the Aliso Canyon natural gas storage facility is ongoing. The Aliso Canyon natural gas storage facility has been an important tool for managing natural gas supply for electric generation (particularly in summer when air-conditioning use is high) and home heating use (in the winter). But use of the storage facility has been severely limited since the leak in late 2015. Going forward, the state must find new ways to maintain the reliability of the energy system as it begins planning for the permanent closure of the Aliso Canyon natural gas storage facility.²⁵

More broadly, as California decarbonizes its electricity sector, it must also rethink the way it conducts energy planning and balances supply and demand. Solar and wind generation have grown dramatically, (see Chapter 3, “Changes in Electricity Generation”) reducing GHG emissions, but also creating more variability in energy supply. Thus, California’s success in advancing renewable energy in the electricity sector has created new operational challenges. Tools for maintaining system reliability as California continues to decarbonize its electricity sector are discussed in Chapter 3.

Resource Conservation and Environmental Protection

Conserving resources and protecting the environment go to the core of the state’s work to transform its energy system to reduce GHG emissions. Efforts discussed throughout this report to increase energy efficiency, advance renewable resources, and electrify the transportation system are focused on reducing GHG emissions. Also, in this *IEPR* the Energy Commission partnered with the CPUC and CARB to look at increasing the use of renewable gas to reduce SLCPs. (See Chapter 9.) Other key efforts include renewable energy and transmission planning, as discussed in Chapter 5.

The *2016 IEPR Update* focused on advancements in the environmental performance of the electricity sector over the last decade, including reducing GHG emissions through the increase in renewables and reduction in coal use, lowering criteria pollutant emissions, phasing out the use of

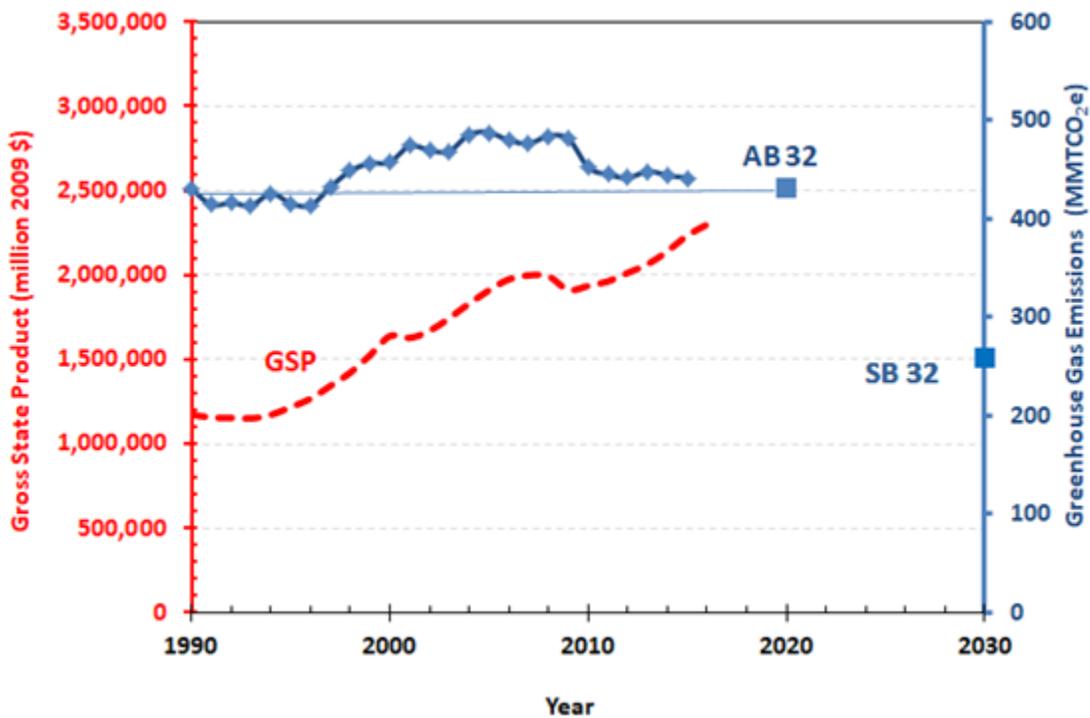
²⁵ Letter from Energy Commission Chair Robert B. Weisenmiller to CPUC President Michael Picker, July 19, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN220299_20170721T134102_July_19_2017_Letter_to_California_Public_Uilities_Commission_P.pdf.

once-through cooling technologies that harm marine life, reducing water consumption, and improving environmental planning for energy infrastructure. California remains committed to reducing the environmental impact of its entire energy system.

Economic Growth

While California takes action to transform its energy system to meet its climate and other energy policy goals, it must also protect the economy by controlling costs. Experience over the last decade has demonstrated that California can reduce emissions while growing its economy. (See Figure 5.) As Governor Brown said, “California, as it does in many areas, must show the way. We must demonstrate that reducing carbon is compatible with an abundant economy and human well-being. So far, we have been able to do that.”²⁶

Figure 5: California Has Reduced Its GHG Emissions While Growing Its Economy



Source: California Energy Commission staff using data from the CARB GHG Inventories and gross state product data from the Bureau of Economic Analysis of the U.S. Department of Commerce. Note: Not shown is California’s 2050 goal to reduce GHG emissions 80 percent below 1990 levels (Executive Order B-30-15).

Since the beginning of the century, California has achieved large economic growth with only modest growth in its energy consumption. From 2015 to 2016, electricity consumption in California grew less than 1 percent from 2015, totaling 285,701 gigawatt-hours (GWh). With this slight increase in electricity consumption, job growth increased nearly 2 percent, and California’s gross state product grew almost 3 percent.²⁷ Between 2000 and 2016, job growth increased nearly 13 percent, while electricity consumption grew almost 9 percent. California’s gross state product

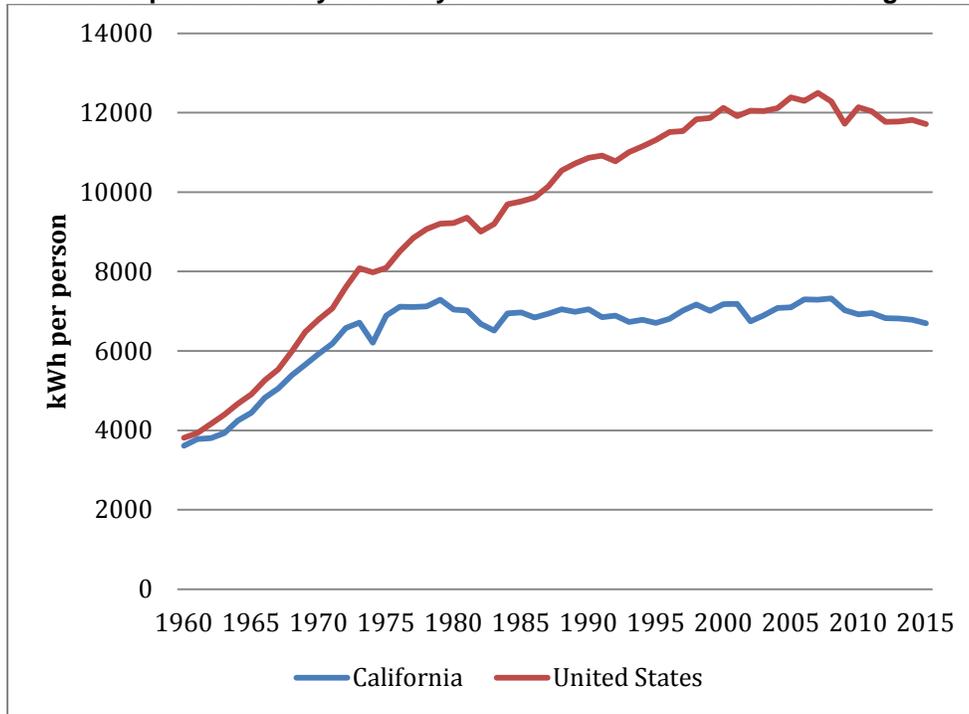
²⁶ <http://governors.library.ca.gov/addresses/39-Jbrown04.html>.

²⁷ Jobs data are from the Employment Development Department and reflect civilian employment growth. The source of gross state product numbers is Moody’s Analytics, January 2017. – June 2017.

grew by 40 percent – more than four times as fast as electricity consumption.²⁸ Meanwhile, the state’s population grew by 15 percent from about 34 million in 2000 to 39 million in 2016.²⁹

Figure 6 shows that per capita energy use in California has remained relatively flat since the 1970s, while it rose nationwide because of the state’s forward-looking energy efficiency regulations, industrial mix, and mild weather. This is shown in Figure 6, which is also termed the “Rosenfeld Curve” in honor of former Energy Commissioner Arthur H. Rosenfeld. See the sidebar for more information on the contributions of Art Rosenfeld.

Figure 6: Per Capita Electricity Use Stays Flat in California While Increasing Nationwide



Source: <https://www.eia.gov/state/seds/seds-data-complete.php>

²⁸ Gross state product data are from U.S. Bureau of Economic Analysis, Moody's Analytics. June 2017.

²⁹ Population data are from BOC, Moody's Analytics. – Department of Finance, December 2016.

One of the ways to help control energy costs and manage energy consumption while reducing GHG emissions in California is through thoughtful energy planning. One requirement of SB 350 is that retail electricity service providers develop integrated resources plans that take a broader, more comprehensive approach to energy planning than the more siloed approach of recent years. (See Chapter 2 for discussion.) SB 350 requires “each electrical corporation to fulfill its obligation to serve its customers at just and reasonable rates” and to “minimize impacts on ratepayers’ bills.”³⁰ While maintaining affordable costs is a principal goal of integrated resource planning, SB 350 also requires that utility IRPs minimize localized air pollutants and other GHG emissions, with early priority on disadvantaged communities.³¹ Some strategies for addressing this priority are described in the Low-Income Barriers Study section. (See Chapter 2.)

The integrated resource plans will complement existing cost control mechanisms embedded in the state’s energy efficiency and renewable energy policies. For example, all energy efficiency standards provide net benefits to the consumer. (Savings to the consumer will more than offset the additional cost to attain the standard.)

Ultimately, innovation in the energy sector will be critical for California to achieve its climate and energy goals at the lowest possible cost. The Energy Commission invests in research and development (R&D) to help spur innovation and bring to market technologies that are needed to help transform California’s energy system. R&D investments made through a rigorous, impartial, and public process can move innovations through the pipeline from concept to market. The Energy Commission funds R&D innovations that advance science and technology to make California’s energy safer, cleaner, more reliable, and less costly.

Arthur Rosenfeld

Physicist, internationally renowned energy expert, and former California Energy Commissioner Arthur H. Rosenfeld, Ph.D. died in January 2017, at age 90.

Dr. Rosenfeld was a driving force in shaping California’s nation-leading energy efficiency policies. He pioneered and championed the energy efficiency standards that have made California an international leader in energy conservation and sustainability.

His work showed that greater energy efficiencies in buildings and appliances would reduce the number of power plants needed and avoid added GHG emissions. He was also an early advocate of bringing energy companies on board as stakeholders to promote energy efficiencies and he helped developed several energy saving innovations such as electronic ballasts for compact fluorescent lights.

Dr. Rosenfeld was appointed to the Energy Commission in April 2000 and reappointed January 2005. During his tenure, he oversaw the Public Interest Energy Research program and energy efficiency issues including standards for buildings and for appliances. He retired from the Energy Commission in January 2010. His many awards and commendations include the Szilard Award for Physics in the Public Interest in 1986, the Carnot Award for Energy Efficiency from the U.S. Department of Energy in 1993, and the Berkeley Citation in 2001 from the University of California. In 2006, he received the prestigious Enrico Fermi Award, one of the highest honors from the U.S. Department of Energy. In 2008, *The Economist* magazine named him Innovator of the Year in the field of Energy and Environment. In 2011, Russian President Dmitry Medvedev presented Rosenfeld with the Global Energy Prize in recognition of his lifetime of achievement in energy efficiency. In 2012, President Barack Obama named Rosenfeld a recipient of the National Medal of Technology and Innovation, one of the highest honors from the U.S. government for scientists, engineers, and inventors.

For more information see http://calenergycommission.blogspot.com/2017/01/long-time-energy-efficiency-visionary_27.html?m=1.

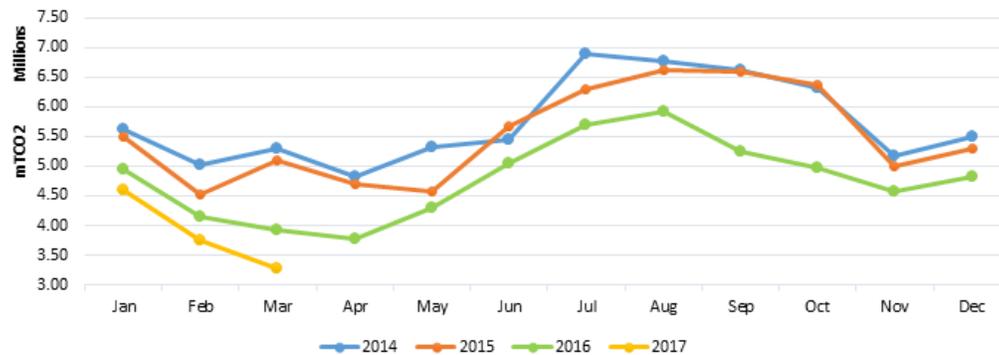
³⁰ PUC 454.52(a)(1)(C) and (D).

³¹ PUC Section 454.42 (a)(1)(H).

Electricity Sector Policy Drivers

The policies identified above are helping shape development of the electricity sector. As discussed in the *2016 IEPR Update*, the electricity sector has already made tremendous progress in reducing GHG emissions and improving environmental performance. Notably, GHG emissions from the electricity system in 2015 were already 23.9 percent below 1990 levels. Figure 7 shows the decline of GHG emissions serving the California ISO annually since 2014.

Figure 7: GHG Reductions in the California ISO System Since 2014
Total GHG Emission to serve ISO load



Source: California ISO, presentation by Mark Rothleder at May 12, 2017, IEPR workshop.

This reduction has been achieved even with declines in two of the state's zero-GHG sources of electricity with the permanent closure of the 2,200 MW San Onofre Nuclear Generating Station in 2013 and the loss of hydropower generation during the four-year drought. The state's last remaining in-state nuclear power plant, Diablo Canyon, will close by 2025 and Pacific Gas and Electric Co. will increase investments in energy efficiency, renewable resources, and energy storage beyond current mandates.³² (For more information on spent nuclear fuel management, see Appendix A.)

Below are highlights of some of the key policy drivers that have helped reduce GHG emissions from the electricity sector in California.

Legislative and Regulatory Drivers

Energy Efficiency

Energy efficiency entails using advancements in technology to provide the same or better level of energy service³³ to a consumer, while using less energy. SB 350 calls for the Energy Commission to establish targets that will achieve a cumulative doubling of energy efficiency savings by 2030. (For more discussion, see Chapter 2.) Additional energy efficiency innovation in buildings and

³² PG&E News Release, "In Step with California's Evolving Energy Policy, PG&E, Labor and Environmental Groups Announce Proposal to Increase Energy Efficiency, Renewables and Storage While Phasing Out Nuclear Power Over the Next Decade." June 21, 2016. Retrieved from http://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160621_in_step_with_californias_evolutionary_energy_policy_pge_labor_and_environmental_groups_announce_proposal_to_increase_energy_efficiency_renewables_and_storage_while_phasing_out_nuclear_power_over_the_next_decade.

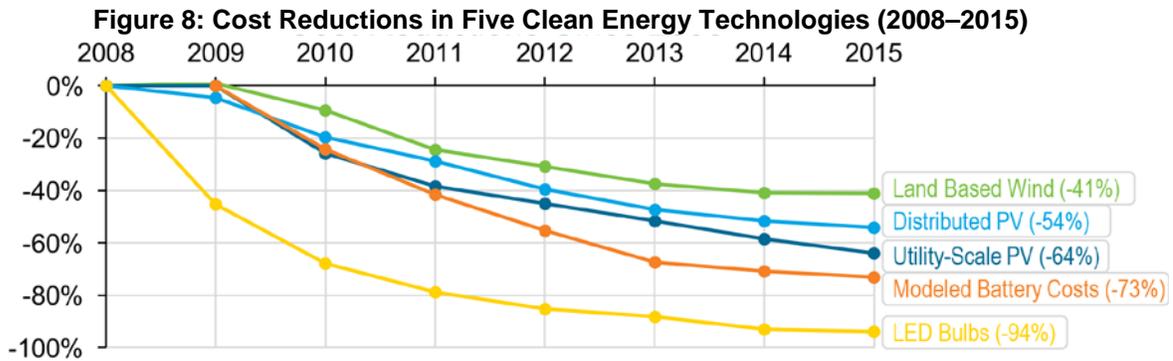
³³ "Energy service" includes all the ways people use energy, including for lighting, heating, and air conditioning.

appliances – the historical focus of California’s energy efficiency work – will be needed to achieve these savings targets. Further, deeper savings will also be needed in industry and agriculture, areas that have received less attention but where additional potential may exist. SB 350 continues, enhances, and expands the existing building energy efficiency program established by Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) and contained in the *Existing Building Energy Efficiency Action Plan*.³⁴

Renewable Energy and Distributed Resources

A major policy driver in the electricity sector is the state’s RPS, which was established in 2002 and accelerated and expanded in subsequent years. The Energy Commission estimates that California’s in-state operating renewable energy capacity (wind, solar, geothermal, biomass, and small hydroelectric) was 27,500 MW as of June 2017,³⁵ up from 6,800 MW in 2001.³⁶ California leads the nation in electricity production from solar energy, geothermal, and biomass.³⁷

Cost reductions in renewable energy sources, particularly solar and wind energy, have helped spur market growth for renewables. Between 2008 and 2015, the cost for land-based wind has declined 41 percent, distributed PV has declined 54 percent, and utility-scale PV has gone down by 64 percent. (See Figure 8.)



Source: U.S. Department of Energy. September 2016. *Revolution ... Now: The Future Arrives for Five Clean Energy Technologies – 2016 Update*.

As the state moves forward to implement the 50 percent requirement, more work is needed to maximize the benefits of renewable energy (for more discussion, see Chapter 3) while electrifying the transportation sector (for more discussion, see Chapters 2, 3, and 4, and Appendix H) and maintaining system reliability. (For more discussion of reliability issues in Southern California, see Chapter 11.)

In 2006, Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) established a suite of solar programs with a goal of building a self-sustaining solar market combined with high levels of

34 <http://www.energy.ca.gov/ab758/documents/>.

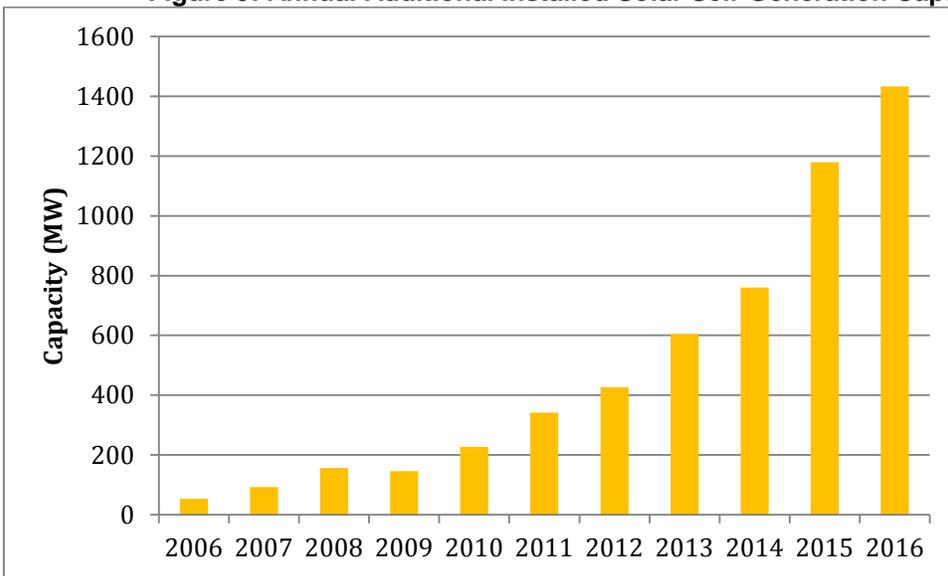
35 The California Energy Commission’s Tracking Progress Web page, Renewable Energy, updated August 2017, http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

36 California Energy Commission Staff. 2016. *2016 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2016-003-CMF.

37 Energy Information Administration California State Profile, Last Updated October 20, 2016.

energy efficiency in the state’s homes and businesses. The legislation set an ambitious goal to install 3,000 MW of behind-the-meter solar by 2017. The state far exceeded the goal with about 5,800 MW of solar photovoltaics installed in California as of June 30, 2017. This is more than triple the amount installed since 2012, and almost 2,700 MW were installed in 2015 and 2016. Figure 9 shows the amount of new solar self-generation (rooftop PV) interconnected to the electricity system annually from 2006 to 2016. The growth in behind-the-meter resources is a fundamental shift in the energy sector away from large-scale facilities, which creates many new challenges and opportunities, as discussed in Chapter 3. (See Chapter 6 for information on efforts to better incorporate behind-the-meter solar into the 10-year electricity forecast.)

Figure 9: Annual Additional Installed Solar Self-Generation Capacity



Source: California Energy Commission staff. Sources include [D8] through [D12], [D14]. Also includes NEM projects that have not received California renewable energy incentives [D14]. Updated June 2017.

Transportation Electrification

California cannot meet its climate and energy goals solely with advancements in the electricity sector. Reducing emissions from the transportation system with low-carbon alternative fuel vehicles is critical. A major policy goal, as discussed below in “Transportation Policy Drivers,” is to electrify the transportation sector, which addresses the use of electricity from external power sources for mobility. With half of all the plug-in electric vehicles driven nationwide located here, California is already leading the way. Further growth in transportation electrification provides challenges and opportunities to the electricity system.

Emission Performance Standard

Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006) established another key policy for reducing GHG emissions – California’s Emissions Performance Standard. This standard prevents California utilities from making new long-term commitments (five years or more) to high GHG-emitting baseload power plants – plants that emit more than 1,100 pounds of CO₂ per megawatt-hour. This restriction is encouraging California utilities’ divestiture of high GHG-emitting power

plants. Coal-fired electricity consumed in California has declined about 86 percent since the standard was enacted in 2006 and is expected to be zero by 2026.³⁸

Water-Use Efficiency and Phase-Out of Once-Through Cooling Technologies

As reported on in the *2016 IEPR Update*, conserving freshwater and avoiding wasteful use have long been part of the state's water policy.³⁹ The Energy Commission encourages power plant developers in California to reduce water consumption by using water-efficient technologies and to conserve freshwater by using recycled water. This policy conserves water and makes the electricity system more resilient to drought.

In 2010, the State Water Resources Control Board (SWRCB) adopted a policy to phase out the use of once-through cooling (OTC) technologies while maintaining the critical needs of the state's electricity system.⁴⁰ The OTC policy reduces the discharge of heated water into marine and estuarine ecosystems and the death of species through impingement and entrainment.⁴¹ Overall, the state is ahead of schedule for OTC phase-out, but in August 2017, the SWRCB approved a request from the energy agencies for a delay in the implementation schedule for one power plant, Encina Units 2–5, to maintain energy reliability in Southern California. The Office of Administrative Law approved the amendment in December 2017. (For more information, see Chapter 11.)

Changes in Electricity Market Structure

As California works to further transform its electricity sector, it must do so in the midst of a fundamentally changing industry. Market developments, technological innovations, and policy actions have helped put into motion a shift away from having the investor-owned and publicly owned utilities as the energy provider for most Californians. Consumer choice is proliferating. For example, millions of Californians are installing their own rooftop solar, and local government agencies are forming community choice aggregators (CCAs) that can directly develop and buy electricity on behalf of their customers.⁴² The CPUC exercises relatively limited authority over CCAs,⁴³ as CCAs' elected officials set rates and determine procurement strategies within certain parameters, including the RPS mandates.

38 The California Energy Commission's Tracking Progress Web page, Actual and Expected Energy From Coal for California, updated December 2017.

39 State Constitution, Article X, Section 2 and SWRCB Resolution 75–58.

40 SWRCB, *Statewide Policy on the Use of Coastal and Estuarine Waters for Power Plant Cooling (Attachment 1)*, 2010, http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/policy100110.pdf.

41 *Impingement* is the entrapment and death of large marine organisms on cooling system intake screens, and *entrainment* is the death of small plants and animals that pass through the intake into the plant.

42 Authorized in 2002 by Assembly Bill 117 (Migden, Chapter 838, Statutes of 2002) and later expanded in 2011 by Senate Bill 790 (Leno, Chapter 599, Statutes of 2011), a CCA is created through a local city or county ordinance and automatically enrolls all customers in its service area, unless the customer opts out. The CCA takes charge of electricity procurement, and the local investor-owned utility retains responsibility for transmission and distribution, metering, billing, and customer service.

43 The following is an excerpt from a report by the CPUC titled *California's Renewables Portfolio Standard, Annual Report*, November 2017, available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Nov%202017%20-%20RPS%20Annual%20Report.pdf. "As additional CCAs are formed, the CPUC will oversee a

At the beginning of 2017, five CCAs were operating in California and collectively serving 915,000 customers: MCE Clean Energy, Sonoma Clean Power, CleanPowerSF, Lancaster Choice Energy, and Peninsula Clean Energy.⁴⁴ By September 2017, four additional CCAs – Silicon Valley Clean Energy, Apple Valley Choice Energy, Redwood Coast Energy Authority, and Pico Rivera Innovative Municipal Energy – had begun serving customers. Up to eight CCAs are anticipated to launch in 2018, and an additional 17 cities and counties are exploring CCAs.⁴⁵ Estimates predict that as much as 25 percent of investor-owned utility retail electric load could be unbundled by the end of 2017 due to the increase in CCAs, self-generation, and electric service providers. This number could reach 85 percent in the next decade – or as many as 15 million to 20 million customers.⁴⁶

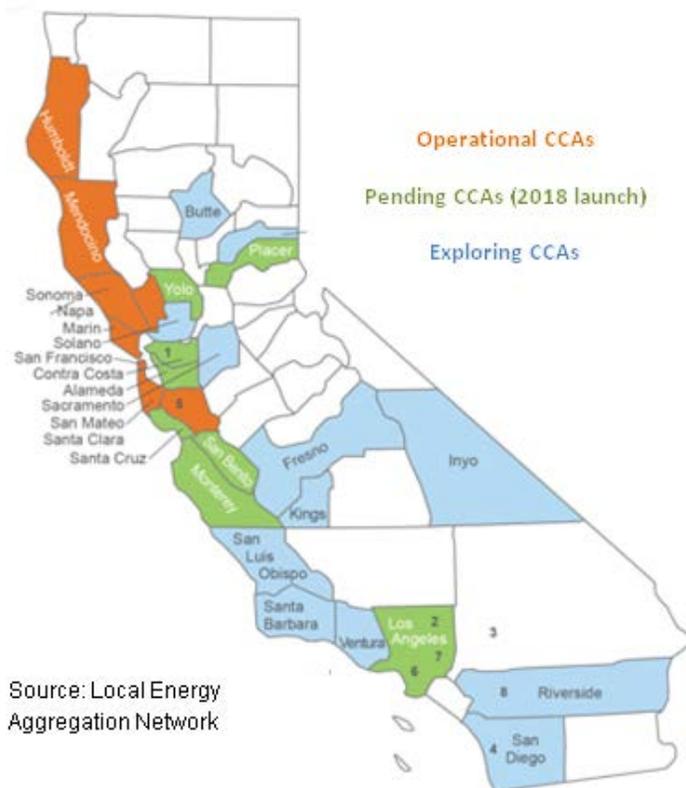
significantly smaller percentage of renewable procurement in the State, as the CPUC has limited jurisdiction over the procurement activities of CCA or ESP providers. If the IOUs lose such large portions of their customer demand, the result will be that the CPUC will not have the authority to monitor most renewable energy procurement activities in as much detail, as it has traditionally done for RPS.”

44 *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*. 2017. California Public Utilities Commission.
http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf.

45 LEAN Energy US. <http://www.leanenergyus.org/cca-by-state/california/>, accessed September 1, 2017.

46 *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*. 2017. California Public Utilities Commission.
http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf.

Figure 10: Operational, Pending, and Potential CCAs



Source: California Energy Commission Tracking Progress on Renewable Energy, Updated December 2017, http://www.energy.ca.gov/renewables/tracking_progress/#renewable

Meanwhile, more consumers are installing their own PV systems with net energy metering, driven largely by cost reductions and technology innovation. This has been an ongoing trend, with about 4,700 MW installed since January 2011 for a total of 5,800 MW of solar self-generation capacity installed by June 2017. As storage costs come down, consumers may also begin installing their own storage systems.

The shift to CCAs, the increase in behind-the-meter solar, and increases in energy efficiency have all contributed to IOUs being long on supply and not entering long-term contracts. PG&E reported that it has not conducted any long-term procurement since 2014 and does not “anticipate a need to do anything besides short-term, small, hourly, monthly procurement.”⁴⁷ PG&E also stated that it is “no longer necessarily a buyer... And as more load continues to shift, PG&E’s position will be more capacity sales.”⁴⁸ As an example, PG&E is selling small hydroelectric facilities.⁴⁹ In response to a question from Chair Weisenmiller about long-term procurement for resource adequacy needs, SCE reported, “Although SCE may ask for terms out to

⁴⁷ Joe Lawlor, PG&E, April 24, 2017, Transcript, pp. 99–100.

⁴⁸ Joe Lawlor, PG&E, April 24, 2017, Transcript, pp. 88–89.

⁴⁹ Jim Gill, PG&E, April 24, 2017, Transcript, pp. 94-96.

five years forward, recently, SCE has been executing shorter term transactions, in consideration of load departure risk.”⁵⁰

More broadly, the increase in self-generation has reduced the IOU and POU customer base and, consequently, the revenue sources that have traditionally been available for other infrastructure investments aside from generation. Achieving the state’s GHG emissions reduction goals will require large investments in EV charging infrastructure, new renewable power plants, solutions to help integrate increasing amounts of solar and wind generation, distribution system upgrades, transmission lines, and more. A staff white paper by the CPUC stated, “Much of the policy framework underpinning the [GHG reduction, RPS, and transportation electrification] goals has presumed the electric utility serves as the central agent for making these investments, raising low-cost capital in financial markets, and then recovering costs through sales of electricity. Yet, at the same time that California is grappling with how to plot a path forward to build this infrastructure in the most efficient, reliable and equitable way, the status quo retail electric service model is being upended.”⁵¹

There is uncertainty about the ability of CCAs to secure financing for the magnitude of the long-term investments needed to advance California’s energy and climate goals. Some CCAs have begun to sign long-term contracts as their growth continues and load forecast stabilizes.”⁵² CCAs do not have credit ratings, however, and although a report by Chadbourne suggested possible workarounds, it noted that “[credit support] would have to come from the municipalities inside the CCA service area and, thus, would require approval by the county board of supervisors or one or more city councils.”⁵³ Matt Freedman from The Utility Reform Network testified to the Senate Standing Committee on Energy, Utilities and Communications on August 2, 2017, that “new CCAs are primarily ... signing short term contracts for existing resources and it takes quite a number of years for CCAs to build the financial capacity to get new projects developed in any significant quantities. So ... what we get is where we are today, which essentially is the valley of death for procurement. ...There are developers that cannot get their projects contracted or built.”⁵⁴ A long-term risk for CCAs is that their customers could opt out of service and return to the investor-

50 SCE Comments on Risk of Economic Retirement for California Power Plants, submitted May 8, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-14/TN217472_20170508T135111_Catherine_Hackney_Comments_SCE_Comments_on_Risk_of_Economic_Ret.pdf.

51 *Consumer and Retail Choice, the Role of the Utility, and an Evolving Regulatory Framework*. 2017. California Public Utilities Commission. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/Retail%20Choice%20White%20Paper%205%208%2017.pdf.

52 Projects include a 100 MW power plant in Kings County based on contracts with Marin Clean Energy and Sonoma Clean Power in 2016 and another 100 MW utility-scale solar project that was financed in 2017 that is expected to go on-line in 2019. Deanne M. B. Barrow, Financing Projects with CCA Contracts, December 2017. http://www.nortonrosefulbright.com/knowledge/publications/158256/financing-projects-with-cca-contracts?utm_source=vuture&utm_medium=email&utm_campaign=20171220%20project%20finance%20newswire_20%20december%202017.

53 Chadbourne, Project Finance NewsWire, *Financing Projects with Community Choice Aggregators*, June 2017. Chadbourne & Parke has since merged with Norton Rose Fulbright.

54 Testimony of Matt Freedman from The Utility Reform Network to the Senate Standing Committee on Energy, Utilities and Communications on August 2, 2017, <https://ca.digitaldemocracy.org/hearing/54261?startTime=60&vid=e321456e2bfa461c2fce3e7c92e65a8a>.

owned utility. David McNeil, finance manager at Marin Clean Energy, stated that “the opt-out rate during an enrollment period does not really matter from a risk perspective because we are not procuring for that load over the long term. The risk that CCAs have is that you have a whole bunch of customers, you procure for those customers, and then they opt out.”

Considerable work is needed to better understand how best to advance the state’s climate and energy goals in the midst of this changing landscape.

To start framing and addressing the policy issues around the shift to consumer choice and decentralization, the Energy Commission and CPUC held a joint “en banc” workshop on May 19, 2017. There are questions about what party will make the capital investments needed, for example, to assure energy reliability as variable, renewable generation grows. Other roles traditionally served by the utilities that may not be well served in the changing market include:

- Energy efficiency programs.
- Research and development.
- Service to low-income consumers.
- Access to advanced technologies for all consumers.
- Large capital investments needed to assure energy reliability.

Conversely, markets and technology innovations can provide new and faster opportunities to reduce GHG emissions. At the workshop, Energy Commission Chair Robert B. Weisenmiller pointed to the need to transform society to meet the state’s climate goals, noting, “Utilities are part of the engine for doing that. And their ability to do that, to provide the financial commitments, is not obvious going forward. So somebody’s got to help us do that transformation. And there are ways that innovation can drive it faster. And there are other ways where we may find the pieces we need are not really in place.”⁵⁵ To aid in making strategic, timely, and informed decisions regarding the transformation of the California electric market, the CPUC formed the California Customer Choice Project. As part of the project, the CPUC held an informal initial public workshop on October 31, 2017, to gather stakeholder input on national and global electric market choice models, including California’s projected 2020 status. Input from the workshop will inform the CPUC’s assessment of the state’s current regulatory structure for customer choice, alternative frameworks, and barriers to implementation. The CPUC plans to issue the California customer choice white paper in early 2018 for stakeholder input and a final paper in spring 2018.

Assuring that California’s climate and energy goals are achieved as the industry evolves, with access for all Californians, will require thoughtful and ongoing consideration by policy makers and regulators.

⁵⁵ May 19, 2017, workshop transcript, pp. 18–19.

Transportation Sector Policy Drivers

As discussed above, the transportation sector is the most significant emitter of GHGs in California, directly accounting for 38.5 percent of in-state emissions and which increases to about 50 percent when including emissions from refineries.⁵⁶ Direct emissions from the transportation sector are also the largest contributor to the formation of ozone and emissions of small particulate matter and diesel particulate matter, accounting for nearly 80 percent of nitrogen oxide emissions and 90 percent of diesel particulate matter emissions in the state.⁵⁷

To meet California's aggressive climate change goals and to protect public health and the environment, the state will need to dramatically reduce these emissions in the coming years. Numerous policy drivers and programs are now in place that, if successful, will help achieve these goals. Table 1 summarizes some of these policies and programs, which are discussed below.

⁵⁶ CARB. *California Greenhouse Gas Emission Inventory*. June 6, 2017. Available at <https://www.arb.ca.gov/cc/inventory/data/data.htm>.

⁵⁷ CARB. *Mobile Source Strategy*. May 2016, <https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrsrc.pdf>.

Table 1: California Transportation Policy Drivers

Policy Origin	Objectives	Goals and Milestones
Policy Goals		
Executive Order B-16-2012, Senate Bill 1275 (2014)	Increased Zero-Emission Vehicles	1 million zero-emission vehicles by 2023 and 1.5 million zero-emission vehicles by 2025, including required infrastructure
Executive Order B-32-15, Sustainable Freight Action Plan	Air Quality Improvement GHG Reduction Petroleum Reduction	Improve freight efficiency and transition freight movement to zero-emission technologies
Senate Bill 1383 (2016)	Increase Renewable Gas Use	Adopt policies and incentives to increase the production and use of renewable gas
Regulations and Requirements		
Advanced Clean Cars Regulation (ZEV requirement)	Increased Zero-Emission Vehicles	Require automakers to produce increasing numbers of ZEVs through Model Year 2025
Senate Bill 350 (2015)	Increased Plug-In Electric Vehicles	Require utilities to plan for or invest in electric vehicle charging or both
Federal Clean Air Act of 1970	Air Quality	80 percent reduction in NO _x by 2031
Low-Carbon Fuel Standard	GHG Reduction	Reduce carbon intensity of transportation fuels in California by 10 percent by 2020
Incentives		
Assembly Bill 8 (2013)	GHG Reduction Air Quality Improvement Petroleum Reduction	Transform the state's fuel and vehicle types to attain state climate change goals and improve air quality
Low-Carbon Transportation Investments (from Greenhouse Gas Reduction Fund)	GHG Reduction Air Quality Improvement	Accelerate development and deployment of clean mobile source technologies
Volkswagen Settlement ("Electrify America")	Increased Zero-Emission Vehicles	Support growth of zero-emission vehicles

Source: California Energy Commission

Policy Goals

Zero-emission vehicles (ZEVs) are a cornerstone of the state's efforts to reduce GHG and criteria pollutant emissions. Two current policy drivers have set ZEV deployment goals, the first of which is Executive Order B-16-12, issued by Governor Brown in March 2012. This executive order set a target for California to have 1.5 million ZEVs, and the infrastructure to support them, on the road by 2025 and tasked various state agencies with specific actions needed to support this goal. The Governor's Office of Planning and Research produced the *ZEV Action Plan*, issued in 2013⁵⁸ and subsequently updated in July 2016,⁵⁹ to identify actions that the state government would take to meet the milestones in the executive order.

⁵⁸ [https://www.opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_\(02-13\).pdf](https://www.opr.ca.gov/docs/Governor's_Office_ZEV_Action_Plan_(02-13).pdf).

⁵⁹ https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf.

Following Executive Order B-16-12, Senate Bill 1275 (De León, Chapter 530, Statutes of 2014) established the Charge Ahead California Initiative, which is administered by CARB in consultation with the Energy Commission and related agencies. This statute establishes a goal of placing 1 million zero-emission and near-zero-emission vehicles in service by January 1, 2023, while providing increased access to these vehicles for disadvantaged, low-income, and moderate-income communities and consumers. (For more information about transportation electrification, see Chapters 2, 3, 4, and 6 and Appendices D and H.) Plug-in electric vehicles are expected to form the majority of these ZEVs, with hydrogen fuel cell electric vehicles accounting for a notable share as well.

Freight vehicles present unique opportunities for target improvement. Even though they represent just 3 percent of the vehicle stock in California, they are responsible for 23 percent of on-road GHG emissions. Executive Order B-32-15, issued by Governor Brown in July 2015, ordered the development of an integrated action plan to improve freight efficiency, transition to zero-emission technologies, and increase the competitiveness of California's freight system. The resulting *California Sustainable Freight Action Plan* was released in July 2016 and identifies state policies, programs, and investments to achieve these targets. The plan was developed as a combined effort by the California State Transportation, California Environmental Protection, and California Natural Resources Agencies, including CARB, the California Department of Transportation, the Energy Commission, and the Governor's Office of Business and Economic Development, in partnership with the public and stakeholders.

A requirement of SB 1383 is for the Energy Commission, along with the CPUC and CARB, to consider incentives and policies that will significantly increase the sustainable production and use of renewable gas. Increasing renewable gas production will not only reduce emissions of methane (an SLCP), but can also provide a low- or negative-carbon transportation fuel well suited for freight and fleet vehicles. For more information, see Chapter 9.

Regulations and Requirements

In 2012, CARB adopted the Advanced Clean Cars program, which included the ZEV regulation. The ZEV regulation requires automakers to produce an increasing mix of battery-electric vehicles, plug-in hybrid electric vehicles, and/or fuel cell electric vehicles from Model Year 2018 through Model Year 2025. Compliance is based on generating or purchasing enough credits, which are assigned to each vehicle based on attributes such as electric driving range. A midterm review of the Advanced Clean Cars program included an assessment of credits generated to date and compliance scenarios for reaching this cleaner mix of vehicles.

Although it did not set a specific goal or milestone, SB 350 also emphasizes transportation electrification as a critical element to achieving the state's GHG emissions reduction goals. In particular, SB 350 requires retail electrical corporations to file applications for investments with the CPUC that will accelerate transportation electrification. The legislation also requires specified

publicly owned electric utilities to adopt IRPs that address procurement for transportation electrification.

The federal Clean Air Act of 1970 (42 U.S.C. 7401) authorized the U.S. Environmental Protection Agency (U.S. EPA) to establish National Ambient Air Quality Standards to protect public health. To achieve these standards, the Clean Air Act directs states to develop state implementation plans that describe how an area plans to attain them. The transportation sector, being responsible for the majority of emissions for several criteria pollutants, continues to be a major focus of state implementation plans. CARB, in coordination with local air quality districts, is the state agency responsible for developing the California state implementation plans and for controlling emissions from cars, trucks, other mobile sources, and consumer products.

In May 2016, CARB released a *Mobile Source Strategy* that outlines a coordinated effort to meet air quality standards, achieve state GHG emissions targets, minimize exposure to toxic air contaminants, reduce petroleum use by up to 50 percent by 2030, and increase energy efficiency and renewable electricity generation. Many of the actions recommended in the strategy, such as increasing the use of ZEVs and renewably sourced alternative fuels, correspond with other state policy goals and activities undertaken by the Energy Commission.

As part of the state's implementation of AB 32, CARB adopted the Low-Carbon Fuel Standard (LCFS) regulation in 2009. The LCFS is designed to encourage the use of cleaner low-carbon fuels by creating market incentives for near-term GHG emissions reductions. It has a goal of reducing the overall carbon intensity of fuel within the transportation sector by 10 percent by 2020. Since the regulation came into effect, regulated parties have had to slowly reduce the carbon intensity of their fuel. The LCFS provides regulated parties with credits for the production of low-carbon fuel, with each credit equal to the reduction of 1 metric ton of carbon dioxide equivalent (CO₂e), or roughly equivalent to the amount of CO₂e released from the combustion of about 90 gallons of gasoline. The credits can then be sold to other regulated parties that are not achieving the required reductions in carbon intensity.

The LCFS program also produces California-specific life-cycle analyses of GHG emissions for fuels using a consistent method of calculation across multiple fuel pathways. The life-cycle GHG emission numbers are used by the Energy Commission to assess opportunities from different alternative fuels and estimate GHG emissions reduction potential.

Incentives

To help address state GHG emissions and air pollution objectives, the California Legislature passed Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007). This legislation created the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP), which is administered by the Energy Commission; the Air Quality Improvement Program (AQIP), which is administered by CARB; and the Enhanced Fleet Modernization Program, which is administered by the Bureau of Automotive Repair and CARB. The ARFVTP provides up to \$100 million per year for projects that transform California's fuel and vehicle types to help attain the state's climate change policies. Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013) extended the collection of fees that support the ARFVTP through January 1, 2024. Through the ARFVTP, the Energy

Commission funds a broad range of projects types without adopting any preferred fuel or technology. Since its inception, the ARFVTP has been a major source of funding for biofuel production plants, electric vehicle charging infrastructure, hydrogen refueling infrastructure, natural gas vehicles and fueling stations, alternative fuel workforce training, and alternative fuel freight vehicles. For more information, see Appendix D: Benefits Report for the Alternative and Renewable Fuel and Vehicle Technology Program. Under AQIP, CARB created the Clean Vehicle Rebate Project, which provides funding incentives for the purchase or lease of new battery-electric vehicles, plug-in hybrid electric vehicles, and fuel cell electric vehicles.

With revenue from the sales of allowances under the AB 32 cap-and-trade system, CARB has also made significant investments into the development and commercialization of cleaner vehicles. Through

Fiscal Year 2016–2017, the state had appropriated \$695 million from its Greenhouse Gas Reduction Fund for low-carbon transportation projects under CARB. This funding covers a wide array of vehicle types and applications, with the largest share of funding supporting the Clean Vehicle Rebate Project incentives for light-duty battery-electric vehicles, plug-in hybrid electric vehicles, and fuel cell electric vehicles. CARB has also prioritized projects addressing the medium- and heavy-duty vehicle sectors, including advanced technology freight demonstration projects and zero-emission truck and bus pilot projects. For Fiscal Year 2017-2018, the state provided an additional \$560 million toward similar low-carbon transportation projects under CARB, plus \$85 million for reducing agricultural sector emissions (including trucks) and \$250 million to support the Carl Moyer and Proposition 1B clean truck programs.

Beginning with its 2009 model year, Volkswagen sold diesel vehicles in California that violated federal and state law by using illegal devices to defeat emission tests. To remedy the harm caused by the use of these devices, Volkswagen agreed to a series of settlement agreements with the state of California. For more information on this settlement, see the sidebar above. Volkswagen's investments will occur over a 10-year period and are expected to fund projects such as fueling infrastructure for zero-emission vehicles, consumer awareness campaigns, and car-sharing programs. The first cycle of the Volkswagen ZEV investments, which covers January 2017 through June 2019, is expected to invest \$120 million in electric vehicle charging infrastructure, including community charging and highway fast charging. The investments also include an estimated \$20 million for public education and \$44 million for planning and infrastructure for a green city initiative.

Greenhouse Gas Reduction Fund

In December 2017, CARB adopted the *Fiscal Year 2017–18 Funding Plan for Clean Transportation Incentives*. The largest part of this funding plan is the Low Carbon Transportation Investments, which are funded with \$560 million of cap-and-trade auction proceeds. These investments include \$140 million for the Clean Vehicle Rebate Project, \$100 million for transportation equity projects, \$140 million for advanced freight equipment demonstration and deployment, and \$180 million for clean truck and bus vouchers.

Volkswagen Diesel Emission Settlement

To remedy the harm caused from the use of illegal emission test defeat devices, Volkswagen has agreed to a series of penalties and investments for the benefit of the people of California. Volkswagen will pay \$422 million to mitigate excess nitrous oxide emissions, \$153.8 million in civil penalties, and \$25 million for low-income consumer vehicle replacement programs. In addition, Volkswagen, through its subsidiary Electrify America, will invest \$800 million over a 10 year period in zero-emission vehicle-related projects in California.

Conclusion

Meeting California's climate goals requires a fundamental transformation of its energy system away from fossil fuels. California is increasingly using renewable fuels in its electricity system and moving to an electrified transportation system. The state will need to draw upon a wide variety of solutions to meet its goals while navigating an evolving market structure. California is moving aggressively to achieve its climate and clean air goals with advanced technologies that can be accessed by all Californians while working diligently to maintain reliability, protect public health and the environment, and enhance the economy.

Recommendations

- **The Energy Commission and the California Public Utilities Commission (CPUC) should continue to address policies issues associated with the decentralization of the electricity sector.** The growth in consumer choice, such as community choice aggregators and behind-the-meter generation, are fundamentally changing the structure of the electricity sector and affecting implementation of public policies such as energy efficiency efforts, services to low income consumers, access to advanced technologies for all consumers, and research and development. The Energy Commission and the CPUC should continue the discussion initiated by the en banc public meeting held May 19, 2017, to address how best to advance public policy in the electricity sector given these changes in the electricity market structure.

CHAPTER 2:

Implementing the Clean Energy and Pollution Reduction Act, Senate Bill 350

On October 7, 2015, Governor Edmund G. Brown Jr. signed the Clean Energy and Pollution Reduction Act, Senate Bill 350 (De León, Chapter 547, Statutes of 2015), into law. SB 350 accelerated the trajectory of California’s clean energy transition to substantially reduce greenhouse gas (GHG) emissions and respond to the threat of climate change by codifying new ambitious clean energy goals to be achieved by 2030. Among other mandates, SB 350:

- Increases the Renewables Portfolio Standard (RPS) procurement target from 33 percent to 50 percent of retail sales by 2030.
- Requires the Energy Commission to “establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses by 2030.”
- Encourages the electrification of the transportation system.

Upon signing SB 350, Governor Brown stated, “California has taken groundbreaking steps to increase the efficiency of our cars, buildings, and appliances and provide ever more renewable energy. With SB 350, we deepen our commitment.”

SB 350 further requires a long-term planning process for California’s load-serving entities (LSEs) and local publicly owned electric utilities (POUs) to cost-effectively reduce GHG emissions and meet other policy goals with a diverse portfolio of supply-side and demand-side resources. In planning for a low-carbon energy future, SB 350 also prioritizes transportation sector electrification and the increased adoption of energy efficiency, demand response, and energy storage while emphasizing the need for providing benefits of clean energy to low-income customers and disadvantaged communities.

SB 350, and subsequently Senate Bill 1393 (De León, Chapter 677, Statutes of 2016), also set the stage for other activities to support the overarching goals of decarbonizing the state’s energy systems and ensuring all Californians are able to participate in the clean energy economy. Other specific requirements include:

- Setting the stage for the California Independent System Operator (California ISO) to become a regional organization, contingent upon approval from the Legislature. (See Chapter 3 for more information.)
- Requiring studies to be completed on the barriers and opportunities for low-income residents and disadvantaged communities in accessing energy efficiency, weatherization,

renewable energy, and clean transportation options. The Energy Commission adopted the Low-Income Barriers Study, Part A in December 2016.⁶⁰

- Regularly updating the *Existing Building Energy Efficiency Action Plan*, consistent with doubling statewide energy efficiency savings by 2030. The first such update was adopted by the Energy Commission in December 2016.⁶¹ Working with the California Public Utilities Commission (CPUC) to establish a disadvantaged community advisory group to provide advice on programs proposed to achieve clean energy and pollution reduction. A draft framework was published for comment in August 2017, with a charter scheduled to be released in fall 2017.
- Adopting responsible contractor policies to ensure retrofits meet high-quality performance standards and to establish consumer protection guidelines for energy efficiency products and services.
- In coordination with the CPUC, establishing a publicly available tracking system to provide current information on progress toward meeting SB 350 goals.

Integrated Resource Planning for the Electric Sector

Integrated resource planning (IRP) is a strategy that balances the mix of demand and supply resources over a long-term planning horizon to meet specified policy goals. (See sidebar for a definition of integrated resource planning.) SB 350 requires a new emphasis on GHG emissions reduction planning targets for 2030 while maintaining grid reliability at reasonable cost. The IRP process, as implemented under SB 350, requires close coordination and alignment of agency processes to bring together the state's previously fragmented, resource-specific planning and procurement activities. The Energy Commission and the CPUC have separate but related roles in California's resource planning processes. The 16 POUs that meet threshold size requirements will file their IRPs with the Energy Commission, while investor-owned utilities (IOUs) and other LSEs

Definition of Integrated Resource Planning

"Rather than least-cost supply expansion, ... [integrated resource planning] means integrating a broader range of technological options, including technologies for energy efficiency and load control on the 'demand-side,' as well as decentralized and non-utility generating sources, into the mix of potential resources. Also, it means integrating a broader range of cost components, including environmental and other social costs, into the evaluation and selection of potential technical resources.

The expected result of the market and non-market changes brought about by IRP is to create a more favorable economic environment for the development and application of efficient end-use technologies and cleaner and less centralized supply technologies, including renewable sources. IRP means that these options will be considered, and the inclusion of environmental costs means that they will appear relatively attractive compared to traditional supply options."

Source: Joel N. Swisher, Gilberto de Martino Jannuzzi, Robert Y. Redllinger, United Nations Environment Programme, *Tools and Methods for Resource Planning, Improving Energy Efficiency and Protecting the Environment*, November 1997

⁶⁰ Scavo, Jordan, Suzanne Korosec, Esteban Guerrero, Bill Pennington, and Pamela Doughman. 2016. *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities*. California Energy Commission. Publication Number: CEC-300-2016-009-CMF.

⁶¹ California Energy Commission. 2016. Existing Building Energy Efficiency Action Plan Update. CEC-400-2016-023-CMF.

will file with the CPUC.

There are a variety of other requirements that POU and LSEs must meet in their IRP filings. Separate processes are underway at each agency to implement the required provisions for their respective jurisdictions. The processes for completing these are described in the next sections, following an explanation of the joint agency process for establishing GHG emissions targets.

Establishing GHG Emissions Planning Targets

SB 350 specifies that the California Air Resources Board (CARB) establish GHG emissions reduction targets, in coordination with the CPUC and the Energy Commission, for the electricity sector. Further, the statute requires CARB to set targets for each LSE and POU that reflect the electricity sector's percentage in achieving economywide GHG emissions reductions of 40 percent from 1990 levels by 2030.⁶² The LSEs and POU will then use these GHG emissions reduction targets in preparing their IRPs.

To develop the methods for establishing these targets, CARB has been participating in a joint agency process with the Energy Commission and the CPUC. Efforts to establish GHG emissions reduction planning targets for use in IRPs began with the February 23, 2017, joint agency IEPR workshop and publication of a staff options paper on the potential pathways for determining GHG targets.⁶³ At the workshop, staff described a preference for using an electric sector target based on the range identified in CARB's Scoping Plan Update, which would then be apportioned between the POU under the Energy Commission's jurisdiction and the LSEs under the CPUC's jurisdiction. Staff suggested that methods for allocating targets to the LSEs and POU be determined separately by the respective agencies before the specific targets are ultimately established by CARB.

At an April 17, 2017, joint agency workshop on Potential Methodologies to Establish GHG Emission Reduction Targets for POU IRPs, Energy Commission staff presented a proposed method for determining POU-specific targets based on CARB's method for allocating free emissions allowances to retail electric providers for 2021–2030. In brief, the proposed method for developing individual targets uses the *2015 Integrated Energy Policy Report (2015 IEPR)* electricity demand forecast for 2030 retail sales and net energy for load (load minus self-generation such as rooftop solar) for each retail electric provider minus the expected amount of zero-GHG energy (renewables needed to meet the 50 percent RPS requirement and other zero-carbon resources such as large hydro or nuclear). This yields a gas-fired residual with an assumed emissions intensity of 0.4354 metric tons per megawatt-hour.⁶⁴ This residual is constrained to be at least 5 percent of net energy for load to allow a small amount of gas-fired generation to balance the portfolio. The resulting value for each LSE and POU would be its share of the sectorwide

⁶² Public Utilities Code, Section 454.2 (a) (A).

⁶³ *Options for Setting GHG Planning Targets for Integrated Resource Planning and Apportioning Targets among Publicly Owned Utilities and Load-Serving Entities*, CPUC and California Energy Commission staff discussion document, February 10, 2017.

⁶⁴ *Proposed Amendments to the California Cap in Greenhouse Gas Emissions and Market-Based Compliance Mechanisms Regulation: 2021-2030 Allowance Allocation to Electrical Distribution Utilities*, December 21, 2016.

target ultimately established by CARB in its Scoping Plan Update. The CPUC informally agreed to use this method to determine the initial apportionment between IOUs and POUs.

The proposed method could be updated with new POU and LSE forecasts developed for the *2017 IEPR* or to reflect any changes in CARB's method or both, but neither of these updates is expected to have a significant impact on the individual targets. The sectoral target established by CARB will be the most significant determinant of POU and LSE targets.

CARB adopted *California's 2017 Climate Change Scoping Plan* on December 14, 2017, building on past successes while also proposing new, integrated strategies to reduce both GHGs and air pollution. The Scoping Plan sets a range of 30–53 MMCTO₂E for estimated GHG reductions below 1990 levels for the electric power sector.⁶⁵ This range will help inform CARB's setting of the SB 350 GHG emission reduction planning targets in coordination with the Energy Commission and the CPUC.

POU Integrated Resource Plans

SB 350 codified Public Utilities Code Sections 9621 and 9622, which require POUs with an average electrical demand exceeding 700 gigawatt-hours – as determined on a three-year average commencing January 1, 2013 – to adopt IRPs and submit them to the Energy Commission for review. Moreover, the Energy Commission is required to review POU IRPs for consistency with Public Utilities Code Section 9621 and provide recommendations for correcting any deficiencies.

Starting with a scoping workshop held in April 2016, the Energy Commission held a public process for developing guidelines that govern the submission of information needed to review POU IRPs. This process culminated in the adoption of guidelines for POU IRPs on August 9, 2017.⁶⁶

As specified in SB 350 and reinforced in the guidelines, affected POUs are required to adopt IRPs that achieve several minimum planning standards. These standards were codified in Public Utilities Code 9621. POU IRPs must:

- Meet the GHG emissions reduction planning targets described above.
- Procure at least 50 percent eligible renewable energy resources by December 31, 2030, consistent with the RPS.
- Minimize impacts to retail rates and, as appropriate, serve its customers at just and reasonable rates.
- Ensure system and local reliability.

⁶⁵ CARB, *California's 2017 Climate Change Scoping Plan*, November 2017, https://www.arb.ca.gov/cc/scopingplan/scoping_plan_2017.pdf.

⁶⁶ Vidaver, David, Garry O'Neill-Mariscal, Melissa Jones, Paul Deaver, and Robert Kennedy. 2017. *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*. California Energy Commission. Publication Number: CEC-200-2017-004-CMD.

- Strengthen the diversity, sustainability, and resilience of the bulk transmission and distribution systems, and local communities.⁶⁷
- Enhance distribution systems and demand-side energy management.
- Minimize localized air pollutants and other GHG emissions, with early priority on disadvantaged communities identified under Section 39711 of the Health and Safety Code.

POU IRPs must also address procurement of:

- Energy efficiency and demand response resources.
- Energy storage.
- Transportation electrification.
- Resource adequacy requirements.
- Diversified resources and contracts.

Furthermore, PUC Section 9622 requires the Energy Commission to review POU IRPs to determine whether each is consistent with PUC Section 9621 and the requirements described above. If determined to be inconsistent, the Energy Commission will then provide recommendations to correct any deficiencies identified.

POU IRP Submission and Review Guidelines

To clarify the scope of activities related to POU IRP submission and review, the Energy Commission developed and adopted guidelines to govern POU IRP submissions. The guidelines identify minimum requirements for analyses and data reporting to allow for Energy Commission review, recommend additional optional analyses, define the administrative procedures for submitting IRPs, and outline the Energy Commission’s review and determination procedures. To develop these guidelines, the Energy Commission reviewed existing POU planning processes and conducted a series of workshops and webinars from May 2016 through May 2017.

PUC Section 9621 requires each POU to adopt an IRP that ensures the utility achieves specific goals and targets by 2030, as described above. The guidelines require POU submit data and supporting information sufficient to demonstrate the utility is meeting these goals and targets. The minimum planning horizon for the first IRP submittal was defined to be January 1, 2019, through December 31, 2030. Although not required, POU are encouraged to undertake and present analysis in IRPs that addresses the post-2030 period.

Long-term planning generally requires the evaluation of multiple planning scenarios; however, it is not required. Therefore, the guidelines require that POU submit data and analyses on at least one scenario that achieves all the goals and objectives of PUC Section 9621. This scenario includes, among other things, annual procurement of energy and capacity, renewable energy, and

⁶⁷ POU are encouraged to report plans for and progress on policies that increase local participation and effective investments in clean energy and transportation programs in their service areas.

demand response resources. POU's are also required to submit an annual projection of GHG emissions from the IRP scenario portfolio.

Under PUC Section 9621, POU governing boards are required to adopt an IRP on or before January 1, 2019. The guidelines specify that these IRPs, data, and supporting analyses must be submitted to the Energy Commission by April 30, 2019. This filing date was chosen to coincide with IEPR data collection. Updated IRPs are to be filed at least once every five years following the initial IRP, with due dates specified based on the date of POU governing board adoption.

The guidelines provide that public comments will be accepted on POU IRPs for 30 days after filing with the Energy Commission. These comments will be considered as related to the consistency of IRPs with PUC Section 9621. As some parties requested during the development of guidelines, the Energy Commission is developing a clearinghouse for local POU meetings and events that highlight the development of IRPs to encourage participation at the local level.

Senate Bill 338 (Skinner, Chapter 389, Statutes of 2017) was signed into law by Governor Brown on September 30, 2017. SB 338 amends PUC Section 9621 and requires POU's to consider net peak demand in their IRP process. The Energy Commission's guidelines will need to be updated to reflect this change in the Public Utilities Code.

San Diego Gas & Electric Company (SDG&E) suggests the Energy Commission should take a more critical look at and address the differences between the Energy Commission and CPUC IRP processes, and advocate broadly for equal levels of oversight and management of the process across all LSEs.⁶⁸ The Energy Commission's guidelines and review process are consistent with the authority granted by the Legislature in SB 350. The Energy Commission will monitor and report to the Legislature in the *2019 IEPR* about the POU IRP efforts and implement any additional requirements from the Legislature.

IOU Integrated Resource Plans

The CPUC's Energy Division launched its IRP proceeding in June 2016 with the intent of breaking down the historically siloed approach to long-term procurement planning, where procurement of clean, preferred resources was based on targets set in separate, independent proceedings (either by statute or programs goals). In contrast, the CPUC's IRP process will be an iterative exercise in optimization, looking at and modeling all the demand and supply-side resources together over a 20-year planning horizon to identify a portfolio of resources that reflects policy goals and grid operational constraints. Responsibilities are divided between the CPUC and its jurisdictional entities, and the analysis depends on an information exchange with the state's other planning activities (such as transportation electrification and distributed energy resources).

As noted by Ed Randolph, director of the Energy Division at the CPUC, at the May 12, 2017, joint agency workshop on the increasing need for flexibility in the electricity system, "The IRP is the first opportunity for California to look at a potential path from today's operational conditions to a

⁶⁸ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221739_20171113T135622_Steve_Lango_Comments_Comments_of_SDGE_on_2017_Draft_Integrated.pdf.

resource mix that achieves the SB 350 and the SB 32 goals.”⁶⁹ SB 350 added two code sections to the Public Resources Code as the statutory basis for the IRP. Section 454.51 specifically requires a “diverse and balanced portfolio,” while Section 454.2 requires the CPUC to adopt a process for filing IRP documents that ensure certain requirements are met.

The CPUC’s May 2017 staff proposal⁷⁰ suggests system modeling to generate diverse portfolios of resources for a variety of futures and then establishing a “reference system plan” through a stakeholder process. This preliminary plan would be a modeled, optimized portfolio that meets the GHG emissions reduction targets reliably and at lowest ratepayer cost. Getting to that plan involves starting with the Energy Commission’s demand forecasts, the existing fleet of resources (including planned retirements), and the existing resource mandates, such as the 50 percent RPS and the doubling of energy efficiency contained in SB 350. Sensitivity analyses will look at how combinations of different policies – for example, more energy efficiency with more or fewer electric vehicles – change cost-effective procurement. The modeling will also evaluate impacts on disadvantaged communities.

Once this CPUC-modeled plan is completed, the LSEs will each develop an individually responsive plan, taking into account local needs and resource capabilities. The CPUC will then compare each plan to the reference system plan. In the final step, the CPUC proposes to aggregate, or combine, these plans in an optimized “preferred system plan” that will form the basis for decisions about systemwide investments, procurement, and other programs.⁷¹

The CPUC issued a proposed decision outlining a two-year planning cycle for the IRP process and the optimal electricity resource portfolio (reference system plan) to reach the emissions planning target on December 28, 2017.⁷² CPUC jurisdictional entities will file their IRPs during the first two quarters of 2018, with CPUC review and evaluation taking place in the final half of 2018, with new aggregated portfolio and associated policy actions adopted as the Preferred System Plan to guide procurement authorization and program activity.

Encouraging Widespread Transportation Electrification

Transportation directly accounts for 38.5 percent of statewide GHG emissions.⁷³ To promote emissions reduction in this sector and maximize the use of clean, renewable electricity, SB 350

⁶⁹ May 12, 2017, Joint Agency workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p.55.

⁷⁰ *Proposal for Implementing Integrated Resource Planning at the CPUC, An Energy Division Staff Proposal*, May 17, 2017.

⁷¹ The preferred resource plan covers the California ISO balancing area including POU load with the California ISO. The POUs outside the California ISO will be included in the analysis, but not be optimized in the CPUC’s modeling. Resources from POUs outside the California ISO are modeled as fixed values obtained from other sources.

⁷² CPUC, Proposed Decision of Commissioner Randolph, *Decision Setting Requirements for Load Serving Entities Filing Integrated Resource Plans*, December 28, 2017. <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M201/K974/201974336.PDF>.

⁷³ CARB Greenhouse Gas Emission Inventory – 2017 Edition, June 6, 2017, <https://www.arb.ca.gov/cc/inventory/data/data.htm>.

encourages widespread transportation electrification across utility service territories to be included in IRPs.

SB 350 directs the development of transportation electrification policies in multiple sections of the Public Utilities Code.⁷⁴ Further, it establishes respective responsibilities for the CPUC and the Energy Commission in overseeing the IOU and POU programs in transportation electrification. Consistent with legislative direction, the CPUC, Energy Commission, and CARB have continued to consult on programs through interagency workshops and working groups to develop policies that enable efficient planning for the growth in electric transportation.

POU Transportation Electrification

The Energy Commission convened three workshops to inform the development of guidance for the transportation electrification aspects of the POU's IRPs. In October 2016, the Energy Commission met with four POU representatives⁷⁵ and the Northern California Power Agency (NCPA) to discuss their challenges, capabilities, targets, forecasting, and program strategies for electrification. In addition, modeling consultants, the Southern California Association of Governments, Nissan, Greenlining Institute, and Electric Vehicle Charging Association provided information on local community, technology, vehicle adoption, and electricity operational factors for consideration in resource planning.⁷⁶

Staff recommended six categories of information, data, and reports to support the Energy Commission's review of electrification plans in the POU IRPs. Staff also recommended that the information serve as a best practice benchmark for the POU's to use in support of their achievement of the state's zero-emission vehicle goals, given their individual priorities, capabilities, and resources.⁷⁷ These categories included:

- A quantification, characterization, and location of transportation load.
- A description of programs intended to solve barriers to electrification, particularly addressing disadvantaged communities.
- A discussion of how programs prioritized the segments of the transportation emissions inventory and leveraged external funding sources.
- A plan for education and outreach.
- A description of the alignment of the plan with California policy and local needs.

⁷⁴ Including Public Utilities Code 237.5, 701.1, 740.3, 740.8, 740.12, 9621 and 9622.

⁷⁵ Sacramento Municipal Utility District, Los Angeles Department of Water and Power, Burbank Water and Power, Palo Alto Utilities.

⁷⁶ California Energy Commission, Presentations – October 5, 2016, Lead Commissioner Workshop on Publicly Owned Utility Integrated Resource Planning, http://www.energy.ca.gov/altfuels/2016-TRAN-01/documents/2016-10-05_workshop/2016-10-05_presentations.php.

⁷⁷ Crisostomo, N., T. Olson, 2017. *Transportation Electrification Guidance for Publicly Owned Utilities' Integrated Resource Plans*, April 12, 2017, Draft, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217040_20170414T105313_Transportation_Electrification_Guidance_for_Publicly_Owned_Utilities_Integrated_Resource_Plans.pdf.

- A description of how transportation electrification programs coordinated with distributed energy resource planning.

Staff emphasized the Energy Commission’s willingness to explore supporting the POUs’ achievement of their targets and the state’s electrification targets through collaborative technical assistance partnerships.

During the two April 2017 workshops, Sacramento Municipal Utility District, Los Angeles Department of Water and Power, Burbank Water and Power, Redding Electric Utility, and utilities represented by NCPA, Southern California Public Power Association, and California Municipal Utilities Association elaborated upon their intent to prioritize rate designs, charging infrastructure incentives, and educational programs that ease adoption. In addition, the POUs commonly suggested the need to use the IRPs to track the expenditures associated with adding electric vehicle load.

Related to this issue, POUs encouraged the use of common industry or government data sets to reduce utility costs while improving the quality of data, improving efficiency of reporting, and enabling economic analysis.⁷⁸ The POUs stated that tracking expenditures would quantify the total infrastructure funding needed to support state policy goals, enable analysis of emissions reductions from transportation electrification among other energy resources to justify investments, and account for ratepayer costs of accommodating the fuel switch from petroleum to electricity.⁷⁹ Critically, the POUs identified the need to remove financial disincentives that may exist from the new emissions obligations resulting from adding new transportation load, per the Cap-and-Trade regulation.⁸⁰ The POUs also highlighted the role of the IRP to qualitatively describe their programs. Overall, the POUs were receptive to the idea of funding partnerships to develop and examine programs collaboratively with the Energy Commission to characterize load and understand the effectiveness of programs.

At the April IEPR workshop on the light-duty vehicles sector, parties identified their information and reporting priorities for the IRPs. CARB stressed the importance of complementary programs to the Advanced Clean Cars regulation – like utility or load-serving entity participation in infrastructure – to enable higher levels of electric vehicle adoption in the current market and the subsequent version of the regulation after 2025.⁸¹ Market researchers compared their methods

78 IEPR workshop on April 18, 2017, on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217403_20170504T100212_Transcript_of_04182017_IEPR_Commissioner_Workshop_on_Integrated.pdf, p. 161-162, and IEPR workshop on April 27, 2017 on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217504_20170509T104539_Transcript_of_04272017_IEPR_Commissioner_Workshop_on_Integrated.pdf, p. 68 and 92.

79 IEPR workshop on April 18, 2017, on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217403_20170504T100212_Transcript_of_04182017_IEPR_Commissioner_Workshop_on_Integrated.pdf, p. 135, 140, 145-146, 156.

80 California Health and Safety Code Section 44258.5(b).

81 Ayala, A., “Update on CARB’s Policies for Electrification of the Light-duty Sector,” California Air Resources Board, April 18, 2017, IEPR workshop on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217141_20170418T082316_Update_on_Carbs_Policies_for_Electrification_of_Light-duty_Sector.pdf.

on how the declining costs of battery storage and changes in mobility could alter zero-emission vehicle penetration used in planning expenditures. Charging providers Greenlots and ChargePoint described the need for utilities to complement their investments – which now include high-power (150 kilowatts+) direct current fast charging – by redesigning rates, enabling the use of storage, and streamlining interconnection.⁸² Tesla, the Alliance of Automobile Manufacturers, and Coalition for Clean Air highlighted the need to maintain direct and targeted incentives for vehicles and charging infrastructure and increase educational efforts.⁸³ The Union of Concerned Scientists indicated how better data about charging behaviors could assist in modeling electric vehicles to provide flexible load.⁸⁴

At the IEPR workshop on the medium- and heavy-duty vehicles sector, parties identified different considerations. CARB stressed the need for the agencies to coordinate vehicle regulations with infrastructural deployment to provide clear signals for market development.⁸⁵ The South Coast Air Quality Management District and San Joaquin Valley Air Pollution Control District commonly emphasized the need for substantial expanded use of zero-emission vehicles to achieve the reductions necessary to attain the requirements of the federal Clean Air Act.⁸⁶ Southern California Edison described the method of designing its application, which focused on medium- and heavy-duty charging infrastructure. The California Electric Transportation Coalition cited an assessment that found the electrification of trucks, buses, forklifts, truck stops, and truck refrigeration provided net benefits to participants and society, as measured against the total resource cost and societal cost tests.⁸⁷

Representatives from CalSTART, the Port of Los Angeles, and the California Transportation Commission agreed about the need to plan immediately for the interconnection of heavy vehicle energy and demand to avoid unnecessary grid upgrades or impinging upon the economic or timely operations of freight and goods movement companies. In particular, these parties

82 IEPR workshop on April 18, 2017, on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217403_20170504T100212_Transcript_of_04182017_IEPR_Commissioner_Workshop_on_Integrated.pdf, pp. 104, 116.

83 IEPR workshop on April 18, 2017, on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217403_20170504T100212_Transcript_of_04182017_IEPR_Commissioner_Workshop_on_Integrated.pdf, pp. 192, 200, 204.

84 IEPR workshop on April 18, 2017, on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217403_20170504T100212_Transcript_of_04182017_IEPR_Commissioner_Workshop_on_Integrated.pdf, pp. 188-189.

85 Brazil, T., “Update on Policies for Electrification of the Heavy Duty Sector,” California Air Resources Board, April 27, 2017, IEPR workshop on Integrated Resource Plans – Medium- and Heavy-Duty Vehicle Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217304_20170426T151237_Update_on_Policies_for_Electrification_of_the_Heavy_Duty_Sector.pptx.

86 IEPR workshop on April 27, 2017 on Integrated Resource Plans – Medium- and Heavy-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217504_20170509T104539_Transcript_of_04272017_IEPR_Commissioner_Workshop_on_Integrated.pdf, pp. 21–22, 33–34.

87 ICF International, Energy + Environmental Economics. *California Transportation Electrification Assessment Phase 3-Part A: Commercial and Non-Road Grid Impacts – Final Report*. <http://www.caletc.com/wp-content/uploads/2016/08/California-Transportation-Electrification-Assessment-Phase-3-Part-A-1.pdf>.

juxtaposed the grid impacts of electrifying the light-duty sector against the volume of heavy-duty vehicles needed to attain air quality standards and the magnitudes more demand expected from heavy vehicle fleets and goods equipment.

The California Transportation Commission, CalSTART, and the Port of Los Angeles highlighted the need to make investments before the rate of PEV adoption accelerates and to experiment with “creative meddling” to find solutions that ultimately avoid negative impacts to ratepayers and the economy.⁸⁸ Similarly, Earth Justice stressed that the utilities need to model the reduction of transportation emissions within their IRPs in compliance with state and federal law. In particular, it recommended the quantitative and qualitative measurement of air and health improvements on disadvantaged communities.⁸⁹ Toward these points, the University of California, Riverside identified how connected vehicle and metering technology, if combined with fleet management systems, could help determine the viability of electrification and associated charging equipment needs and emissions benefits.⁹⁰

As a result of the workshops and in response to comments, the Energy Commission modified recommendations for the POUs to include the following information, in summary, in their IRPs:⁹¹

- 1) Charging profiles for light-duty vehicles and tariffs.
- 2) Quantity, type, and location of charging infrastructure, and planned investments.
- 3) Information on other transportation electrification sectors and associated GHG emissions impacts.
- 4) A description of how investments are prioritized to promote electrification in the different transportation sectors and complement nonutility initiatives.
- 5) Utility costs associated with serving transportation electrification.
- 6) A description of how transportation electrification investments and planning or modeling scenarios are aligned with federal, statewide, and/or local air pollution reduction and zero-emission-vehicle initiatives.

88 IEPR workshop on April 27, 2017, on Integrated Resource Plans – Medium- and Heavy-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217504_20170509T104539_Transcript_of_04272017_IEPR_Commissioner_Workshop_on_Integrated.pdf, p. 119, 125, 148.

89 CCAEJ, EYCEJ, and Earth Justice Comments on Freight Electrification, May 19, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217666_20170519T165118_Adenike_Adeyeye_Comments_CCAEJ_EYCEJ_and_Earthjustice_Comments.pdf.

90 IEPR workshop on April 27, 2017, on Integrated Resource Plans – Medium- and Heavy-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217504_20170509T104539_Transcript_of_04272017_IEPR_Commissioner_Workshop_on_Integrated.pdf, p. 137.

91 Vidaver David, Garry O'Neill-Mariscal, Melissa Jones, Paul Deaver, and Robert Kennedy. 2017. *Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines*. California Energy Commission. Publication Number: CEC-200-2017-004-CMD. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220089_20170707T143350_Publicly_Owned_Utility_Integrated_Resource_Plan_Submission_and.pdf.

- 7) Plans to coordinate with adjacent or similarly situated utilities to meet broader community or regional infrastructure needs and ensure harmonious interterritory operations of electric transportation technologies.
- 8) Current or planned programs to promote transportation electrification in disadvantaged communities.
- 9) Customer education and outreach efforts.
- 10) Coordination of transportation electrification investments and incentives with other distributed energy resource programs or planning.

IOU Utilities Transportation Electrification

A September 2016 assigned commissioner's ruling in R.13-11-007,⁹² developed through workshops held in April 2016⁹³ and as ratified in D.16-11-005,⁹⁴ ordered applications from the six IOUs that addressed the goals of transportation electrification. The CPUC ruling instructed the utilities to design a portfolio of programs that modified rates to accommodate electrification; expanded electrification efforts beyond light-duty vehicles into the medium- and heavy-duty vehicle on-road, off-road, maritime, rail, and aviation sectors; expanded customer education and outreach; and leveraged the results of previous state investments. In addition, the ruling highlighted the need to coordinate with existing state and local regulatory efforts related to transportation, emissions reduction, and integrated resource planning; to ensure safe interconnection of charging infrastructure and vehicles as storage devices; to complement nonutility efforts; and to enable standardized communications with vehicles and infrastructure. Lastly, the ruling permitted utilities to consider new utility incentives or regulatory mechanisms to advance transportation investments in conjunction with greater use of renewable energy, while minimizing the financial impact on ratepayers and encouraging market competition.

The CPUC's guidance discussed the need for a utility's portfolio of programs to reduce vehicle emissions in proportion to its share of statewide reductions (described in CARB's *Climate Change Scoping Plan* and *Mobile Source Strategy* to reduce air pollution). In addition, it requested that the portfolio align to and inform the respective IRP and use the Energy Commission and CARB forecasts for vehicles. The CPUC outlined how utilities should describe the projects in their portfolios to assist planning:

- Market segment and vehicles targeted
- Time frame
- Relevant regulations

92 CPUC, Assigned Commissioner's Ruling Regarding the Filing of the Transportation Electrification Applications Pursuant to Senate Bill 350, September 14, 2016, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M167/K099/167099725.PDF>.

93 California Public Utilities Commission's Transportation Electrification Activities Pursuant to Senate Bill 350 Web page, <http://www.cpuc.ca.gov/sb350te/>.

94 CPUC, Decision 16-11-005, *Decision Making Small Electrical Corporations Respondents to this Rulemaking*, November 16, 2016, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M169/K717/169717954.PDF>.

- Vehicles supported
- Monitoring and evaluation plan
- Costs and rate impacts
- Grid impacts
- Leveraged funding and project partners
- Emissions benefits
- Stranded asset risk mitigation

In January 2017, Southern California Edison, Pacific Gas and Electric, and San Diego Gas & Electric submitted applications requesting ratepayer investments totaling \$1.06 billion. These programs consisted primarily of charging infrastructure for on-road medium- and heavy-duty vehicles (73 percent) and residential light-duty vehicles (23 percent).⁹⁵ The remainder consisted of public direct current fast charging, off-road infrastructure, taxi/ride-sharing, and education and outreach programs. In June 2017, Bear Valley Electric, PacifiCorp, and Liberty Utilities submitted applications totaling \$7.4 million, primarily consisting of public DC fast chargers and residential make-ready infrastructure. The CPUC approved a decision⁹⁶ authorizing six SDG&E projects (\$18.5 million), five SCE projects (\$16 million), and four PG&E projects (\$8.1 million) that are designed for a pilot deployment for the electrification of school buses, delivery trucks, airport/seaport equipment, truck stops, commuter locations, DC fast charging in urban locations, and car dealership incentives. The CPUC prioritized 100 percent deployment in disadvantaged communities where feasible. The CPUC is anticipated to approve or modify the IOUs' remaining proposals in 2018.

95 Mesrobian, A., "SB 350 Transportation Electrification: A Perspective from the CPUC," California Public Utilities Commission, April 18, 2017, IEPR workshop on Integrated Resource Plans—Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217133_20170417T164542_SB_350_Transportation_Electrification.ppt.

96 California Public Utilities Commission, Proposed Decision of ALJs Golberg and Cooke, Decision on the Transportation Electrification Priority Review Projects, November 22, 2017, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M198/K874/198874393.PDF>.

Figure 11: 2017 IOU Transportation Electrification Portfolios

	Onroad Medium/Heavy Duty Infrastructure	Residential Infrastructure	Offroad Infrastructure	Public DC Fast Charging	Taxi/ Ridesharing	Education/ Outreach		
	~\$779 M	~\$230 M	~\$13 M	~\$30 M	~\$7.5 M	~\$3.6 M		
SDG&E	Fleet Delivery Services \$3.7 M	Residential Charging Infrastructure \$226 M	Airport Ground Support Equipment \$2.8 M	Electrify Local Highways \$4 M	Taxi/Shuttle/ Rideshare \$3.5 M	Car Dealer Incentives \$1.8 M	Total SDG&E Request: \$244 M	
	Commercial Grid Integration Rate	Residential Grid Integration Rate	MD/HD and Forklift Port Electrification \$2.4 M	Public Charging Grid Integration Rate				
SCE	Transit Bus Make- Ready & Rebate \$4 M	Residential Make- Ready Rebate \$4 M	Port of Long Beach Gantry Crane \$4 M	Urban DC Fast Charger Clusters \$4 M	EV Driver Rideshare Reward \$4 M		Total SCE Request: \$574 M	
	MD/HD Charging Infrastructure \$554 M		Port of Long Beach ITS Terminal Yard Tractor \$0.5 M					
	Commercial EV Rate Design							
PG&E	MD/HD Fleet \$3.4 M		Idle-Reduction Technology \$3.4 M	Fast Charge Infrastructure \$22 M		Home Charger Information \$1.8 M	Total PG&E Request: \$253 M	
	Electric School Bus Renewables Integration \$3.4 M							
	FleetReady Make- Ready Infrastructure \$210 M	PG&E also proposed conducting a request for third-party EV innovators to design a project or program to spend the remainder of its priority review budget (\$8.2 M)			<table border="1"> <tr><td>Priority Review</td></tr> <tr><td>Standard Review</td></tr> <tr><td>Rate Design Proposals</td></tr> </table>			Priority Review
Priority Review								
Standard Review								
Rate Design Proposals								
	Public DC Fast Charging	Residential Infrastructure	Commercial Infrastructure	Heavy-Duty Infrastructure	Education & Outreach			
	\$4 M	\$1.74 M	\$1.18 M	\$223,000	\$235,000			
Bear Valley (\$746,500)		EV TOU Pilot Rate (\$139,000)	Destination Make-Ready Rebate (\$607,500)					
Liberty Utilities (\$6.2 M)	DC Fast Charger Project (\$4 million)	Residential Make-Ready Rebate (\$1.6 million)	Small Business Make-Ready Rebate (\$300,000)	EV Bus Infrastructure Program (\$223,000)	Customer Online Resource Project (\$65,000)			
PacifiCorp (\$440,000)			Demonstration & Development Grant Program (\$270,000)		Outreach & Education Program (\$170,000)			

Source: California Public Utilities Commission Energy Division

Next Steps

The Energy Commission will work with the CPUC and CARB to identify how transportation electrification investments in integrated resource planning can be further aligned to attain statewide GHG and air pollutant emissions reduction goals. Specific actions toward this

alignment beyond and in complement to the IRP process are included in the Recommendations section below.

Other Lessons Learned

Drawing on workshops conducted as part of the *2017 IEPR* proceeding, the Energy Commission staff identified several additional themes relevant to the accelerated deployment of charging technologies across multiple classes of vehicles. Although these additional themes were not discussed during the IEPR proceeding, the Energy Commission believes it important to tee them up for possible further consideration.

Rapidly Evolving PEV Technologies and Uses

Rapid declines in battery costs are enabling greater diversification in electric vehicle classes and models, affordability, and driving range between charges. The principal technology driver of transportation electrification is the improving economics of battery energy storage and corresponding increase in electric driving range.

Increases in overall vehicle use through sharing fleets and automated driving will also advance transportation electrification. This prevalence is derived from potential lower operational and fueling costs of an EV compared to a conventional vehicle and recovering any incremental capital expenses over more miles. In fact, per-mile trip costs might be reduced further with autonomous vehicles that are capable of driving themselves at even higher usage factors. CARB and the Energy Commission have pursued research and demonstrations of shared mobility technologies,^{97, 98} including those that can be integrated with the grid to guide these trends toward environmental benefits.^{99, 100} The CPUC is also considering how transportation network company regulations might apply to autonomous vehicles providing passenger transportation service.¹⁰¹

Ongoing Need for Coordination and Partnerships

At the state level, infrastructure funding needs to be used as strategically as possible. This can be better achieved by consistently tracking budgets and expenditures across sectors, identifying gaps for additional needed funds, and identifying opportunities to reduce the need for public funding through coordinated, scaled investment (such as for commercial applications of electrified transportation). Better coordination will help leverage the results of prior infrastructure funding efforts, enable more strategic procurement, advance infrastructure development, and share best

97 California Air Resources Board, "Summary of the Car Sharing and Mobility Options Pilot Project," June 2016, https://www.arb.ca.gov/msprog/aqip/ldv_pilots/car_sharing_faq.pdf.

98 California Energy Commission, "Request for Information Innovative Electric Mobility (E-Mobility) Services," May 10 2017, http://www.energy.ca.gov/contracts/notices/2016-05-10_ARFVTP_eMobility_RFI.pdf.

99 Gutierrez, A., V. Lew, A. Ng, F. Piña, L. Spiegel, E. Stokes. 2017. *EPIC Proposed 2018-2020 Triennial Investment Plan*. California Energy Commission, CEC-500-2017-023-CMF. http://docketpublic.energy.ca.gov/PublicDocuments/17-EPIC-01/TN217366_20170501T115606_Application_of_the_California_Energy_Commission_for_Approval_of.pdf.

100 IEPR workshop on April 18, 2017, on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217403_20170504T100212_Transcript_of_04182017_IEPR_Commissioner_Workshop_on_Integrated.pdf, p. 37.

101 Randolph, L. Amended Phase III. B. Scoping Memo and Ruling of Assigned Commissioner, California Public Utilities Commission, June 12, 2017, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M190/K174/190174048.PDF>.

practices. Better coordination could be achieved through partnerships with local transportation and energy decision makers to track policy and procurement developments that affect electric transportation demand. Comments highlighted the need for local governments to lead and develop “EV readiness plans and [pass] local ordinances to increase EV adoption and ensure sufficient infrastructure is built out.”¹⁰² Under Assembly Bill 1236, all cities and counties must adopt ordinances to expedite and streamline the permitting process for EV charging stations by September 30, 2017. The Government Operations Agency is coordinating the state’s effort to enable construction in existing nonresidential buildings and multifamily dwellings.¹⁰³ Further, requirements for new buildings will be considered in the Building Standards Commission’s 2018 Code Adoption Cycle.¹⁰⁴ The ARFVTP’s EV Ready Communities Challenge emphasizes the importance of “accelerated deployment of electrified transportation within the local and regional levels with a holistic and futuristic view of regional transportation planning” and will support subsequent installations.¹⁰⁵

There is much to be learned at the national level and internationally as well. For example, while the U.S. market is relatively small compared to that of Europe and China, the marginal effects of customer demand or regulatory policy from a single market on total international production volumes can influence the time frame when vehicles become cost-effective for customers and profitable for automakers.¹⁰⁶

Economics of Faster Charging Infrastructure

By 2020, the time to recharge light-duty EVs is expected to converge toward parity with conventional, liquid-fueled vehicles, with the introduction of EVs designed with batteries capable of accepting direct current (DC) “high power charging” from 1 kilovolt and 350–400 ampere infrastructure.¹⁰⁷ For example, the Combined Charging Standard has developed technology capable of providing energy seven times as quickly as commonly available 50 kW DC fast chargers. However, sites and facilities may not be able to sustain economic service to high-power fast chargers or arrays of charging to fully-electrified vehicle fleets if they do not plan for interconnection, electrical upgrades, and manage the added load on retail electric rates. This is certainly a topic that warrants further research and discussion, including within the context of

102 Tesla comments on 2017 Draft IEPR, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221738_20171113T140110_Francesca_Wahl_Comments_2017_Draft_IEPR__Tesla_Comments.pdf.

103 Office of the Governor, October 12, 2017, https://www.gov.ca.gov/docs/AB_1239_Veto_Message_2017.pdf.

104 California Green Building Standards Code (Cal. Code Regs., Title 24, Part 11) and California Building Standards Commission, 2018 Triennial Code Adoption Cycle, <http://www.bsc.ca.gov/Rulemaking/adoptcycle/2018TriennialCodeAdoptionCycle.aspx>.

105 California Energy Commission Grant Funding Opportunity GFO-17-604, Electric Vehicle Ready Communities Challenge Phase 1 – Blueprint Plan Development <http://www.energy.ca.gov/contracts/transportation.html#GFO-17-604>.

106 IEPR workshop on April 18, 2017, on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217403_20170504T100212_Transcript_of_04182017_IEPR_Commissioner_Workshop_on_Integrated.pdf, p. 60.

107 CharInN., “The path to a global charging standard,” March 23, 2017, http://www.charinev.org/fileadmin/Downloads/Presentations/2017_CharIN_Charge_Days_Bracklo.pdf.

medium- and heavy-duty PEVs, as a result of pending incentives for electric trucks and buses¹⁰⁸ and given the importance of connector standards and leveraging load control technologies to manage costs.¹⁰⁹

Furthering Customer Education

One critical hurdle to rapidly increasing uptake of zero-emission vehicles is that most of the public does not realize that these vehicles are here and available for purchase. Programs to continue consumer education about electric cars and available options to refuel these cars are essential to driving rapid adoption. Government agencies, automakers, utilities, charging companies, and environmental advocacy and community organizations unanimously support the need for mass market public outreach campaigns that increase awareness about electrification.¹¹⁰ These efforts will need to be sustained to broaden potential customers' awareness and comfort with EVs.

While outside the scope of the IEPR workshops that took place as part of the 2017 report, all four of these other lessons learned warrant further discussion and attention.

Doubling Energy Efficiency Savings

SB 350 directs the Energy Commission to establish ambitious annual targets to achieve a statewide cumulative doubling of energy efficiency savings in electricity and natural gas final uses by January 1, 2030. Achieving the doubling targets is one of the primary ways the electricity sector can help the state achieve its long-term climate goal of reducing GHG emissions to 40 percent below 1990 levels by 2030. The Energy Commission has proposed targets for electricity and natural gas savings that can be achieved through utility and nonutility energy efficiency programs.¹¹¹ The doubling targets were developed in collaboration with the CPUC, IOUs, POUs, and other stakeholders in a public process. In addition to establishing the doubling targets, the Energy Commission is required to report to the Legislature biennially on progress being achieved toward the targets and the impacts on disadvantaged communities. The energy efficiency savings doubling targets were adopted by the Energy Commission on November 7, 2017. Thus, the current methods and results have been finalized. However, the Energy Commission encourages strong stakeholder participation in future updates, and the framework for the targets is expected to evolve over time.

108 California Air Resources Board, Proposed Fiscal Year 2017-18 Funding Plan for Clean Transportation Incentives, Board Presentation, December 14, 2017, <https://www.arb.ca.gov/board/books/2017/121417/17-12-4pres.pdf>.

109 California Energy Commission, Fourth Annual California Multi-Agency Update on Vehicle-Grid Integration Research, Discussion Panel: Identifying Opportunities and Barriers to Advance Vehicle-Grid Integration into the Medium- / Heavy-Duty Sector, December 5, 2017, <http://www.energy.ca.gov/research/notices/#12052017>.

110 IEPR workshop on April 18, 2017, on Integrated Resource Plans – Light-Duty Vehicles Sector, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217403_20170504T100212_Transcript_of_04182017_IEPR_Commissioner_Workshop_on_Integrated.pdf, p. 161-162, 192, 200, 204.

111 Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. *Senate Bill 350: Doubling Energy Efficiency Savings by 2030*. California Energy Commission. Publication Number: CEC-400-2017-010-CMD. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN220927_20170828T144323_Senate_Bill_350_Doubling_Energy_Efficiency_Savings_by_2030.pdf.

The Energy Commission acknowledges the proposed SB 350 energy efficiency savings targets are bold. Meeting them will require the concerted effort of many entities, including state and local governments, utilities, program deliverers, private lenders, market participants, and end-use customers. The state will need to harness new and emerging technologies, along with innovative program designs and creative market solutions, to unlock California's potential energy efficiency savings. But with proper tracking of savings, midcourse corrections, and ongoing support from the state's leadership, California is poised to meet the doubling targets by 2030.

At the public workshop on the *SB 350: Doubling Energy Efficiency Savings by 2030 Draft Report*, the energy efficiency industry encouraged the Energy Commission to continue the work needed to realize the energy savings targets presented. In particular, it was suggested that specific action steps should be established with responsible entities and time frames identified to achieve the objective of realizing significant increases in the energy savings derived from efficiency.¹¹² The Energy Commission expects to accomplish this in its ongoing collaborations with the CPUC, other state and local governments, and industry, which will be reflected in the future combined updates to the SB 350 target-setting and the *Existing Buildings Energy Efficiency Action Plan*.

Establishing SB 350 Doubling Targets

SB 350 directs the Energy Commission to base the SB 350 targets on a doubling of additional achievable energy efficiency (AAEE) contained in the *California Energy Demand Updated Forecast, 2015–2025* extended to 2030 using an average annual growth rate and the most recent energy efficiency targets adopted by POUs, to the extent doing so is cost-effective, feasible, and will not adversely impact public health and safety.¹¹³ AAEE savings include incremental savings from the future market potential identified in utility potential studies not included in the baseline demand forecast, but reasonably expected to occur, including future updates of building codes, appliance regulations, and new or expanded IOU or POU efficiency programs.¹¹⁴

Energy efficiency savings projections were developed for utility-based and nonutility activities. Utility program portfolios are funded by ratepayers under either the CPUC or a local jurisdiction and administered by the state's IOUs, other LSEs, community choice aggregators (CCAs), regional energy networks (RENs), or the state's POUs. Nonutility activities may be funded by state agencies and local governments but also include efforts led by private third parties, industry, and consumer groups with little or no government resources. Such market-oriented programs can increase energy efficiency at the final uses of retail customers through financing, directly installing energy efficiency measures, and increasing public awareness of energy efficiency best practices. The Energy Commission used utility and nonutility categories as an initial attempt to distinguish between energy efficiency savings potential captured in the IOU and POU potential and goals studies, and savings potential beyond these studies that can be achieved by a host of

112 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN221285_20170921T135907

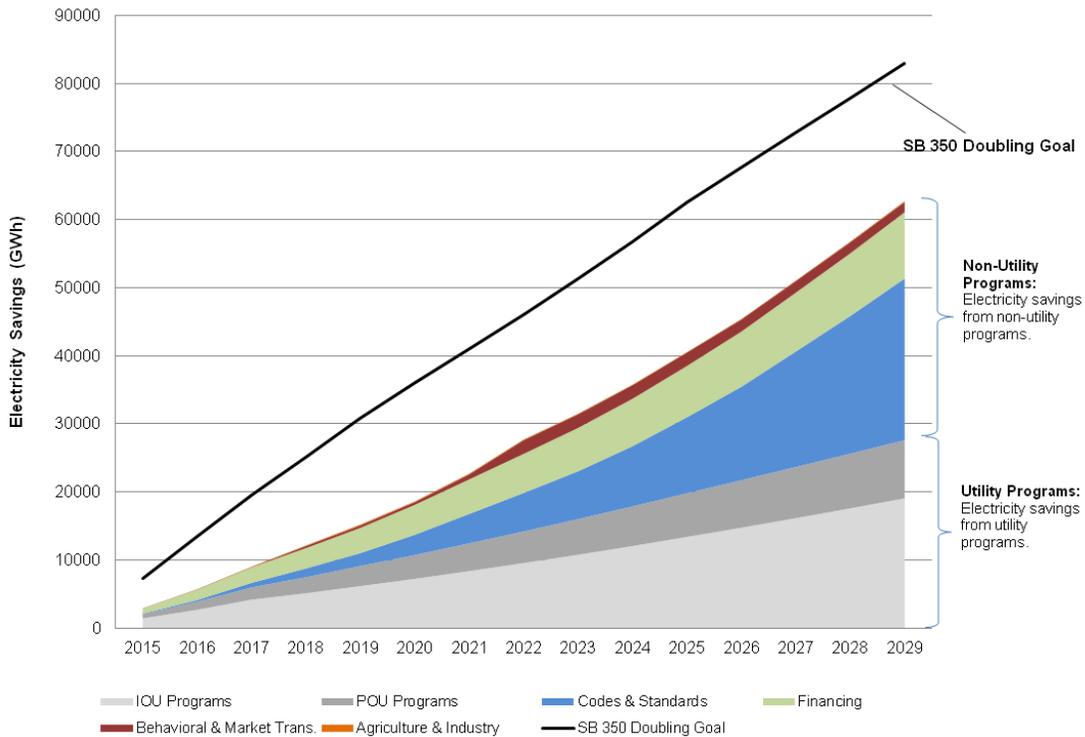
113 Kavalec, Chris, 2015. *California Energy Demand Updated Forecast, 2015-2025*. California Energy Commission, Electricity Supply Analysis Division. Publication Number: CEC-200-2014-009-CMF. <http://www.energy.ca.gov/2014publications/CEC-200-2014-009/CEC-200-2014-009-CMF.pdf>.

114 AAEE savings are incremental projections beyond the committed energy efficiency included in the Energy Commission's baseline demand forecast.

energy efficiency providers. These categories are expected to evolve over time as the Energy Commission works with utilities and stakeholders to implement the SB 350 doubling targets and provide updates to the Legislature.

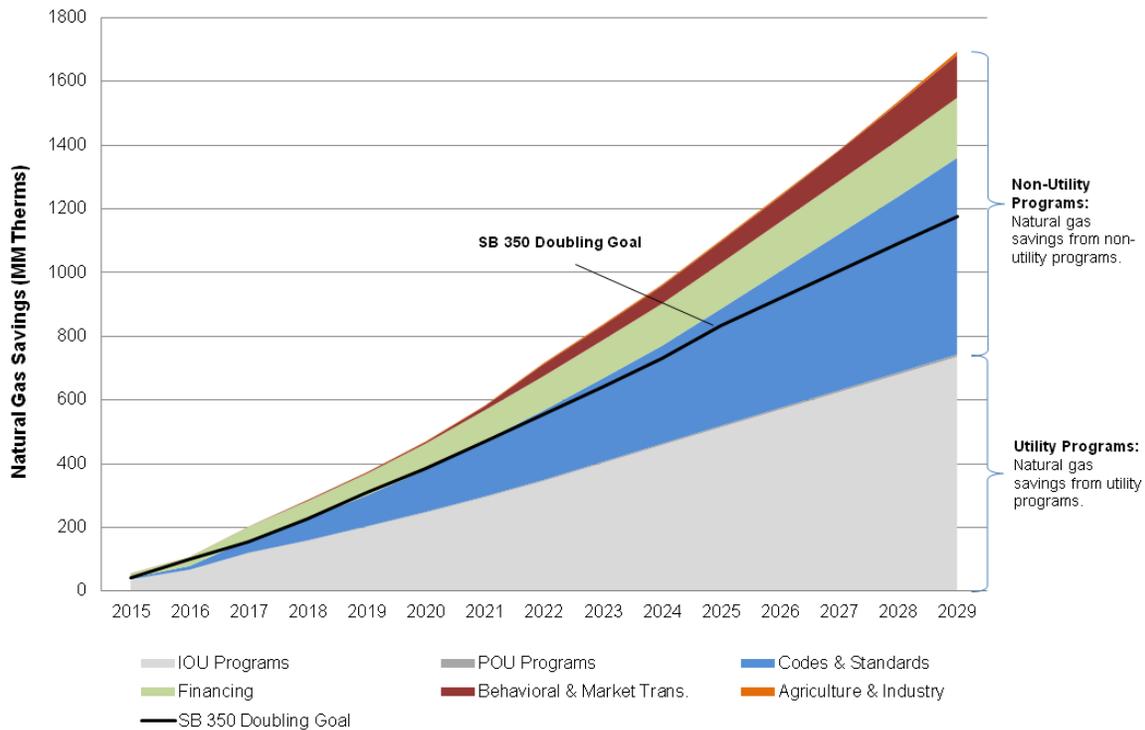
The statewide cumulative energy efficiency savings targets for electricity and natural gas, along with projected savings from utility and nonutility programs, are presented in Figures 12 and 13. The top line is the arithmetic doubling of projected AEE savings from 2015 to 2025, with the 2026-to-2030 projected savings extrapolated using a trend line. In addition, preliminary estimates of projected energy savings from the agricultural and industrial sectors are included in the subtargets.

Figure 12: Proposed SB 350 Doubling Target for Electricity (GWh)



Source: California Energy Commission staff, September 2017

Figure 13: Proposed SB 350 Doubling Target for Natural Gas (MM Therms)



Source: California Energy Commission staff. September 2017.

Utility Energy Efficiency Program Savings

Since the 1970s, California utilities have been offering energy efficiency programs to their residential and nonresidential customers, including the agriculture and industrial sectors. The energy efficiency programs the utilities offer are funded by a small fee included in customer bills. SB 350 directs the Energy Commission, when assessing the feasibility and cost-effectiveness of utility energy efficiency programs, to consider the results of potential studies. Under current law, the CPUC and POU must identify all potentially achievable cost-effective energy efficiency savings by conducting potential and goals studies.¹¹⁵ The CPUC must establish energy efficiency goals for the IOUs, while POU boards set their own efficiency goals. These studies estimate all the potential energy savings that are available through different technologies, program measure savings, savings from codes and standards, and savings from behavioral programs that the IOUs and POUs can use to make up their energy efficiency portfolios.

The CPUC is setting energy efficiency goals for the IOUs based on the most recent IOU potential and goals study that determines market-based savings potential for IOUs under a given set of assumptions.¹¹⁶ The POUs' 2017 report on energy efficiency potential and goals was submitted in

¹¹⁵ Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) and Assembly Bill 2021 (AB 2021) (Levine, Chapter 734, Statutes of 2006).

¹¹⁶ CPUC. *Final Public Report: Energy Efficiency Potential and Goals Study for 2018 and Beyond*. August 25, 2017. <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M194/K614/194614840.PDF>.

March 2017.¹¹⁷ Because the most recent studies were not specifically designed to achieve SB 350 targets, additional efforts will be necessary to identify utility program savings beyond the current goal-setting effort. Because CCAs and RENs will be important in meeting the SB 350 targets, they should be an important element of future potential and goals studies carried out by the CPUC.

Additional Utility Energy Efficiency Opportunities

In addition to traditional energy efficiency programs, SB 350 allows fuel substitution to count toward the doubling goal in some circumstances. The Energy Commission defines *fuel substitution* as a measure involving the substitution of one utility-supplied or interconnected energy source for another, such as electricity and natural gas.¹¹⁸ For example, advances in heat pump technology have made substituting electricity for natural gas for heating systems more viable and offer increased efficiency compared to traditional resistance heating devices such as electric water heaters. The SB350 framework allows fuel substitution to count when equipment installations and replacements that provide both end-user energy savings and GHG emission reductions.

The vast majority of buildings in California use natural gas for water and space heating. Substituting heat pumps for natural gas space and water heating might reduce both energy consumption and GHG emissions.¹¹⁹ The potential energy efficiency savings from fuel substitution are included in the projections of nonutility program savings in the following section.¹²⁰ To tap into this potential, there are several issues to resolve, including developing appropriate methods for quantifying energy savings and GHG emission reductions, as well as addressing cost considerations. Several stakeholders encouraged the Energy Commission and the CPUC to address all existing policy barriers that limit the ability of utility incentive programs and the Title 24 Energy Efficiency Standards to encourage fuel substitution.¹²¹ The Energy Commission will seek to resolve any outstanding technical, policy, and cost barriers regarding fuel substitution, in collaboration with stakeholders. A key step will be to include the topic of fuel substitution in buildings and industries to reduce the GHG emissions from fossil fuels in future

117 California Municipal Utilities Association, *Energy Efficiency in California's Public Power Sector: 11th Edition – 2017*, March 15, 2017, http://www.ncpa.com/wp-content/uploads/2015/02/2017_POU_EE_Reportv2.pdf.

118 In contrast, fuel switching involves shifting from an energy source that is not utility-supplied or interconnected, for example petroleum, to a utility-supplied or interconnected energy source. These measures are not allowed under SB 350.

119 If the electricity used (the marginal resource) is renewable-based electricity, then GHG emissions would be reduced. If the marginal generation resource is natural gas-fired electricity, then the coefficient of performance of the heat pump (the ratio of the useful heat or cooling to work required) would need to be factored into an analysis of emissions.

120 SoCalGas commented, "According to the Energy Planning Analysis Tool, SoCalGas found that full electrification of the state would cost Californians approximately \$345 million annually in higher energy costs, and would cost over \$5 billion to retrofit California's more than 12 million households with high efficiency electric water heating, space heating, and cooking end uses." http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221758_20171113T165037_Southern_California_Gas_Company_Comments_SoCalGas_Comments_on_t.pdf.

121 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN221277_20170921T025212;
http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN221294_20170921T164758_Rachel_Golden_Comments_Sierra_Club_Comments_on_SB350_Doubling_EE.pdf;
http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN221291_20170921T164333_Mohit_Chhabra_Comments_Comments_of_the_Natural_Resources_Defens.pdf.

policy forums and working groups. This will bring together stakeholders to discuss and overcome the barriers mentioned above.

SB 350 also allows conservation voltage reduction (CVR), which is a proven technology to reduce energy use and peak demand. By controlling voltage on a distribution circuit to the lower end of the tolerance bands, efficiency benefits can be realized by end users and the distribution utility. The energy efficiency potential studies do not include CVR since it is outside the scope of what has historically been considered energy efficiency. Newer technologies can enable CVR to be more targeted, uniform, and effective than traditionally was the case. Moving forward, the Energy Commission can help shape CVR programs that can count toward SB 350 goals.

Utilities may also achieve additional savings by adopting innovative incentive programs that tackle deeper retrofits of existing buildings. These programs could include upgrades to building envelopes while coordinating with statewide marketing campaigns such as FlexAlert. A program that combines retrofits with ongoing marketing could achieve reliable savings compared to relying on real-time individual customer behavior changes.

Nonutility Energy Efficiency Program Savings

The nonutility subtargets include savings possible from programs at the Energy Commission, other state agencies, local governments, and private financing institutions, as well as savings due to broader efficiency market trends that may not be directly traceable to any program at all. The Energy Commission developed projections of nonutility savings that are incremental to those identified in the utility potential studies, making every effort to minimize possible double counting. Energy savings from nonutility activities were categorized in three areas: codes and standards, financing, and behavioral and market transformation programs. Specific programs within these categories are shown in Table 2. While the Energy Commission has categorized these additional cost-effective energy savings as nonutility programs, some of these savings could also be realized by future expansions of utility energy efficiency programs.

The purpose for the SB 350 energy efficiency projections was to understand how existing or new programs could be scaled up to meet the doubling goal. That purpose is different from the additional achievable energy efficiency projections used to modify a baseline demand forecast (create a managed forecast) for CPUC and California ISO planning purposes. The nonutility program-specific analyses used “what if” assumptions and interpolated backward from 2029 for intermediate year savings. The SB 350 energy efficiency nonutility program projections did not include peak demand savings projections nor savings at the customary geographic regions that are used in the electricity and natural gas forecast. In response, Energy Commission staff evaluated each of these nonutility programs to create an energy scaling factor that reduced published SB 350 savings projections for some programs for purposes of the demand forecast. These adjustments were vetted publicly with the Demand Analysis Working Group on October 31, 2017.¹²² (More in-depth discussion about these changes is found in Chapter 6 and in the *2018–2030 California Energy Demand Forecast* report.)

¹²² Mike Jaske, *Role of SB 350 Energy Efficiency Savings in 2017 AAEI*, http://www.dawg.info/sites/default/files/meetings/2017%20IEPR%20AAEI%20webinar_v4_MJ_10-27-2017.pdf.

Table 2: Nonutility Energy Efficiency Programs

Program Categories	Programs
Codes & Standards	Building Energy Efficiency Standards (Title 24, Part 6)
	California Green Building Standards Code (Title 24, Part 11)
	Appliance Efficiency Regulations (Title 20)
	Federal Appliance Standards
Financing	Property Assessed Clean Energy (PACE)
	Local Government Challenge
	Proposition 39
	Energy Conservation Assistance Act
	Low-Income Weatherization Program
	Water Energy Grant
	Energy Savings Program (CA Dept. of General Services)
	Potential Air Quality Management District Programs
Behavioral & Market Transformation	State-wide Benchmarking and Public Disclosure Program
	Smart Meter and Controls
	Behavioral, Retrocommissioning, and Operational Savings
	Energy Asset Rating
	Fuel Substitution
Industrial	
Agricultural	

Source: California Energy Commission staff, Efficiency Division, August 2017

Codes and Standards

Since the 1970s, the Energy Commission has been responsible for establishing standards for buildings and appliances that conserve electricity and natural gas. Specific programs within the codes and standards category that can contribute future energy savings to meet the SB 350 doubling target include Title 24 Building Energy Efficiency Standards (building standards) and Title 20 state Appliance Efficiency Regulations (appliance regulations), discussed below. Although the Energy Commission includes codes and standards as non-utility programs for SB 350 program classification, all the IOUs and more of the POUs have included ratepayer-funded code advocacy programs within their energy efficiency portfolios. The energy savings expected from Title 24 and Title 20 in the SB 350 target setting assume the ongoing resource commitments from the Energy Commission, as well as the utilities across the state.

Building Energy Efficiency Standards

The 2016 building standards that went into effect January 1, 2017, include new requirements for high-performance insulation within walls and attics. The nonresidential building energy efficiency standards underwent numerous important yet small changes to building envelope, lighting,

mechanical, electrical, covered processes, and commissioning.¹²³ The 2019 building standards cycle focuses on additional efficiency opportunities, and for the first time adding self-generation to the minimum code requirements for residential new construction. Additional goals of the 2019 building standards are to continue to reduce GHG emissions, to manage impacts of PV on the grid, to achieve grid harmonization, and to provide independent compliance paths for both mixed-fuel and all-electric homes. Future building standards updates will likely focus on pursuing similar goals in high-rise multifamily and nonresidential buildings.

Appliance Efficiency Standards

The Energy Commission sets energy efficiency standards for appliances that are not regulated by the U.S. Department of Energy. In 2017, the Energy Commission adopted several updates to the appliance regulations, including improved lighting efficiency by moving toward light-emitting diode lamps (LEDs) and away from less efficient incandescent, halogen, and compact fluorescent lamp technologies. Earlier this year, the Energy Commission adopted efficiency standards for computers and computer monitors.

In Spring 2017, the Energy Commission formally began considering standards, test procedures, labeling requirements, and other efficiency measures for several appliances, including commercial and industrial fans and blowers, general service lamps, spray sprinkler bodies, tub-spout diverters, and irrigation controllers. In addition, since energy use by plug loads and miscellaneous electrical loads is growing rapidly in both the residential and commercial sectors, the Energy Commission recently began developing a roadmap for reducing device electricity consumption in standby and other low-power modes.¹²⁴

Financing Programs

Several financing programs offered by state and local agencies and private entities contribute to nonutility energy savings, as shown in Table 2. Several of these programs are discussed below.

Property Assessed Clean Energy

Since 2007, private lenders have been allowed to offer Property Assessed Clean Energy (PACE) programs in California.¹²⁵ Property owners of residential and commercial buildings can fund energy efficiency, water efficiency, or renewable energy projects with limited upfront capital using PACE loans. PACE loans rely on the existing framework of residential property taxes by allowing property owners to repay the entire loan for a project through a special tax assessment made on the property.¹²⁶ Loan payments can be amortized for a period of up to 20 years, with an option to extend the payback period as necessary. Some common efficiency measures funded by PACE

123 California Energy Commission. "2016 Building Energy Efficiency Standards What's New for Residential" California Energy Commission, accessed June 15, 2017, http://www.energy.ca.gov/title24/2016standards/documents/whatsnew_2016_building_efficiency_standards.pdf.

124 <http://energy.ca.gov/appliances/2017-AAER-06-13/17-AAER-12.html>.

125 Assembly Bill 811 (Levine, Chapter 159, Statutes of 2008).

126 PACE programs are limited to participating districts where the private lenders have legal agreements with cities and counties that allow repayment of the loans through property taxes.

financing include building envelope, attic insulation, HVAC equipment and controls, lighting equipment and controls, and cool roofs.¹²⁷

Local Government Challenge

The Local Government Challenge program was developed to create an opportunity for local governments to leverage their connection with constituents and jurisdiction over building and land-use decisions to help meet local and state energy goals. This grant opportunity is open to cities, counties, joint powers authorities, consortia, councils of governments, housing authorities, and special districts. The first challenge funding opportunity was divided into two categories: one for local governments with populations that do not exceed 150,000, to design and implement their climate action plans or other planning efforts; and the other for all local governments that have already set climate and energy goals to propose innovative efficiency deployment projects.

The California Clean Energy Jobs Act

The California Clean Energy Jobs Act (Proposition 39) changed the corporate income tax code and allocates projected revenue to the state general fund and the Clean Energy Job Creation Fund for five fiscal years, beginning with fiscal year 2013–14. The Energy Commission leads the implementation of this program and administers the Proposition 39 K–12 Program, which provides funding annually for energy efficiency upgrades and clean energy generation projects at local educational agencies (LEAs). LEAs include public school districts (K–12), charter schools, state special schools, and county offices of education. The program's Citizens Oversight Board produces an annual report to the Legislature, typically published in March.¹²⁸

Behavioral and Market Transformation

Additional energy efficiency savings can result from behavioral and market transformation changes, as opposed to installing a physical measure like new lighting or HVAC. These measures include behavioral, retrocommissioning, and operational changes that are initiated by informing the customer or building owner of energy usage. As of January 1, 2017, utilities across the state are required to provide whole-building energy data to most commercial and multifamily building owners upon request. Further, in October 2017, the Energy Commission adopted complementary regulations implementing requirements for benchmarking and public disclosure, to take effect in mid-2018.¹²⁹ Prospective building tenants and owners, energy consultants, policy makers, and others can use this information to decide where to live and work, to target building assessments and improvements to develop new energy policies, and ultimately to track progress toward the SB 350 doubling targets.

¹²⁷ The term *cool roof* refers to a roofing product with high solar reflectance and thermal emittance properties. These properties help reduce electricity used for air conditioning by lowering roof temperatures on hot, sunny days. <http://www.energy.ca.gov/2015publications/CEC-400-2015-014/CEC-400-2015-014-BR.pdf>.

¹²⁸ Citizens Oversight Board Reports are found at: http://www.energy.ca.gov/efficiency/proposition39/citizens_oversight_board/documents/.

¹²⁹ Assembly Bill 802 (Williams, Chapter 590, Statutes of 2015).

Energy Efficiency in Existing Buildings

Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) recognized the need for California to address climate change through reduced energy consumption in existing buildings and has as its roadmap the *Existing Buildings Energy Efficiency Action Plan* (EBEE Action Plan).¹³⁰ As part of his January 2015 inaugural address, Governor Brown put forward the goal to “double the efficiency of existing buildings and make heating fuels cleaner” by 2030. The activities described in the EBEE Action Plan plus the expanded set of programmatic strategies for all retail end uses will be critical to achieving the Governor’s energy efficiency savings doubling goal as codified in SB 350.

Further, SB 350 requires the CPUC to revisit its rules governing energy efficiency programs, both to authorize a broader array of program types and to tie incentive payments to measurable efficiency results. Also, where feasible and cost-effective, SB 350 requires that energy efficiency savings be measured with consideration toward the overall reduction in normalized metered electricity and natural gas consumption.

As required by SB 350, an update to the *2015 EBEE Action Plan* was adopted by the Energy Commission in December 2016, and additional updates will be completed periodically. The *2016 EBEE Action Plan Update*¹³¹ expanded upon the strategies identified in the *2015 EBEE Action Plan* and added new information. Since the *2015 IEPR* was published, many recommendations from the EBEE Action Plan have been put into motion. Additional strategies for addressing multifamily buildings to build upon the recommendations from the action plan are described in the “Addressing Barriers Faced by Low-Income Residents and Disadvantaged Communities” section of this chapter.

¹³⁰ *Existing Buildings Energy Efficiency Action Plan*, September 2015, CEC-400-2015-013-F
http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-05/TN206015_20150904T153548_Existing_Buildings_Energy_Efficiency_Action_Plan.pdf.

¹³¹ *2016 Existing Buildings Energy Efficiency Plan Update*, December 2016, CEC-400-2016-023-CMF.
http://docketpublic.energy.ca.gov/PublicDocuments/16-EBP-01/TN214801_20161214T155117_Existing_Building_Energy_Efficiency_Plan_Update_Deceber_2016_Thi.pdf.

Strategy 1.2 in the *2016 EBEE Action Plan Update* describes the importance of benchmarking and public disclosure and lists the tasks necessary to realize the benefits of such a program. In October 2017, the Energy Commission adopted regulations implementing the whole-building energy use data access, benchmarking, and public disclosure provisions of Assembly Bill 802 (Williams, Chapter 590, Statutes of 2015). The data access portion of the program provides building owners with the information they need to understand energy usage in their buildings and make appropriate improvements. The benchmarking and public disclosure portion of the program will require the owners of buildings larger than 50,000 square feet to report building characteristic and energy use information to the Energy Commission annually beginning in 2018.

Beginning in 2019, the Energy Commission will disclose building-level information on a public website to help building owners, prospective buyers and tenants, energy services companies, researchers, and the public better understand the buildings in which they live and work. (For information on how data from AB 802 will be used in the Energy Commission’s forecasting, see the section “Data and Analytical Needs” in Chapter 7).

Renewables Portfolio Standard

California has long been a leader in transforming the electricity sector through its embrace of renewable energy. California’s Renewables Portfolio Standard (RPS) was established in 2002 by Senate Bill 1078 (Sher, Chapter 516, Statutes of 2002) and subsequently accelerated in 2006, requiring retail sellers of electricity to meet at least 20 percent of retail sales with eligible

Changes at the National Level Are Affecting the Solar Market

President Trump’s administration has promoted an agenda that focuses federal programs and budget on traditional manufacturing and fossil fuel industries and is rolling back several environmental requirements that support the transition to clean energy on a national level. Further, although the federal tax reform bill signed on December 22, 2017, preserves the solar investment tax credit for commercial developers and homeowners, the net impact on solar development from the tax reform, including a lower corporate tax rate, is unknown.¹

Additionally, on January 22, 2018, President Trump approved recommendations to impose safeguard tariffs on imported solar cells and modules. The tariffs start at 30 percent and decrease each year, leveling at 15 percent in the fourth year. The first 2.5 gigawatt of cells imported each year are excluded from the tariffs. Depending on the cost of the PV modules, the tariff could add about \$355 for a 3.2 kW system, and would drop to \$178 after four years when the tariff lowers from 30 percent to 15 percent. Even at the 30 percent level, the tariff will not change the cost-effectiveness conclusions of the Energy Commission’s Title 24 Building Energy Efficiency Standards for 2019.

The tariffs resulted from a petition filed with the U.S. International Trade Commission in April 2017 by Suniva and SolarWorld, two solar panel manufacturing companies. The petitioners claimed they are experiencing extreme financial losses caused by unfair competition from less expensive foreign manufactured imports and requested the federal government impose tariffs and establish a floor price on imported crystalline silicon PV cells and modules. The Solar Energy Industries Association (SEIA), other members of the solar industry, elected officials, and U.S. trading partners argued against and continue to oppose the tariffs. SEIA has argued that tariffs on solar equipment will increase the price of solar panels and reverse the high-growth trajectory of the market and result in the loss of up to 88,000 solar jobs across the country, including as many as 16,000 in California. Despite bipartisan opposition, the ITC found that imports of less expensive solar panels have caused injury to domestic solar manufacturers, and on November 13, 2017, sent remedy recommendations to President Trump, which provided the basis for the President’s decision.

¹ Keith Martin, *Final US tax bill: effect on project finance market*, Norton Rose Fulbright, December 16, 2017, <http://www.nortonrosefulbright.com/knowledge/publications/160375/final-tax-bill-effect-on-project-finance-market>.

renewable resources by 2010. Senate Bill X1-2 (Simitian, Chapter 1, Statutes of 2011) increased the RPS target to 33 percent by 2020, with benchmarks of 20 percent by the end of 2013 and 25 percent by the end of 2016. The bill also expanded the codified RPS obligations to publicly owned utilities (POUs).

In 2015, Senate Bill 350 codified the state's commitment to decarbonize California's economy. Among the provisions, SB 350 increased the RPS target to 50 percent by 2030 for all load-serving entities, including investor-owned utilities (IOUs), electricity service providers, CCAs, and publicly owned utilities.

Supporting the implementation of SB 350, Senator De León highlighted the need for California utilities, under the leadership of the Energy Commission and the CPUC, to act quickly to procure as much new renewable energy as possible in advance of the potential expiration of federal clean energy tax credits. In a letter submitted to CPUC President Michael Picker and Energy Commission Chair Robert B. Weisenmiller, Senator De León requested that both agencies report on the steps taken to take advantage of these tax credits in their respective planning processes.¹³² Chair Weisenmiller relayed this directive to publicly owned utility representatives and other stakeholders in attendance at a public workshop held at the Energy Commission on May 25, 2017.¹³³ The CPUC and Energy Commission followed-up with a response letter to Senator de León describing the agencies' activities in support of his request and some of the challenges faced by utilities in procuring additional renewable energy resources.¹³⁴ Below is a discussion of the Energy Commission's efforts in implementing the RPS, with particular focus on RPS rules under SB 350. There is also a discussion of the role of the CPUC in RPS implementation, as well as progress toward meeting the state's RPS goals.

Renewables Portfolio Standard Background

The Energy Commission and the CPUC work collaboratively to implement the RPS. The CPUC establishes and administers RPS compliance rules for retail sellers of electricity; the Energy Commission has parallel responsibilities for the POUs. The Energy Commission is also charged with:

- Certifying renewable facilities as eligible for the RPS.
- Developing and implementing a tracking and verification system to ensure that renewable energy output is counted only once for the RPS.
- Verifying RPS procurement claims.

¹³² May 19, 2017, Letter from Senator de León to CPUC President Picker and Chair Weisenmiller, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217743_20170526T074739_5192017_Letter_from_Senator_De_Leon_to_CPUC_and_CEC.pdf.

¹³³ May 25, 2017, workshop on Publicly Owned Utility Integrated Resource Plans, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN218252_20170613T135044_Transcript_of_the_05252017_IEPR_Commissioner_Workshop_on_Draft.pdf, p. 89.

¹³⁴ August 1, 2017, Letter from CPUC President Picker and Energy Commission Chair Weisenmiller to Senator de León

- Adopting regulations specifying procedures for enforcement of the RPS for POUs and overseeing compliance activities for POUs.

Retail sellers and POUs demonstrate RPS compliance via renewable energy credits (RECs), certificates of proof representing the renewable attributes of one megawatt-hour of electricity generated by an RPS-eligible energy resource.¹³⁵ Retail sellers and POUs retire RECs corresponding to a certain percentage of retail sales to meet each RPS compliance period target.

As part of its administrative responsibilities, the Energy Commission verifies the eligibility of renewable energy procured for each RPS compliance period by both retail sellers and POUs. The Energy Commission also determines the procurement target calculations for POUs. In light of these responsibilities, Energy Commission staff is dedicated to closely following developments in the changing retail market, including the potential growth of CCAs in both IOU and POU territories, to understand and respond to issues affecting RPS procurement.

Major Renewables Portfolio Standard Changes Under SB 350

SB 350 brought significant changes to both the RPS targets and rules for compliance. Most notably, SB 350 expanded the RPS to 50 percent by December 31, 2030. Furthermore, SB 350 provided for new compliance periods for the years after 2030, securing the future position of renewable energy in California's electricity sector. These requirements advance the transformation of the grid and will necessitate the integration of a significantly increased level of renewable energy resources. (See Chapter 3 for more information.)

SB 350 also sets requirements to bring about more long-term contracting; under SB 350, at least 65 percent of RECs applied in a given compliance period must originate from contracts at least 10 years in length, beginning January 1, 2021. The certainty of long-term contracts can provide security for developers to finance new renewable generation, as well as stability in future resource planning.

The RPS program has sought to provide flexibility to retail sellers and POUs in meeting the RPS targets. In keeping with this goal of flexibility, SB 350 adjusted rules governing the optional compliance measures that may be applied by a retail seller or POU in meeting RPS requirements.

Additional Flexibility for Publicly Owned Utilities

California's POUs are widely diverse in size, demographics, customer base, geography, resources, and governance. In recognition of the unique challenges that certain POUs may face, particularly as the RPS mandate ramps up to 50 percent by 2030, SB 350 provides partial exemptions under specific criteria for POUs impacted by single-year fluctuations in qualifying large hydro output or unavoidable, long-term, out-of-state contracts for coal-fired generation.

SB 350 also acknowledges the role of voluntary green pricing and shared renewables programs in meeting California's renewable energy and GHG reduction goals. Such programs allow utility

¹³⁵ Eligible renewable resources for the RPS may include wind, solar photovoltaic, solar thermal, geothermal, small hydroelectric, biogas, and biomass. Refer to the *Renewables Portfolio Standard (RPS) Eligibility Guidebook* for complete eligibility criteria.

customers greater access to renewable energy, such as through options to purchase electricity with a higher mix of renewables or to directly access the output of individual renewable energy generation. SB 350 allows a POU to exclude from its retail sales any renewable generation credited to a customer participating in a voluntary green pricing or shared renewables program, effectively reducing a POU's additional RPS obligation. This recognition of green pricing and shared renewables programs in the RPS is consistent with the treatment of IOU programs under the Green Tariff Shared Renewables Program enacted by Senate Bill 43 (Wolk, Chapter 413, Statutes of 2013).

Implementation Schedule

The bulk of the RPS changes for SB 350 take effect January 1, 2021; however, certain provisions allowing program flexibility may be applied in earlier compliance periods. The Energy Commission and CPUC are working to implement the changes in a timely manner and are coordinating to ensure consistent application of the statute, as appropriate.

The Energy Commission has already reflected changes following SB 350 in the *RPS Eligibility Guidebook*, revised in April 2017. The Energy Commission is also responsible for establishing compliance requirements for local POUs, codified in the *Enforcement Procedures for the Renewables Portfolio Standard for Local Publicly Owned Electric Utilities* ("RPS POU Regulations"). Energy Commission staff is preparing to update the RPS POU Regulations to implement SB 350 and to update provisions regarding the application and review of optional compliance measures and anticipates initiating a formal rulemaking in the first half of 2018.

The CPUC implements RPS compliance rules for retail sellers. In Decision 16-12-040, the CPUC adopted new compliance periods and procurement quantity requirements for retail sellers under SB 350. On June 29, 2017, the CPUC approved Decision 17-06-026, which implemented new long-term contracting requirements and updated rules for excess procurement and identified that a subsequent decision will implement any needed changes to the RPS enforcement processes.

Progress Toward 50 Percent Renewables

The RPS provides a path for the state's utilities to procure renewable resources equal to 50 percent of their retail sales by 2030 by establishing increasingly progressive procurement targets for multiyear compliance periods. Table 3 below illustrates the RPS targets from the first compliance period through 2030.

Table 3: RPS Targets

End of Compliance Period	RPS Target for Last Year in Compliance Period¹³⁶
December 31, 2013	20%
December 31, 2016	25%
December 31, 2020	33%
December 31, 2024	40%
December 31, 2027	45%
December 31, 2030	50%

Source: California Energy Commission staff

As described, the Energy Commission verifies the eligibility of RPS claims for both retail sellers and POUs. Final RPS compliance is determined by the Energy Commission and the CPUC, for POUs and retail sellers respectively, after the Energy Commission has verified all RPS claims. Thus, RPS compliance may be determined only after the conclusion of each compliance period.

The Energy Commission and CPUC are finalizing RPS compliance results for the 2011–2013 compliance period, and the Energy Commission is verifying RPS claims for the 2014–2016 compliance period. Based on early results from the first compliance period, as well as a proxy estimate of RPS compliance, the Energy Commission estimates that California is well on track to meeting its RPS mandate.

Statewide Progress

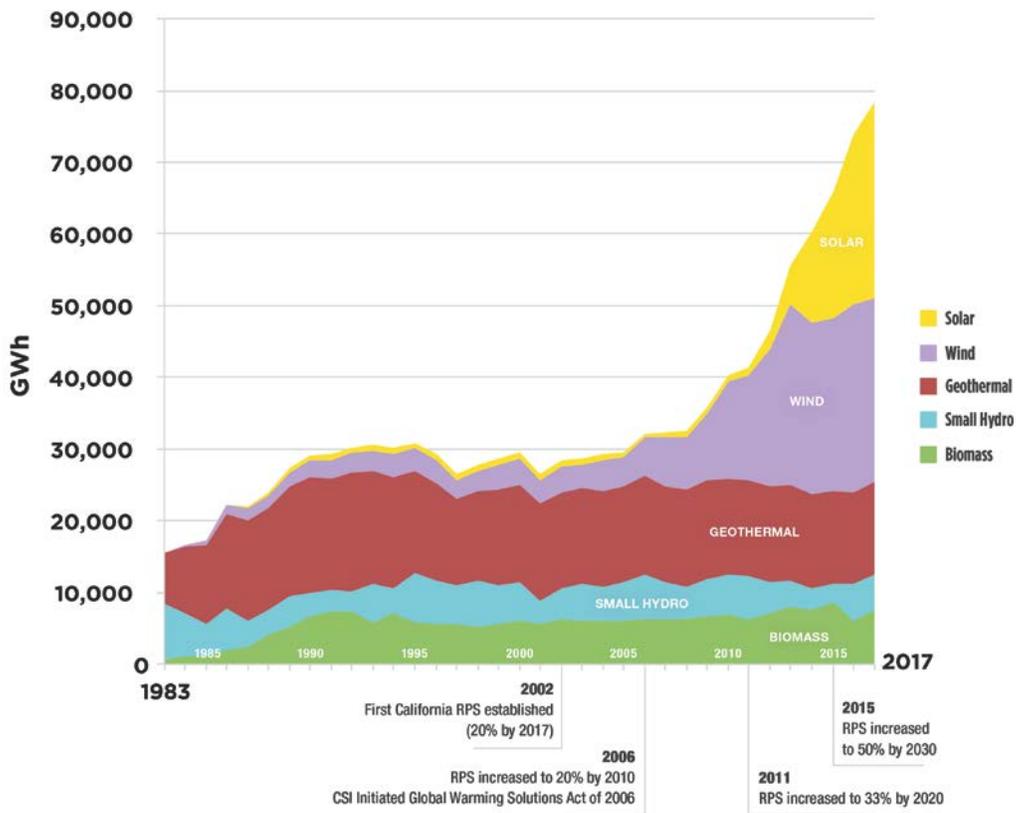
Since the California’s RPS was established in 2002, renewable-based electricity has increased by about 2.5 times. This growth is a result of state policies to advance renewable energy (Figure 14), coupled with reductions in the cost of renewables discussed in Chapter 1.

The Energy Commission estimates that about 30 percent of California’s retail electricity sales in 2017 were served by renewable energy generated from RPS-eligible resources.¹³⁷ Though this estimate is a proxy for RPS progress, rather than an exact accounting, it nonetheless indicates significant progress toward achieving the state’s renewable energy goals.

¹³⁶ The Energy Commission and CPUC are charged with adopting soft targets for the intervening years of each compliance period to reflect reasonable progress toward achieving the RPS. A load-serving entity’s RPS procurement obligation for a given compliance period is the sum of procurement needed to meet the RPS target in the last year and the soft targets for the intervening years.

¹³⁷ The generation reflected in this estimate is subject to verification and does not reflect the full accounting rules used to determine RPS compliance.

Figure 14: California Renewable Energy Generation by Resource Type (In-State and Out-of-State)*



Source: California Energy Commission, Tracking Progress, Renewable Energy, updated December 2017
 *Does not include behind-the-meter generation

Investor-Owned Utility Progress

The CPUC estimates that for the 2011–2013 compliance period, California’s three largest IOUs collectively served 22.7 percent of their retail electricity sales with eligible renewable electricity based on verified RPS compliance numbers, exceeding the 20 percent target. Furthermore, the CPUC reports California’s three largest IOUs collectively served 27.6 percent of their electric retail sales in 2015 with electricity generated by eligible renewable resources (Table 4 below). At the same time, these IOUs are forecasted to have contracted sufficient RPS procurement to meet their compliance obligations in 2020, indicating substantial progress.

Table 4: IOU Renewable Procurement Status

Actuals						Forecasted			
Compliance Period 1			Compliance Period 2			Compliance Period 3			
20% Requirement			25% Requirement			33% Requirement			
2011	2012	2013	2014	2015	2016	2017	2018	2019	2020
20%	20%	23%	28%	30%	35%	38%	42%	47%	50%

Source: CPUC <http://www.cpuc.ca.gov/renewables/>, accessed January 5, 2018.

POU Progress

For the first compliance period, the Energy Commission has adopted final verification reports¹³⁸ for 43 POUs. These 43 POUs reported to the Energy Commission a combined 20.6 percent of retail electricity sales from eligible renewable resources, collectively meeting the 20 percent RPS target for 2013. Based on the adopted verification reports, 26 POUs met the procurement requirements, and 16 POUs had a procurement target shortfall but applied optional compliance measures to meet the procurement requirements for the first compliance period, as allowed by the RPS POU Regulations.¹³⁹ In December 2017, the Energy Commission’s Executive Director notified 15 POUs that their adoption and application of optional compliance met the requirements of the RPS POU Regulation, and as such, they had met the RPS requirements for Compliance Period 1. Commission staff is completing all remaining verification and compliance activities for the remaining POUs.¹⁴⁰ All numbers will be updated when the final verification and compliance activities for the first compliance period are complete for all POUs.

Growth of RPS-Eligible Facilities

To achieve the 50 percent RPS mandate, it is implicitly necessary to have sufficient RPS-eligible generation capacity to support that mandate. The Energy Commission is tasked with developing and maintaining criteria for RPS eligibility, as well as approving certification to qualifying renewable facilities. The Energy Commission regularly updates the *Renewables Portfolio Standard Eligibility Guidebook* to accommodate advancements in technology and efficiency improvements, as well as to address other burgeoning developments in the renewable energy landscape, such as the role of energy storage.

As of December 19, 2017, there are more than 2,000 facilities with active RPS certification with a combined nameplate capacity of 46,000 MW,¹⁴¹ located in 11 states, Canada, and Mexico. Of these, more than 1,800 are in California with a combined capacity of more than 28,000 MW, which represents 60 percent of all RPS-certified facility capacity. This value includes certified aggregate units, which consist of multiple distributed generation facilities. Figure 15 represents

¹³⁸ http://www.energy.ca.gov/portfolio/documents/verification_results/cp01_2011-2013/pous_reports.php.

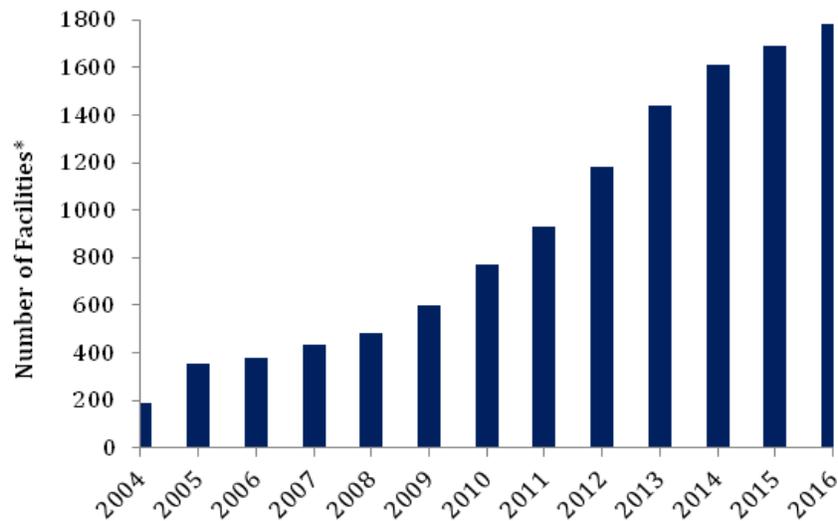
¹³⁹ <http://www.energy.ca.gov/2016publications/CEC-300-2016-002/CEC-300-2016-002-CMF.pdf>.

¹⁴⁰ A complaint may be issued against a POU for failure to meet an RPS requirement, initiating an Energy Commission proceeding, in accordance with the RPS POU Regulations.

¹⁴¹ Excludes capacity classified as confidential.

the growth in RPS-eligible facilities since 2004 estimated by the approved RPS eligibility date for each facility.¹⁴²

Figure 15: Growth in RPS Facilities With Approved Certification



Source: California Energy Commission

The Energy Commission anticipates beginning an update to the *Renewables Portfolio Standard Eligibility Guidebook* in 2018 to address current technologies and market conditions and to ensure that the certification guidelines support anticipated capacity growth, integration capabilities, and technology development necessary to meet the 50 percent RPS mandate.

Addressing Barriers Faced by Low-Income Residents and Disadvantaged Communities

As California accelerates the trajectories of its low-carbon energy resource portfolio, it is important that all Californians are able to benefit from the new economic opportunities created. With this tenet in mind, SB 350 required the Energy Commission and CARB, with input from other agencies and the public, to complete and publish studies by January 1, 2017, on:

- Barriers for low-income customers to energy efficiency and weatherization investments, including those in disadvantaged communities, and recommendations on how to increase access to those investments.
- Barriers to and opportunities for solar photovoltaic energy generation and other renewable energy by low-income customers.
- Barriers to contracting opportunities for local small businesses in disadvantaged communities.

¹⁴² Based on the eligibility date of facilities that had active RPS certification as of January 2017, which is not the date facilities were certified but acts as a reasonable proxy to represent change over time.

- Barriers for low-income customers, including those in disadvantaged communities, to zero-emission and near-zero-emission transportation options and recommendations on how to increase access to these options (conducted by CARB).

On December 14, 2016, the Energy Commission adopted the *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities* (Barriers Study).¹⁴³ Adoption of the Barriers Study represented the culmination of staff efforts over the preceding year, informed by an extensive literature review, a series of local community meetings across the state, and several technical workshops hosted in Sacramento.

The study identified three broad categories of barriers faced by low-income residents and disadvantaged communities. Structural barriers include low home ownership rates, insufficient access to capital, split incentives for renters and building owners, complexities of multifamily buildings, issues common to older residential buildings, and challenges unique to remote communities. Program and policy barriers include inconsistent definitions and eligibility criteria across programs, limited data sharing, unrecognized non-energy benefits, and issues with market delivery. The third category is contracting barriers faced by local small businesses in disadvantaged communities and includes lack of access to resources, technical assistance, and information regarding contracting opportunities.

The Barriers Study concluded with 12 recommendations, including numerous subrecommendations to help address the barriers identified in the study. Priority was placed on putting forth recommendations that present scalable, sustainable solutions; address low-income customers' inability to access traditional financing mechanisms; and help maximize the benefits of public investments. Summaries of the specific recommendations are included in Table 5.

¹⁴³ Scavo, Jordan, Suzanne Korosec, Esteban Guerrero, Bill Pennington, and Pamela Doughman. 2016. *Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities*. California Energy Commission. Publication Number: CEC-300-2016-009-CMF.

Table 5: Energy Commission Low-Income Barriers Study Recommendations

#	Recommendation
1	Organize a multiagency task force to facilitate coordination across state-administered programs
2	Enable community solar offerings for low-income customers.
3	Formulate a statewide clean energy labor and workforce development strategy.
4	Develop new financing pilot programs to encourage investment for low-income customers.
5	Establish common metrics and encouraging data sharing across agencies and programs.
6	Expand funding for photovoltaic and solar thermal offerings for low-income customers.
7	Enhance housing tax credits for projects to include energy upgrades during rehabilitation.
8	Establish regional outreach and technical assistance one-stop shop pilots.
9	Investigate consumer protection issues for low-income customers and small businesses in disadvantaged communities.
10	Encourage collaboration with community-based organizations in new and existing programs.
11	Fund research and development to enable targeted benefits for low-income customers and disadvantaged communities.
12	Conduct a follow-up study for increasing contracting opportunities for small businesses located in disadvantaged communities.

Source: California Energy Commission *Low-Income Barriers Study, Part A*

CARB released a draft of its *Low-Income Barriers, Study Part B: Overcoming Barriers to Clean Transportation Access for Low-Income Residents*¹⁴⁴ (draft guidance document) in April 2017, which includes recommended actions that support the recommendations in the Energy Commission's Part A. Although CARB's guidance document is not expected to be finalized until early 2018, CARB is moving ahead with implementation of priority clean transportation and mobility option access recommendations, to coordinate with the Energy Commission's ongoing efforts. CARB's priority recommendations, as determined by conversations with low-income residents and communities, task force agencies and key stakeholders, are summarized in Table 6. Additional recommendations are described in CARB's draft guidance document.

¹⁴⁴ CARB's draft guidance document is available at https://www.arb.ca.gov/msprog/transoptions/draft_sb350_clean_transportation_access_guidance_document.pdf

Table 6: Draft Guidance Document Priority Recommendations

#	Recommendation
1	Expand assessments of low-income resident transportation and mobility needs to ensure feedback is incorporated in transportation planning.
2	Develop an outreach plan targeting low-income residents across California to increase awareness of clean transportation and mobility options.
3	Develop regional one-stop shops to increase awareness and technical assistance.
4	Develop guiding principles for grant and incentive solicitations to increase access to programs and maximize low-income resident participation.
5	Maximize economic opportunities and benefits for low-income residents from investments in clean transportation and mobility options by expanding workforce training and development.
6	Identify and expand funding and financing for clean transportation and mobility projects, including infrastructure, to meet the accessibility needs of low-income and disadvantaged communities.

Source: California Air Resources Board, *Low-Income Barriers Study, Part B Draft Guidance Document*

SB 350 Low-Income Barriers Multiagency Task Force

The first recommendation from the Barriers Study was for the Governor’s Office to assemble a multiagency task force “to facilitate coordination of all state agencies administering energy, water, resilience, housing, and low-emission transportation and infrastructure programs for low-income customers and disadvantaged communities.” Convening the task force was an essential first step to determining roles and responsibilities for each of the involved agencies, identifying resources available for implementing recommendations in both the Barriers Study and CARB’s draft guidance document, and seeking opportunities to align with other existing state efforts.

Key priorities of the task force include encouraging multi-level collaboration, standardization, streamlining, integration, and cofunding opportunities; leveraging lessons learned and best practices from prior experience within and outside California; building upon existing programs that have demonstrated success; and leveraging partnerships to amplify energy and non-energy benefits to low-income customers and disadvantaged communities. Under the direction of the Governor’s Office, agencies represented on the task force are working together to implement the Barriers Study recommendations and establish guiding principles and common measurements to track progress on performance of clean energy and transportation programs in low-income and disadvantaged communities over time.

To augment the task force’s efforts, the Energy Commission is also working with the United States Department of Energy and other states through the Clean Energy for Low-Income Communities Accelerator project, as part of the Better Buildings Initiative.¹⁴⁵ Many states across the country are working through similar efforts to address clean energy and transportation barriers for low-income customers, and participation with this group allows knowledge transfer and coordination.

¹⁴⁵ <https://betterbuildingsinitiative.energy.gov/accelerators/clean-energy-low-income-communities>.

Potential Solutions for Multifamily Low-Income Clean Energy Issues

Almost half of low-income residents live in multifamily housing, and 20 percent of all multifamily housing is rent assisted, which equates to roughly 900,000 households in California.¹⁴⁶ As such, the Barriers Study calls for developing a comprehensive action plan to improve opportunities for energy efficiency, renewable energy, demand response, energy storage, and electric vehicle infrastructure for multifamily housing, with particular attention to pursuing pilot programs for properties in low-income and disadvantaged communities. The SB 350 task force has placed a strong priority on improving clean energy opportunities for residents of multifamily buildings. In 2018, the Energy Commission, in close coordination with other agencies, will work to define the scope and schedule for developing this multifamily building distributed energy resource action plan.

Stakeholders identified that collaboration with building owners is essential to ensuring proposed energy upgrade solutions meet owners' needs. One strategy suggested to address this issue is to enlist the participation of trade allies, such as contractors or consultants that have established relationships with building owners. They will then be driven to convince the owners to make improvements because it affects their bottom line. Another strategy could be to offer higher incentives to owners for tenant energy savings measures to surmount the split incentive barrier.¹⁴⁷

Additional strategies to address issues with multifamily buildings are described in the *2015 Existing Building Energy Efficiency Action Plan* and 2016 plan update described in the Doubling Energy Efficiency Savings section above.

Statewide Low-Income Clean Energy Labor and Workforce Strategy

The Barriers Study calls on relevant state agencies to collaborate with labor and workforce experts to form a statewide labor and workforce development strategy across clean energy and transportation programs. Specific subrecommendations include creating a green workforce fund to address local workforce development in clean energy and transportation programs, offering preference points for energy service companies that commit to hiring employees from disadvantaged communities, expanding the use of community workforce agreements, and coordinating IOU programs with California training and education institutions.

Expanding upon this goal, Energy Commission staff is engaged with stakeholders, including the CPUC and building owners, on the best ways to implement changes to state workforce and contracting policies. Energy Commission staff and stakeholders are working on ways to use contracting opportunities to foster small business supplier networks that focus on the growth of workforce development opportunities in disadvantaged communities. One commenter stated that as California increases access to clean energy technologies in disadvantaged and low-income

146 Bill Pennington (Energy Commission), "Potential Solutions for Multifamily Low-Income Clean Energy Issues" presentation, May 16, 2017, IEPR Workshop. TN217584.

147 May 16, 2017, IEPR Workshop Transcript, pp. 36–37.

areas, it is important to also promote “well-paying, family-sustaining clean energy job opportunities for residents in these communities.”¹⁴⁸

This goal is also shared by CARB in its draft guidance document, which emphasizes the need to maximize economic opportunities and benefits for low-income residents from investments in clean transportation and mobility options by expanding workforce training and development. CARB’s draft guidance document suggests accomplishing this by strategizing and tracking progress of clean transportation and mobility option access workforce goals; prioritizing incentive projects that demonstrate local economic benefits for low-income residents (such as job creation, training opportunities, and workforce development, including for youth); and expanding access to vocational training and preapprenticeship and apprenticeship programs to support clean transportation and energy jobs and workforce development in low-income and disadvantaged communities, especially for youth.

The May 16, 2017, workshop panel discussion on a clean energy labor and workforce strategy hammered on the importance of identifying actual job types before focusing too much on training. Apprenticeships and preapprenticeship programs fostering hands-on experiences in the construction trades were highlighted as the most effective mechanisms for preparing disadvantaged workers for actual clean energy jobs. A recent study by the UC Berkeley Labor Center highlighted the importance of the solar industry and apprenticeships in creating well-paying jobs for residents of disadvantaged communities, using Kern County as an example.¹⁴⁹

As summarized by Sarah White of the California Workforce Development Board, “to unlock the health and economic benefits of the clean energy economy with communities who have suffered the worst impacts of the old energy economy, the State needs to offer something more substantial than a simple training program. Solutions need to engage the entire system.”¹⁵⁰

Apprenticeship and preapprenticeship programs address only part of the workforce development equation. Community workforce agreements are most powerful when they intersect with local community-based organizations and local businesses to advise how to identify the most relevant strategies to target workforce opportunities for residents in low-income and disadvantaged communities.

Regional Outreach and One-Stop Shop Pilots

During development of the Barriers Study, stakeholders expressed concerns about their inability to access information on available clean energy offerings. Even those who know how to find the correct information may not know how to take full advantage of available programs. Therefore, the Barriers Study calls for state and local agencies to coordinate on establishing regional outreach and technical assistance one-stop shop pilots to streamline access to energy efficiency,

148 Brightline October 27, 2016, Brightline Defense Project Comments on Staff Draft Recommendations. Submitted to Energy Commission Docket 16-OIR-02, http://docketpublic.energy.ca.gov/PublicDocuments/16-OIR-02/TN214215_20161027T154439_Ivan_Jimenez_Comments_Brightline_Defense_Project_Comments_on_St.pdf.

149 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN221127_20170912T134715_New_Study_Finds_Diversity_in_EntryLevel_Renewable_Energy_Jobs.pdf.

150 May 16, 2017, IEPR Workshop Transcript, pp. 162–163.

clean energy, low-emission transportation infrastructure, and water-efficient upgrades in existing buildings across low-income and disadvantaged communities. CARB's draft guidance document also identifies one-stop shops as a critical mechanism in increasing awareness, education, and outreach in low-income and disadvantaged communities and is moving ahead with implementing this priority recommendation in close coordination with the Energy Commission, Strategic Growth Council, and other relevant state agencies.

These cross-cutting one-stop shop pilots would use some combination of physical centers and online portals (bricks and clicks) to provide information and resources needed by low-income consumers and local stakeholders to navigate existing incentive programs and funding opportunities. A critical success factor for the development of one-stop shops will be tailoring the distribution and packaging of information to the specific needs of California's diverse low-income populations and disadvantaged communities. Partnering with local community-based organizations will be key to building relationships and trust with target communities.

Any potential pilots should leverage and expand on existing regional programs that have demonstrated success. One such example is a recent pilot program conducted by CSD that successfully combined weatherization funding from multiple sources.¹⁵¹ Efforts should also be combined with other pre-existing outreach programs to increase coverage at a lower cost. In the same spirit, statewide funding should be combined with other local utilities and water districts to provide locally tailored services to streamline access and create efficiencies. This model reportedly worked well for Southern California Edison (SCE) and its partners in the Irvine Ranch Water District and should be considered a model for a pilot.¹⁵²

The success of a one-stop shop model has been demonstrated in the Chicago area, as documented in a recent study. The study showed that rates from first outreach to owner completion of a retrofit exceeded 40 percent for owners participating in a one-stop intake/technical assistance program. In comparison, reported completion rates for other programs that didn't employ the one-stop/technical assistance model were about 7 percent.¹⁵³

Innovative Financing Pilots to Unlock Access to Funding

As discussed in the Barriers Study, existing rebates and incentives are not enough to meet the need for an estimated \$80 billion in building retrofits in California, taking into account the building stock in Title 24. Taxpayer dollars are insufficient to meet this need, so creative market solutions are needed, coupled with public-private partnerships, to unlock new financing opportunities. Comments from the Silicon Valley Leadership Group also highlighted the need for increased coordination across state financing efforts to "ensure that the stakeholders and

¹⁵¹ May 16, 2017, IEPR Workshop Transcript, pp. 102–104.

¹⁵² May 16, 2017, IEPR Workshop Transcript, pp. 105–106.

¹⁵³ May 16, 2017, IEPR Workshop Transcript, p. 40.

intended beneficiaries of the programs easily understand what programs are available to them and how they work.”¹⁵⁴

While not aimed exclusively at low-income customers, there are some ongoing energy efficiency financing pilots in development that have yet to bear fruit. In 2013, the CPUC approved \$75 million in funding to develop the California Hub for Energy Efficiency Financing (CHEEF), a collaborative public-private partnership established to get more capital providers into the energy efficiency market to lower costs of and expand access to financing.¹⁵⁵ The CHEEF program is aimed at surmounting the upfront cost barrier for energy efficiency retrofits with pilots intended to address single-family, affordable multifamily, and commercial markets.

The Barriers Study called for developing a series of new financing pilot programs to encourage investment for low-income customers. While four potential new pilots are identified in the study, much of the discussion at the May 16, 2017, IEPR workshop focused on the proposed tariffed on-bill financing pilot to encourage investments in energy efficiency and drive customer adoption without requiring low-income customers to take on new debt.

The workshop discussion highlighted Arkansas as a case study for successful implementation of a tariffed on-bill financing mechanism using the pay-as-you-save model with the Ouachita Electric Cooperative. The program allows the utility to finance any upgrade on the customer side of the meter, as long as those upgrades are cost-effective, and to recover costs with a charge on the bill that is substantially less than the estimated savings. This same concept has been used in other states like Kansas, Kentucky, North Carolina, and New Hampshire and on a limited basis in a few counties in California.¹⁵⁶

California utilities are already taking additional steps beyond the CHEEF program to unlock new financing mechanisms. For example, PG&E is developing a menu of financing solutions, including a revolving commercial unsecured loan fund for small businesses and others, alternative underwriting, and a program that will provide energy efficiency loans of up to \$2,000 with on-bill repayment. PG&E has also expanded on-bill financing for multifamily buildings and offering up to 10 years and up to \$2 million potentially for buildings serving low-income people.¹⁵⁷ Separately, Sempra Utilities has also revised loan terms to expand on-bill financing program for multifamily rental properties.¹⁵⁸

From the POU perspective, there is wide diversity of local priorities and program offerings, although there are very few POU programs providing financing options geared toward this

154 Silicon Valley Leadership Group Comments Clean Energy Financing Clearinghouse. Comments submitted to the 17-IEPR-08 docket on May 30, 2017. TN-217631.

155 “New & Existing Clean Energy Financing Pilots for Low-Income Customers.” Presentation from Deana Carrillo, California Alternative Energy and Advanced Transportation Financing Authority at the May 16, 2017 Low-Income Barriers Workshop. TN # 217580.

156 *Expanding Opportunity with Inclusive Financing* comments submitted to the 17-IEPR-08 docket on May 30, 2017. TN-217631.

157 August 1, 2017, IEPR workshop transcript, pp. 217–220.

158 Sempra Utilities comments submitted to 17-IEPR-08 on May 30, 2017 – TN 217771.

segment of the market. POU's tend to view efficiency as a customer service. This differs from the IOU perspective, which is focused on strict cost-effectiveness tests. POU's have collectively urged the Energy Commission to focus on improving and expanding use of the California Utility Allowance Calculator to drive efficiency investments, as it has the potential to achieve scale and impact.¹⁵⁹ Staff is working toward exploring the option to transfer the California Utility Allowance Calculator database from its Microsoft Access implementation to a Web-based application to make the tax credit renewal process easier for housing developers. Implementing the calculator as a web-based application could help developers get their projects approved more quickly by the California Tax Credit Allocation Committee by providing developers with access to their prior years' applications.

Better Use and Sharing of Data to Benefit Disadvantaged Communities

The Barriers Study underscored the need for establishing common metrics and encouraging data sharing across agencies to track progress towards achieving statewide clean energy equity goals. To this end, Energy Commission staff published and sought public comments on a draft *California Clean Energy Equity Framework and Indicators* paper in May 2017.¹⁶⁰ The draft paper identifies six geospatial indicators related to the local economy, geography, demography, social engagement, public health, and environmental quality. The draft paper also proposes 12 performance indicators that can be used to form a baseline and evaluate progress on energy equity efforts across California. At the May 16, 2017, IEPR workshop on Low-Income Barriers, the Los Angeles Department of Water described a similar effort, the Equity Data Metrics Initiative, which tracks performance of programs across its service territory.¹⁶¹ This program serves as a world-leading model for future improvements to the Energy Commission's energy equity indicators tracking progress efforts.

The proposed indicators are intended to support three major objectives, including increasing access to clean energy resources and technologies; amplifying clean energy investments in low-income and disadvantaged communities; and improving local energy-related resilience, or the ability to recover from grid outages and extreme weather events.

Staff anticipates releasing an initial draft tracking progress¹⁶² report for comment in February 2018, which will focus on a subset of the indicators described in the May 2017 draft framework

¹⁵⁹ "Joint POU Comments on Implementation of the SB 350 Low-Income Barriers Study" submitted to the 17-IEPR-08 docket on May 30, 2017. TN-217772.

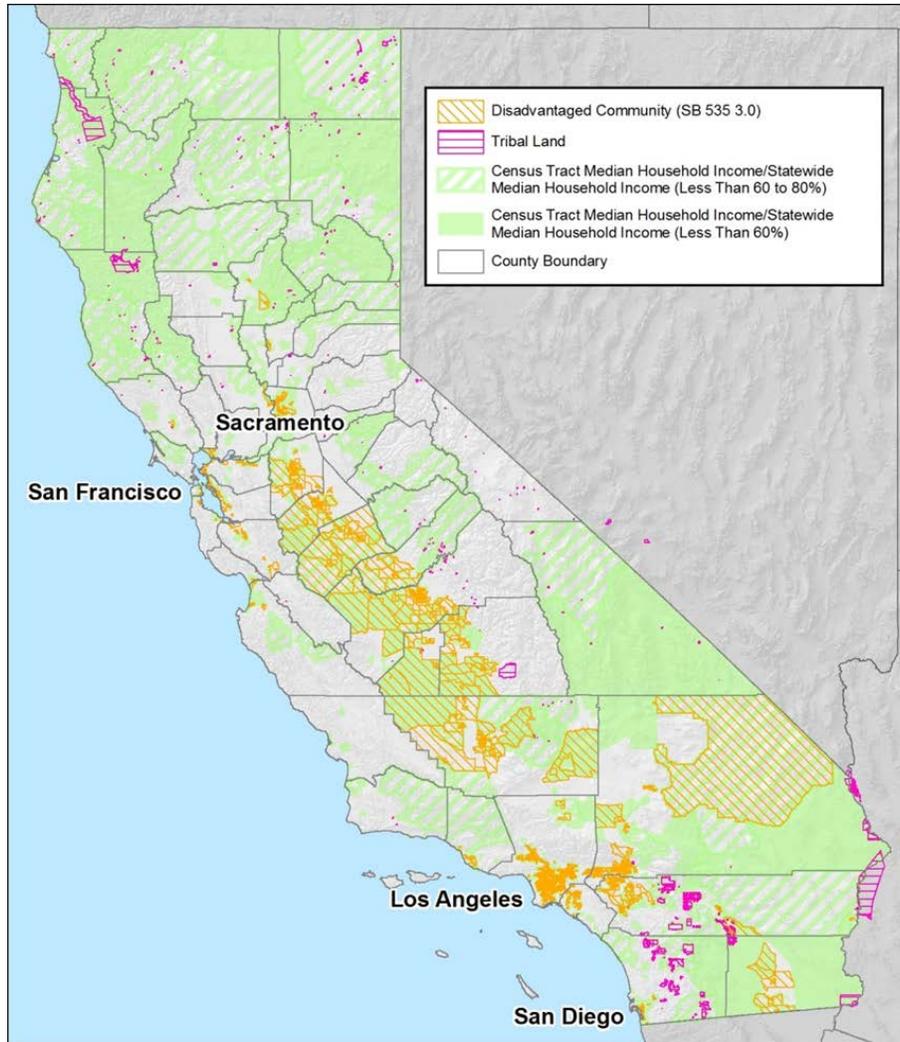
¹⁶⁰ Doughman, Pamela, and Michael J. Sokol. 2017. *California Clean Energy Equity Framework and Indicators: An Approach for Tracking Progress of Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities*. California Energy Commission. Publication Number: CEC-300-2017-051-SD.

¹⁶¹ "Equity Metrics Data Initiative." Presentation given by John Chen, Los Angeles Department of Water and Power, at the May 16, 2017, Low-Income Barriers Workshop. TN # 217582. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN217582_20170512T140144_Equity_Metrics_Data_Initiative.pdf.

¹⁶² http://www.energy.ca.gov/renewables/tracking_progress/index.html.

paper.¹⁶³ Moving forward, indicators will be refined and augmented during future annual updates as additional data sources are identified and relevant information is obtained. In addition to the annual tracking progress report, the Energy Commission intends to develop an interactive mapping tool to allow stakeholders to perform their own analysis using the energy equity indicators displayed in the report. Figure 16 shows an example of the type of map layers that will be available in this tool, showcasing the locations of low-income and disadvantaged communities across the state.

Figure 16: California Disadvantaged Communities, Low-Income Communities, and Tribal Lands



Source: California Energy Commission

In addition to establishing energy equity indicators and tracking progress, the Barriers Study highlighted limitations with the current use of data to inform and align existing state programs and encourage agencies administering programs to “collect and use data systematically across

¹⁶³ The Energy Commission regularly posts sector-specific updates to California’s clean energy goals at http://www.energy.ca.gov/renewables/tracking_progress/.

programs to increase the performance of these programs in low-income and disadvantaged communities.” Discussions among the agencies participating in the barriers task force are working to improve data sharing practices and identify opportunities for further collaboration to improve programs serving disadvantaged communities.

Plug-Load Efficiency Opportunities for Low-Income Customers

The Barriers Study recommends ensuring that low-income persons have product selection options and information necessary to avoid driving up their plug-load energy use. As such, a panel at the August 1, 2017, IEPR workshop was charged to identify opportunities for expanding plug-load efficiency to low-income households.

One large opportunity highlighted by a panelist from Enervee follows from implementation of Assembly Bill 793 (Quirk, Chapter 589, Statutes of 2015), which required utilities to develop online marketplaces that include energy-efficient appliances. These marketplaces will also include energy management technologies, which will help reduce standby load of plug-load devices when they are not in use. Using this information, the total projected economic savings from increased efficiency in low-income neighborhoods may be much larger than are expected. For example, in New York, research showed that for every dollar spent in energy efficiency for low-income customers, there were four fewer dollars of California Alternate Rates for Energy (CARE) program subsidies needed.¹⁶⁴ Any CARE savings accrued from improved energy efficiency have the potential to improve cost-effectiveness of low-income programs, both for building retrofits and appliance purchase programs. These platforms could be used to further lower program costs, increase participant satisfaction, and bolster data collection for low-income programs, consistent with the goals of the SB 350 Barriers Study.

Smart meter data could also be leveraged to reduce home energy use and better understand low-income consumer behaviors. However, even with data available, there is a need to educate energy consumers on how to reduce the use of old, inefficient appliances and operate them more efficiently. To be more energy-efficient, people do not necessarily need to buy new products: they can also realize efficiency gains simply by changing their behavior.

There is also a need for more frequent and precise research to inform improvements to energy efficiency programs. Data show that generic surveys of the devices people own often do not represent accurately how much energy they are using. Further, the devices people have in their homes vary greatly from household to household. In some cases, something that appears as if it would save energy may in fact do the opposite. For example, a study conducted by the California Plug Load Research Center found that 67 percent of people did not know that their computer sleep settings were incorrect and inadvertently using more energy than expected.

Ultimately, the biggest barrier low-income households face in purchasing energy-efficient products is cost. The least expensive products tend to be inexpensive because they are only designed to perform the core function, with energy efficiency as an afterthought. There may be

¹⁶⁴ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220847_20170822T082055_Transcript_of_the_08012017_Joint_Agency_Workshop_on_Senate_Bill.pdf. p. 266.

significantly more efficient options available that are only slightly more expensive. Purchasing a more efficient ENERGY STAR® major appliance might add \$50 to \$150 to the total product cost, which may deter low-income customers. Note that this is not always the case, the online marketplaces have identified numerous examples of more efficient products for sale at no incremental cost. The barrier in these cases is purely informational. As pointed out by panelist Marti Frank, representing Efficiency for Everyone, at the August 1, 2017, IEPR workshop this creates an opportunity to realign incentives and encourage these customers to purchase more efficient products, helping lift the bottom of the market and allowing Californians with the most limited budgets to support the state's efforts to curb GHG emissions.¹⁶⁵

Existing Utility Efforts to Improve Clean Energy Access for Low-Income Customers

As highlighted at a disadvantaged community en banc held on July 6, 2017, SB 350 helped shift the CPUC's thinking in terms of broadening IOU programs to consider more holistically the impacts and benefits to disadvantaged communities.¹⁶⁶ Similarly, California's POU's also have diverse offerings to assist low-income ratepayers, and SB 350 has stimulated POU activity to strengthen this priority. In addition, community choice aggregators now have a growing role to play in enabling access for all energy customers to energy efficiency, renewables, and clean transportation options.

Of the disadvantaged community population in California, 47 percent reside within SCE's territory,¹⁶⁷ making this area an important priority for early action. To explore opportunities for success, SCE has assembled a working group with environmental justice groups and community-based organizations to better understand needs within their territory. Similarly, about 23 percent of the top-ranked disadvantaged communities are in PG&E service territory, according to CalEnviroScreen.¹⁶⁸

In Southern California Gas Company (SoCalGas) territory, more than one-third of customers receive bill assistance each month, with energy affordability being of primary importance.¹⁶⁹ Current efforts also include partnerships with Los Angeles Department of Water and Power (LADWP) and South Coast Air Quality Management District to offer a simplified, one-stop approach for their customers. This approach allows access to a suite of gas, water, and electricity measures without having to deal with multiple touch points. This approach has resulted in 1.2

¹⁶⁵ First cost as the key barrier to efficiency among lower-income households. Marti Frank comments submitted to 17-IEPR-08 in response to August 1, 2017, Low-Income Barriers Workshop. TN # 220748. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220748_20170814T224855_Marti_Frank_Comments_First_cost_as_the_key_barrier_to_efficienc.pdf.

¹⁶⁶ En Banc Hearing on Environmental Justice and Disadvantaged Communities. California Public Utilities Commission. July 6, 2017. <http://www.cpuc.ca.gov/calEvent.aspx?id=6442453767>

¹⁶⁷ August 1, 2017, Workshop Transcript. Page 47. TN 220847.

¹⁶⁸ "PG&E Barrier Study Comments." Submitted to 17-IEPR-08 in response to August 1, 2017, Low-Income Barriers Workshop. TN #220778. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220778_20170815T151323_Valerie_Winn_Comments_PGE_Barriers_Study_Comments.pdf.

¹⁶⁹ "SoCalGas Comments on Low-Income Barriers Workshop." Submitted to 17-IEPR-08 in response to August 1, 2017 workshop. TN # 220779. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220779_20170815T150305_Jennifer_Morris_Comments_SoCalGas_Comments_on_LowIncome_Barrier.pdf.

megawatt-hours, 51,000 therms, and 26 million gallons of water savings in just the first half of 2017.¹⁷⁰

From the POU perspective, Sacramento Municipal Utility District (SMUD) has been reexamining its efforts to assist low-income communities in light of SB 350 and the Barriers Study. Its programs include the Energy Assistance Program Rate, in which roughly 20 percent of its residential customers participate.¹⁷¹ SMUD also works closely with the City of Sacramento by sharing customer information and allowing automatic discounts on city utilities (sewer, water, trash, and so forth). In addition, SMUD has several new program offerings aimed at accelerating adoption of solar technologies, energy efficiency, and electric vehicles for low-income customers across its territory.

Offering a different POU perspective, Imperial Irrigation District (IID) estimates that roughly 70 percent of its service territory is designated as disadvantaged according to CalEnviroScreen, with about 86 percent of the contract accounts designated as residential. With this in mind, IID recently evaluated its low-income energy subsidies and concluded that the existing program offerings were not effective in engaging with this customer group. IID looked closely at its customers' needs, system needs, and technical needs in light of SB 350 and, as a result, developed the eGreen program, which leverages a utility-scale solar program offering to provide a financial settlement on-bill for its low-income customers.¹⁷² The eGreen program provides opportunities for low-income customers to access solar power without the need to install photovoltaics on their roofs.

Efforts to help low-income customers overcome the burden they face in meeting basic energy needs now extend beyond traditional utilities to include community choice aggregators as well, with Marin Clean Energy (MCE) serving as an example. MCE administers energy efficiency efforts with implications for disadvantaged customers, including a proposed pilot program blending Energy Savings Assistance funds and core energy efficiency program funds at a single touch point to overcome some of the split incentives barriers encountered in multifamily properties.¹⁷³

Investigating Consumer Protection in the Clean Energy Economy

The Barriers Study called for the state, in coordination with local entities, to investigate the need for heightened consumer protection in the clean energy economy, with particular emphasis on reducing cases of fraud against low-income and disadvantaged residents. New York State Public

170 August 1, 2017, Workshop Transcript. Page 78. TN 220847.

171 "SMUD Comments Re Senate Bill 350 Low-Income Barriers Study Implementation." Submitted to 17-IEPR-08 in response to August 1, 2017, Low-Income Barriers workshop. TN # 220784.
http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220784_20170815T163029_Lourdes_JimenezPrice_Comments_Comments_Re_Senate_Bill_350_LowIn.pdf.

172 "Imperial Irrigation District Comment Letter SB 350 Barriers." Sean Neal. Comment submitted to 17-IEPR-08 in response to the August 1, 2017, Low-Income Barriers Workshop. TN 220797.
http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220797_20170815T165449_Seal_Neal_Comments_Imperial_Irrigation_District_Comment_Letter.pdf.

173 Beckie Menten on behalf of Marin Clean Energy. August 1, 2017, IEPR Workshop Transcript, pp. 57-62,
http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220847_20170822T082055_Transcript_of_the_08012017_Joint_Agency_Workshop_on_Senate_Bill.pdf.

Service Commission has recently pursued a similar investigation into energy service companies operating in its territory that have allegedly been overcharging customers.¹⁷⁴

At the IEPR workshop on May 16, 2017, David Fogt of the Contractors State License Board provided some information and resources about the state of consumer protection in the California clean energy economy and the solar energy industry, in particular. During his presentation, Mr. Fogt highlighted the need for increased scrutiny in the face of increasing solar industry complaints.

To highlight a recent example, a task force was established in 2016 to investigate instances of abuse in the solar industry. As a result, \$600,000 has been recovered for consumers who were financially harmed by dishonest practices. The types of complaints received include misrepresentation regarding green funding, power purchase agreements, and lease agreements. Complaints usually occur because there are unlicensed contractors, some salespersons who are not registered, and/or contracts that are being given in a language the customer does not speak. Therefore, this is an area where the Energy Commission can help by implementing more intense verification measures within its programs and promoting the same practices at other state agencies. In 2017, there continue to be about 40 complaints per month, and the task force would like to see that number drop to below 25.

Research and Development to Encourage Adoption of Advanced Technologies in Disadvantaged Communities

A recommendation from the Barriers Study is for the Electric Program Investment Charge (EPIC) program to target 25 percent of the Technology Demonstration Deployment funds to projects in disadvantaged communities. As of August 2017, \$53.4 million out of \$172.7 million of EPIC funds, or roughly 31 percent,¹⁷⁵ has gone to projects in the most disadvantaged census tracts across the state as defined by CalEnviroScreen.

To increase this number, the EPIC program has developed a three-pronged strategy that is reflected in the Proposed 2018–2020 Triennial EPIC Investment Plan.¹⁷⁶ This strategy includes:

- Ramping up outreach to reach a broader and more diverse group of stakeholders.
- Implementing new approaches to motivate technology developers to seek project sites in disadvantaged communities.
- Identifying key pain points in low-income market segments and scoping out possible technology solutions to address those needs.

174 “Commission Moves Ahead with ESCO Investigation.” Press Release. Submitted to IEPR docket on 8/10/17. TN# 220640. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220640_20170810T100932_Commission_Moves_Ahead_with_ESCO_Investigation.pdf.

175 “Adoption of Advanced Technologies in Disadvantaged Communities.” Presentation given by Erik Stokes, California Energy Commission, at the August 1, 2017, Low-Income Barriers Workshop. TN # 220464. Slide 9. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220464_20170731T142151_Adoption_of_Advanced_Technologies_in_Disadvantaged_Communities.pdf.

176 California Energy Commission, 2017. *The Electric Program Investment Charge: Proposed 2018 – 2020 Triennial Investment Plan*. Publication Number: CEC-500-2017-023-CMF.

Existing projects benefiting disadvantaged communities have been classified into four categories, including projects where technology advancement is helping improve critical services needed by these communities and projects aimed at improving the living environment for residents by lowering their energy costs. The third category is for projects that are benefitting the local economy in disadvantaged communities, and lastly, there are projects developing new analytical tools that can better inform policy and program decisions. The Natural Resources Defense Council offered specific action items to ensure that the benefits of research and development funding flow to disadvantaged communities.¹⁷⁷

One example is the Central Valley Innovation Cluster by BlueTechValley. The project helps incubate energy sector technologies and entrepreneurs, with a focus on enabling technology deployment in remote localities within the Central Valley. The discussion of this project at the IEPR August 1, 2017, workshop, highlighted some opportunities for Chinese investment in California clean energy technology ventures, and encouraged some startups to travel there. The suggestion was taken by Ismael Herrera from BlueTechValley.¹⁷⁸

As a second example project discussed at the August 1, 2017, workshop, Chollas EcoVillage is designing plans for developing an advanced energy community at Chollas Creek Regional Park in San Diego. Lessons learned thus far include that residents are motivated and interested in participating in clean energy programs because they recognize the larger social and community benefits. There is also a need for more trust. Unfortunately, the current political climate has contributed to a reluctance from part of the community to even talk to outsiders, as residents are not sure of who is coming into their neighborhoods. Therefore, the project team has worked to identify trusted members of the community, like local faith-based organizations and schools, and identifying key champions on each block to be the messengers for the project.¹⁷⁹

Small Business Contracting Opportunities in Disadvantaged Communities

The Barriers Study calls for an in-depth, data-driven follow-up study on the barriers faced by small businesses in disadvantaged communities, including potential opportunities to address those barriers. Several key agencies need to be involved in this study to enable success across programs. For example, the Governor's Office of Business and Economic Development (GO-Biz) is a one-stop shop to assist businesses in navigating state government. Small businesses need help to make sense of all the contracting rules they are subject to when receiving state funding. The Department of General Services (DGS) should also play a role in this study, given the oversight responsibilities of state agency procurement and contracting requirements.

177 "Natural Resources Defense Council comments on SB 350 Implementation Workshop Regarding EPIC Application." Comments submitted to 17-IEPR-08 in response to the August 1, 2017, Low-Income Barriers Workshop. TN #220786.

178 August 1, 2017, IEPR Workshop Transcript. Page 210-211. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220847_20170822T082055_Transcript_of_the_08012017_Joint_Agency_Workshop_on_Senate_Bill.pdf.

179 August 1, 2017, IEPR Workshop Transcript. Page 199. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220847_20170822T082055_Transcript_of_the_08012017_Joint_Agency_Workshop_on_Senate_Bill.pdf.

To reinforce the conclusions and recommendations from the Barriers Study, a DGS survey of 2,300 contractors found that responding contractors faced a number of issues, including that many are financially insecure, and it often takes longer for them to receive payments from prime contractors. Some contractors are very difficult to reach, as they may not be able to attend events during business hours. To provide an idea of scale, the survey found that 78 percent of contractors' earnings come from private contracts, 4 percent from contracts with the state, 3 percent from federal contracts, and 3.5 percent from utilities.¹⁸⁰

One of the major gaps identified during the August 1, 2017, workshop is that many firms do not travel more than 50 miles, and state officials are having difficulty finding firms based in rural areas. There are a lot of good job opportunities if contractors can begin to look past this 50-mile range. As Tanya Little with DGS noted in written comments, even if a small business is able to get a contract, often they simply do not have the capacity necessary to fulfill the requirements, and they may not have access to the network of vendors necessary to do the work.¹⁸¹

To complicate matters, contractors often do not know about the full range of opportunities available to them, such as how to get bonded, how to get a line of credit, and how to take advantage of innovative programs such as NOW Account, which is a federal program that accelerates their payment process. At the August 1, 2017, IEPR workshop, Angelica Tellechea with Brownstone advocated for providing a cheat sheet to local small businesses so they can see the steps they need to follow and provided an example for consideration.¹⁸²

Recommendations

Integrated Resource Plans

Energy Commission staff expects that the initial integrated resource plan (IRP) will demonstrate the feasibility of the process and the success of efforts to bring fragmented planning and procurement efforts into alignment.

- **Continue to provide guidance and assistance to publicly owned utilities (POUs) as needed while they develop their initial IRPs for submittal in 2019.** The Energy Commission will continue to hold webinars or workshops as necessary for POUs to be able to meet the *IRP Guidelines*.
- **Periodically update the IRP Guidelines for POUs to account for new laws and regulations affecting POUs and the electricity sector.** The Energy Commission

180 "DGS Licensed Contractor Demographic Information." Submitted to 17-IEPR-08 docket on September 5, 2017, in response to August 1, 2017, Low-Income Barriers Workshop. TN # 221036-2. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN221036-2_20170905T155220_DGS_Licensed_Contractor_Demographic_Information.pdf.

181 "California Barriers to Small Businesses in Disadvantaged Communities." Comments submitted to 17-IEPR-08 docket on September 5, 2017 in response to August 1, 2017, Low-Income barriers Workshop. TN# 221036-1. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN221036-1_20170905T155221_California_Energy_Commission_California_Barriers_to_Small_Busin.pdf.

182 DVBE/DBE/SBA Cheat Sheet 2017. Submitted to 17-IEPR-08 on August, 8, 2017 in response to August 1, 2017, Low-Income Barriers Workshop. TN # 220736. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220736_20170814T094049_DVBEDBESBA_Cheat_Sheet_2017.pdf.

will conduct any updating through its public IEPR process with input from all affected parties.

- **In coordination with the Energy Commission and the California Public Utilities Commission (CPUC), the California Air Resources Board (CARB) should adopt greenhouse gas (GHG) emissions reduction targets for use in integrated resource planning, consistent with the requirements of Senate Bill 350.** CARB should implement the Energy Commission's proposed allocation method for assigning POU-specific GHG targets based on the identified sectorwide target.

Transportation Electrification

Moving forward, the Energy Commission will work with the California Public Utilities Commission (CPUC) and the California Air Resources Board (CARB) to identify how integrated resource planning (IRP) filings can be further aligned. Specific actions toward this alignment that complement the IRP process include the following:

- **Formalize load research and infrastructure cost tracking capabilities.** The Energy Commission should develop analytical, technological, or regulatory means to enable the utilities to track the market growth of advanced vehicle technologies, and associated charging behaviors for load planning. The Energy Commission will explore collecting energy-use data from plug-in electric vehicle (PEV) charging service providers and other market participants. Although the Energy Commission has not previously collected data from these entities, data related to PEV charging are becoming increasingly important in energy planning as the state works to meet its electric transportation goals. In spring 2018, the Energy Commission anticipates starting Phase 2 of the Title 20 Data Collection Rulemaking and through this process looks forward to engaging PEV market participants on what data are available to share with the Energy Commission.
- **Coordinate electric transportation emissions allowance policies with CARB.** The Energy Commission should assist the utilities and CARB in identifying and quantifying potential financial liabilities associated with the emissions from serving electric transportation load, as described in Health and Safety Code Section 44258.5. In 2018, the Energy Commission intends to convene workshops with CARB and utilities, to identify how to use load research, Title 20 data collection, and charging infrastructure program information collected through integrated resource plans to measure emissions costs and to assess utilities' alignment with charging investments. If emissions allowances pose a disincentive for investments in electric transportation, the Energy Commission and CARB should explore whether mechanisms exist with existing programs, such as the Cap-and-Trade regulation, to remove financial disincentives for publicly owned utilities, as well as other types of mechanisms.
- **Align with established emissions assessment methods.** The Energy Commission should consider how transportation electrification emissions and electricity quantification methods and measurements used in integrated resource planning are consistent with methods permissible for CARB-jurisdictional programs, such as the Cap-

and-Trade Program, Low Carbon Fuel Standard, Mobile Sources Strategy, and Greenhouse Gas Inventory programs.

- **Enhance accessibility for charging infrastructure programs and tracking.** The Energy Commission should collaborate with researchers as well as local government, air district, or utility charging infrastructure program administrators to share data about charging infrastructure programs. This collaboration can help enhance existing program practices and may serve to enable more strategic and better coordinated charging infrastructure deployments. The Energy Commission's charging infrastructure modeling and planning tools and its recently launched block grant project for electric vehicle charging infrastructure, for instance, could serve as a critical conduit for information on electric vehicle charging infrastructure programs serving metropolitan transportation and air management regions and utility territories throughout the state.

Additional recommendations on transportation electrification not directly related to the IRP process include the following (see Chapter 4 for recommendations related to vehicle grid integration):

- **Partner with local utilities and governments.** Increase the frequency of non-regulatory engagements outside the formal integrated resource planning process with publicly-owned utilities to identify areas to support utility, governmental, and community initiatives that advance transportation electrification, including funding partnerships for readiness and implementation planning and collaborative procurement and deployment initiatives.
- **Learn and share from interstate and international charging technology best practices.** The Energy Commission should use informal partnerships or memoranda of understanding or both with other state energy and transportation offices, international governments, or industry standards bodies or any of these entities to encourage joint procurements and technology deployment.
- **Support development of specialized consumer education and engagement tools.** The Energy Commission, in coordination with the CPUC, CARB, and nonprofit outreach organizations like Veloz, should enhance public understanding of the adequacy of electric vehicles for their transportation needs, the costs and benefits of using utility electricity rates, and the availability of public charging infrastructure services.

Doubling Energy Efficiency Savings

To carry out the mandates of Senate Bill 350 and ensure that the doubling goals are achieved, recommended actions are outlined below. The Energy Commission should coordinate with other agencies to:

- **Develop a comprehensive roadmap to achieve a doubling of energy efficiency savings.** Combine the required 2019 updates to the SB 350 energy efficiency doubling targets and the Existing Building Energy Efficiency Action Plan into a single comprehensive document that provides stakeholders with both an update to the efficiency

doubling targets and an action plan for achieving the bulk of the savings through retrofitting existing buildings.

- **Enhance workforce training.** This would improve the quality of energy efficiency equipment installation and maximize opportunities for disadvantaged customers to benefit from the clean energy economy. The Energy Commission will pursue a responsible contractor policy with stakeholder input that improves the energy efficiency workforce.
- **Expand education and outreach to improve code compliance.** Increase interagency collaboration and stakeholder engagement for outreach and education at the local level, especially for local building permit offices and contractor communities. The creation, adoption, and enforcement of a responsible contractor policy in ratepayer-funded energy efficiency programs will also help improve code compliance and result in additional energy savings.
- **Coordinate closely with the CPUC and POU's to ensure comparability of their respective potential and goals studies developed in support of the Senate Bill 350 doubling targets.** Detailed baselines are required for characterizing consumption, identifying locational and sector trends, and tracking realized savings over time. Improved analytical methods are needed for estimating future energy savings, as well as for tracking savings by source.
- **Work with utilities and the CPUC to develop guidelines for conservation voltage reduction techniques and fuel substitution that can count toward Senate Bill 350 goals.** The Energy Commission recommends the Energy Commission, CPUC, CARB, utilities, and stakeholders develop a comprehensive framework to implement fuel substitution that maximizes energy savings and GHG emission reductions. Part of this effort should include coordination with the state's *Short-Lived Climate Reduction Pollutant Strategy* to develop recommendations about complementary or competing roles of substituting electricity for natural gas and replacing natural gas with renewable gas as strategies for reducing GHG emissions.
- **Implement an effective food processor emission reduction program.** Greenhouse Gas Reduction Fund budget control language in Assembly Bill 109 (Ting, Chapter 249, Statutes of 2017) tasks the Energy Commission with developing a \$60 million research and development program for grants, loans, or other financial incentives to food processors to implement projects that reduce greenhouse gas emissions. The Governor's Office has convened a California Food Processors Task Force to examine issues and identify strategies that will assist food processors' compliance with California's climate programs. Agencies including the Energy Commission, the CPUC, CARB, California Department of Food and Agriculture (CDFA), California Department of Water Resources (DWR), U.S. Department of Agriculture (USDA), and the Treasurer's Office are partnering with food processor industry members to identify technology needs and incentive funding to address those needs. The Energy Commission will use the task force

- input to inform the program design and issuance of competitive grant opportunities for efficiency and renewable projects.
- **Work with the CPUC, utilities, other state and local agencies, and stakeholders to identify and pursue additional energy savings from the agricultural and industrial sectors.** These efforts to reduce carbon emissions from California’s food processing energy needs could be replicated for other major industrial processes in the state. Identifying cost-effective and feasible energy and demand reductions from energy efficiency and demand response, as well as emission reductions from fuel substitution in industrial facilities, will be a focus in the next update to the SB 350 energy savings targets to achieve a doubling of energy efficiency by 2030. The Energy Commission will also engage industry in its research roadmapping to align research grants with industries’ efficiency and renewable priorities. The Energy Commission will seek out innovative and resilient programs that may be best determined through the California Technical Forum. The goal is to use a venue for resolving barriers to new program design that rewards risk-taking to an appropriate extent.
 - **Work with other state, regional, and local agencies; building owners; builders; financial institutions; small businesses; inspectors; consumer groups; environmental and environmental justice groups; and other stakeholders to identify new energy savings opportunities that would help achieve the state’s doubling goal.**
 - **Ensure that clean energy investments in buildings, agriculture, and industry – including behind each meter – support grid resilience.** The *2019 Building Energy Efficiency Standards* will develop compliance pathways that encourage investments in all distributed resources within both new and existing buildings, thus supporting systematic attention to grid resilience.
 - **Evaluate and introduce wide-scale remote auditing tools to use multiple datasets for modeling and reporting facilities with the greatest need for assistance.** Using better data on existing buildings, additional policies and programs can be made to focus incentive dollars where the most impact can be made to reduce GHG emissions. As each of these modular pieces becomes functional in this larger analytical suite, audit and utility data will become valuable pieces, offering an additional dimension to better understand the building stock as a whole.
 - **Improve the efficiency and comfort of existing homes with whole-building retrofit solution incentives.** Whole-building retrofits will play a role in reaching the state’s energy goals. Such efficiency improvements can be exploited through pay-for-performance programs and the CalTrack tool that PG&E has developed. CalTrack does not depend on (often inaccurate) engineering estimates, but rather quantifies real-world impacts of upgrades, which enables appropriate and effective payment and provides much needed and timely insight on programmatic trends and issues. Other incentive programs could be coordinated with FlexAlert marketing to offer consumers a meaningful way to permanently improve the efficiency of their homes, improving the predictability of

communitywide energy savings compared to relying solely on behavior changes in real time.

Renewables Portfolio Standard

The Energy Commission should:

- **Coordinate with the CPUC for implementation of new Renewables Portfolio Standard (RPS) rules.** As the Energy Commission and the CPUC jointly implement the RPS, the agencies should continue to work closely together, as well as with their respective stakeholders, to ensure that the new rules are implemented consistently and appropriately for the load-serving entities to which they apply.
- **Continue to improve and accelerate RPS program administration.** In January 2017, the Energy Commission launched a new online reporting system for the RPS program aimed at simplifying and expediting the certification of eligible renewable energy facilities as well as utility reporting under the RPS. The online system will also support efficient verification of reporting by staff. The Energy Commission should continue to explore and implement program administration improvements to ease reporting burdens for regulated entities and to expedite administrative activities.
- **Monitor the impact of decreased demand due to factors such as increased energy efficiency, increased distributed generation, and more competitive electricity markets on RPS procurement obligations and long-term contracting.** Though actual RPS procurement targets are calculated based on annual retail sales, load-serving entities must procure renewable electricity based on forecasted sales. Decreasing load and particularly rapid and unpredictable load changes associated with increases in retail choice could affect development of new RPS-eligible resources. Lack of long-term load certainty has adversely affected the willingness and ability of a load-serving entity to enter into long-term contracts for RPS procurement.
- **In assessing paths to achieve the 50 percent renewable mandate, consider the role of smaller-scale and distributed renewable energy generation.** As the penetration of rooftop solar and other distributed renewable generation continues to rise, the Energy Commission should evaluate the future role of distributed renewables in the RPS through public processes in future revisions of the *Renewables Portfolio Standard Eligibility Guidebook*.
- **Continue to update the *Renewables Portfolio Standard Eligibility Guidebook* to reflect technological advancements.** In support of the 50 percent RPS mandate, the Energy Commission should continue to revise the *Renewables Portfolio Standard Eligibility Guidebook* to ensure that the certification guidelines appropriately address technology developments and do not hinder increased renewable energy development.
- **Emphasize that the RPS program can support POU initiatives to serve disadvantaged communities.** Along with the renewable energy and greenhouse gas

emissions reduction goals, SB 350 affirmed the state's commitment to promoting equitable access to clean energy for all Californians. In recognition that the circumstances and financial resources of load-serving entities, and particularly POU, vary substantially, the RPS program provides flexibility in achieving the associated mandates through application of optional compliance measures, such as adopting cost limitations. The Energy Commission should continue to support flexibility in the RPS program to ensure that achieving the RPS mandate is not at odds with POU efforts to reach underserved and disadvantaged communities.

Low-Income Barriers

The Energy Commission should:

- **Coordinate closely with CARB, the CPUC, community groups, key stakeholders, and other state and local agencies to implement the Barriers Study recommendations**, beginning with those recommendations identified as high priority by the Senate Bill 350 barriers task force. One of the key priorities for 2018 will be leading the development of a multifamily building distributed energy resource action plan focused on addressing barriers for low-income and disadvantaged communities.
- **Continue to conduct regional outreach meetings and workshops across the state to engage with local residents and community groups representing low-income and disadvantaged residents to identify and reinforce key local priorities and amplify program benefits.** Outreach should be coordinated with local stakeholders and community-based organizations to increase participation and trust in information provided.
- **Work with the California Tax Credit Allocation Committee and other relevant stakeholders to implement the California Utility Allowance Calculator for multifamily housing retrofits.**
- **Continue to refine proposed energy equity indicators based on best available information and use those indicators to help track progress over time and inform opportunities to refine California's energy programs as they affect low-income and disadvantaged communities.** As indicators and data are refined, the Energy Commission should move from a static tracking progress report to an interactive mapping tool containing a variety of layers for stakeholders to use in conducting their own assessments of the performance of the clean energy and transportation programs' in such communities.
- **Implement more intense clean energy technology and contractor verification measures within Energy Commission programs and promote similar actions by other state agencies administering energy programs to increase consumer protection.** Particular emphasis should be placed on limiting predatory practices against low-income customers and those that live in disadvantaged communities.

CHAPTER 3:

Increasing the Resiliency of the Electricity Sector

As California transforms its electricity system to reduce greenhouse gases (GHGs) further work is needed to increase the resiliency of the system. Reducing GHGs through increasing additions of new renewable resources to meet the state's 50 percent Renewables Portfolio Standard (RPS) necessitates changes in how operators manage the grid. Most new renewable generation is expected to come from wind and solar, for which output varies depending on if the wind is blowing or if the sun is shining. Thus, solar and wind are intermittent unlike the fossil fuel power plants they are displacing.

There are other factors that will also impact the operation of the grid. For example, California wants to electrify transportation to reduce emissions of both GHGs and criteria air emissions. (For more information on transportation electrification policies and forecasts, see Chapters 1, 2, and 7 and Appendix H.) Electrifying transportation should significantly increase electricity demand (Chapter 6). Electric vehicle charging could place further strains on grid operations if it occurs at the "wrong" times or could promote grid operation if the batteries in these vehicles can be smoothly integrated into grid operations.

Similarly, between now and 2030, the state also expects changes in the natural gas infrastructure system, such as the likely closure of the Aliso Canyon natural gas storage facility (for more information, see Chapters 8 and 11) and similar changes to the electricity system with the closure of California's remaining nuclear power plant at Diablo Canyon. In addition, climate change is expected to exacerbate variations in the hydroelectric system, increase the frequency and severity of forest fires, and increase coastal flooding, as well as affect energy demand (such as increased demand for air conditioning in the summer; for more information see Chapters 6 and 10).

The term "resilience" in this chapter focuses on the reliable operation of the electricity grid in light of these technical, market, and climatic factors that pose new challenges to the system.¹⁸³ For example, along with rising temperatures and drought, the state needs to plan for even more forest fires in the future. (See Chapter 10 for more discussion of fire hazards.) As an indication of the risk, in 2017 California suffered the largest wildfire in history with a record number of deaths. To have a more resilient energy system, the CPUC has substantially enhanced fire safety requirements and utilities are increasing wind monitoring and starting to deenergize parts of the

¹⁸³ The National Academies of Sciences, Engineering, and Medicine defined *resiliency* in the electricity sector as follows: "Resilience is not the same as reliability. While minimizing the likelihood of large-area, long-duration outages is important, a resilient system is one that acknowledges that such outages can occur, prepares to deal with them, minimizes their impact when they occur, is able to restore service quickly, and draws lessons from the experience to improve performance in the future."

National Academies of Sciences, Engineering, and Medicine, *Enhancing the Resilience of the Nation's Electricity System*, Washington, D.C.: The National Academies Press, 2017, <https://doi.org/10.17226/24836>.

grid in high hazard areas. California must fundamentally rethink its energy practices and infrastructure to have a more resilient grid given the growing fire hazards.

Another major factor that must be addressed to increase the resiliency of the grid is the increasing variation in generation and demand. This requires a more flexible and nimble system and use of a variety of tools as discussed below.

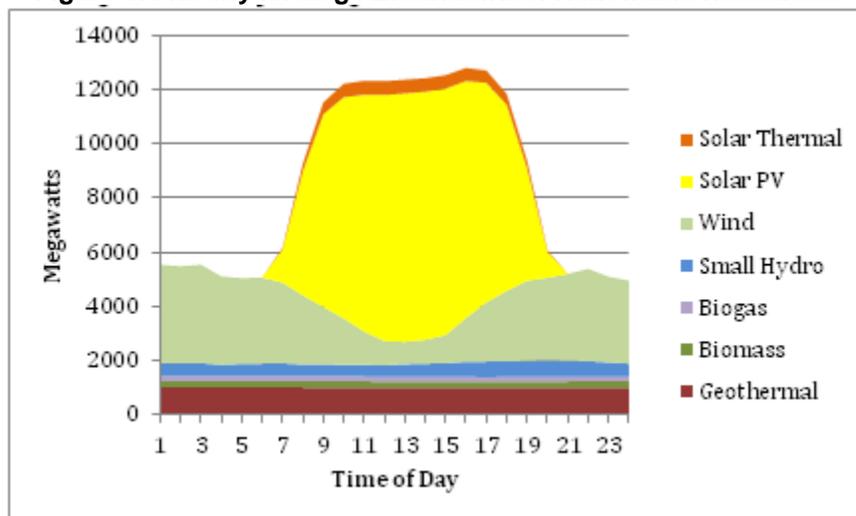
The successful use of these tools, however, will be affected by the evolving market structure of California's power industry. (See the section in Chapter 1 titled, "Changes in Electricity Market Structure," for more information.) Utilities are not making short-term, let alone long-term, financial commitments in the power procurement area due to a growing number of customers switching to community choice aggregators. Community choice aggregators have limited credit worthiness to make investments. At the May 24, 2017, IEPR workshop, several parties suggested that the challenges to increasing flexibility are not technical, but rather commercial and contractual.¹⁸⁴ Efforts to advance the flexibility of renewable and conventional generation, to deploy storage that can compensate for variability, and to retain power plants that provide fast, flexible capacity are all examples of tools to increase the resiliency of the electricity grid that are facing contractual barriers stemming from market uncertainty. Still, the state must advance a portfolio of solutions that can be drawn upon to increase resiliency as it decarbonizes its energy system.

Operational Changes

The shift to renewable resources and the growth in solar resources in particular have dramatically shifted when and how much conventional generators produce electricity in California. Figure 17 shows how solar generation dominates California renewable energy production in the middle of a summer day.

¹⁸⁴ May 24, 2017, IEPR workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-13/TN217924_20170607T144655_Transcript_of_05242017_IEPR_Lead_Commissioner_Workshop_on_Strat.pdf, Matt Barmack from Calpine, p. 85, Brian Theaker from NRG, p. 92, Josh Nordquist from Ormat, p.95, Energy Commission Chair Robert B. Weisenmiller, p. 120.

Figure 17: Hourly Average Breakdown of Renewable Resources



Source: California ISO Daily Renewables watch, July 1, 2017, http://content.caiso.com/green/renewrpt/20160701_DailyRenewablesWatch.pdf.

The California ISO’s graphic representation of the “net load,” electricity demand minus electricity and wind and solar generation, is emblematic of how changes in the generation profile are creating challenges and opportunities for grid operators. (See Figure 18.) When solar peaks at midday and the net load is low, the figure shows the “belly of the duck.” As solar generation trails off at the end of the day and demand remains high, the steep ramp up is referred to as the “neck of the duck.” The ramps up and down (“the tail of the duck”) in the net load curve have become more pronounced and steeper than the California ISO anticipated. In fact, during the summer of 2017, the net load fell below 9,000 MW twice, which was not anticipated until well after 2020. When the California ISO initially developed the “duck curve,” it did not expect renewable generation to achieve current levels before 2020, nor did it expect the rapid rate of growth in behind-the-meter solar generation.¹⁸⁵

Ramping

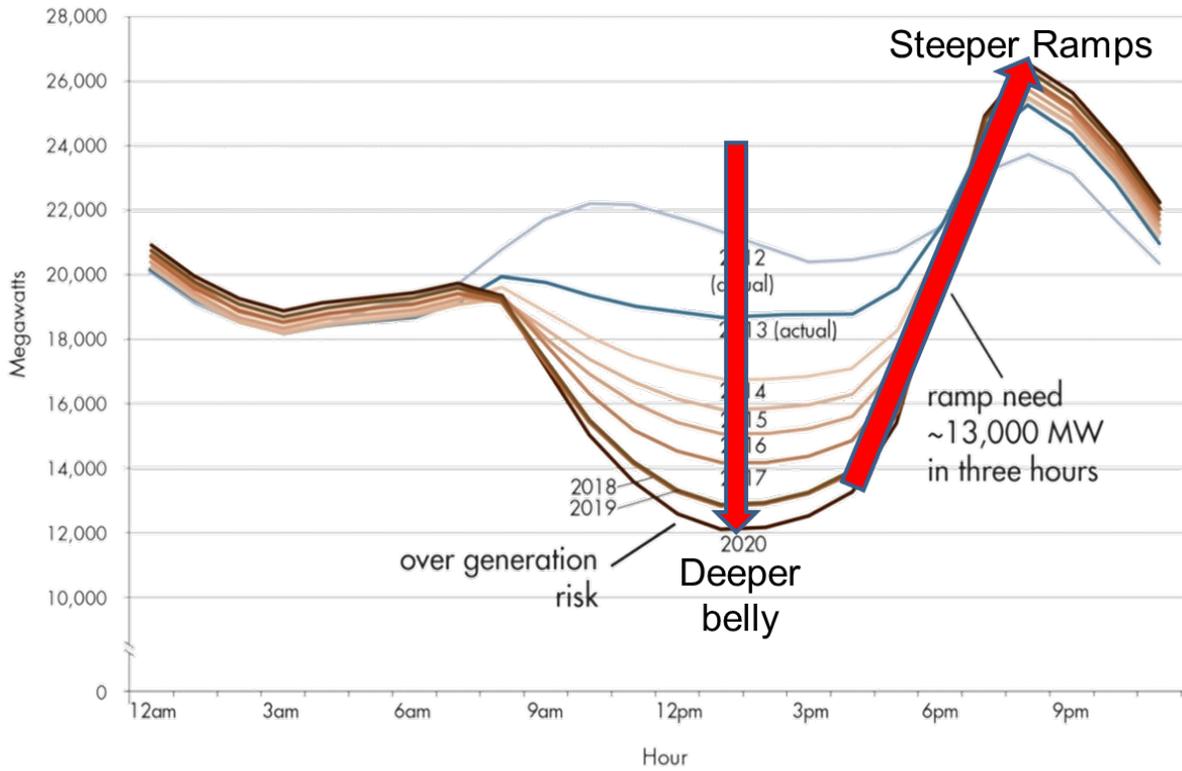
Multihour ramps up and down have been a factor in California’s electrical system for decades, but the deployment of large amounts of renewable capacity with strong daily cycles exacerbates these patterns – especially in winter and spring months – and is spurring the need for increased flexibility in the system.¹⁸⁶

¹⁸⁵ Rothleder, Mark, California ISO, May 12, 2017, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 11.

¹⁸⁶ “Tracking Progress, Resource Flexibility,” updated December 15, 2016, California Energy Commission, http://www.energy.ca.gov/renewables/tracking_progress/documents/resource_flexibility.pdf.

Figure 18: Duck Curve, Electricity Demand Minus Wind and Solar Generation on a Typical Spring Day

Typical Spring Day



Source: California ISO, presentation by Mark Rothleder at May 12, 2017, IEPR workshop.

Challenges Meeting a Spring 2017 Evening Ramp

During the afternoon and evening of May 3, 2017, the California ISO experienced conditions that led to it declaring a first Stage 1 emergency from 7:00 p.m. to 9:00 p.m. This was the California ISO's first Stage 1 emergency declaration in 10 years. Although the California ISO routinely provides generation and other resources to respond to rapidly changing solar generation during the day, not enough resources responded to requests as the event unfolded from afternoon through the evening.

The first significant sign of trouble was the unexpected shutdown of a 330 MW unit at AES's Alamos generation station. This unit had been scheduled the day before to provide 270 MW on May 3. Then, 1,150 MW of power scheduled the previous day for May 3 did not arrive. Next, 1,230 MW was "awarded" in the hour-ahead market for the hour from 8 to 9 p.m., but only about 400 MW was delivered. By 6:45 p.m., solar generation was well into the rapid plunge to zero MW, and the emergency was declared about 7 p.m.

At the same time, the California ISO started arranging for almost 850 MW of demand response resources from its utilities. The utilities responded, and the California ISO was able to release the emergency at 9 p.m.

For more information, see <https://www.rtoinsider.com/caiso-stage-1-emergency-43153/>.

During the day, when net load is lowest – the belly of the duck – the system operator works to get as many resources off the system as possible to make room for the renewable generation. (See “Overgeneration” below.) At the same time, some resources need to be available to ramp up to compensate for renewable generation decreasing. The late afternoon ramp from the belly of the duck up is approaching 13,000 MW in a three-hour period on some of the hottest days. The potentially thin margin of energy available to meet the evening ramp is illustrated in the sidebar “Challenges Meeting a Spring 2017 Evening Ramp.” The transition from the low net-load

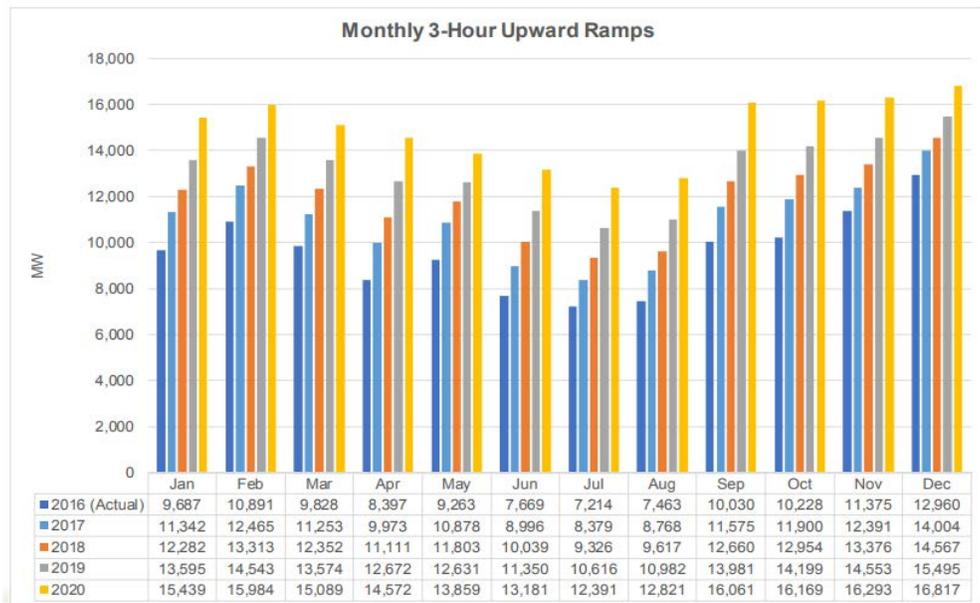
condition to the head of the duck is an operational challenge for the California ISO but also presents opportunities for better managing the grid to maximize the benefits of renewables.¹⁸⁷

The ramps are also becoming increasingly steep. Over the last six years, the three-hour net load ramp has increased 62 percent, and the one-hour net load ramp has increased about 50 percent.¹⁸⁸ Figure 19 illustrates projected maximum monthly three-hour ramps (the metric that defines flexible capacity needs) for the California ISO for 2018 and 2026, as well as historical values for 2012.

¹⁸⁷ Rothleder, Mark, California ISO, May 12, 2017, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp. 11–12.

¹⁸⁸ Theaker, Brian, NRG, May 12, 2017, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 89.

Figure 19: Actual and Projected Maximum Three-Hour Ramps, California ISO, Years 2016 (Actual), and the Projection to 2017, 2018, and 2020 (MW)



Source: California ISO

Overgeneration

As the late afternoon ramp is expected to become steeper, the net load during midday and afternoon hours is expected to drop further. In March 2016, average net loads at midday were just under 18,000 MW.¹⁸⁹ However, the projected net loads were about 12,000 MW by 2020¹⁹⁰ and 8,800 MW by March 2026.¹⁹¹ As mentioned previously, the grid has actually experienced much lower net loads ahead of projections, and in 2017, the net load was already as low as 9,187 MW. Net load projections may fall farther if California continues to see a rebound in hydroelectricity generation and as the state pursues a doubling of energy efficiency savings. (See Chapter 2 for more information on the energy efficiency savings goal.) Moreover, the net load may further decrease based on Energy Commission staff’s projection that more than 9,700 MW of additional customer-side rooftop PV could be installed as early as 2022 in the low demand scenario and more than 6,000 MW by 2030 in the high demand scenario of the revised California energy demand forecast for 2018–2030. (See Chapter 6 for more information.)¹⁹²

The lower net load has led to increases in oversupply and curtailment of electricity generation. This is exacerbated by the high hydroelectric generation conditions in 2017, following four years

¹⁸⁹ California ISO daily renewables output data

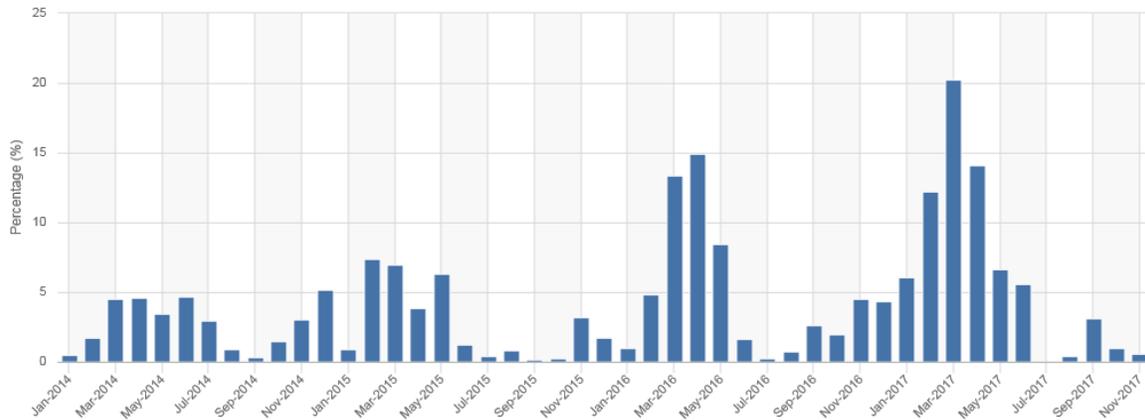
¹⁹⁰ Mark Rothleder, California ISO, May 12, 2017, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p.10.

¹⁹¹ Dataset from California ISO used for special studies in the 2016–17 Transmission Plan; provided by Shucheng Liu, May 18, 2017.

¹⁹² California Energy Commission, *California Energy Demand Forecast, 2018 –2030 Revised Forecast*. Note that the high demand scenario assumes a slower adoption rate for PV than does the low demand scenario.

of drought. Figure 20 shows the effect of increasing renewable generation (and high hydroelectric generation in 2017) on the frequency of negative prices. While on average about 2 percent of total wind and solar power is being curtailed, it is much higher on specific days. At times, more than 30 percent of the renewable energy is being curtailed to maintain grid operation. Instead of curtailing the energy, increasing and better aligning the flexibility of loads (see “Demand Response” below) and supply will increase system resiliency and help California further reduce GHG emissions.¹⁹³

Figure 20: Frequency of Negative 5-Minute Prices by Month in 2016 and 2017



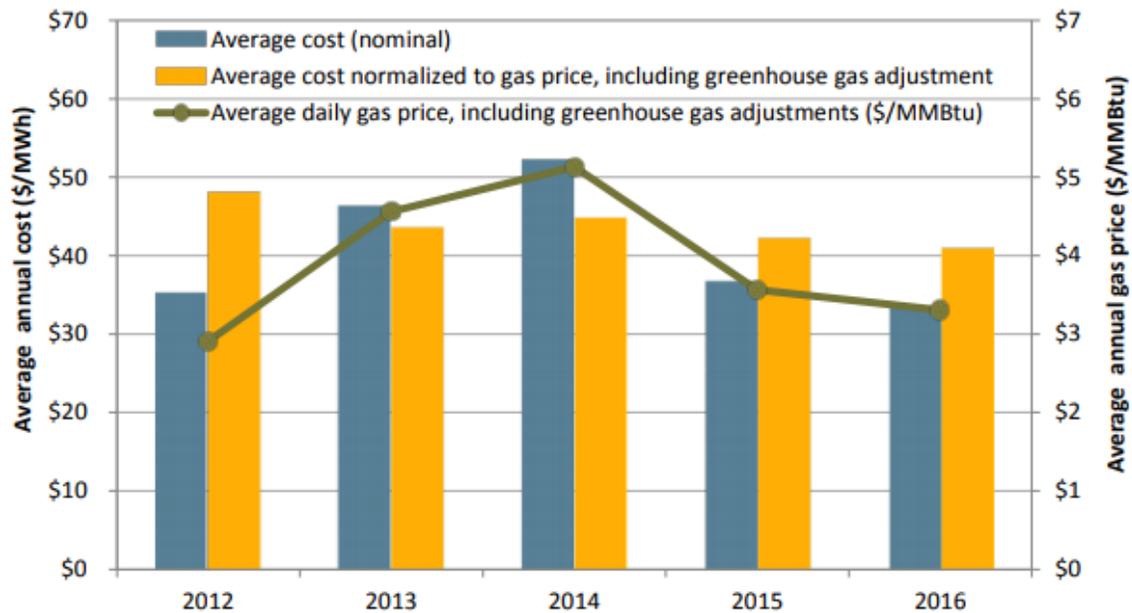
Source: California ISO, <http://www.caiso.com/Documents/MonthlyRenewablesPerformanceReport-Nov2017.html>

Oversupply causes low or negative prices for wholesale energy during periods of overgeneration. Negative bids often represent the lost opportunities for the generator to take advantage of tax credits for renewable energy production or sell renewable energy credits.¹⁹⁴ (For more information about renewable energy credits, see Chapter 2, section on “RPS Background.”) When load is settled at negative prices, either the generator foregoes this revenue or the purchasing utility must make the generator whole and ratepayers incur excess costs. Increasingly, the California ISO is able to anticipate when negative pricing will occur. Figure 21 illustrates a declining trend in the price of wholesale energy on the California ISO markets since 2014, reflecting the downward price pressures of increasing generation output from renewable resources with very low operating costs.

¹⁹³ Rothleder, Mark, California ISO, May 12, 2017, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 14.

¹⁹⁴ Rothleder, Mark, California ISO, May 12, 2017, IEPR workshop transcript, pp. 11–12.

Figure 21: Total Annual Wholesale Costs per MWh of Load Served, 2012–2016



Source: California ISO, <http://www.caiso.com/Documents/2016AnnualReportonMarketIssuesandPerformance.pdf>.

Reliability

Another challenge is related to maintaining the reliability of the electricity system. Traditionally, natural gas power plants are equipped with automatic governor control (to adjust the power output of multiple generators at various power plants as needed in response to load changes) and automatic voltage regulation (to adjust fluctuating voltage to keep it at a constant level).¹⁹⁵ These power plants are being displaced with renewable resources that typically do not include such controls, although efforts are underway to launch technologies that will help make variable resources increasingly “grid-friendly.” In 2015, a North American Electric Reliability Corporation (NERC) task force report suggested that to maintain adequate reliability with the increased use of variable resources nationwide, such generation resources need to provide sufficient voltage control, frequency support, and ramping capability—the “essential components of a reliable bulk power system.”¹⁹⁶ (See the sidebar on “Reliability Issues With Transmission-Interconnected PV Generation.”)

¹⁹⁵ Loutan, Clyde, and Vahan Gevorgian, “Using Renewables to Operate a Low-Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant.” California ISO, National Renewable Energy Laboratory, 2016, <https://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf>.

¹⁹⁶ North American Electric Reliability Corporation. *Essential Reliability Services Task Force Measures Framework Report*, November 2015, <http://www.nerc.com/comm/Other/essntlrbltysrvctskfrDL/ERSTF%20Framework%20Report%20-%20Final.pdf>.

A primary responsibility of a system operator is to maintain system frequency at 60 hertz and to make sure that the amount of energy coming into or out of the system matches what was scheduled in a manner that meets, both NERC reliability requirements and Federal Energy Regulatory Commission-approved tariffs. The California ISO meets or exceeds the annual standard by balancing every 4 seconds through automatic generation control, but is experiencing an increasing number of instances in which it is not. This is associated with the high levels of volatility in renewable generation not previously experienced. For example, while the daily swings in solar generation are fairly predictable, cloud formations can suddenly develop over large solar arrays and cause rapid changes in electricity generation that were not anticipated and, therefore, difficult to manage. Still, while the state has had to take more mitigation measures to manage the increased variability, it has maintained the reliability of the grid.¹⁹⁷

Reliability Issues With Transmission-Interconnected PV Generation

In recent months, there have been several instances of transmission-level disturbances that resulted in a regional loss of generation from large PV generators whose inverters ceased to inject power. These disturbances were transmission-level faults, and the most significant instance was the loss of nearly 1,200 MW of PV generation on August 16, 2016. The inverter-based resources affected were primarily utility-scale resources interconnected at the transmission level under the jurisdiction of the California ISO. Due to the large amount of PV generation impacted in multiple events, NERC issued an alert on June 20, 2017, that references their report (*1,200 MW Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report*) and recommends a review of inverter-based control settings for PV resources.

In response to the alert, the California ISO contacted the inverter-based generators under their jurisdiction to gather additional information about existing inverters. The California ISO determined, based on information gathered, if the inverters could be adjusted to improve functionality. Depending on the inverter vintage, some inverter manufacturers were able to work with the California ISO to adjust setting functions, including voltage and frequency “ride-through,” increased tolerance of disturbances, and reduced time an inverter ceases to inject electricity after an event. The California ISO held a workshop on July 24, 2017, to discuss the issues with stakeholders. The main conclusion was that NERC should require the development of new standards for inverter-based resources specific to transmission level operations—separate from IEEE 1547. The development of a transmission interconnection standard would greatly impact utility-scale inverters and would take several years to complete and standardize throughout existing lines.

The increased use in behind-the-meter generation also poses reliability and operational challenges. Most of California’s behind-the-meter generation is small, load-serving PV generation interconnected at the distribution level that may export excess generation to the grid, depending on the interconnection type. These small projects are not visible to system operators and until recent years had little to no impact on distribution system operations. However, with increased penetrations, the exported electricity can cause disturbances to the distribution system. Conversely, cloud cover can cause a rapid decline in rooftop solar output, triggering increases in demand. The failure of a large generator can cause a sudden drop in system frequency, causing many roof top solar units to “trip off,” leading to a sudden, sharp increase in demand.¹⁹⁸ In the

¹⁹⁷ Rothleder, Mark, California ISO, May 12, 2017, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 35.

¹⁹⁸ <http://www.cpuc.ca.gov/General.aspx?id=4154>.

near term, smart inverters can increase resiliency and even enable market participation in grid-benefitting services, as discussed below in “Increasing Operational Flexibility of Renewable Resources.”¹⁹⁹

While the state faces new challenges in managing its electricity system, these issues are not unique to California. Germany and China – regions that are also increasing the use of renewable resources – are experiencing many of the same challenges. Energy Commission Chair Robert B. Weisenmiller noted that Texas, Germany, and China have their own versions of the duck curve and that China has periods when renewable curtailment is 40 percent.²⁰⁰ The state has opportunities to learn from other regions as they encounter challenges while working to decarbonize their respective electric grids. Moreover, California’s leadership in advancing its own grid operations can help spur renewable development and GHG emissions reductions throughout the world.

Solutions to Increase Flexibility in the Electricity System

The operational challenges described above are the result of California’s successes in transforming its power mix. It is time to redouble the planning for ever-increasing levels of renewables. There is no one measure that will address all flexibility needs, but rather a suite of tools can help manage the fluctuations in supply and demand. Chair Weisenmiller noted, “Some of them are more significant than others. Although, frankly, I think we’re going to need a portfolio of solutions.”²⁰¹ These solutions include:

- Managing the grid on a more regional scale, capturing a greater diversity of loads and resources.
- Ensuring that market mechanisms are in place to encourage ongoing operation of the most flexible natural gas power plants in strategic locations
- Improving the operating characteristics of existing and new resources, both natural gas-fired and renewables.
- Improving forecasting capabilities.

¹⁹⁹ The Energy Commission and the CPUC facilitate the Rule 21 Smart Inverter Working Group, which made recommendations for autonomous functions (Phase I of its three phases of recommendations) that will reduce adverse impacts of high penetrations of PV on the California grid. Phase I recommendations will become mandatory for new inverters in September 2017. Phase II recommendations relate to enabling communications functionality and are expected to become mandatory in 2018. The Energy Commission is funding two projects to test and validate the Phase I and II functions that will conclude in 2019. Phase III includes recommendations for inverters to respond to signals from the utility to support the grid, allowing DER systems to provide grid services. The Energy Commission is funding two projects to test and validate Phase III functions that will conclude in 2020.

²⁰⁰ Chair Weisenmiller, Energy Commission, May 12, 2017, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp. 2 and 35.

²⁰¹ Chair Weisenmiller, California ISO May 12, 2017, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 3.

- Expanding and improving the use of pricing signals, particularly time-of-use rates and potentially dynamic pricing signals (which would allow smart devices to help manage the grid by actively responding to system conditions), to encourage consumers to use electricity when it is clean and abundant and reduce usage at other times.
- Deploying energy storage.
- Using excess electricity productively.
- Managing the charging of electric vehicles smartly and accessing the batteries of plug-in electric vehicles to ease grid operations issues.

The discussion below lays out the opportunities and barriers for each solution. For a detailed discussion of actions needed to advance demand response, energy storage, vehicle-to-grid, and distributed energy resources in general, see Chapter 4.

Regional Coordination

California has targeted increased regional coordination as one of its strategies for achieving the state's renewable energy and GHG reduction goals. The benefits of increased regional coordination, to both California's utility customers and those of the entire Western Interconnection, include more efficient use and integration of renewable energy (including hydro in the Pacific Northwest), reduced carbon emissions, more efficient use of the transmission grid, reduced costs, and enhanced reliability.

Western Region Electricity Trade Opportunities

Most of the sought-after western electricity transactions involve the operation of the existing generation systems to take advantage of regional diversities and the availability of surplus generation. Consequently, between one-quarter to one-third of California's electricity loads are supplied from out-of-state wholesale electricity transactions.

California's electricity grid is interconnected with a larger system that serves 11 western states and parts of two countries: British Columbia and Alberta, in Canada, and Baja California Norte, in Mexico. This interconnection is mutually beneficial by allowing greater dispatch flexibility and sharing of surplus capacity. Overall, the Western Interconnection is summer peaking, including California, though the Northwest is winter-peaking.²⁰² Because these seasonal peaks do not coincide, these areas can share excess seasonal capacity and therefore do not need to build the full capacity to meet their annual peak demand.

There are also opportunities to develop renewable generation in regions with high-capacity-factor renewable resources that have seasonal and diurnal operating profiles that complement California's operational needs. Specifically, the resource diversity implicit with widely dispersed solar resources, which capitalize on variations in production patterns from east to west, as well as improved resource portfolio mixtures incorporating high-quality wind outside California offer significant potential benefits.

²⁰² See page 6 of [https://www.wecc.biz/Reliability/State%20of%20the%20Interconnection%20Digest%20\(Summer%202017\).pdf](https://www.wecc.biz/Reliability/State%20of%20the%20Interconnection%20Digest%20(Summer%202017).pdf).

Western markets present an opportunity to sell California renewable generation during surplus periods instead of potentially curtailing operations. Studies of expanded regional markets, including the California ISO SB 350 Study,²⁰³ calculate and catalog expected benefits from improved system operating efficiencies, GHG reductions and improved air quality in critical California communities, and improvements in job creation and broad economic stimulation through reductions in retail electricity rates.

Utilities that are at risk of losing market sales and needed revenues, such as the Bonneville Power Administration, are unbundling and reshaping their energy products to become more competitive in the western wholesale energy market. Competitive wholesale markets and an expanding Western Energy Imbalance Market (EIM) footprint as discussed below allow increased transparency into emissions trends and the ability to monitor for potential resource shuffling.²⁰⁴ The California ISO and California Air Resources Board (CARB) continue to collaborate on comprehensive GHG tracking measures that are likely to be the foundation for emissions tracking under any future regional grid operator market implementation.

Western Energy Imbalance Market

The recent formation and implementation of the Western EIM have proven to be an unprecedented step forward in exploring new and highly effective methods of increased regional coordination. The EIM has been in place since November 2014, has produced substantial savings, and continues to grow through the continual addition of new participants.²⁰⁵ As shown in Table 7, the benefits of avoided renewables curtailment are significant according to California ISO studies, with an estimated 502,357 MWh exported instead of curtailed, which displaced an estimated 214,927 metric tons of carbon dioxide (CO₂) since inception. The total gross benefits for Western EIM participants are \$254.98 million as of September 30, 2017. Table 7 also shows the volume of avoided renewable curtailments, the estimated metric tons of CO₂ displaced, and the total gross benefits for each quarter. The Western EIM delivers significant efficiency enhancements in real-time operations. The expansion of renewable resources in the Western Interconnection (primarily in California) and EIM implementation have encouraged additional assessments of system efficiency and driven operational enhancements.

²⁰³ The Brattle Group, Inc., Energy and Environmental Economics, Inc., Berkeley Economic Advising and Research, LLC., and Aspen Environmental Group. 2016. *Senate Bill 350 Study. The Impacts of a Regional ISO-Operated Power Market on California*. Prepared for California ISO. July 8, 2016. http://docketpublic.energy.ca.gov/PublicDocuments/16-RGO-01/TN212271_20160713T111132_SB_350_Study_Aggregated_Report.pdf.

²⁰⁴ *Resource shuffling* is implementing pairwise changes in buyers and sellers of energy (for example, contract reassignment) to reduce GHG emissions allowance obligations without reducing actual emissions. For a detailed discussion of what activities constitute resource shuffling and regulatory measures to prevent it, see 17 CCR 95852.

²⁰⁵ Utilities participating in the Western EIM include Oregon-based PacifiCorp; NV Energy of Las Vegas; Puget Sound Energy of Washington state; Arizona Public Service of Phoenix, Arizona; and Portland General Electric. Other utilities that have formally agreed to join the Western EIM include Powerex Corp. of Canada and Idaho Power in April 2018; the Balancing Authority of Northern California/SMUD and the Los Angeles Department of Water and Power (LADWP) in April 2019; and Seattle City Light and Phoenix-based Salt River Project in April 2020.

Table 7: Western EIM Reduced Curtailment of Renewable Energy, Associated Reductions in CO₂, and Participant Gross Benefits by Quarter

Year	Quarter	Participants	Avoided Renewable Curtailment (MWh)	Equivalent Metric Tons of CO ₂ Displaced	Total Participant Gross Benefits in Millions USD ₂₀₀₆
2014	4	California ISO, PacifiCorp	N/A	N/A	\$5.97
2015	1	California ISO, PacifiCorp	8,860	3,792	\$5.26
	2	California ISO, PacifiCorp	3,629	1,553	\$10.18
	3	California ISO, PacifiCorp	828	354	\$12.00
	4	California ISO, PacifiCorp, NV Energy (Dec. 2015)	17,765	7,521	\$12.29
2016	1	California ISO, PacifiCorp, NV Energy	112,948	48,342	\$18.90
	2	California ISO, PacifiCorp, NV Energy	158,806	67,969	\$23.60
	3	California ISO, PacifiCorp, NV Energy	33,094	14,164	\$26.16
	4	California ISO, PacifiCorp, NV Energy, Arizona Public Service (APS, Oct. 2016), Puget Sound Energy (PSE, Oct. 2016)	23,390	10,011	\$28.26
2017	1	California ISO, PacifiCorp, NV Energy, APS, PSE	52,651	22,535	\$31.10
	2	California ISO, PacifiCorp, NV Energy, APS, PSE	67,055	28,700	\$40.71
	3	California ISO, PacifiCorp, NV Energy, APS, PSE	23,331	9,986	\$40.55
	Total	All	502,357	214,927	\$254.98

Source: Adapted from California ISO, Western EIM Benefits Report: Third Quarter 2017, October 18, 2017, available at https://www.westerneim.com/Documents/ISO-EIMBenefitsReportQ3_2017.pdf.

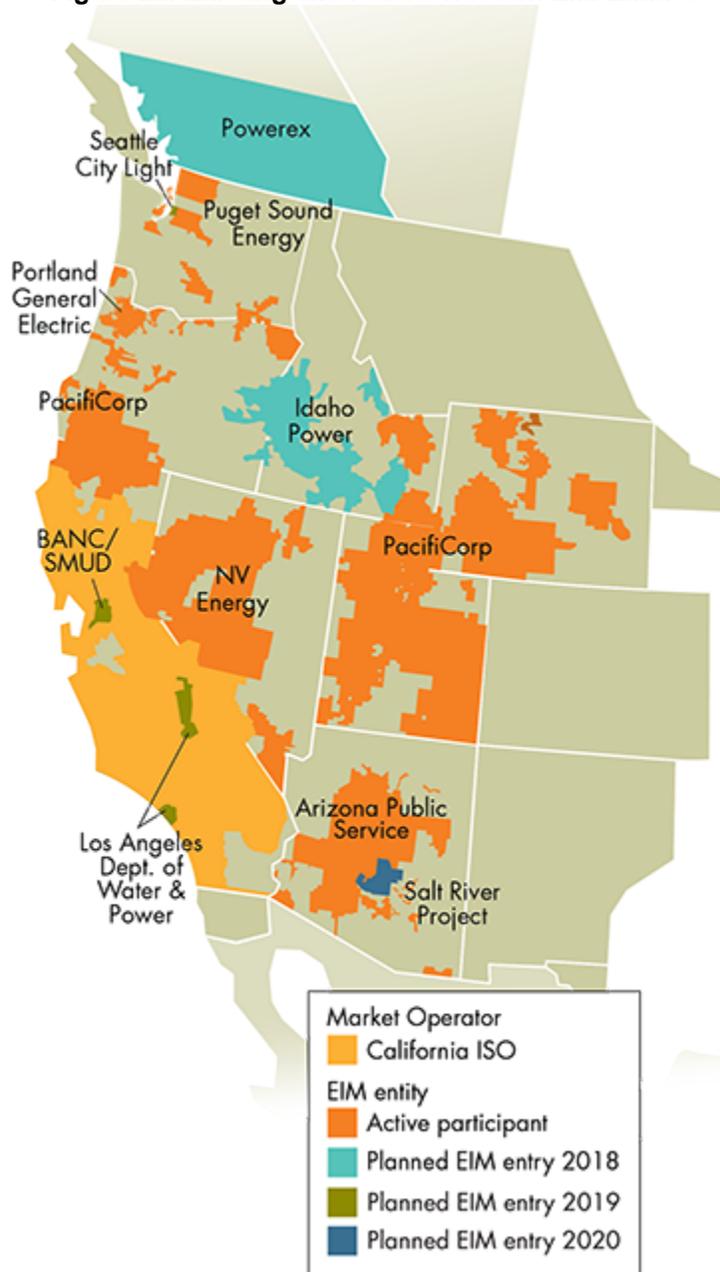
The most recent map of Western EIM entities is shown in Figure 22.^{207, 208}

²⁰⁶ For attribution of gross benefits by participant, see each quarterly Western EIM benefits report, available at <https://www.westerneim.com/Pages/About/QuarterlyBenefits.aspx>.

²⁰⁷ For more information, see <https://www.westerneim.com/pages/default.aspx>.

²⁰⁸ In its November 13, 2017, comments on the *Draft 2017 IEPR* and workshop, LADWP indicated that “the realistic planned EIM entry for LADWP has been updated to 2020 due to an ongoing gap analysis.” See http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221735_20171113T143301_Ramon_D_Gamez_Comments_LADWP's_Comments_to_DRAFT_2017_IEPR_and.pdf.

Figure 22: Existing and Future Western EIM Entities



Source: Western Energy Imbalance Market, <https://www.westerneim.com/Pages/About/default.aspx>, accessed January 25, 2018. Note: The Los Angeles Department of Water and Power commented that it has updated its planned entry into the Western EIM to 2020. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221735_20171113T143301_Ramon_D_Gamez_Comments_LADWP's_Comments_to_DRAFT_2017_IEPR_and.pdf

From the foundation of the Western EIM and the voluntary participation of Western Interconnection entities, innovative market opportunities are evolving.

Bonneville Power Administration

Power transfers between California and the Pacific Northwest have a long and rich history. A substantial surplus of electrical generating capacity and energy can exist depending on

hydroelectricity conditions in the Pacific Northwest, the operational requirements of the Columbia River system managed by the Bonneville Power Administration (BPA) and the seasonal demand characteristics of the region. Demand in the Pacific Northwest peaks in the winter, along with majority of load on the western system, while California demand peaks in the summer. Thus, during the spring and early summer, a period of low demand and high hydroelectric supply in the Pacific Northwest, a large amount of surplus power can be, and often is, available for export to California. Likewise, the Pacific Northwest has the opportunity to purchase surplus generation from California during the winter peak season. The complementary nature of California and the Pacific Northwest electricity supply and demand patterns makes the two regions natural trading partners.

About 8,020 MW of transmission capacity links the Pacific Northwest with California – the California-Oregon Intertie allows for the scheduling of up to 4,800 MW in 15-minute increments. The Pacific Direct Current Intertie (PDCI) is scheduled hourly, and recent upgrades to it, completed in November 2016, expanded the power transfer capability from 3,100 MW to 3,220 MW. BPA was pursuing its Interstate 5 Corridor Reinforcement Project, which was intended to reduce potential future congestion, but cancelled it in early 2017 after extensive review. The decision “reflects a shift for BPA – from the traditional approach of primarily relying on new construction to meet changing transmission needs, to embracing a more flexible, scalable, and economically and operationally efficient approach to managing our transmission system.”

Operational practices can prove to be valuable sources of increased transfer capability. BPA has long advocated for improved coordination of California ISO market timelines with WECC real-time scheduling practices. BPA indicates that the capacity of the California-Oregon Intertie can be described in terms of the flexibility that can be offered. For example, at the May 12, 2017, IEPR Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, BPA indicated that 400 MW are flexible within 5-minute intervals to support 5-minute dispatch and delivery of dynamic resources, and 4,800 MW are flexible on a 15-minute scheduling interval. BPA further indicated that the PDCI can similarly be described in terms of flexibility: 3,220 MW are flexible from one hourly scheduling interval to the next.

Further, the California ISO and BPA have collaborated on a great deal of telemetry and operational data sharing in support of the EIM implementation. BPA does not directly participate in the Western EIM but operates some 75 percent of the high-voltage transmission facilities in the Northwest and has an operational interest in EIM transfers.

At the May 12, 2017, workshop, BPA expressed interest in California developing intra-hour and day-ahead flexible capacity products. BPA suggested that the new flexible capacity products can be developed using existing proceedings and entities, such as the California ISO’s Flexible Resource Adequacy Criteria and Must Offer Obligations stakeholder process,²⁰⁹ the CPUC

²⁰⁹ This initiative is exploring enhancements to flexible capacity requirements to help address generation oversupply and ramps less than three hours. This effort also seeks new rules to allow intertie resources and storage resources not operating under nongenerator resource provisions to provide adjustable capacity. Through this effort the California ISO will also assess the impact of merchant variable energy resources on flexible capacity requirements. For more information, see <https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx>.

Resource Adequacy proceedings and integrated resource plan, the long-term procurement proceeding (R.16-02-007), and the IEPR proceeding.²¹⁰ BPA has stated that the federal hydro resources, which have within-hour adjustability, can provide the flexibility California needs to support increasing amounts of renewables if California adopts appropriate adjustable capacity products; a durable long-term method and solution for resource adequacy; and bilateral power exchanges with load-serving entities in the Pacific Northwest. An appropriately structured flexible capacity product may be offered in large quantities into a day-ahead market when supply-demand conditions in the Pacific Northwest are known and a surplus is available. The California ISO and BPA successfully negotiated an agreement for BPA to provide frequency responsive reserves, which the Federal Energy Regulatory Commission (FERC) approved. Collaborations such as these hold the potential for innovative and fruitful solutions.

Currently, Northwest hydro generation is providing a limited amount of within-hour flexibility to the California ISO. The flexibility of Northwest hydro generators is under-utilized by the California ISO due to a combination of physical limitations on dynamic transfer capability (DTC), current market timing and rules, and the resulting inadequate economic incentives. Addressing these limiting factors has the potential to support system operations and provide economic benefits to both California and the Pacific Northwest. One significant source of flexible carbon-free capacity is the extensive hydro system that exists in the Pacific Northwest. In 2018, the California ISO has begun to investigate market design changes that can unlock the flexibility benefits from hydro resources and result in an overall more efficient market for all participants in the long run.

BPA continues to engage in the market design processes at the California ISO. The 2018 Draft Policy Initiatives Catalog reflects a productive dialogue among the California ISO, BPA, and the broader group of stakeholders. For example, BPA submitted a candidate stakeholder initiative to the process that proposed to shorten Western EIM timelines for binding schedules. Discussions of the core issues revealed that cost-related aspects of the proposal would best be treated through modifications to the Open Access Transmission Tariffs of affected transmission providers. Other aspects of the proposal, in particular shortened Western EIM process timelines, will be affected under a few other key stakeholder initiatives.

Two stakeholder initiatives added to the initiatives catalog by the California ISO prove responsive to the demands of market participants in a fast-changing regional market space. The “Combined Integrated Forward Market and Residual Unit Commitment” initiative proposes to add backstop capacity reservation into the co-optimization of day-ahead energy and ancillary service market clearing. The “15-minute day-ahead scheduling granularity” initiative proposes to assess benefits of incorporating subhourly scheduling features into the Integrated Forward Market.^{211, 212} The

210 BPA comments on the Joint Agency Workshop on Increasing Need for Flexibility in the Electricity System, June 1, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217795_20170601T144930_Aimee_Higby_Comments_BPA_Comments__Joint_Agency_Workshop_on_Inc.pdf.

211 California ISO, Draft *Policy Initiatives Catalog*, November 8, 2017, <http://www.caiso.com/Documents/2018DraftPolicyInitiativesCatalog.pdf>

212 In its December 7, 2017 Market Notice, the California ISO states, “The ISO will also post a 2018 Final Policy Initiative Catalog that includes an effort that would enhance its day-ahead market. The proposed enhancements could dramatically

California ISO has begun outreach to regulatory bodies to inform decision makers about the proposed enhancements to its market designs.

California's energy agencies must continue working with Pacific Northwest balancing authorities, hydro asset owners, and other stakeholders on developing a flexible capacity product that encourages the provision to California in day-ahead markets. This may be best facilitated in the context of increasing grid regionalization, with the goal of conducting commitment, dispatch, and planning over a larger geographic area. Entities in the Pacific Northwest anticipate this regionalization, themselves increasing the flexibility of their existing thermal resources to accommodate a low-carbon, variable-energy regional system. The Energy Commission agrees that operational practices, as well as intrahour scheduling and continued market development, are important ways to increase transfer capability and support greater coordination among California, BPA, and other parties.

Regional Westwide Electricity Market Development

Development of a regional, westwide electricity market is critical to help integrate renewable energy resources, maximize the use of these resources, and achieve benefits beyond those gained with the Western EIM.²¹³ The Energy Commission, CPUC, and CARB held several workshops in 2016 to discuss matters related to a regional westwide market, including governance structure and studies on the environmental and economic impacts of a regional grid operator.²¹⁴ In July 2016, the California ISO released final study results of the effects of a transformation to a regional market and found that California ratepayers would save \$55 million per year under a limited expansion with only PacifiCorp fully participating in a regional grid in 2020. The final studies also estimate that California ratepayers would save up to \$1.5 billion per year assuming a larger regional footprint that includes all the U.S. balancing authorities in the Western Interconnection except for the two Western federal power marketing administrations.

The Energy Commission should continue to support broad-based objective consideration of potential new regional coordination opportunities. Of high importance is improved understanding and tracking of the environmental impacts (GHG and other) of dispatch under different market arrangements (for example, Western EIM versus full or partial regional day-ahead market), dispatch coordination protocols (for example, voluntary bilateral, subregion only, or centralized regional), and varying generation futures.

Some developments under consideration in the West have the potential to challenge traditional concepts of the bulk electric system. On September 22, 2017, the Mountain West Transmission Group participants announced they were beginning final negotiations with the Southwest Power

increase the efficiency of the day-ahead market by establishing resource schedules that more closely reflect expected real-time operation. The catalog also includes an effort to extend the day-ahead market to EIM participants. Both initiatives will also present an opportunity for participants in the western EIM to explore expansion into the day-ahead timeframe.”

²¹³ The California ISO prepared a matrix that compares the responsibilities of a conventional balancing authority (BA), an ISO BA, the Western Energy Imbalance Market, and a regional ISO BA. See <http://www.caiso.com/Documents/BA-EIM-FullParticipation-Checklist.pdf>.

²¹⁴ For more information see http://www.energy.ca.gov/sb350/regional_grid/.

Pool for regional transmission organization membership.²¹⁵ If these negotiations and the resulting implementation are successful, the Southwest Power Pool would become the first regional transmission organization to operate in separate synchronous interconnections. This development represents one of several fronts in a many-faceted competition to deliver competitive market solutions to participants in the Western bulk electric system.

Another development announced on December 7, 2017, has Peak Reliability, the reliability coordinator for the majority of the Western Interconnection, engaging with PJM Connex, a subsidiary of the PJM Interconnection (PJM), to explore alternative market solutions in the Western region.²¹⁶ The announcement has proven somewhat controversial, as market participants in the Western region have expressed concern that PJM lacks experience in the West.²¹⁷

On January 2, 2018, the California ISO announced it plans to become its own reliability coordinator²¹⁸ and offer reliability services to other balancing authorities and transmission operators in the Western United States. The California ISO also notified Peak Reliability of its intent to withdraw from the Reliability Coordinator Funding Agreement it has with Peak, effective September 2019. The California ISO plans for its new reliability coordinator unit to be certified and operational by spring 2019.

Using Natural Gas Power Plants to Integrate Renewables

To date, natural gas power plants have been the primary resource for managing the integration of renewable resources. Natural gas power plants that can be readily turned up and down to balance supply and demand are the workhorses of the grid. They can be called upon in response to the myriad fluctuations, including variations in hydropower

Risk of Flexible Generation Retiring

Natural gas-fired power plants are California's primary source of operational flexibility to maintain reliability in its electricity system. On April 24, 2016, the Energy Commission jointly conducted a workshop with the CPUC and California ISO titled "Risk of Economic Retirement for California Power Plants." The workshop revealed a variety of market issues threatening the ongoing operations of some of California's most nimble gas-fired power plants that needed to maintain reliability. Further work is needed to ensure that market mechanisms are in place to encourage ongoing operation of the most flexible power plants in locations where they are most needed.

More than 11,000 MW of capacity in California has retired since 2010 and an additional 12,263 MW is scheduled to do so by 2030 (see Table 8). Table 8 shows a total estimated retirement of natural gas and nuclear capacity between 2010 and 2029 of about 23,285 MW. Additionally, PG&E is evaluating another 47 MW of hydropower plants for possible sale or decommissioning.

²¹⁵ <https://www.wapa.gov/newsroom/NewsReleases/2017/Pages/Mountain-West-SPP-negotiations.aspx>.

²¹⁶ Peak Reliability and PJM Connex, Press Release titled *Peak Reliability and PJM Connex Agree to Jointly Explore Reliability Services and Markets in the West*, December 7, 2017, https://www.peakrc.com/aboutus/Newsletters/2017_12_07%20Final%20Release.pdf.

²¹⁷ RTO Insider, PJM Unit to Help Develop Western Markets, December 8, 2017, <https://www.rtoinsider.com/pjm-connex-peak-reliability-western-electric-markets-81332/>.

²¹⁸ A *reliability coordinator* is responsible for complying with NERC and regional standards, including providing oversight, monitoring operational and security risks, acting or directing action to preserve system reliability, and providing leadership in system restoration following a major reliability event. As noted in the January 2, 2018, press release, the RC services the California ISO is contemplating will include outage coordination and day-ahead planning, in addition to real-time monitoring for reliability. For more information see California ISO, News Release titled *California ISO Announces Plans to Become Reliability Coordinator*, January 2, 2018, <http://www.caiso.com/Documents/CaliforniaISOAnnouncesPlanstoBecomeReliabilityCoordinator.pdf>.

availability, daily swings in renewable resource generation, power plant outages, and changes in demand. Conversely, California needs to retire inflexible natural gas power plants to meet its climate goals (See Chapter 8 for discussion on long-term trends in natural gas).

Retaining Natural Gas Power Plants Needed for Reliability

In its written comments on the *Draft 2017 IEPR*, Cogentrix recommended that the California energy agencies identify the existing flexible natural gas-fired generation that will be needed for reliability during the next five years; work together on a comprehensive, immediate plan for retaining this generation; and facilitate related power purchase contracts.²¹⁹ The Northern California Power Association, a consortium of publicly owned utilities (POUs), also noted the need for a comprehensive plan for retaining generation resources that increase the resiliency of the electricity system in its submitted comments.²²⁰ During 2018, the energy agencies are evaluating the necessary operating characteristics for dispatchable resources in a high-renewable, low-carbon, and reliable electricity system as well as mechanisms for procuring and retaining them.

For example, the California ISO's Flexible Resource Adequacy Criteria and Must Offer Obligations initiative, which is undergoing a stakeholder update, provides an example of collaboration on near-term options for ensuring reliability. The California ISO also conducted initial studies in 2017 that examined the impact of retiring natural gas-fired generation capacity on reliability, GHG emissions, and cost. Staff is undertaking a study examining the status of the merchant natural gas combined-cycle, peaking, and cogeneration units in each local capacity area. The issue of identifying natural gas generation units most needed for reliability applies to POU facilities as well as merchant plants.

While the need for flexible capacity will increase substantially as solar capacity is added on both sides of the meter, the amount of flexible capacity available in the near term is projected to fall. About 6,200 MW of flexible capacity in the California ISO service territory is slated to retire by the end of 2020 because the state's policy to phase-out once-through-cooling technologies. Table 8 shows power plants in the Los Angeles Department of Water and Power (LADWP), Imperial Irrigation District, and California ISO service areas that have been retired since 2010 or planned for retirement.²²¹ The CPUC and the Energy Commission have approved about 2,000 MW of replacement capacity which is in the early phase of construction, with approximately 260 MW under consideration in the Energy Commission's licensing process. (For more information see Chapter 11.)

219 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221822_20171117T151946_Greg_Blue_Comments_Cogentrix_Comments_on_2017_Draft_Integrated.pdf.

220 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221746_20171113T161515_Susie_Berlin_Comments_Northern_California_Power_Agency_Comments.pdf.

221 Tracking progress is available at http://www.energy.ca.gov/renewables/tracking_progress/documents/once_through_cooling.pdf. Note, staff updated information for the Encina power plant. Staff also updated the repower dates for Scatergood 1 and 2 and Haynes 1, 2, 5, and 8 based on written comments from LADWP, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221735_20171113T143301_Ramon_D_Gamez_Comments_LADWP's_Comments_to_DRAFT_2017_IEPR_and.pdf. PG&E provided information on hydro facilities.

In an April 24, 2017, joint agency workshop, numerous merchant power plant owners noted an inability to secure contracts, which they assert are needed to continue operations. The investor-owned utilities (IOUs) commented that they are no longer in a position to offer contracts for natural gas generation, other than for resources needed to meet resource adequacy requirements. (See Chapter 1, the section on “Changes in Electricity Market Structure.”) If a merchant gas-fired plant does not receive a utility contract but is needed for reliability, the California ISO can award a temporary Reliability Must-Run (RMR) contract or use its Capacity Procurement Mechanism to award a contract of up to one year. It has entered into RMR contracts for 2018 with three Calpine facilities: Feather River (46 MW), Yuba City (46 MW), and the Metcalf Energy Center (580 MW). In January 2018, the CPUC issued a resolution²²² requiring PG&E to solicit and procure sufficient multi-hour energy storage to obviate the need for RMR contracts with these plants in 2019.

²²² CPUC, Agenda ID number 16195, Energy Division Resolution E-4909, January 11, 2018, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M200/K602/200602742.PDF>.

Table 8: Actual and Planned Retirements of Natural Gas and Nuclear Power Plants in California and PG&E Hydro Facilities Under Evaluation (2010–2029)

Facility & Units	Fuel Type	Capacity (MW)	Retirement Date	Reason
Humboldt Bay 1, 2	nat. gas	135	9/30/2010	OTC compliance
South Bay	nat. gas	296	12/31/2010	OTC compliance
Potrero 3	nat. gas	207	2/8/2011	OTC compliance
Texaco Exploration Cogeneration	nat. gas	19	3/14/2011	Economic retirement
Wellhead Gates	nat. gas	47	12/31/2011	Economic retirement
El Centro 3	nat. gas	50	12/31/2011	Economic retirement
JRW Associates Cogeneration	nat. gas	10	12/31/2011	Economic retirement
United Cogeneration	nat. gas	31	3/31/2012	Economic retirement
Huntington Beach 3, 4	nat. gas	452	11/1/2012	OTC compliance
Escondido Energy Center	nat. gas	44	12/31/2012	Economic retirement
Los Esteros Critical Energy	nat. gas	192	12/31/2012	Economic retirement
Contra Costa 6, 7	nat. gas	674	4/30/2013	Retired 4/30/2013
Wheelabrator Lassen Cogeneration	nat. gas	39	5/21/2013	Economic retirement
San Onofre 2, 3	nuclear	2,246	6/7/2013	Economic retirement
Haynes 5, 6	nat. gas	535	6/1/2013	OTC compliance; replaced as air-cooled
El Segundo 3	nat. gas	335	7/27/2013	OTC compliance; replaced as air-cooled
Lake Shore Mojave Cogeneration	nat. gas	55	8/5/2013	Economic retirement
Morro Bay 1–4	nat. gas	912	2/5/2014	OTC compliance
North Midway Cogeneration Plant	nat. gas	11	5/9/2014	Economic retirement
Kearny 1	nat. gas	15	12/28/2014	Economic retirement
Coolwater	nat. gas	727	1/15/2015	Economic retirement
Cardinal Cogeneration	nat. gas	54	3/31/2015	Economic retirement
El Segundo 4	nat. gas	335	12/31/2015	OTC compliance
Scattergood 3	nat. gas	450	12/31/2015	OTC compliance; replaced as air-cooled
Kearny 3	nat. gas	55	12/31/2015	Economic retirement
Oildale Cogeneration	nat. gas	40	1/5/2016	Economic retirement
Moss Landing 6, 7	nat. gas	1,510	12/31/2016	OTC compliance
El Cajon	nat. gas	13	12/31/2016	Economic retirement
Mid-Set Cogeneration	nat. gas	39	12/31/2016	Economic retirement
Miramar	nat. gas	33	12/31/2016	Economic retirement
Pittsburg 5, 6, 7	nat. gas	1,307	12/31/2016	OTC compliance
Encina 1	nat. gas	106	4/18/2017	OTC compliance
San Joaquin Cogeneration	nat. gas	48	6/27/2017	Economic retirement
Mandalay 1, 2, 3	nat. gas	565	2/7/2018	Economic retirement
Encina 2, 3, 4, 5	nat. gas	840	12/31/2018	OTC compliance
Metcalf 1, 2, 3	nat. gas	565	TBD 2018	Economic retirement
Feather River	nat. gas	48	TBD 2018	Economic retirement
Yuba City	nat. gas	48	TBD 2018	Economic retirement
Redondo 7	nat. gas	493	10/1/2019	OTC compliance
Huntington Beach 1	nat. gas	226	12/31/2019	OTC compliance; being replaced as air-cooled
Alamitos 1, 2, 5	nat. gas	848	12/31/2019	OTC compliance; being replaced as air-cooled
Moss Landing 1, 2	nat. gas	1,020	12/31/2020	OTC compliance deadline
Huntington Beach 2	nat. gas	226	12/31/2020	OTC compliance deadline
Redondo 5, 6, 8	nat. gas	850	12/31/2020	OTC compliance deadline
Alamitos 3, 4, 6	nat. gas	1,163	12/31/2020	OTC compliance deadline
Ormond Beach 1, 2	nat. gas	1,516	12/31/2020	OTC compliance deadline
Diablo Canyon 1	nat. gas	1,120	11/2/2024	Owner decision to close; forego federal relicensing
Scattergood 1, 2	nat. gas	367	12/31/2024	OTC compliance; plans to replace as air-cooled
Diablo Canyon 2	nuclear	1,120	8/26/2025	Owner decision to close; forego federal relicensing
Haynes 1, 2	nat. gas	444	12/31/2025	OTC compliance; plans to replace as air-cooled
Haynes 8	nat. gas	575	12/31/2028	OTC compliance; plans to replace as air-cooled
Harbor 5	nat. gas	229	12/31/2029	OTC compliance; plans to replace as air-cooled
TOTAL RETIREMENTS		23,285		
DeSabra-Centerville	hydro	26	TBD	Facility owner has not announced retirement plans
Narrows	hydro	12	TBD	Facility owner has not announced retirement plans
Potter Valley	hydro	9	TBD	Facility owner has not announced retirement plans
Hydro Facilities Under Evaluation		47		

Source: Energy Commission, Tracking Progress, Once-Through Cooling Phase-Out, 3/8/2017.

Modify Operations of Natural Gas Plants

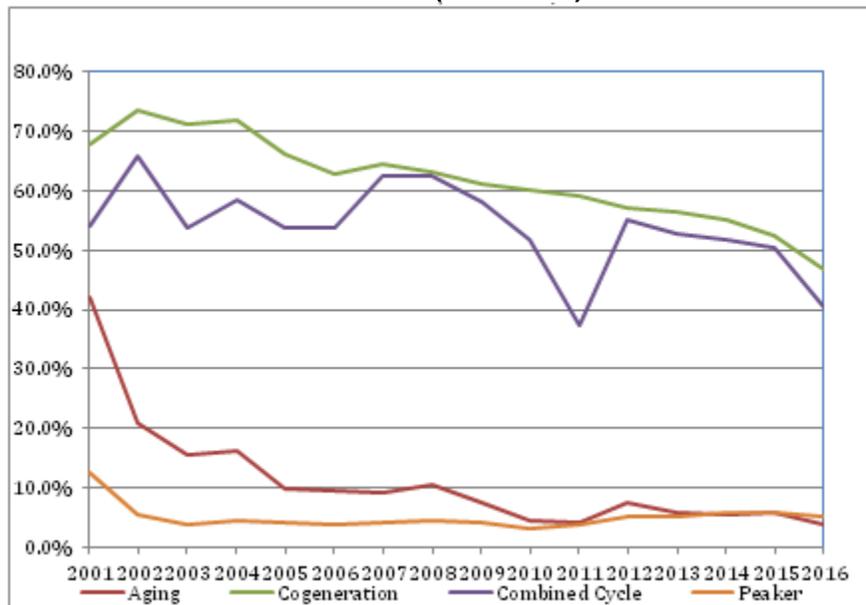
Renewable curtailment and GHG emissions can be avoided in part by reducing the level at which nonrenewable generators must run. Figure 23 below shows an overall trend in capacity factors declining for the gas-fired fleet, although annual results vary depending on several factors, including hydro availability and marginal gas prices. Meanwhile, the heat rates of combined-cycle gas turbines have increased from an average of 6,974 Btu/KWh in 2001 to 7,329 Btu/KWh. (An increase in heat rate means that the overall efficiency of the power plants is declining.)²²³ The change in heat rate and efficiency reflects operational changes at the power plants are increasingly being used to ramp up and down to integrate renewables and run at lower levels to limit renewable curtailment.

Resiliency During Record Heat on September 1, 2017

California experienced record high temperatures and correspondingly high demand for electricity on September 1, 2017. San Francisco had a peak temperature of 106° F, while temperatures in Los Angeles reached 101° F. Electricity demand in the California ISO footprint peaked at 50,116 MW. Based on the Energy Commission's 1-in-2 forecast plus a planning reserve margin of 15 percent, the total Resource Adequacy capacity was 47,000 MW. After credits for demand response and outages, the operational Resource Adequacy capacity was just under 45,000 MW. Nonetheless, a combination of factors allowed the California ISO to maintain reliability. First, the California ISO issued a Flex Alert on September 1, 2017, and the preceding two days, requesting that customers reduce air conditioning use and shift appliance operation to off-peak times. Second, the market responded with 8,700 MW of imports at peak load and the major IOUs activated their various demand response programs both in and out of the California ISO markets. SCE, PG&E and SDGE report that approximately 500 MW, 139 MW and 70 MW of demand response was activated in their service territories, respectively.

²²³ Nyberg, Michael. 2016. *Thermal Efficiency of Gas-Fired Generation in California: 2015 Update*. California Energy Commission. CEC 200-2016-002.

Figure 23: Changes in the Capacity Factor of Various Types of Natural Gas Power Plants in California (2001–2016)



Source: California Energy Commission, <http://www.energy.ca.gov/2016publications/CEC-200-2016-002/CEC-200-2016-002.pdf>

For the natural gas facilities that continue operating, there is an increasing need to reduce minimum loads and increase the speed of start times. One innovative solution is to pair storage with a peaker power plant. (Storage is discussed in detail Chapter 4.) SCE converted its Center and Grapeland peaker power plants to a hybrid system that pairs the gas turbine peaker with a 10 MW lithium-ion battery. The battery provides immediate energy to the grid, allowing time for the gas turbine to ramp up and provide energy, if needed. The battery is later recharged.²²⁴ The system is called a *hybrid enhanced gas turbine* and is the first in the world. SCE is also considering converting three additional peaker plants.²²⁵

There are also opportunities to modify natural-gas fired combined-cycle power plants to increase flexibility. Combined-cycle power plants combine a combustion turbine and a steam generator such that the waste heat from the former is used to generate electricity. At the May 12, 2017, IEPR workshop, Matt Barmack, director of market and regulatory analysis at Calpine, explained that flexibility limitations are related to the steam component of the power plant, which does not operate well with temperature swings (thermal transience) associated with the rapid start and stop of the combustion turbine. Opportunities to increase the flexibility of combined-cycle power plants include redesigning control systems to minimize the impact of thermal transience on the heat recovery steam generator and steam turbine. These operational changes can also allow for a

²²⁴ Aoyagi-Stom, Caroline. April 18, 2017. "SCE Unveils World's First Low-Emission Hybrid Battery Storage, Gas Turbine Peaker System. Press Release." <http://insideedison.com/stories/sce-unveils-worlds-first-low-emission-hybrid-battery-storage-gas-turbine-peaker-system>.

²²⁵ SCE, August 1, 2017, IEPR workshop on Senate Bill 350 Low-Income Barriers Study Implementation, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-08/TN220847_20170822T082055_Transcript_of_the_08012017_Joint_Agency_Workshop_on_Senate_Bill.pdf, p.81

faster start time.²²⁶ Improvements in emission controls and control systems can also ensure stable emissions rates over a broader range of combustion turbine output, allowing for lower minimum loads (for example, 10 to 25 percent of full combustion turbine output, rather than 50 percent).

Renewable Resource Forecasting

Forecasting is an important and cost-effective tool for integrating the variable production of solar and wind generation into an affordable and reliable power system.²²⁷ Improved renewable energy forecasting models can help grid managers accurately anticipate the fluctuation of variable resources to better anticipate power generation availability and improve grid operations. Research and development projects on renewable generation forecasting are ongoing and will become increasingly important as the state integrates greater amounts of renewable resources. From 2011 to 2014, the Energy Commission funded projects that developed tools and strategies that improve short-term solar forecasting models and support grid operations and electricity market planning.²²⁸

Through the EPIC program, the Energy Commission is contributing to the advancement of solar and wind forecasting by developing advanced modeling tools. The tools will:

- Improve forecasting accuracy of solar and wind resource and power generation in short-term horizons to increase confidence in the operation of large-scale renewable energy resources.
- Develop low-cost irradiance sensors to provide real-time data on solar power plant production and assess the performance of a network of sensors to assist with intrahour market dispatch.
- Improve the understanding of the impact of behind-the-meter solar PV on loads and identify needed modifications to the California ISO's load forecast models.
- Identify the benefits and costs of improved forecasts to determine the value of these forecasts to utilities, grid operators, and California IOU ratepayers.
- Integrate an improved solar forecast into a feed-forward charge controller²²⁹ to minimize net-load variability of electric vehicle charging and solar generation.

²²⁶ Barmark, Matt, Calpine, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp. 83–85.

²²⁷ <http://www.nrel.gov/docs/fy16osti/65728.pdf>.

²²⁸ For example, one of the funded projects developed the FleetView forecast that is used by the California ISO, and another funded project tested and verified a sky-camera forecasting model for shorter-term forecasting at both the utility-scale and distribution levels. A sky-camera forecasting model is a solar production forecast based on fisheye camera images (ultrawide-angle, panoramic images).

²²⁹ A *feed-forward charge controller* is a controller that uses future (forecast) information to schedule electric vehicles for charging.

Newer research projects are focused on holistic electricity forecasting for the day-ahead and short-term horizons that consider all grid-connected renewable generation, and improved forecasting systems that better integrate meteorological data. A research and development project with the Electric Power Research Institute will develop an improved forecasting system for solar irradiance in California, with a focus on fog and stratus conditions, through targeted use of instrumentation. Another research project, with Clean Power Research, will provide the California ISO with an improved next-minute to day-ahead high-resolution, systemwide, probabilistic power production forecast for all California PV systems, including rooftop PV.

At the May 12, 2017, IEPR workshop, Mark Rothleder, vice president of market quality and renewable integration at the California ISO, suggested that forecasting techniques are good at anticipating east-west cloud movement, but that cloud cover that develops over solar fields creates significant differences between even 10- and 30-minute forecast values and actual generation. He identified a day when the California ISO anticipated 4,000 MW of solar generation, but only 2,000 MW was available due to unanticipated monsoonal cloud cover.²³⁰ A research project titled "High-Fidelity

Demonstration of Advanced Reliability Services From a Utility-Scale PV Power Plant

The California ISO worked with the National Renewable Energy Laboratory (NREL) and First Solar to test advanced power controls on a 300 MW PV power plant. The tests showed that PV power plants can provide services that range from spinning reserves, load following, voltage support, ramping, frequency response, variability smoothing, and frequency regulation to power quality.¹ In total, the test results exceeded the performance of conventional generation sources.

For example, the demonstration tested ramp rate capability. The power plant successfully ramped from 280 MW to zero and back to 250 MW at 30 MW per minute, consistent with expectations for a natural gas-fired power plant. Then they looked at how well the plant could follow a 4-second regulation signal. A combined-cycle power plant can typically follow a 4-second ramp rate with about 40 percent accuracy, a gas turbine can with about 63 percent accuracy. The PV power plant test followed the 4-second regulation signal with 87 percent to 94 percent accuracy. The study also tested voltage control, which has been typically available from conventional generation – voltage tends to be high off-peak and low during peak demand. The reactive capability (ability to adjust to help stabilize the voltage of the electricity system) is typically about one-third of the capacity of the resource. The expectation for a 300 MW plant is to provide 100 megavolt ampere reactive (Mvar),² at 50 percent output, the expectation is to provide about 50 Mvars. The test results showed a startling capability to provide reactive power support: The plant could provide full reactive power support of 100 Mvar when operating at only 5 MW. Further, the plant could provide voltage support even at night.³

The test also showed that the plant was able to follow frequency response well and respond very quickly to a simulated frequency event in which a large amount of capacity drops off the system. In the test, the power plant increased output when frequency dipped and decreased output as the frequency recovered. These tests showed that the newer solar plants can provide the central, reliable services needed to control the grid. Later this year, the California ISO will similarly test a wind plant.

1 Loutan, Clyde, and Vahan Gevorgian, "Using Renewables to Operate a Low-Carbon Grid: Demonstration of Advanced Reliability Services from a Utility-Scale Solar PV Plant." California ISO, National Renewable Energy Laboratory, 2016, <https://www.caiso.com/Documents/UsingRenewablesToOperateLow-CarbonGrid.pdf>.

2 *Volt-ampere reactive (VAR)* is a measure of reactive power that exists when current and voltage are not in phase in the transmission or distribution system. Reactive power reduces system efficiency and its management is important to ensure voltage stability throughout the grid.

3 Clyde Loutan, California ISO, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp. 42–43.

²³⁰ Rothleder, Mark, California ISO, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp. 17-18.

Solar Power Forecasting Systems for the 392 MW Ivanpah Solar Plant (CSP) and the 250 MW California Valley Solar Ranch (PV)"²³¹ may help address this forecasting challenge. With funding from the Energy Commission, this project is developing and validating tools to forecast components of solar irradiance that are critical to concentrating solar technologies like those at Ivanpah; predicting wind speed that impacts the use of heliostats (the moving or tracking mirrors used to focus solar energy on boilers in the solar power plant); and improving the Resource-to-Power model for Ivanpah and the California Valley Solar Ranch.

To identify other renewable energy forecast research needs in California, the Energy Commission held a workshop on January 17, 2017, seeking input from forecast modeling experts, California ISO staff, and utility representatives. Participants discussed forecasting research and development needs, as well as solutions to address the anticipated operational needs of utilities and balancing authorities. Recommendations for research included:

- Developing a long-term forecasting tool covering all types of generation resources.
- Identifying distributed sensor networks that could enable telemetry-intensive forecasting models, as well as developing forecasting tools that do not use telemetry.²³²

Increasing Operational Flexibility of Renewable Resources

Renewable power plants also offer opportunities to increase the flexibility of California's evolving grid and help increase resiliency of the system. The greatest opportunities are with wind and solar resources, particularly as they are showing the most growth. (See sidebar below "Existing Hydroelectric, Geothermal,²³³ and Biomass Generation Have Limited Potential to Provide Flexibility.")

Solar

Deployment of utility-scale, "grid-friendly" PV power plants that can support grid stability and reliability will be key for the large-scale integration of PV generation. (See sidebar on "Demonstration of Advanced Reliability Services From a Utility-Scale PV Power Plant.") Advanced or "smart" inverters greatly increase the value of PV to the grid, as discussed above in "Reliability." A typical utility-scale PV power plant often includes multiple power electronic inverters that can contribute to grid stability and reliability with the use of advanced controls.

²³¹ The project received funding from the Energy Commission's EPIC program. For more information see <http://innovation.energy.ca.gov/SearchResultProject.aspx?p=29961&tk=636504249153870171>.

²³² http://www.energy.ca.gov/research/notices/2017-01-17_workshop/2017-01-27_Forecasting_Workshop_Summary_and_Recommendations.pdf.

²³³ IID commented that the *IEPR* should remove the qualifier that the potential for geothermal resources to provide flexibility is "limited" stating that technological advances allow geothermal resources to be fully dispatchable." IID also noted that 70 percent of its service territory is designated as disadvantaged communities and "the development of geothermal generation in the IID service territory provides a helpful synergy to meeting the needs of disadvantaged communities in terms of jobs ... and contributing to the local economy." http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221751_20171113T162523_Sabrina_C_Barber_Comments_Imperial_Irrigation_District's_Commen.pdf.

In addition to converting direct current (DC) to alternating current (AC) power for transmission over distribution and transmission lines, a smart inverter can provide benefits to the grid, including voltage ride-through (the ability of an electric generator to maintain connection to the grid during short periods of lower electric network voltage) in response to conditions on the grid or signals from the grid operator.

Smart inverters can:

- Reduce the impact of variable renewable resources.
- Provide grid services to improve grid operations and system efficiency.
- Increase distribution grid safety and reliability.
- Reduce or defer the need for the distribution system upgrades to integrate variable renewables and distributed energy resources.²³⁴

The California ISO continues to work with inverter manufacturers to evaluate their ability to modify inverter settings for frequency tripping and voltage blocking in

existing PV power plants within the California ISO's jurisdiction. For the long-term, the California ISO is supporting efforts to develop or revise NERC standards around needs to develop transmission specific inverter standards. (Standards developed for Rule 21 apply to distribution interconnected generation.)

ERCOT's Integration of Wind Resources

ERCOT has developed and refined over time market rules to maintain reliability with large amounts of wind resources. When ERCOT first experienced the rapid influx of wind resources, it implemented a real-time, five-minute market in which all wind resources are dispatched by ERCOT and penalized if they do not follow curtailment requirements. The rapid energy fluctuations due to curtailment, however, caused frequency problems, so ERCOT added restrictions on how fast wind generators may ramp up or down. Further, most wind resources were required to provide primary frequency response such that if a generator is curtailed and the frequency is low, then it is released from curtailment. Conversely, if frequency is too high, then the wind generator curtails itself.

Next, ERCOT added market signals to secure ancillary services to help maintain grid reliability. In ERCOT, ancillary services are generally served by natural gas-fired resources that can start within 10 minutes. ERCOT also implemented other reliability requirements (such as a voltage, ride-through, reactive power requirement) and is evaluating whether further requirements are needed to assure that adequate ramping capability and inertia are available. When ramping resources are limited, prices spikes create a market signal to add resources including dispatching distributed resources. As part of its control operations, ERCOT has dedicated staff reduce the risks introduced by renewables. These operators determine generation requirements based on their evaluation of probabilistic, five-minute wind forecasts and compare that with generator commitments to evaluate whether further ramping capability and/or inertia will be needed in the next five minutes.

Texas Experience Integrating Wind Resources

Texas has demonstrated that large amounts of wind resources – equivalent to up to 50 percent of load – can be successfully integrated into the grid. The Electric Reliability Council of Texas (ERCOT) is a balancing authority that is isolated and does not have the advantage of the regional grid that California can access. It has about 18,000 MW of wind, which is expected to rise to 24,000 MW by the end of 2017 and 28,000 MW by 2020.²³⁵ In comparison, as of June 2017,

²³⁴ For example, smart inverters can increase *hosting capacity*, the upper bound for the size of PV installation that will pose no risk to the network; it will not trigger the need for an upgrade to the electricity system. For instance, the deployment of smart inverters with distributed solar resources can increase the solar hosting capacity of a circuit by an average of more than 75 percent. <https://www.osti.gov/scitech/servlets/purl/1242804>.

²³⁵ Surendran, Resmi, ERCOT, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, <http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR->

California had about 5,600 MW of wind in-state²³⁶ – about a third of the wind capacity in ERCOT. Overall, ERCOT is larger than the California ISO, with about 25 percent more capacity, 30 percent more load, and a 40 percent higher annual peak than the California ISO.²³⁷

ERCOT developed a suite of market rules and operating requirements to integrate wind resources and maintain reliability. (See sidebar for additional information.) At the May 12, 2017, IEPR workshop, Resmi Surendran, senior manager for wholesale market operations and analysis at ERCOT, reported that although the high influx of wind energy initially created some reliability concerns, the market rules have corrected the issues, and reliability is not a problem.²³⁸

Recently, ERCOT has experienced rapid growth in solar energy that it anticipates will be on a similar scale to its wind resources. In response, ERCOT has put forward the same requirements for solar as for wind. Unlike California, ERCOT does not expect a rapid

Existing Hydroelectric, Geothermal, and Biomass Generation Have Limited Potential to Provide Flexibility

Hydroelectric generation has limited flexibility and may require variable-speed pumps to improve responsiveness. However, some projects are expected to shut down due to increasing environmental mitigation costs, decreasing wholesale prices, and utility disinterest in long-term contracts.

Geothermal has primarily been a baseload resource, and flexible-mode production typically results in extraordinary stress on the wellbore and reservoir system. Existing geothermal facilities, however, can provide flexible generation through retooling or the use of advanced technologies. For example, Matt Barmack stated at the May 12, 2017, IEPR workshop that the 720 MW Geysers geothermal power plant routinely offers flexible capacity into the California ISO market and has ramped down the dispatch by 300 MW several times in close succession. Josh Nordquist from Ormat testified that a newer geothermal power plant in Hawaii uses advanced technology and is dispatchable from 22 to 38 MW and can ramp up or down at 2 MW/min.¹ The Energy Commission encourages new geothermal resources to have flexibility capabilities.

Bioenergy tends to provide baseload generation, but the California Biomass Energy Alliance reports that biomass facilities often can be turned down 40-60 percent of rated output without significant loss in performance.² Since 1980, the number of biomass plants in California has decreased significantly because of expiring long-term contracts and because they are hindered by high operation and feedstock transportation costs, which can result in insufficient capital for operation and for maintenance expenses.³ Also, they sometimes lack support from the community or environmental organizations.

1. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 96-97
2. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217739_20170525T162302_California_Biomass_Energy_Alliance_Comments_Re_IEPR_20170512_Wo.pdf.
3. Application of the California Energy Commission for Approval of EPIC Proposed 2018-2020 Triennial Investment Plan, p. 161, http://docketpublic.energy.ca.gov/PublicDocuments/17-EPIC-01/TN217366_20170501T115606_Application_of_the_California_Energy_Commission_for_Approval_of.pdf.

07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 102.

²³⁶ California Energy Commission, Renewable Energy, Tracking Progress, updated December 2017 http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

²³⁷ <https://ferc.gov/market-oversight/mkt-electric/texas/elec-texas-glance.pdf> and <https://ferc.gov/market-oversight/mkt-electric/california/glance.pdf>.

²³⁸ Surendran, Resmi, ERCOT, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp.128–129.

growth in behind-the-meter solar resources due to market conditions in Texas. Instead, it expects growth in utility-scale solar, which is more readily visible and controllable. Still, ERCOT is examining reliability issues associated with distributed solar in response to the reliability challenge it expects the growth would pose.²³⁹

Time-of-Use Rates

At the May 12, 2017, IEPR workshop, Mr. Rothleder with the California ISO described the need for time-of-use (TOU) rates that encourage people and businesses to make energy-use decisions consistent with system costs. The TOU rate design – in particular, the peak and off-peak period definition – needs to be aligned with system needs; otherwise, it can exacerbate the conditions it is intended to address.²⁴⁰

To date, although almost all nonresidential customers are on TOU rates, most IOU TOU periods do not reflect current conditions. All three large electric utilities have proposed changes to TOU rates to reflect changes in the times of day when electricity expected to be at the highest value, and demand reductions are needed to help manage the grid, as shown in Table 9. In Decision 17-01-006, the CPUC adopted a framework for designing, implementing, and modifying the time intervals reflected in TOU rates. Among the guiding principles is that TOU periods should be based on forecasted marginal generation costs, thereby aligning price signals with grid needs. In December 2017, SDG&E began implementing recently adopted periods that reflect expected conditions. Decisions in PG&E and SCE rate cases are expected in 2018, allowing implementation in late 2018 or 2019. This shift to updated TOU periods for standard rates should be largely completed by 2020 and will affect both nonresidential and residential customers.

Table 9: IOU Proposed or Adopted Base Time-of-Use Periods

		On-Peak	Partial Peak	Off-Peak
PG&E	Summer (June-September)	5:00pm - 10:00pm nonresidential;	3:00pm - 5:00pm nonresidential only	All other hours
	Winter (October-May)	4:00 - 9:00pm residential	10:00pm - 12:00pm nonresidential only	
SCE	Summer (June-September)	4:00pm - 9:00pm weekdays	4:00pm - 9:00pm weekends	All other hours
	Winter (October-May)	4:00pm - 9:00pm	9:00pm - 8:00am	
SDG&E	Summer (June-October)	4:00pm - 9:00pm	6:00am - 4:00pm; 9:00pm - midnight	Midnight - 6:00am (Midnight - 2:00pm weekends)
	Winter (November-May)		All other hours	Midnight - 6:00am; 10:00am - 2:00pm in March and April

Sources: PG&E 2017 General Rate Case, Phase II, A.16-06-013; SCE 2016 Rate Design Window, A.16-09-003; SDG&E 2016 General Rate Case, Decision 17-08-030, August 24, 2017.

²³⁹ Ibid., p. 127.

²⁴⁰ Rothleder, Mark, California ISO, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 20.

Most residential customers are not on time-varying rates, and voluntary participation rates have been very low. A TOU pricing pilot conducted by SMUD in 2012 and 2013 provided important insights on the implementation of TOU rates for residential customers. Dr. Stephen George, senior vice president at the consulting firm Nexant, described key findings from the pilot that Nexant evaluated. The pilot tested opt-in (the ratepayer chooses to use TOU rates) and default implementation (the ratepayer must opt out from having TOU rates), as well as multiple rate options for TOU pricing and critical peak pricing. A key finding was that, given the low opt-out rates of default customers, default plans are likely to produce much higher total load reductions at lower cost than opt-in plans, even considering the lower per-household reductions. At the same time, most customers preferred a time-varying rate to the standard tiered rate (non-TOU rate). See the sidebar for highlights on the pilot results.

Taking note of the SMUD pilot study and changing system

conditions, the CPUC concluded that the potential benefits clearly warranted a transition to default residential TOU rates by 2019, as enabled by Assembly Bill 327 (Perea, Chapter 611, Statutes of 2013), and directed the IOUs to begin preparations.²⁴¹ In response, the IOUs are conducting a TOU pilot study to assess customer understanding and acceptance of various rate

SMUD'S Smart Pricing Options (SPO) Pilot

The SPO pilot was the first in the industry to compare enrollment and load impacts from time-varying rates for both opt-in and default recruitment. The SPO pilot ran for two summers, 2012 and 2013. Customers were allowed to remain on the SPO pricing plans at the end of the pilot period, and most did. Some key findings include the following:

- For default customers, the opt-out rates were very low: about 2 to 3 percent before enrollment at the beginning of the pilot and about 5 to 8 percent over the next two years. The opt-out rate was higher for the customers in the opt-in group but still relatively low, with about 16 to 19 percent of customers opting out.
- The default customers reduced their summertime peak period load by about 6 to 8 percent. Opt-in consumers reduced their peak period consumption by about 10 to 12 percent.
- Due to the high enrollment and low opt-out rate of the default customers, total load reduction from all default customers was higher than for the opt-in customers.
- For six of the eight pricing plans, average load reductions per customer persisted across the two summers
- The pilot also measured load reductions from critical peak pricing for very high load days. The default customers reduced their demand about 12 to 14 percent and the opt-in customers reduced demand about 20 to 25 percent.
- Energy savings were statistically insignificant for all but three pricing plans. Savings for the default TOU plan equaled 1.3 percent.
- Almost 60 percent of respondents said they preferred some type of time-variant rate over the standard tiered rate.
- Significantly more customers on time-variant pricing plans agreed with the statement, "My current pricing plan provides me with opportunities to save money" than did customers on the standard rate.

George, Stephen S., Jennifer Potter and Lupe Jimenez. *SmartPricing Options Final Evaluation*. September 5, 2014, https://www.smartgrid.gov/files/SMUD_SmartPricingOptionPilotEvaluationFinalCombo11_5_2014.pdf

²⁴¹ CPUC Decision 15-12-012.

designs, estimate load and bill impacts, evaluate the effects of enabling technologies, and address concerns about vulnerable populations. Vulnerable populations including low-income, seniors, and households in hot climate zones were oversampled to assess the potential for hardship. Interim results for summer 2016 are available, and key findings were discussed at the May 12, 2017, IEPR workshop. To allow time to further evaluate the likelihood of unreasonable hardship, the CPUC decided to exclude economically vulnerable customers in hot climate zones from the planned 2018 default pilots.²⁴² Whether these customers will be defaulted to TOU rates in 2019 will be addressed in 2018 rate design applications.

The interim IOU pilot results showed similar opt-out rates as the SMUD program and resulted in peak load reductions of about 4 to 6 percent. Aside from load shifting, there was also 1 to 3 percent total load reduction. CPUC staff estimated the implications of these peak and total load reductions. Assuming a 20 percent opt-out rate, which is much higher than that observed in the pilot, the IOUs would achieve a 280 to 330 MW peak demand reduction. The CPUC noted that this could potentially rise as more automated technologies become available to better capture the value of TOU rates and as consumers become more familiar with the rates.²⁴³ However, Dr. George noted that research to date indicates that enabling technology increases load impacts for dynamic, but not TOU, rates. The second interim study on pilot results reported that customers also reduced peak period loads by statistically significant amounts during winter and spring, although impacts were about half the size of summer impacts. For most rates, there were small increases in off-peak electricity use.²⁴⁴ The demand forecasts developed for the *2017 IEPR* include scenarios on load impacts of default TOU rates. (See Chapter 6 for more information about the demand forecast.)

Dr. George pointed out that a key finding of both the SMUD and IOU pilots was that the TOU rates resulted in “meaningful demand reductions” during the late afternoon and early evening periods, when ramp rates are highest. For SMUD, the peak period was fairly narrow, from 4:00 p.m. to 7:00 p.m., and for two TOU rates in PG&E’s hot climate zones, the peak periods were 4:00 p.m. to 9:00 p.m. and 6:00 p.m. to 9:00 p.m. There were similar findings for the SDG&E service territory, which sometimes has weekend peak demand.²⁴⁵ These results are encouraging in light of the relatively mild peak to off-peak rate differential. To promote customer acceptance and address concerns about bill volatility, the CPUC directed that default rates should have this “TOU

²⁴² CPUC Decision 16-09-016, September 15, 2016.

²⁴³ Murtishaw, Scott, CPUC, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp 146–150.

²⁴⁴ *California Statewide Opt-in Time-of-Use Pricing Pilot Second Interim Evaluation*, November 1, 2017, Nexant and Research Into Action. <http://www.cpuc.ca.gov/General.aspx?id=12154>.

²⁴⁵ George, Stephen, SMUD, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp 150–151.

Lite” structure. The IOUs will also offer optional TOU rates with steeper differentials that could allow some customers to save more.²⁴⁶

The IOUs will launch large-scale default pilots in 2018 to gain information on operational readiness for implementing TOU rates in 2019. These default pilots will also test a variety of marketing, outreach, and education options to find the cost-effective mix of approaches that maximizes awareness and understanding and educates enough customers to achieve meaningful load impacts while maintaining high customer satisfaction.²⁴⁷

Meanwhile, SMUD’s board of directors has approved a default TOU rate with a year-round 5:00 p.m. to 8:00 p.m. peak period. The transition will begin in 2018 with a soft launch, with all customers moved to the TOU rate by the end of 2019. SMUD will offer additional programs and tools to help customers adjust throughout the transition.²⁴⁸ For example, a new bill scenario analysis tool will allow SMUD representatives to provide customers with personalized estimates of their bills under various energy-use scenarios, such as shifting energy use to different periods, deploying rooftop solar, or adding an electric vehicle.²⁴⁹

The redesign of TOU periods has significant potential to encourage shifts in electricity-use patterns, but unlocking the greatest benefits will require adaptation and investment by customers, many of whom have planned operations around TOU periods that have not changed in decades. At the May 12, 2017, IEPR workshop, Lon W. House, an energy consultant for AQUA, discussed an opportunity for urban water managers to shift when they pump water to better align their load with grid management needs. He described how urban water management operates on a daily, 24-hour schedule in which water is pumped in the evening to fill storage by morning and then drained throughout the day to meet water demand. A shift in the pumping schedule from evening to afternoon is an opportunity to use excess renewable generation and help avoid curtailment. (See “Opportunities to Use Excess Energy” below for more opportunities to use excess energy.) A constraint is that water managers are reluctant to make investments to shift their electricity usage without some stability in TOU rates over a multiyear time horizon.²⁵⁰

The CPUC addressed the need to balance the customer perspective with rate designs based strictly on grid conditions in its guidance on TOU time intervals, directing that base TOU periods should continue for a minimum of five years. The guidance also indicates that a menu of options should be available that take into account customers’ need for predictable TOU periods when they make investment decisions regarding energy efficiency, storage, photovoltaics, electric vehicles, and

246 CPUC Decision 15-07-001, pp. 136–144.

247 Chair Weisenmiller and Mr. Murtishaw, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp. 182–183.

248 <https://www.smud.org/assets/documents/pdf/board-packet-06-15-2017.pdf>.

249 <https://www.smud.org/en/about-smud/news-media/news-releases/2017/2017-08-17-smud-gridx-agreement.htm>.

250 House, Lon W., energy consultant for AQUA, May 12, 2017, IEPR workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, p. 227.

other distributed energy resources, or consider major operational changes to shift usage outside peak periods.

Demand Response and Storage

Mr. Rothleder with the California ISO also described the need for demand response that responds to system conditions, both for reducing load when needed and for increasing load during overgeneration. Demand response increases the flexibility of load to respond to system needs, allows for more cost-effective use of electric infrastructure, and can increase the resiliency of the electric system. It is an important tool for managing the grid but unfortunately it has declined in recent years and continues to be underused in California. See Chapter 4 for more information about actions needed to advance demand response in California.

Energy storage (such as pumped hydropower, thermal energy, batteries, and flywheels – not underground gas storage such as the Aliso Canyon natural gas storage facility) can be used to capture electricity or heat for use later. It is another key tool for managing fluctuations in supply and demand. It is also discussed further in Chapter 4.

Opportunities to Use Excess Energy

The availability of excess electricity produced from low-emission or carbon-free resources presents a new opportunity for productively using low-cost and clean energy. Rather than curtailing renewables or selling the power at low or negative prices as discussed above, the power can be used to benefit both the consumers and the grid. Below is a discussion of some of the opportunities.

Desalination

Assembly Bill 2717 (Hertzberg, Chapter 957, Statutes of 2002) authorized the Department of Water Resources to convene a Water Desalination Task Force to advise on the economic and environmental impacts of desalination, the impediments or constraints to increasing the use of desalinated water, methods for streamlining regulatory processes, the potential relationship of desalination technology and alternative energy sources, and the need for research, development, and demonstration for more cost-effective and technologically efficient desalination processes. In a 2003 report to the Legislature, the Department of Water Resources stated that a primary finding of the task force is that “economically and environmentally acceptable desalination should be considered as part of a balanced water portfolio to help meet California's existing and future water supply and environmental needs.”²⁵¹

Desalination also offers an opportunity to productively use excess energy. After one and a half years of operation, California's largest desalination plant is performing as expected with a load of 30 MW to 35 MW. Graham Beatty with Poseidon Water – the infrastructure developer who built the Carlsbad desalination plant – sees the potential for positive benefits to grid management. Operational experience indicates that load can be shifted or dropped fairly quickly, along the lines of demand response in the water treatment realm. This is true not just for ocean desalination, but

²⁵¹ Department of Water Resources, *Water Desalination Findings and Recommendations*, October 2003, <http://www.water.ca.gov/desalination/docs/Findings-Recommendations.pdf>.

for water recycling and advanced sewage treatment plants; the general concept of pumps that can be ramped up or down to match a load profile are the same. Managing desalination plants to shift load has two key challenges: capital investments and tariffs.²⁵²

A desalination plant is not like a battery that can charge and discharge. Building larger water storage tanks, however, is one way to shift load. The water companies that are Carlsbad's customers expect water flows to be constant and care about costs. Using larger tanks could balance this dual water and electrical balancing problem by filling and discharging at a variable rate, while water continues to the customer at a constant flow. Larger water intakes to flow more water during the middle of the day and then ramp back down is another possibility for using surplus day time energy. Capital infrastructure for such changes takes 5 to 10 years to plan, design, permit, and construct, so some form of assurance for these long-run investments in this highly regulated industry is desired.

Significant demand charges, which are based on the highest 15-minute average usage within a given month, typically provide incentives for load shifting. Using power at more consistent rates over the month rather than at high intensity for short periods tends to lessen these charges.²⁵³ Shifting peak energy use into midday, however, is contrary to 30 years of practice and will require a realignment of and more long-term certainty about tariffs and use periods. (See "Time-of-Use Rates" above and "Demand Response" in Chapter 4.)

Hydrogen Production From Electrolysis of Water

Another pathway for preserving the value of excess renewable electricity is to use it in the electrolysis of water. This involves the use of electricity to split water molecules into hydrogen and oxygen gases. The hydrogen can be stored more cheaply than electricity in a battery and can be used on demand in fuel cells. These fuel cells convert the hydrogen back into electricity, whether for stationary applications or for the powering of fuel cell electric vehicles.

Alternatively, the hydrogen produced from excess renewable electricity can be combined with waste or captured carbon dioxide to create renewable methane for the direct displacement of fossil fuel natural gas. This renewable hydrogen or methane can be directly injected into natural gas pipelines. This strategy of transferring electrical energy into gaseous chemical energy for energy storage or other useful purposes is termed *power-to-gas*. Power-to-gas systems can provide long-term energy storage and be deployed in scales similar to pumped hydropower and compressed air, but are modular and flexible in siting. Compared to electric battery storage, while battery costs go up in proportion to the quantity of energy stored, power-to-gas costs are nearly independent of the quantity of energy stored when the existing gas grid is used as the storage medium.

²⁵² Beatty, Graham, Poseidon, May 12, 2017, IEPB workshop on the Increasing Need for Flexibility in the Electricity System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN220098_20170710T104319_Transcript_of_the_05122017_IEPR_Joint_Agency_Workshop_on_the_In.pdf, pp. 219–223.

²⁵³ *Demand charges* usually apply to commercial and industrial customers that pay time-of-use rates and cover the infrastructure and maintenance costs utilities incur providing energy to their customers.

The University of California, Irvine, in partnership with SoCalGas, is demonstrating power-to-gas technology on the campus microgrid. Preliminary results of the demonstration using 0.24–0.78 percent of pipeline hydrogen have shown that power-to-gas technology can increase the use of intermittent renewable energy. The portion of renewable energy used in the campus microgrid could increase from 3.5 percent to 35 percent by implementing a power-to-gas strategy.²⁵⁴

Energy + Environmental Economics (E3) performed a preliminary cost-effectiveness analysis of various strategies for CARB’s 2017 Climate Change Scoping Plan Update and for the Energy Commission’s scenario analysis of long-term energy strategies through 2050. The study included a power-to-gas system consisting of 7 percent of pipeline hydrogen and 25 percent of pipeline synthetic methane would provide 19 million MT-CO₂e of emissions reduction at a cost of \$1,100/MT-CO₂e.²⁵⁵ In comparison, increasing RPS from 33 percent to 95 percent would cost \$200/MT-CO₂e, and a 35 percent electrification of industrial non-electric end use energy would cost \$900/MT-CO₂e. The costs of delivered compressed hydrogen and synthetic methane in 2050 were assumed to be \$62/GJ and \$81/GJ, respectively, while the commodity price for pipeline blending was assumed to be \$49/GJ. An electrolysis power-to-gas hydrogen system would have a capital cost of \$0.65/kg/year, whereas a synthetic methane system that uses air- or sea-capture of CO₂ reduced to methane with electrolytically produced hydrogen, powered by grid electricity would have a capital cost of \$7.6/MMBTU/yr.

Detailed economic analyses by the National Fuel Cell Research Center calculated the levelized cost of returned energy for a power-to-gas system to be \$20.57–\$66.60/MMBtu under current costs and efficiencies for the production of fuel with free electricity. Using excess renewable energy to produce hydrogen was discussed at the May 12, 2017, IEPR workshop and at the June 27, 2017, IEPR workshop on Renewable Gas. (See Chapter 8, “First Steps in Transforming the Natural Gas Sector” and Chapter 9, “Renewable Hydrogen,” for more information.) Commenters suggested that power-to-gas and power-to-hydrogen could be used in various applications including grid services, such as voltage and frequency regulation, demand response, ramping services, and avoiding curtailment or negative pricing of renewables.²⁵⁶ Within these workshops and in written comments, stakeholders suggested several actions that could accelerate the development and use of power-to-gas and power-to-hydrogen:

- Develop a means to track and verify the renewable attributes of power-to-gas when the production sources are not colocated with the demand sources.

254 <http://www.prnewswire.com/news-releases/socalgas-and-university-of-california-irvine-demonstrate-power-to-gas-technology-can-dramatically-increase-the-use-of-renewable-energy-300432101.html>.

255 Energy + Environmental Economics, Long-Term Energy Scenarios In California: Draft results, October 12, 2017.

256 California Hydrogen Business Council, comments on the May 12, 2017, IEPR workshop, May 25, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217733_20170525T152821_Emanuel_Wagner_Comments_California_Hydrogen_Business_Council_Co.pdf; ITM Power Comments, Hydrogen Energy Storage can Play a Key Role Just Like it Does in Europe, May 25, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217727_20170525T125714_Steve_Jones_Comments_Hydrogen_energy_storage_can_play_a_key_rol.pdf; SoCalGas, Comments on 2017 IEPR, Docket number: 17-IEPR-07, Joint Agency Workshop on the Increasing Need for Flexibility in the Electricity System, May 26, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217755_20170526T141048_Jennifer_Morris_Comments_SoCalGas_Comments_on_Joint_Agency_Work.pdf.

- Develop protocols for the injection of hydrogen into the natural gas pipeline.
- Consider granting access to wholesale markets for power-to-gas projects and encourage utilities to pursue rate structures that reflect the flexibility of electrolysis.
- Recognize renewable hydrogen as an eligible storage resource under CPUC regulations.
- Develop a commercial-scale power-to-gas pilot project in California to develop a clearer understanding of costs and potential revenue streams.

Under its Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP), the Energy Commission released a competitive solicitation on December 22, 2017, to fund the production of renewable hydrogen. (See Appendix D for more information on the ARFVTP.) This renewable hydrogen must be generated using electricity from RPS-eligible resources or reformation from biogas or biomethane (except landfill gas). (Given the ARFVTP’s purpose of reducing transportation sector emissions, the hydrogen must be used for refueling fuel cell electric vehicles.) The funding allocation for this solicitation is \$3.9 million.

Integrating Electric Vehicles

SB 350 states that electric vehicles should “assist in grid management, integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions.” This section highlights the status of plug-in electric vehicle (PEV) charging; for more information on the recent progress of the *Vehicle-Grid Integration Roadmap*, see Chapter 4 and Appendix H.

Charging Trends

To date, most PEV owners rely primarily on overnight charging at home for most of their recharging needs. This is consistent with early efforts to encourage PEV charging at night to best match historical electric system needs. Based on data from a California vehicle survey used in the transportation energy demand forecast (see Chapter 7), Figure 24 shows the percentage of personally owned battery-electric vehicles (BEVs) that are plugged in each hour by location.²⁵⁷ Slightly more than two-thirds of these BEVs are plugged in during the middle of the night. This self-reported behavior matches findings from IOU load research, which shows that on average, the peak charging time for residential customers with PEV TOU rates is between midnight and 2 a.m.²⁵⁸

One reason for reliance on nighttime charging is the relative ubiquity of detached homes with garages or driveways among early PEV adopters.²⁵⁹ However, this convenient access to home

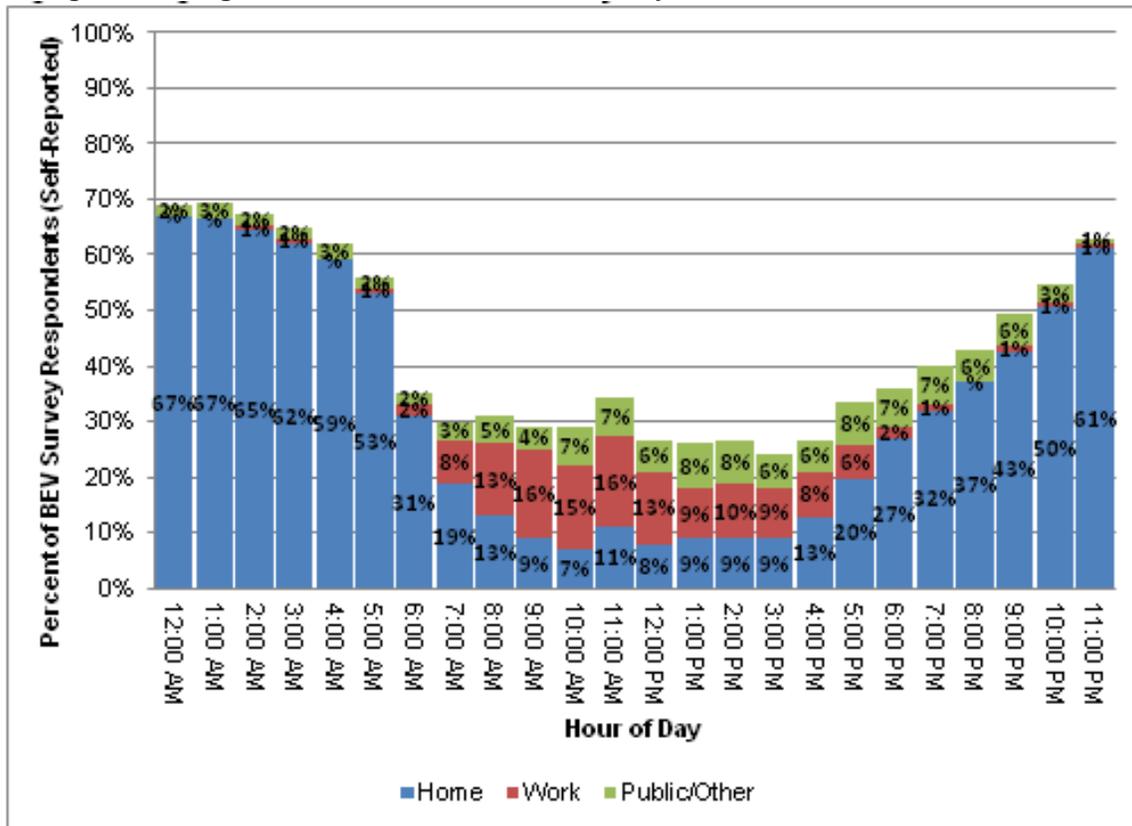
²⁵⁷ Adapted from the Energy Commission 2016-2017 California Vehicle Survey. Transportation Energy Forecasting Unit, *Transportation Energy Demand Forecast, 2017–2030*, California Energy Commission, June 20, 2017, IEPR workshop on the Preliminary Transportation Energy Demand Forecast, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-05/TN219810_20170620T141018_Transportation_Energy_Demand_Forecast_20172030.pdf.

²⁵⁸ Southern California Edison, Pacific Gas and Electric, and San Diego Gas & Electric. *Joint IOU Electric Vehicle Load Research Report. 5th Report. Electric Vehicle Load Research and Cost Studies. R.09-08-009/R.13-11-007*. Filed on December 30, 2016, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M171/K806/171806139.PDF>.

²⁵⁹ Johnson, Clair, Brett Williams, Carlos Hsu, and John Anderson (2017).

charging is not the norm, as only about 45 percent of all personal vehicles are parked within 20 feet of a residential electrical outlet in California.²⁶⁰

Figure 24: Plug-In Times and Locations of Battery Electric Vehicles for Personal Use



Source: California Energy Commission

Smart Charging to Help Manage the Grid

As renewable generation during the day has grown, the aim has shifted to encourage day time charging and capitalize on the opportunity to use the excess energy available. Figure 24 shows that during the day, when PV systems are generating maximum power, fewer than 30 percent of PEVs are being charged.

Assumptions about charging behaviors and infrastructure placement may need to change to enable increased use of daytime charging during peak solar generation and encourage continued electric vehicle (EV) adoption. As nonresidential charging options expand, they could encourage PEV adoption among customers who may not have ready access to charging at home. For example, if chargers located at workplaces become more prevalent and can be managed among

²⁶⁰ Energy Commission analysis of the U.S. Energy Information Administration, Residential Energy Consumption Survey Data, 2009, <https://www.eia.gov/consumption/residential/data/2009/index.php?view=microdata> and

National Research Council of the National Academies of Science. *Overcoming Barriers to Deployment of Plug-In Electric Vehicles*, 2015, <https://www.nap.edu/read/21725/chapter/7#84>.

other colocated building demand, EVs could help increase the daytime net load, essentially “lifting” the belly of the duck.²⁶¹

Getting the timing of charging right is important. If the more than 60 percent of PEV owners that are not subscribed to TOU rates²⁶² plug in and initiate charging when returning home from work, during evening system peaks, charging could exacerbate ramping requirements.²⁶³ As charger capacity continues to increase,²⁶⁴ and if controllable vehicle load is delayed to initiate during periods of low prices (when residential customers are defaulted to TOU rates by 2019), a “timer spike” may cause a local peak distribution transformer capacity constraint.²⁶⁵ This could be controlled by installing charging equipment with the localized intelligence needed to avoid simultaneous loading without compromising charging preferences. (See Appendix H.) On the other hand, charging during peak renewable generation can offer benefits to consumers and the grid.

As discussed in Chapter 4, California has the largest demonstration for vehicle-to-grid integration worldwide, but it is only 40 vehicles. Because it holds promise, barriers preventing vehicle-grid integration should be addressed so that flexible charging becomes readily available for grid management.

Conclusion

California’s increased use of renewable resources, predominantly solar and wind, has been successful in reducing GHGs but has also created new challenges in maintaining the reliability of the electricity system. In response to the variation in renewable generation, having the capability to turn up or down both generation and load as needed is increasingly important. A variety of tools are available to do so, but they hold varying levels of promise both in terms of magnitude and timeline of availability.

The Western EIM is an example of an important tool in managing fluctuations in supply and demand on a 5- to 15-minute-ahead basis that is already operating and is expanding rapidly. Increasing opportunities for power exchanges with the BPA offers another solution that could readily be advanced to improve the resiliency of California’s system. Creating regional opportunities for power exchanges in day-ahead markets over a larger geographic area is an

261 Tesla, written comments submitted May 25, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217744_20170525T165931_Damon_Franz_Comments_Comments_on_Workshop_addressing_need_for_f.pdf.

262 Johnson, Clair; Williams, Brett; Hsu, Carlos; and Anderson, John (2017), *The Clean Vehicle Rebate Project: Summary Documentation of the Electric Vehicle Consumer Survey, 2013–2015 Edition*, Center for Sustainable Energy, San Diego, California, June 2017.

263 Crisostomo, N. “Vehicle-Grid Integration Communications Standards.” California Energy Commission, December 7, 2016, workshop on Vehicle-Grid Integration Communications Standards, http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN214649_20161207T080617_VehicleGrid_Integration_Communications_Standards.pdf.

264 Ibid.

265 Kaluza, S., D. Almeida, P. Mullen. *BMW i ChargeForward: PG&E’s Electric Vehicle Smart Charging Pilot*, BMW Group, BMW/Mini, and Pacific Gas & Electric Company, June 2017, <http://www.pgecurrents.com/wp-content/uploads/2017/06/PGE-BMW-iChargeForward-Final-Report.pdf>.

involved process that has proven difficult realize, although it holds promise to substantially increase resiliency and lower GHGs.

Improvements in TOU rates to encourage shifts in energy usage patterns are also important but will not be implemented on a large-scale in California before 2019. Also, they are not designed to provide the rapid responses needed to help manage large and fast ramps in generation. As discussed in Chapter 4, demand response has failed to realize the potential to play a significant role in helping manage grid needs. Storage has been more promising in the short term but faces cost barriers to large-scale deployment.

As electric vehicle demand grows, it will be important to encourage smart charging that can help increase the resiliency of the grid. California is on a trajectory to rapidly increase deployment of electric vehicles, and its potential to use electric vehicles in grid management is a near-term opportunity for increased grid stability and reliability.

On the generation side, more work is needed to improve the flexibility of renewable resources. Ongoing work to modify inverters at existing power plants and development of NERC standards for transmission specific inverter standards are critical for improving the reliability of solar power plants. There are limited opportunities to increase the flexibility of existing hydropower, geothermal, and biomass. At least in the short term, natural gas-fired power plants that can provide fast responses to grid needs are a critical tool that can be deployed in the magnitude needed. Yet, market conditions are putting ongoing operations of flexible natural gas power plants at risk. More work is needed to ensure that California has the resources it needs to increase the resiliency of its grid as it further decarbonizes its energy system.

Recommendations

- **Expand and improve rate setting to send price signals aimed at adjusting energy usage to help better manage the grid and integrate renewable resources.** By offering a variety of rate designs that maintain the integrity of the price signal, while addressing the customer need for transparency and certainty, the California Public Utilities Commission (CPUC) and utilities can motivate customer innovation and investment in clean, cost-effective ways to use electricity.
- **Support regional coordination opportunities.** The Energy Commission should continue supporting potential new regional coordination opportunities. Of high importance are improved understanding and tracking of the environmental (greenhouse gas and other) impacts of dispatch of the system under different market arrangements, dispatch coordination, and generation mixes.
- **Continue to support advancements in smart inverters.** The Energy Commission should continue participating in the Smart Inverter Working Group and funding research to test and verify the smart inverter functions for both behind-the-meter and utility-scale applications. Wide deployment of smart inverters with inverter-based generators will lead to greater resiliency in the grid with fewer issues with inverter-based generation like those that led to the North American Electric Reliability Corporation's report, *1,200 MW*

Fault Induced Solar Photovoltaic Resource Interruption Disturbance Report. For behind-the-meter applications, it will also allow higher hosting capacity and simpler interconnection. The Energy Commission should also support the California Independent System Operator (California ISO) in developing a North American Electric Reliability Corporation standard for transmission-interconnected, inverter-based generation.

- **Continue to support research to improve forecasting capabilities.** The Energy Commission should continue to fund research that improves solar irradiance, photovoltaic production, and gross load forecasting models. Improvements in these areas will enable solar generators to bid more frequently into short-term markets and allow grid operators to more accurately predict the amount of generation that will be needed to meet the net load.
- **Establish mechanisms to retain power plants that increase the resiliency of the electricity system.** The Energy Commission, the CPUC, and the California ISO should work together to develop a thoughtful and comprehensive plan to retain generation that is needed for reliability.
- **Use excess renewable electricity productively.** California is likely to have significant and increasing amounts of renewable electricity, with an excess at times. Along with development of increasing amounts of regional markets, flexible resources, storage, controlled and/or bidirectional charging, California should continue to explore near- and long-term options to productively use excess renewable energy. Potential uses for excess electricity include desalination or conversion to hydrogen either to fuel stationary or mobile fuel cells or to store power.
- **See Chapter 4 for recommendations to support the advancement of distributed energy resources, including demand response, storage, and vehicle grid integration.**
- **The Energy Commission should re-examine the status of power-to-gas in four years as part of the Integrated Energy Policy Report.** The reexamination should draw on experience in Europe and at University of California, Irvine. See Chapter 9 for recommendation to reexamine renewable gas in general in four years.

CHAPTER 4:

Accelerating the Use of Distributed Energy Resources on the California Grid

Distributed energy resources (DER) – including demand response, distributed renewable energy generation, energy storage, and electric vehicle resources – have important roles in helping increase the resiliency of California’s electricity grid. California has set a goal to double energy efficiency savings by 2030 and calls for increased investments in transportation electrification as key parts of its strategy to reduce greenhouse gas (GHG) emissions. (See Chapters 1 and 2 for more information.) Demand response, energy storage, and electric vehicles are important tools to help modify electricity demand and supply – a need that is becoming increasingly important as the state increases its use of zero-GHG renewable resources. (See Chapters 1 and 2 for information on renewable goals and Chapter 3 for information on increasing resiliency in the electricity grid.) The growth of distributed renewable energy has played a major role in changing the supply of electricity in California, helping reduce GHG emissions, but also contributing to excess supply during the day and the need for added resources in the evening when the sun sets, as discussed in Chapter 3.

DERs provide important opportunities for customers to generate electricity and help manage California’s electricity grid, but they also add complexity to electricity planning and operations. (See Chapter 6 for discussion of how DERs are being factored into the electricity and natural gas forecast and Chapter 7 for the transportation demand forecast, including electric vehicles.) To help navigate this emerging complexity and maximize the benefits of DERs, in 2013 and 2014, the Energy Commission, California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO) worked together to develop roadmaps for demand response,²⁶⁶ storage,²⁶⁷ and vehicle-grid integration.²⁶⁸ A summary of the roadmaps and accomplishments to date is provided in Appendices H and J.

In 2016, the CPUC initiated implementation of California’s Distributed Energy Resources Action Plan and developed working groups to help implement the transition to this new grid system.²⁶⁹ The CPUC has initiated public rulemakings for energy storage, demand response, electric vehicle integration, and time-of-use rate development. Also, as part of the CPUC’s smart inverter proceeding, the Smart Inverter Working Group has developed new requirements for inverter-

²⁶⁶ California ISO, December 2013. *Demand Response and Energy Efficiency Roadmap: Maximizing Preferred Resources*. <https://www.caiso.com/Documents/DR-EERoadmap.pdf>.

²⁶⁷ California ISO, CPUC, and the Energy Commission. *Advancing and Maximizing the Value of Energy Storage Technology: A California Roadmap*. December 2014. https://www.caiso.com/Documents/Advancing-MaximizingValueofEnergyStorageTechnology_CaliforniaRoadmap.pdf.

²⁶⁸ California ISO. February 2014. *California Vehicle-Grid Integration (VGI) Roadmap: Enabling Vehicle-Based Grid Services*. Available online at <http://www.caiso.com/informed/Pages/CleanGrid/Vehicle-GridIntegrationRoadmap.aspx>.

²⁶⁹ California’s Distributed Energy Resources Action Plan (November 10, 2016 and May 3, 2017) and related documents are available online from CPUC President Picker’s Web page, <http://www.cpuc.ca.gov/picker/>.

connected DERs in California to help distribution systems operate smoothly with high levels of rooftop solar systems and other distributed energy resources.²⁷⁰

The Energy Commission is assisting the CPUC in its working group activities through research under the Electric Program Investment Charge (EPIC) Research and Development Program and by leading a three-agency working group (Energy Commission, CPUC, and the California ISO) to develop a roadmap for the commercialization of microgrids in California.²⁷¹ Microgrids²⁷² are one of the most effective methods to help integrate DER on the grid.

In addition, the California ISO has completed several activities to incorporate DER into its markets. For example:

- In 2014, the California ISO received Federal Energy Regulatory Commission approval of the Reliability Demand Response Resource Participation Model. This model helped enable integration of emergency-triggered utility demand response programs into the California ISO market, which started in 2015.
- By the summer of 2015, SCE had integrated about 1,000 MW of demand response into the California ISO markets, well ahead of the 2018 deadline set by the CPUC for demand response to receive resource adequacy credit.²⁷³
- The California ISO made changes to allow demand response to participate in nonspinning and spinning reserve markets and the flexible resource adequacy must-offer obligation market.
- Beginning in 2016, the California ISO revised its network modeling to allow DER resources to be interconnected quickly, without waiting up to six months for a full network model update.
- Also, in 2016, the California ISO implemented statistical sampling methods for behind-the-meter generation use where 15-minute data were not available.²⁷⁴

²⁷⁰ Smart Inverter Working Group, <http://www.cpuc.ca.gov/General.aspx?id=4154>. Also see, Lydic, Brian. June 28, 2016. How California's Rule 21 inverter requirements expand grid capacity, limit energy (revenue) generation. <http://solarbuildermag.com/featured/california-rule-21-inverters-explained/>.

²⁷¹ <http://www.energy.ca.gov/research/microgrid/documents/index.html>.

²⁷² *Microgrids* combine distributed energy resources, including generation, energy storage, and demand response capabilities, with a controller to manage energy use. A key feature of many microgrids is the ability to continue operating even if the surrounding electricity grid experiences an outage due to severe weather or other challenging operational conditions. For further information, see Bower, Ward, Dan Ton, Ross Guttromson, Steve Glover, Jason Stamp, Dhruv Bhatnagar, and Jim Reilly. March 2014. The Advanced Microgrid: Integration and Interoperability. Sandia National Laboratories. <https://energy.gov/oe/downloads/advanced-microgrid-integration-and-interoperability-march-2014>

²⁷³ Kaneshiro, Bruce. CPUC. August 8, 2017. Transcript of the August 8, 2017, IEPR workshop. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN221097_20170908T094338_Transcript_of_08082017_IEPR_Commissioner_Workshop_on_Demand_Res.pdf. Pages 25-26.

²⁷⁴ Jill Powers. California Independent System Operator. August 8, 2017. Transcript of the August 8, 2017, IEPR workshop. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN221097_20170908T094338_Transcript_of_08082017_IEPR_Commissioner_Workshop_on_Demand_Res.pdf, p. 46-52.

- At the wholesale level, the California ISO worked with stakeholders to develop a platform for DERs to participate in the wholesale electricity market. In March 2016, the California ISO filed tariff revisions with FERC to enable resources connected to distribution systems within the California ISO's balancing area authority to form aggregations of 0.5 MW or greater to participate in California ISO energy and ancillary services markets. FERC approved the California ISO's new DER aggregation platform in June 2016.²⁷⁵

As discussed in Chapter 3, California has made great gains in the use of many types of distributed energy resources in recent years (Table 10).²⁷⁶ However, additional work is needed to capture opportunities for demand response in California.

Table 10: DER in California 2013 Compared to 2017 (Percentage Change)

Technology	2013	2016 / 2017	Percent Change
Energy Efficiency ¹ (GWh)	1,693	3,197	89%
Demand Response ² (MW)	2,187	1,997	-9%
Behind-the-Meter PV ³ (MW)	2,102	5,900	180%
Plug-In Electric Vehicle (PEV) ⁴ (number of PEV registrations)	69,999	266,866	281%
Distributed Advanced Energy Storage ⁵ (MW)	54	350	548%
Microgrids ⁶ (MW)	122	390	220%

Source: 1. Total electricity saving within PG&E, SCE and SDG&E service territories in 2013 and 2016, California Energy Efficiency Statistics Website - <http://eestats.cpuc.ca.gov/Views/EEDataPortal.aspx>. 2. The total capacity of IOU-operated demand response programs in 2013 and 2016, 2016 *Annual Report on Market Issues and Performance*, California ISO annual report. 3. The California Energy Commission's Tracking Progress Web page, Renewable Energy, updated December 2017, http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf. 4. California New Car Dealers Association: "California Auto Outlook Covering Fourth Quarter 2014: New Light Vehicle Registrations Likely to Exceed 1.9 million units in 2015" and "California Auto Outlook Covering First Quarter 2017: State New Vehicle Market Predicted to Remain Strong in 2017." 5. U.S. Department of Energy - Energy Storage Database, <http://www.energystorageexchange.org/>. 6. Navigant Research - Microgrid Database.

Accelerating the use of DERs is a high priority to maintain system reliability, especially in Southern California. Relying on these preferred energy resources continues to be critical in managing energy demand following the permanent closure of the San Onofre Nuclear Generating Station (San Onofre) in 2013 and the massive leak of natural gas from the Aliso Canyon Natural Gas Storage Facility in 2015. (See Chapter 11 for more information.) As discussed at the May 22, 2017, IEPR joint agency workshop on Energy Reliability in Southern California, interagency coordination to advance preferred resources helped the region provide reliable electricity service without San Onofre. The workshop also reviewed energy reliability issues for the summer of 2017

²⁷⁵ <http://www.caiso.com/participate/Pages/DistributedEnergyResourceProvider/Default.aspx>.

²⁷⁶ The National Fuel Cell Research Center commented that fuel cells should be a unique DER. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221737_20171113T140701_Professor_Scott_Samuelsen_Comments_NFCRC_Comments_on_the_2017_D.pdf. They are not called out as a separate DER in the *IEPR*, however, to be consistent with the CPUC's definition in "California's Distributed Energy Resources Action Plan: Aligning Vision and Action" but they are an integral part of microgrids discussed below and have been a preferred technology in addressing reliability issues in Southern California as discussed in Chapter 11.

related to operational limitations of the Aliso Canyon Natural Gas Storage Facility.²⁷⁷ In July 2017, at the request of Governor Edmund G. Brown Jr., Energy Commission Chair Robert B. Weisenmiller announced that the Energy Commission plans to work with other agencies to plan for the permanent closure of the Aliso Canyon natural gas storage facility within 10 years. Urging the CPUC to do the same, Chair Weisenmiller stated, “Closure of Aliso Canyon is no small task, and the recommendation to close the facility is not one that I take lightly or without thoughtful consideration. However, I am confident that through sustained investments in renewable energy, energy efficiency, electric storage technologies, and other strategies, we can make this transition a reality.”²⁷⁸

This chapter asks what steps are needed to accelerate deployment of DERs in California, especially Southern California. Specific questions include the following:

- What work remains unfinished, and what updates are needed in DER-related action plans and roadmaps?
- How can California continue to help drive down DER costs?
- What steps are needed to expand business opportunities for DERs?
- What are the key issues and opportunities to ease integration of DERs into California’s electricity system?

The chapter concludes with recommendations to accelerate the use of DERs in California.

Demand Response

At the August 8, 2017, IEPR workshop on Demand Response, Commissioner Andrew McAllister summarized the importance of accelerating demand response: “We’re at a critical juncture in the way we’re organizing the operation of our grid. ... We’ve got to reduce combustion. We’ve got to figure out new ways to do load management at the local, regional, and statewide levels. Demand response has to be a key piece of that or else we’re going to over invest in hardware.”²⁷⁹

²⁷⁷ http://www.energy.ca.gov/2017_energypolicy/documents/#05222017.

²⁷⁸ http://www.energy.ca.gov/releases/2017_releases/2017-07-19-energy-commission-chair-releases-letter-ailso-canyon_nr.pdf.

²⁷⁹ Transcript August 8, 2017, IEPR workshop, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN221097_20170908T094338_Transcript_of_08082017_IEPR_Commissioner_Workshop_on_Demand_Res.pdf, p. 12.

As noted by PG&E,²⁸⁰ demand response is unique among DERs “in the sense that it is a tool for enabling ... other behind-the-retail-meter DERs to be dispatched when needed by the grid.” Demand response is broadly applied to technologies such as communications and controls, rate designs such as time-variant pricing, programs that provide incentives for load reduction upon notification or surrender of end-use control to the utility, and wholesale markets that treat load like generation. Ultimately, it can serve as both a resource in and of itself and a tool to manage *both* loads and DERs such as storage. A 2017 study by Mary Ann Piette of the Lawrence Berkeley National Laboratory indicates there is a largely untapped potential for demand response in California, including the potential to shift 2 to 5 percent of daily load by 2025 with a system value of \$200 million to \$500 million per year.²⁸¹ Another major contribution of the study was to categorize demand response as four types (shed, shift, shape, and shimmy) that reflect the load-reduction capability of different customers and explore options for attributing resource adequacy value to load-modifying demand response. Recognizing demand response reliability programs can provide a critical resource in the event of a grid emergency, a notable conclusion of the study is that while traditional “shed” demand response is of limited value in a system that is long on capacity, “shift” resources can be very valuable given the highly

Retrospective on Demand Response – Working to Get More

From the 1970s until the energy crisis in 2000-2001, volunteers offered to help reduce peak demand under emergency conditions in exchange for compensation. Following the energy crisis, a new idea, price-responsive demand response, was developed. This type of demand response is intended to be called upon frequently to reduce the risk of price fluctuations; however, participation in this type of demand response remains low in California. In 2012, the Federal Energy Regulatory Commission reported that demand response was growing in the PJM Interconnection and the Midwest Independent System Operator, but not in California. The 2013 *IEPR* provided the following summary of issues limiting the use of demand response to address more dynamic, market-based needs:

“There is a need for wholesale market design to recognize the advantages and limitations of demand response as compared to traditional generation. Customer loads cannot always be as easily and consistently manipulated as traditional generation. These issues are manageable by a functioning marketplace: demand response products can be composed of a large number of loads that together provide a portfolio, consisting of both load reductions and strategic load additions, that balances performance risk and customer needs. Finally, rules for participation by demand response providers in existing California ISO wholesale markets need to be resolved and finalized. On the technology side, current telemetry requirements are a challenge because of expensive equipment requirements to participate in the demand response market”

At the August 8, 2017, demand response workshop, Susan Kennedy asked, “Large commercial and industrial customers are installing these technologies today because they want reliability and cost control. The key is how do you enable, how do you take those technologies and design them in such a way that you’re also providing grid resources?” Also, she offered the following observation on work underway that will jump start price-responsive demand response in California:

- “The single-most important policy that’s underway right now is the bifurcation of the demand response resources [into supply and load modifying] ... that the CPUC undertook several years ago, and is just now coming into fruition.”
- “The second is the integration of those supply-side demand response resources into the California ISO wholesale market.”
- “And the third is the very nascent efforts to integrate demand response, distributed generation, and energy efficiency customer incentives into one demand-side management bucket.”

²⁸⁰ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221734_20171113T143653_Pacific_Gas__Electric_Comments_PGE_Comments_on_2017_Draft_IEPR.pdf.

²⁸¹ LBNL. March 1, 2017. *2025 California Demand Response Potential Study*. Presented at the August 8, 2017, IEPR workshop http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN220511_20170802T120454_2025_California_Demand_Response_Potential_Study.pdf. The full report is available online at <http://www.cpuc.ca.gov/General.aspx?id=10622>.

temporal nature of today's grid management challenges.²⁸² Demand response is in a period of transition as utilities (and CCAs), grid operators, and policy makers struggle to translate that potential into a value stream that garners meaningful levels of customer participation.

California Has Not Realized the Potential of Demand Response

Despite this impressive potential, demand response is not thriving in California. The amount of demand response in the state has remained fairly flat, even declining slightly in recent years. Concern over the lack of progress in demand response has been a theme in prior *IEPRs*, such as the 2007 *IEPR* and the 2013 *IEPR*, with lack of coherent policy direction being raised as one of the major causes. While there have been a number of efforts to expand participation – including development of new IOU programs and growing third-party provider participation in California ISO markets – California still has a serious demand response underperformance problem. Solutions do exist but require proactive and coordinated leadership in the policy and ratemaking realms to achieve their potential. Additional research is also needed to develop and demonstrate innovations that use demand response as both an energy supply resource and a tool to manage load and other DERs.

On the one hand, demand response is a technology success. Impressive technologies are enabling ingenious approaches and business models to develop services that provide value to end-use customers. The August 8, 2017, workshop highlighted several such approaches that essentially extend and modernize on-site energy management approaches by applying modern monitoring, analysis, and automation. Customer-sited DER technologies are a natural complement to these new services: self-generation, storage, and demand management can enable improved load factors and reduced utility charges via arbitrage and the like.

However, the value being produced is almost entirely – and unnecessarily – behind the meter. Robust technological advances have not resulted in demand response becoming a grid-relevant resource. California's lack of success in cultivating, aggregating, and scaling-up its demand response resource has been and remains the result of limited, episodic policy attention. Through sustained efforts at the California ISO and CPUC, California is making some necessary policy improvements. However, the state also needs new approaches to support rapid growth of demand response-enabled capacity that can take its place among the state's broad array of DERs and, most critically, help assimilate – at scale – the increasingly diverse array of renewables, distributed and centralized. DERs, including combinations with microgrid control, can enhance the capabilities of DERs to provide flexible energy services to meet customer needs and provide grid services.

Critical to this demand response expansion are widespread communications, control functionalities, and electricity rates that consistently reflect grid needs and constraints, clearly and temporally, such that customers can perceive value from their actions. The former area, technology, has seen significant progress in the last few years. In contrast, despite tentative

²⁸² The authors define “shed” as traditional demand response in which loads can be curtailed to provide peak capacity and support the system in emergencies or contingency events. “Shift” represents demand response that encourages the movement of energy consumption from times of high demand to times of the day when there is excess renewable generation.

evolutions toward time-differentiated pricing for customers, overall tariff regimes remain inflexible and unadapted to the new grid realities. (See “Time-of-Use Rates” in Chapter 3 for more information.) At the August 8, 2017, workshop, Chair Weisenmiller, Commissioner McAllister, and others pointed out that in the past the Energy Commission has used its authority under the Warren Alquist Act to issue load management standards. They questioned whether it might not be appropriate to revisit this statutory authority in the context of expanding the use of demand response.²⁸³

Working to Reshape Load Through Demand Response

Published in December 2013, the *Demand Response and Energy Efficiency Roadmap: Pathways for Maximizing Preferred Resources* included recommendations to reshape load through actions to advance energy efficiency programs and incentives, evolve demand forecasting, align load-modifying efficiency and demand response with grid conditions, and assess value and effectiveness of conservation messaging.²⁸⁴

Commercialization of emerging technologies is creating new opportunities to reshape load through demand response. For example, many new energy-efficient appliances, such as dishwashers, dryers, and other home appliances, come from the factory with automated demand response capabilities.²⁸⁵ Such appliances create untapped opportunities for expanding demand response. Because the impacts would be categorized primarily as load-modifying, the incentive to invest in such technologies and to program them to provide demand response is muted. One way to provide incentives for load-modifying demand response is to count it toward system resource adequacy requirements. Other options suggested by the California ISO at the August 8, 2017, workshop include:²⁸⁶

- Time-variant rate options to encourage energy shifts timed to match grid needs.
- Flexible demand response programs that can be tailored to customers’ demand response capabilities.
- Improved demand response dispatching systems and algorithms with incremental and locational dispatch capabilities.
- Improved real-time visibility of demand response performance and availability using existing advanced metering infrastructure.

Doubling energy efficiency by 2030 will require aggressive investments by utilities as well as expansion of market-based efficiency services. (See Chapter 2 for further discussion.) Recognizing

²⁸³ Transcript August 8, 2017, IEPR workshop, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN221097_20170908T094338_Transcript_of_08082017_IEPR_Commissioner_Workshop_on_Demand_Res.pdf, pp. 12, 110-111, and 287.

²⁸⁴ <https://www.caiso.com/Documents/DR-EERoadmap.pdf>.

²⁸⁵ For further information, see <http://www.openadr.org/over-50-certified-products>.

²⁸⁶ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN220578_20170807T113157_CAISO_Progress_on_Meeting_IEPR_Demand_Response_Recommendations.pdf.

the potential for cost-saving synergies, CPUC staff proposes to promote coordinated energy efficiency and demand response equipment incentives. The proposal includes suggestions to:²⁸⁷

- Develop customer-friendly time-of-use thermostats to make it easy for customers to reduce energy use during high-price hours.
- Provide training and incentives to accelerate deployment of nonresidential heating, ventilation, and air-conditioning (HVAC) and lighting controls. Conduct pilots to advance variable-frequency irrigation pumps and variable-frequency drives for commercial HVAC.
- Combine demand response and energy efficiency potential studies to inform 2019 integrated resource planning. (See Chapter 2 for more information.)

A finding of the June 29, 2017, IEPR roadmap workshop was the need to update the demand response/energy efficiency roadmap to address the need for more demand response capabilities to support the rapidly changing electric grid.

At the August 8, 2017, IEPR demand response workshop, Susan Kennedy, founder and chief executive officer of Advanced Microgrid Solutions, noted the following challenges for demand response:²⁸⁸

- “Rationalizing the rate design around what you’re trying to achieve with load-modifying resources, with the rate recovery that’s necessary for maintaining the system on the utility side.”
- On the supply side, “make the economics beneficial to [large commercial and industrial customers] to install the technology that allows them to respond without the economic pain of having to shut things down.”

In addition, to accelerate price-responsive demand response, actions are needed to:

- Reduce the transaction costs for customers to sign up and participate in demand response programs, particularly with third-party demand response providers.
- Streamline customer and customer-designated demand response provider access to data.
- Launch a new integrated DER/microgrid roadmap effort to determine how to clarify and improve income opportunities for load-modifying demand response.

Electricity Storage Systems

Energy storage can be used to capture electricity or heat for use later in the electric power sector. It is a key tool for managing fluctuations in supply and demand. Because of legislation and state policy, California is becoming the largest energy storage market in the United States.

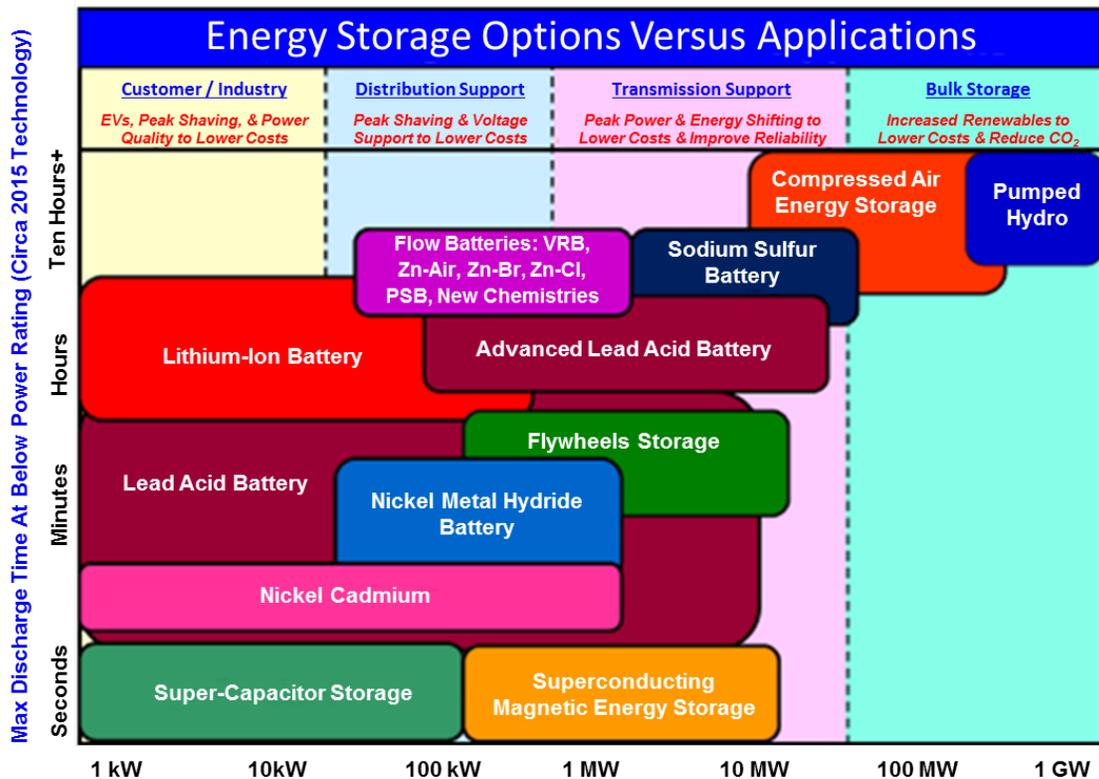
²⁸⁷ Lamming, Jean. CPUC. August 8, 2017, presentation. EE-DR Integration: Energy Division Staff Proposal. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN220508_20170802T120455_EEDD_Integration_Energy_Division_Staff_Proposal.pdf. The staff proposal is available online at <http://www.cpuc.ca.gov/General.aspx?id=7032>.

²⁸⁸ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN221097_20170908T094338_Transcript_of_08082017_IEPR_Commissioner_Workshop_on_Demand_Res.pdf, p. 212-213.

IOUs must procure more than 1.3 gigawatts (GW) of energy storage by 2020 (Assembly Bill 2514, Skinner, Chapter 469, Statutes of 2010) and an additional 500 MW of energy storage (Assembly Bill 2868, Gatto, Chapter 681, Statutes of 2016), with specific targets for transmission, distribution, and customer-side energy storage systems. Examples include pumped hydropower, thermal energy (such as molten salt), batteries, flywheels, and compressed air and do not include natural gas storage facilities. Energy storage can be used to buffer variable costs (storing energy when prices are low and using it when costs are high), store excess renewable generation, provide “load-shaving” services by injecting energy into the system during peak demand, and other ancillary services. Through these services, storage can help reduce GHG emissions and increase resiliency to variable demand and generation.

Some technologies are commercially available and well established, whereas others are in various stages of research and development. Figure 25 shows various energy storage technologies²⁸⁹ grouped by end use applications in relation to the duration of discharge (from minutes to days) and power output (from watts to gigawatts [GW]).

Figure 25: Energy Storage Technologies by Discharge Time, Size, and Use



Source: Electric Power Research Institute

289 The Hydrogen Business Council commented that hydrogen and power-to-gas should be included in Figure 25. They are not included, however, because CPUC Decisions 14.10.045 and 17.04.039 clarified that hydrogen and power-to-gas systems do not qualify as energy storage under the implementation of AB 2514 and AB 2868. The Hydrogen Business Council comments are available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221779_20171115T071055_California_Hydrogen_Business_Council_Comments_Hydrogen_Scaling.pdf.

The CPUC requires investor-owned utilities (IOUs) to procure 700 MW of transmission-level electricity storage, 425 MW of distributed electricity storage, and 200 MW of customer electricity storage by 2020. Moreover, the CPUC requires community choice aggregators (CCAs) and electricity service providers to procure electricity storage in an amount equivalent to 1 percent of their annual 2020 peak load.²⁹⁰

California agencies have made substantial progress toward improving planning, opening the procurement process, developing new rates, simplifying grid interconnection requirements, and opening market participation to more energy storage systems. Examples of electricity storage systems are shown in Figure 26. (For more information see Appendix B.)

Figure 26: Examples of Battery Storage Used on the California Grid



Source: Pacific Gas and Electric and Southern California Edison for the photo on the left and right, respectively.

At the August 8, 2017, IEPR workshop, stakeholders highlighted new opportunities for demand response created by the availability of lower-cost battery storage.²⁹¹ For example, Susan Kennedy said that batteries combined with energy efficiency and state-of-the-art demand control make it possible for customers to earn energy savings and participate in demand response programs without reducing comfort.²⁹²

Several issues warrant further attention to accelerate electricity storage investment opportunities in California. Based on information from the June 29, 2017, and August 8, 2017, IEPR workshops, an updated roadmap is needed with next steps to accelerate development of energy storage. Actions to consider advancing through the roadmap include:

- Developing and approving the rules by which electricity storage systems can provide multiple services from the same system and ensure the rate payer is not paying more than once for the same service. Also, ensuring the system can actually provide these services and meet the overall requirements.
- Addressing how the state should deal with the end-of-life, behind-the-meter, utility-scale, and electric vehicle battery systems.

²⁹⁰ CPUC Decision 13-10-040.

²⁹¹ Also see http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN220857_20170822T173619_Damon_Franz_Comments_Tesla_Comments_on_Barriers_to_DR_Workshop.pdf.

²⁹² August 8, 2017, workshop transcript, pages 237–238.

- Developing consumer protection and standardized testing/certification for behind-the-meter electricity storage to ensure batteries meet the expected lifetime anticipated when installed.

Vehicle-Grid Integration

In October 2016, the Governor’s Interagency Working Group on Zero-Emission Vehicles published the *2016 ZEV Action Plan*, an updated roadmap toward 1.5 million zero-emission vehicles on California roadways by 2025. Some of the high-priority actions included steps to:²⁹³

- Make ZEVs affordable by reducing upfront costs of owning or leasing a ZEV.
- Ensure availability of convenient charging and fueling stations, including expanded financial incentives for employers and commercial property managers to install workplace PEV charging,
- Maximize economic and job opportunities from ZEV technologies, including a recommendation to promote collaboration among state, local, and federal partners to maximize in-state manufacturing opportunities.

To advance deployment of zero-emission vehicles, the proposed California Air Resources Board (CARB) *2017 Climate Change Scoping Plan Update* sets a target of 4.2 million ZEVs by 2030.²⁹⁴ California’s energy agencies and the California ISO are working to create the infrastructure and smooth integration of ZEVs to help prepare for rapid growth needed to achieve this goal. Plug-in electric vehicles, which contribute to California’s ZEV goals, present an opportunity to help integrate high levels of distributed photovoltaic energy systems to the extent charging can be shifted away from early evening hours. (See Chapters 1, 2, 3, and 6 and Appendix H for more information on transportation electrification.)

As part of implementing the 2014 vehicle-grid integration roadmap, the Energy Commission’s Alternative and Renewable Fuel Vehicle and Technology Program (ARFVTP) provided funding with the Department of Defense to assess the ability of a fleet of electric vehicles to participate in the California ISO ancillary services market²⁹⁵ and assess its effectiveness on battery health.²⁹⁶ Located at the Los Angeles Air Force Base, the project was the largest vehicle-to-grid (V2G)

²⁹³ https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf.

²⁹⁴ https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf.

²⁹⁵ Black, Douglas, “U.S. Department of Defense Vehicle-to-Grid Demonstrations in California,” Lawrence Berkeley National Laboratory, November 19, 2014, First Annual California Multi-Agency Update on Vehicle-Grid Integration Research, http://www.energy.ca.gov/research/notices/2014-11-19_workshop/presentations/Doug_Black_CEC-VGI-Workshop-LBNL-DOD-V2G_2014-11-19.pdf; Michael Genseal, “LAAFB Technical Update,” Concurrent Technologies Corporation, December 14, 2015, Second Annual California Multi-Agency Update on Vehicle-Grid Integration Research, http://www.energy.ca.gov/research/notices/2015-12-14_workshop/presentations/13_CTC_Los_Angeles_Air_Force_Base_Genseal_Kenner.pdf; Southern California Edison, “Vehicle-to-Grid Pilot Overview,” December 12, 2016, Third Annual California Multi-Agency Update on Vehicle-Grid Integration Research, http://www.energy.ca.gov/research/notices/2016-12-12_workshop/presentations/08_SCE_Los_Angeles_Air_Force_Base.pptx

²⁹⁶ Markiewicz, Dan, “California Energy Commission Vehicle-to-Grid Testing and Demo with DoD,” Concurrent Technologies Corporation, December 5, 2017, Fourth Annual California Multi-Agency Update on Vehicle-Grid Integration Research, http://www.energy.ca.gov/research/notices/2017-12-05_workshop/presentations/07_CTC.pdf

demonstration in the world with more than 40 vehicles providing frequency regulation when at charging stations on the base. Following the V2G demonstration, some batteries will be removed from the PEVs/plug-in hybrid electric vehicles (PHEVs) to evaluate and quantify potential impacts to the batteries from V2G operational cycles and to predict potential long-term impacts. This analysis will provide real-world data on the viability of V2G cost for BEVs/PHEVs and fill gaps in understanding the potential impacts of V2G operations on BEV/PHEV batteries.²⁹⁷ The need to collect V2G data is discussed further in the section of Chapter 2 titled “Encouraging Widespread Transportation Electrification.” In 2017, the Energy Commission awarded a follow-on grant to LBNL funded by EPIC to continue the data collection and assessments at LA AFB ensuring this critical data will continue to be collected and evaluated.

Comments from the joint utility-automakers and SCE call for redirecting funding in support of a partnership among automakers, utilities, charging-station providers, and others to assess vehicle grid integration (VGI) valuation and pursue “large-scale, multi-year demonstration projects to validate the real-world value of VGI.”²⁹⁸ The Energy Commission recognizes that further demonstrations are needed to advance V2G technologies and will consider ideas for demonstration projects through the ARFVTP’s investment plan proceeding and through the 2018–2020 triennial Electric Program Investment Charge.²⁹⁹

During the June 13, 2017, workshop to discuss progress on California’s energy roadmaps, the Energy Commission discussed advances on VGI, including the completion of pilots, assessments of economic value, advancements in distributed energy resource proceedings and initiatives, growth in the smart charging industry, development of new utility rates and infrastructure programs, development of protocols for metering and communications, and continued research and development in the capabilities of VGI technologies.³⁰⁰

A conclusion drawn from the June 13, 2017, IEPR workshop is that the VGI Roadmap needs to be updated to address new opportunities generated in this rapidly changing market in recent years.³⁰¹ Comments from the joint utility-automakers³⁰² pointed out that VGI is a complex issue

297 See <https://building-microgrid.lbl.gov/projects/los-angeles-air-force-base-vehicle-grid> and http://www.energy.ca.gov/research/energystorage/tour/af_v2g/.

298 Final (Updated) Joint Utility Automaker Comments re: Draft Oct. 2017 IEPR, November 15, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221781_20171115T100743_Hannah_Goldsmith_Comments_Final_Updated_Joint_Utility_Automaker.pdf and SCE Comments on the Draft IEPR, November 13, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221731_20171113T150258_Catherine_Hackney_Comments_SCE_Comments_on_the_CEC_Docket_No_17.pdf.

299 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221731_20171113T150258_Catherine_Hackney_Comments_SCE_Comments_on_the_CEC_Docket_No_17.pdf and http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221781_20171115T100743_Hannah_Goldsmith_Comments_Final_Updated_Joint_Utility_Automaker.pdf. California Public Utilities Commission Decision 18-01-008, Addressing applications of the California Energy Commission, PG&E, SCE, and SDG&E for approval of their Triennial Investment Plans for the Electric Program Investment Charge Program for the years 2018 through 2020, and Modifying Decision 12-05-037, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M199/K995/199995953.pdf>.

300 Pratt, K., and N. Crisostomo, “California Vehicle-Grid integration Roadmap Gap Analysis and Update” California Energy Commission, June 13, 2017, Joint Agency Staff Workshop on the Review of the Actions and “Statue of State-level Energy Roadmaps,” http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN218219_20170613T112307_California_VehicleGrid_Integration_Roadmap_Gap_Analysis_and_Upd.pdf.

301 IEPR workshop on June 13, 2017, on Joint Agency Staff Workshop on the Review of the Actions and Status of the State-Level Energy Roadmaps, <http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR->

that has been difficult to resolve despite ongoing efforts by the VGI Communications Protocol Working Group. They also suggest that the “value barrier” should be addressed as part of the updated VGI roadmap.³⁰³

The Energy Commission agrees that development of the new roadmap is critical, that issues are complex, and that expeditious progress is needed.³⁰⁴ The updated roadmap should be led by the California ISO, Energy Commission, and CPUC with input from a diverse group of stakeholders (such as industry, academia, and other governmental agencies) and representatives from disadvantaged communities to prioritize and address the value and technical barriers to the VGI use cases identified by the VGI Communication Protocol Working Group for accelerated PEV adoption (discussed further in Appendix H).³⁰⁵

Drawing on comments from the June 13, June 29, and August 8 IEPR workshops held in 2017, the next VGI Roadmap should be integrated with other DER technologies to better promote rapid growth and business opportunities arising from aggregating, or combining, DERs within and across buildings.

At the June 29, 2017, IEPR workshop, the following were identified as top priorities for updating the Vehicle-Grid Integration Roadmap that need to be addressed expeditiously, and through a broad stakeholder process, to realize the benefits that VGI offers:³⁰⁶

- Establish interoperability capabilities so that these vehicle resources can be certified and operated as a dispatchable demand response or eventually storage device and grid resource with three considerations: seamless interoperability across public networks, consistent charging experiences at home or work and among power levels, and integration with larger home and building energy management systems, so that these vehicles work in concert as a suite with other building demand.
- Promote the return of value of ancillary services and controlled charging grid integration investments to drivers, automakers, charging providers, and utilities and provide clarity for business planning and component and equipment manufacturing decisions.

12/TN220754_20170815T091531_Transcript_of_06132017_Joint_Agency_Staff_Workshop_on_the_Revie.pdf, pp. 123–124.

302 Representing California Electric Transportation Coalition, American Honda Inc., BMW of North America LLC, Fiat Chrysler Automobiles, Ford Motor Company, General Motors. PG&E, SMUD, SDG&E, SCE, and Southern California Public Power Authority.

303 Joint Utility-Automaker Parties, Comments on the Draft 2017 Integrated Energy Policy Report, November 13, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221781_20171115T100743_Hannah_Goldsmith_Comments_Final_Updated_Joint_Utility_Automaker.pdf.

304 Comments from Oxygen Initiative also expressed frustration with the slow progress of the VGI Working Group, commenting that, “stakeholders that have been involved in an unproductive stalemate for years simply replicated that unproductive dialogue in the VGI working group.” http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN221741_20171113T155256_Stephen_Davis_Comments_Oxygen_Initiative_2017_IEPR_Comments.pdf.

305 California Energy Commission, Fourth Annual California Multi-Agency Update on Vehicle-Grid Integration Research, Discussion Panel: Identifying Opportunities and Barriers to Advance Vehicle-Grid Integration into the Medium- / Heavy-Duty Sector, December 5, 2017, <http://www.energy.ca.gov/research/notices/#12052017>.

306 Transcript for June 29, 2017, IEPR workshop, pages 46–58.

- Coordinate vehicle technology research and development plans with charging infrastructure deployment plans, including the use of the U.S. Environmental Protection Agency’s ENERGY STAR certification of chargers with demand response and grid dispatchability capabilities.

The 2014 vehicle-grid integration roadmap requires annual research review workshops coordinated by the Energy Commission to monitor progress on VGI research and demonstration projects, including VGI research under the EPIC program. The fourth annual multiagency update on the Vehicle-Grid Research Review Workshop held December 5, 2017, highlighted the cost savings and importance of open standards communication protocols in enabling the design of integrated control systems capable of smart charging and vehicle-to-grid services that are friendly enough for use by mass market PEV adopters. The workshop included presentations from representatives of projects that were awarded EPIC funds, utilities, agencies, and the California ISO.³⁰⁷ The workshop also explored the roles and relationships between medium- and heavy-duty electrification stakeholders and how existing research could be leveraged to address the barriers to medium- and heavy-duty electrification. Based on the presented research, the Energy Commission solicited stakeholder feedback on future research opportunities to advance VGI and vehicle electrification.

Microgrids

The Energy Commission, CPUC, and California ISO are working with stakeholders to develop a roadmap for actions needed to commercialize microgrids in California. Although a standard definition is still under development, these agencies have used the following working definition: a small, self-contained electricity system with the ability to “manage critical customer resources, provide services for the utility grid operator, disconnect from the grid when the need arises, and provide the customer and the utility different levels of critical support when the need exists. Microgrids can incorporate clean, low-carbon energy resources with increased energy efficiency, and distributed energy resources, such as energy storage, distributed renewables, fuel cells,³⁰⁸ demand response, electric vehicles, and other advanced generation and advanced distributed energy systems.”³⁰⁹

Made of DERs, storage, and demand response capabilities, microgrids can be used to shift commercial load to help address net load ramps (in the morning and afternoon when solar energy is not available) in a distribution network. A microgrid with a properly configured controller can provide higher reliability, lower electricity bills, and cleaner air. The controller allows the management of electricity generation and consumption. It can control the rate and schedule of DER generation, coordinate the use of energy storage, and implement demand response. Figure 27 provides an example of a microgrid. Table 11 provides a list of the renewable capacity, generation type, and energy storage capacity of the top 10 California microgrids from Navigant’s

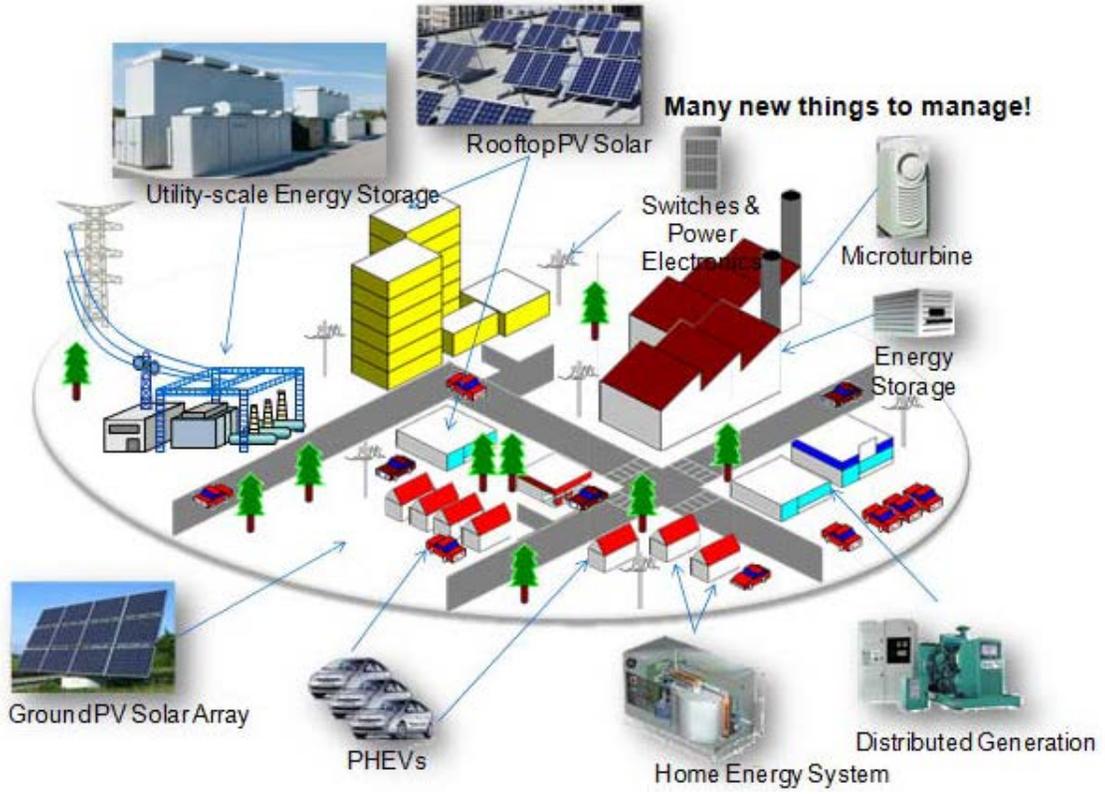
307 <http://www.energy.ca.gov/research/notices/#12052017>.

308 AB 1400 (Friedman, Statutes of 2017, Chapter 476) denies funding spent on diesel generators within microgrids.

309 <http://www.caiso.com/Documents/CEC-CPUC-ISOCaliforniaMicrogridRoadmapJointWorkshop100217.html>.

Microgrid Tracker.

Figure 27: Microgrid



Source: <https://microgridknowledge.com/wp-content/uploads/2016/12/distributed-energy-graphic-e1480617672252.png>

Table 11: Top California Microgrids in the Navigant Research Q2 2017 Microgrid Tracker

Top California Microgrids			
Host	Total Renewables Capacity	Generation Type	Energy Storage Capacity
Santa Barbara County	93 MW	Solar PV	0 MW
Imperial Irrigation District	83 MW	Solar PV, Energy Storage	33 MW
Moffett Field	50 MW	CHP, Solar PV, Energy Storage, Other	Not available
UC San Diego	37.6 MW	CHP, Solar PV, Energy Storage, Fuel Cell, Other	2.5 MW
Borrego Springs Microgrid	33.8 MW	Diesel, Solar PV, Energy Storage, Other	4.23 MW
Marine Corps Air Station Miramar	24.7 MW	Diesel, CHP, Solar PV, Energy Storage, Fuel Cell	0.25 MW
UC Irvine	24.2 MW	Solar PV, Fuel Cell, Blogas, Other	0 MW
Twentynine Palms Marine Corps Air Ground Combat Center	22.2 MW	Diesel, CHP, Solar PV, Energy Storage	1 MW
Apple Campus 2	21 MW	Solar PV, Fuel Cell	0 MW

Source: Navigant Research Q2 2017 Microgrid Tracker, as reported in *California Energy Markets* on September 18, 2017.

The Energy Commission's EPIC research program is making progress toward advancing the capabilities of microgrids. As part of the first Triennial EPIC Investment Plan, the Energy Commission developed and issued a competitive solicitation (PON 14-301) that offered EPIC funding for microgrid research and focused mainly on using microgrids to support high penetrations of renewables and the operations of critical facilities such as hospitals, fire stations, and regional command centers. The microgrid projects awarded through this solicitation in 2015 have equipment installed, have systems that are operational, and are collecting data on performance, value streams, and reliability. These ongoing projects reduce GHG emissions, improve reliability, and increase resiliency and flexibility to provide critical services in emergencies. Further, they are providing a wealth of information on microgrid configurations, interconnection of multiple DERs through a single controller, and system interconnection challenges. These demonstrations help increase the electric industry's knowledge of the operations of microgrids and advance commercial acceptance of the business cases being developed.

In 2017, the Energy Commission released an EPIC competitive solicitation, GFO-17-302, to fund research to promote commercialization of microgrids.³¹⁰ Through this solicitation, the Energy Commission seeks to fund research to identify opportunities where microgrids can be developed into standardized configurations that are easily repeatable to provide benefits to the grid and end users.

³¹⁰ <http://www.energy.ca.gov/contracts/epic.html#GFO-17-302>.

Much of the growth in California DER from 2013–2017 has been driven by research, incentives, and procurement programs funded by ratepayers of California’s three largest IOUs. Going forward, the growth of CCAs in California is creating uncertainty regarding the scope and structure of these programs. (For more information, see Chapter 1, “Changes in Electricity Market Structure.”) The Energy Commission urges and welcomes CCA participation in advancing innovation in DERs.³¹¹ CCAs can participate in research to help the state evaluate the value of DER systems while recognizing the need to protect customer data.

The three agencies have completed a series of five workshops in developing the *Roadmap for the Commercialization of Microgrids in California*. This roadmap, scheduled to be published in early 2018, addresses the key obstacles that microgrids face in commercialization and recommends how to address those obstacles. The stakeholders in attendance at the workshops recommended actions the three agencies can consider. Key topics included:

- How microgrids can improve resiliency and reliability for the microgrid owner/operator.
- Ways to provide financial value to the services provided by a microgrid.
- How microgrids can help the state meet future DER integration goals.
- What new grid services microgrids can provide the utility grid.
- How microgrids might receive financial compensation for utility grid services.
- Ways microgrid research and demonstration projects can address the issues around fielding multiple advanced technologies onto one operating system.

During the IEPR public comment period, Bloom Energy recommended that the microgrid roadmap also address overcoming barriers to deploying multiple technologies at one location. This recommendation was incorporated in the action items section of the roadmap.

Since no specific state policies or directives to implement microgrids exist, this roadmap is addressing how commercially available microgrids can play a role in the future implementation of the state’s aggressive energy policies.

As mentioned previously, the Energy Commission EPIC program will award several new microgrid research grants in 2018 under GFO-17-302. The top priorities from these new microgrid research projects include:

- Developing microgrid configurations that can easily be configured to accept high concentration of DER systems.
- Developing solid business cases for microgrids that clearly define the economic value of microgrids while clearly identifying all the benefits microgrids will provide to the larger California electric grid.

³¹¹ Marin Clean Energy commented that “MCE encourages the [Energy Commission] to leverage CCAs as laboratories of innovation to develop and test the market readiness of DER” and that “each CCA is in a unique position to test technologies that best suit their communities’ and programs’ needs.”
http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221749_20171113T161412_MCE_Comments_on_Draft_2017_IEPR_Report.pdf.

- Like with energy storage systems, developing and approving the rules by which energy storage systems can provide multiple services from the same system to maximize value to the customer, grid, and utility, ensuring the rate payer is not paying more than once for the same service, and ensuring the system can actually provide these services and meet these overall requirements.

Costs

Continued reduction in costs is the top priority for accelerating DERs. Demand response is one of the cheapest resources for addressing local area reliability concerns in Southern California.

Advanced Microgrid Solutions is one of the few companies stepping forward with energy management services to help meet the call³¹² for greater demand response in the area affected by the closure of San Onofre and restrictions at the Aliso Canyon natural gas storage facility.³¹³ More work is needed, however, to bring down soft costs, such as installation, customer acquisition, interconnection, and integration.

As discussed in Chapter 1, recent years have seen steep declines in cost for clean energy technologies. For example, in 2016, the U.S. DOE estimated battery costs dropped 74 percent.³¹⁴ The growth in electric vehicle sales has helped generate economies of scale to bring down the price of lithium-ion batteries (Figure 28).³¹⁵

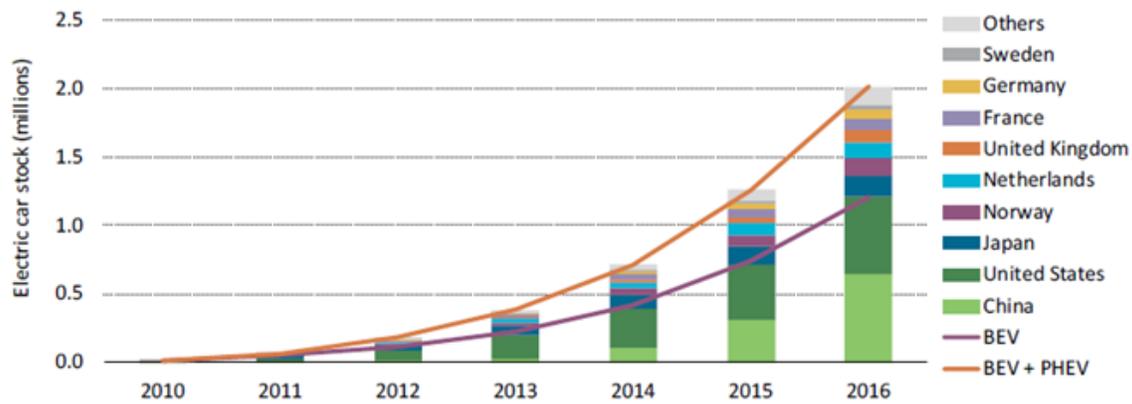
312 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN221097_20170908T094338_Transcript_of_08082017_IEPR_Commissioner_Workshop_on_Demand_Res.pdf, p. 113.

313 For example, see Advanced Microgrid Solutions, June 22, 2016, press release "California State University and Advanced Microgrid Solutions Announce a Portfolio of State-of-the-Art Hybrid Electric Buildings," <http://advmicrogrid.com/assets/docs/press/pr-ams-csu-joint-announcement.pdf> and AMS November 2, 2016, press release "Invesco Real Estate Collaborates with Advanced Microgrid Solutions to Introduce Hybrid Electric Technology" <http://advmicrogrid.com/assets/docs/press/pr-invesco.pdf>. Also see AMS April 20, 2017, press release "Advanced Microgrid Solutions to Build 16 MWh Distributed Energy Storage Project in San Diego," <http://advmicrogrid.com/assets/docs/press/pr-sdgc.pdf>.

314 U.S. Department of Energy. September 2016. *Revolution ... Now: The Future Arrives for Five Clean Energy Technologies – 2016 Update*.

315 <https://www.iea.org/publications/freepublications/publication/GlobalEVO Outlook2017.pdf>.

Figure 28: China and United States Lead Growth in Electric Vehicles (2010–2016)



Notes: The electric car stock shown here is primarily estimated on the basis of cumulative sales since 2005. When available, stock numbers from official national statistics have been used, provided good consistency with sales evolutions.

Source: International Energy Agency, *Global EV Outlook 2017*

The central question for advanced energy storage is how to continue to drive costs down. For example, should investment go to development of new chemistries or expansion of economies of scale? Electric vehicles continue to play a big role in bringing down costs through economies of scale. Tesla is building the first Gigafactory in Nevada and has announced plans for more.³¹⁶ China is expected to be home to a dominant share of lithium-ion battery manufacturing by 2020.³¹⁷ Lithium iron phosphate batteries are also widely used in China and in electric buses in the United States.³¹⁸ For example, BYD, a Chinese manufacturer of automobiles and rechargeable batteries, sold more than 100,000 electric cars in 2016.³¹⁹ Other chemistries, such as chemistries suitable for flow batteries, hold promise as well.

Expanding DER Income and Savings

At the August 8, 2017, IEPR Demand Response workshop, Commissioner Andrew McAllister highlighted the importance of promoting customer participation in opportunities for demand response income and savings: “We need the correct rates, we need the right programs, and we need an integrated suite of policies that work together well and seamlessly.”³²⁰ This suite of policies includes rate designs, such as the CPUC time-of-use programs. (See Chapter 3.)

As discussed in Chapter 1, the section on “Changes in Electricity Market Structure,” on May 19, 2017, the CPUC and the Energy Commission held an en banc meeting to discuss the rapid growth

³¹⁶ Tesla. February 22, 2017. “Tesla Fourth Quarter & Full Year 2016 Update.” <http://ir.tesla.com/releases.cfm>.

³¹⁷ Ryan, Joe. June 28, 2017. “China is About to Bury Elon Musk in Batteries.” Bloomberg. <https://www.bloomberg.com/news/articles/2017-06-28/china-is-about-to-bury-elon-musk-in-batteries>.

³¹⁸ <http://www.byd.com/usa/about/>.

³¹⁹ <http://www.afr.com/business/transport/automobile/chinas-byd-has-overtaken-tesla-in-the-battery-and-electric-car-business-20170517-gw6wal>.

³²⁰ August 8, 2017, IEPR Commissioner Workshop on Demand Response, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN221097_20170908T094338_Transcript_of_08082017_IEPR_Commissioner_Workshop_on_Demand_Res.pdf, p. 13.

in community choice aggregators and behind-the-meter DER anticipated over the next several years. DER-related CPUC rules and requirements designed for the current market will require adjustment to function well in the new context. For example:

- In the new market structure, what types and levels of DERs will be eligible for CCA procurement processes?
- Current rules limit the geographical footprint eligible for demand response resource adequacy credit and limit customers to a single LSE. If customers move from one LSE to another within a small geographical area, this can put the ability of the demand response aggregator to meet contracted demand response obligations at risk.³²¹ In PJM, for example, curtailment service providers are allowed to compete with utilities to provide demand response throughout the PJM system.³²² Should systemwide services be allowed in California to help ramp up demand response?

Many DERs seek to provide services and earn revenues at multiples levels of the system. Although current market rules do not support stacking of incremental values that DERs can provide to the wholesale market, distribution grid, and end users, the CPUC and California ISO have undertaken a joint effort to examine a path forward.³²³

As noted above, today most DERs do not participate in the California ISO wholesale market as supply resources, but “self-dispatch” as load modifiers to the end-use customer. At this level, DERs could provide end-use customer services from behind the customer meter such as time-of-use bill management, service resilience to critical loads, or reducing the customer’s demand charges. However, load-modifying demand response does not have resource adequacy value, reducing customers’ incentive to participate in such programs.

Also, DERs could provide services to the distribution operator to support reliable operation (for example, voltage and power quality) or defer a distribution infrastructure upgrade. The definition and provision of these services are the subject of the CPUC’s Integrated Distributed Energy Resource proceeding.³²⁴

At the wholesale market level, the California ISO has developed several market participation models³²⁵ to enable the many forms of DER to participate in the wholesale market. As a result, it

321 Barkovich, Barbara. California Large Energy Consumers Association. Transcript of the August 8, 2017, IEPR workshop. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN221097_20170908T094338_Transcript_of_08082017_IEPR_Commissioner_Workshop_on_Demand_Res.pdf. Pages 92-94.

322 PJM. Curtailment Service Providers. <http://www.pjm.com/markets-and-operations/demand-response/csps.aspx>. Accessed September 10, 2017.

323 The CPUC is examining multiple-use applications for storage in Rulemaking (R.) 15-03-011. The California ISO is examining multiple-use applications in its Energy Storage and Distributed Energy Resources (ESDER) stakeholder initiative. Together, the CPUC and California ISO have held joint workshops on the topic and issued a joint staff proposal on May 18, 2017. The joint staff proposal may be found at <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M187/K237/187237488.PDF>.

324 CPUC Rulemaking (R.) 14-10-003.

325 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN219945_20170628T090419_Transmission_and_Distribution_DER_Activities_DER_Participation.pdf.

is expected that the amount of DER participating in the wholesale market is likely to grow over time. Demand response is able to participate in the California ISO wholesale market through use of the proxy demand response and reliability demand response resource market participation models. Demand response participating in the wholesale market today is less than 200 MW for proxy demand response and about 1,250 MW for reliability demand response resource. Distributed storage is able to participate using the nongenerator resource model, which is designed to accommodate resources that can vary between consuming and producing energy.

Increasingly, building operators, demand response aggregators, and others are working to integrate multiple DERs into a single system to capture energy-saving, cost-saving, and reliability-enhancing opportunities.³²⁶ Microgrids provide a tool to help manage such integrated systems.

Aggregations of all types of DER are able to participate in the wholesale market by virtue of the California ISO's distributed energy resource provider platform. Although there are not yet aggregations of DER participating in the wholesale market, it is expected that such aggregations will use the nongenerator resource model to participate. To lower barriers and enhance the ability of DER to participate in wholesale markets, the California ISO has been enhancing these market participation models through successive phases of its energy storage and distributed energy resource stakeholder initiative.

Transmission and Distribution Implications of the Growth in Distributed Energy Resources

As discussed in the *2007 IEPR*,³²⁷ while providing many opportunities for helping manage California's evolving grid, the growth in DER also poses new operational and planning complexities. California's interconnected transmission and distribution systems drive the need for advanced operational models and methods, improved coordination to manage interactions across transmission and distribution systems, and new market design and pricing policies.³²⁸ DERs use both the transmission and distribution systems, whether they operate autonomously (in other words, "self-dispatch" as load modifiers), provide distribution services to the distribution operator, or participate in the California ISO wholesale market.

In response to these challenges, *More Than Smart*³²⁹ brought together diverse industry participants and stakeholders to identify needs and develop recommendations toward building a new transmission and distribution grid coordination framework. In 2017, *More Than Smart* published a paper highlighting new ways for California's grid operators to coordinate operations

³²⁶ Susan Kennedy, AMS, August 8, 2017, IEPR workshop, Transcript, p. 235.

³²⁷ See Chapter 5, "California's Electric Distribution System" in California Energy Commission 2007, *2007 Integrated Energy Policy Report*, CEC-100-2007-008-CMF. <http://www.energy.ca.gov/2007publications/CEC-100-2007-008/CEC-100-2007-008-CMF.PDF>.

³²⁸ De Martini, Paul, K. Mani Chandy, and Neil Fromer, eds. September 2012. *GRID 2020: Towards a Policy of Renewable and Distributed Energy Resources*. The Resnick Institute. California Institute of Technology. http://resnick.caltech.edu/docs/R_Grid.pdf.

³²⁹ Information about *More Than Smart* is available at www.morethansmart.org.

to maintain reliable customer service in a more decentralized power grid.³³⁰ The findings of this paper were discussed at the June 29, 2017, joint agency IEPR DER workshop.

DER has the potential to provide nonwire alternatives, deferring the need for new or upgraded transmission and distribution infrastructure. To capture this potential, planners must consider where and when DER will develop and whether it will develop to the levels forecasted. Also, to update technical modeling inputs, planners need information on the portion of the load profile to be served/managed by DERs by geographic area (coastal versus inland), as well as demand response aggregators. Aggregators, such as Advanced Microgrid Solutions, offer energy management products incorporating energy storage technologies to adjust the load profile of buildings and groups of buildings. Going forward, such services may be bid into the California ISO wholesale market as nongenerating services to help balance supply and demand for electricity.

For system operations, recent efforts to address DER complexities and opportunities include:

- Deploying enhanced inverter capabilities for voltage regulation, as recommended by the Smart Inverter Working Group, discussed above.
- Developing the capability to incorporate the photovoltaic-related peak shift (from midday to early evening) within the IEPR demand forecasts, starting with the final *2017 IEPR* forecast. (See Chapter 6.)

Remaining issues for transmission and distribution planning and operation include the following:

- Higher levels of DER may make balancing loads among the three phases³³¹ of the distribution system and managing voltage regulation more challenging. More sophisticated interconnection and planning processes may help address this challenge.
- Today, the California ISO communicates with the utility transmission owners, but there is no direct connection between the California ISO and the utility distribution operators. In a high-DER future, operational coordination between the California ISO and the utility distribution operators will be needed, and the transmission-distribution interface is where this coordination comes together.

To illustrate these information gaps, consider the relatively simple scenario where a DER does not engage in multiple-use applications but only bids into the California ISO wholesale market and receives a California ISO dispatch instruction. Under today's existing processes and procedures, the utility distribution operator will be unaware of the bids of the DER or California ISO dispatches and thus is unable to predict whether this impacts the distribution grid and whether

³³⁰ *Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid*, More Than Smart, June 2017. The paper was prepared by the California Independent System Operator, Pacific Gas and Electric, Southern California Edison and San Diego Gas & Electric, in partnership with More Than Smart. The paper is available at http://morethansmart.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf.

³³¹ Electric power is generated, transmitted, and distributed using a three-phase system. A three-phase system is more economical than a single-phase system. In a three-phase system, there are three wires that carry the power. Each wire carries an alternating current of the same frequency and voltage but with a phase difference of one-third. Three-phase power may serve a neighborhood, but the household loads are connected only as single phase. In a perfectly balanced case, all three wires share equivalent loads.

any adjustments may be necessary. In addition, both the California ISO and DER will be unaware of current distribution system conditions that could inhibit the DER from fully responding to a California ISO dispatch instruction. Without increased operational coordination, the three entities lack the information needed to assess effects to the distribution system or how distribution system conditions may affect dispatch feasibility. Under a scenario involving multiple-use applications, the operational coordination and communication needs become even more complicated.³³²

The More Than Smart paper proposes four near-term recommendations to begin addressing the need for increased coordination and communication at the transmission-distribution interface. These recommendations may be implemented as pilots or manual procedures for the near term and then considered for automation as DER volumes increase:³³³

- Utility distribution operators should communicate advisory information on current system conditions to DERs, so that DERs can modify their California ISO market bids accordingly and, if necessary, submit outage or derate notifications to the California ISO.
- The California ISO should provide day-ahead DER schedules to the utility distribution operators, for the utility distribution operators to pilot a feasibility assessment to identify schedules that may create distribution system reliability problems.
- DER providers should communicate constraints on the performance of its resources to the California ISO in the form of updated market bids or outage notifications, if needed.
- The utility distribution operators should pursue a pro forma “integration agreement”³³⁴ with the DER provider with regard to DER aggregations.

The More Than Smart paper also identifies several topics for continuing work. One topic is to explore how different “distribution system operator” (“DSO”) constructs that are being explored in the industry would affect the structure of DSO-DER-ISO coordination. Although More Than Smart acknowledges that the different possible DSO models are beyond the scope of the paper, it points out that the design of an optimal transmission-distribution coordination framework will depend on the functions, roles, and responsibilities of the future DSO.

³³² On the afternoon of September 8, 2011, an 11-minute system disturbance occurred in the Pacific Southwest, leading to cascading outages and leaving nearly 2.7 million customers without power for up to 12 hours. Arizona Public Service Company, Imperial Irrigation District, California ISO, and Southern California Edison Company agreed to pay civil penalties of more than \$21 million, with cash penalties of more than \$7 million shared between the U.S. Treasury and NERC, and credits for enhancements to the reliability of the grid beyond the requirements of the reliability standards and required mitigation that included a utility-scale battery storage system, an innovative system for visualizing real-time system conditions, equipment to maintain system voltage in vulnerable areas, and additional system operators for the reliability coordinator, among other improvements. See <https://www.ferc.gov/media/news-releases/2015/2015-2/05-26-15.asp#.WahcZrJ97Z5> and <http://www.nerc.com/pa/rrm/ea/Pages/September-2011-Southwest-Blackout-Event.aspx>.

³³³ More Than Smart, *Coordination of Transmission and Distribution Operations in a High Distributed Energy Resource Electric Grid*, June 2017, available at http://morethansmart.org/wp-content/uploads/2017/06/MTS_CoordinationTransmissionReport.pdf.

³³⁴ The distribution operator will typically have an interconnection agreement with a DER on its system, but when multiple DERs are aggregated into a virtual resource for ISO market participation, today there is no comparable agreement between the distribution operator and the DER provider. The agreement could specify, for example, the responsibilities of the parties to support reliability of the system and enable the DER provider to realize the full value of the DER aggregation through provision of the various services its performance characteristics allow.

Recommendations

To accelerate use of distributed energy resources in California, the Energy Commission, the California Public Utilities Commission (CPUC), and the California Independent System Operator (California ISO) should:

- **Promote rapid growth in demand response.** Reconvene a commissioner-led demand response working group to coordinate work to quickly expand demand response, especially in Southern California, and explore options for attributing resource adequacy value to load-modifying demand response. Demand response can be a cost-effective, carbon-free substitute for fossil resources and for capturing excess renewable energy.
- **Consider New Load Management Standards.** The Energy Commission should consider developing load management standards. Load management standards hold some promise to reduce regulatory barriers that are one of the factors inhibiting expanded use of demand response.
- **Develop an updated integrated distributed energy resources/microgrid roadmap.** With input from stakeholder groups and representatives from disadvantaged communities, the California ISO, the Energy Commission, and the CPUC should coordinate development of an integrated roadmap to identify technical requirements and market rule changes to promote coordination of distributed energy resources (DER), including energy efficiency, demand response, electricity storage, and electric vehicle expansion in the context of unprecedented growth in community choice aggregators.
- **Update the Vehicle-Grid Integration (VGI) Roadmap.** The Energy Commission should work with the California ISO and the CPUC to update the VGI Roadmap reflecting the needs to use open standards, to return the value of grid integration to stakeholders, and to commercialize prior investments in research and maintain leadership in advanced technology development. For details, see Chapters 2, 3, 6, and Appendix H.
- **Standardize electric vehicle charging equipment to enable resource dispatch.** The Energy Commission should work with the CPUC, the California ISO, CARB, and interested stakeholders including charging equipment and vehicle manufacturers to help standardize charging equipment to better integrate electric vehicles with the grid.
- **Continue to support research on distributed energy resources (DER), including demand response, storage, VGI, and microgrids.** Continue to fund research that enables the ability of DER to provide flexibility and grid services. While large-scale renewables are most cost-effective,³³⁵ utilities are not planning to enter long-term procurement contracts in the near term, limiting the ability of large-scale resources to provide electricity system flexibility, DER must fill the gap. Improved communication,

³³⁵ The California Energy Commission's Tracking Progress Web page, Renewable Energy, updated December 2017, Figure 13: U.S. Residential and Nonresidential PV System Prices, http://www.energy.ca.gov/renewables/tracking_progress/documents/renewable.pdf.

control platforms, cybersecurity, and business models will be needed to accelerate customer participation in DER aggregation and in electricity markets.

- **Expedite revision of retail rates to clarify DER value streams.** Clear information on value streams will expedite rapid ramp-up of energy-as-a-service business models for demand response combined with energy storage, building management, and other DER resources, especially in the high-priority area affected by the Aliso Canyon natural gas storage facility.
- **Continue to improve coordination between the transmission and distribution system operators through continuation of the More than Smart working group.** As the amount of DER in California grows, greater communication is needed to enable efficient and effective dispatch of energy resources and grid stabilizing services.

CHAPTER 5: Strategic Transmission Plan and Landscape-Scale Planning

Introduction

As noted in previous chapters, the *2017 IEPR* focuses on the implementation of Senate Bill 350 (De León, Chapter 547, Statutes of 2015), including implementing integrated resource plans (IRPs) for the electricity sector and achieving 2030 Renewables Portfolio Standard (RPS) and greenhouse gas (GHG) reduction goals. As noted in the *2017 IEPR Scoping Order*, the Renewable Energy Transmission Initiative 2.0 (RETI 2.0) recognizes that additional transmission or restructuring of the transmission system may be required to achieve renewable energy goals and reduce GHG emissions 40 percent below 1990 levels by 2030. RETI 2.0 found that while there may be a relative abundance of transmission capacity at the system level, there are likely to be limits in specific areas that would require additional evaluation, depending on the level of renewable development assumed in each area. RETI 2.0 concluded that multiple scenarios reflecting different portfolios of renewable energy development would be useful to inform planning as well as to guide decisions necessary to maximize use of the existing transmission system.³³⁶

Measures to achieve GHG reduction, RPS, and other clean energy goals should minimize the environmental and land-use impacts of transmission infrastructure while ensuring that reliability (both planning and operational) standards are met, even as transmission and distribution-level issues create new challenges and opportunities. As discussed in Chapter 4, in the last several years, California has evaluated opportunities for greater use of the distribution system to promote distributed energy resources (DER) and other technologies, including electric vehicles, energy storage, and demand response, as an alternative to transmission upgrades. This shift in focus has resulted in fewer transmission projects and greater attention to DER and distribution system upgrades as a way to transform California's electric system and achieve GHG reduction goals. However, as the state continues to move toward higher levels of renewable resources, transmission infrastructure will continue to play a role in meeting reliability, economic, and policy goals.

Consistent with the Garamendi Principles,³³⁷ the state should pursue strategies to maximize the use of the existing transmission system and existing rights-of-way before considering the

³³⁶ http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN216198_20170223T095548_RETI_20_Final_Plenary_Report.pdf.

³³⁷ Senate Bill 2431 (Garamendi, Chapter 1457, Statutes of 1988) recognized the value of the transmission system and the need for coordinated long-term transmission corridor planning to maximize the efficiency of transmission rights-of-way and avoid single-purpose lines. The bill established four principles, commonly referred to as the "Garamendi Principles," for the planning and siting of transmission facilities that are to be pursued in the following order: 1) Encourage the use of existing rights-of-way by upgrading existing transmission facilities where technically and economically feasible; 2) when construction of new transmission lines is required, encourage expansion of existing rights-of-way, when technically and economically feasible; 3) provide for the creation of new rights-of-way when justified by environmental, technical, or

expansion or creation of new rights-of-way. Such strategies should include advanced transmission technologies as well as targeted supply resources in strategic locations.

Where new rights-of-way or corridors are needed, landscape-scale planning provides an important tool for ensuring the most appropriate locations for future transmission are identified. The Energy Commission's transmission corridor designation responsibilities under Senate Bill 1059 (Escutia and Morrow, Chapter 638, Statutes of 2006) provides a mechanism for ensuring that only those transmission locations that are expected to be needed, consistent with the attainment of the state's long-term GHG reduction and clean energy goals, are environmentally appropriate, designated, and preserved. The designation of a transmission corridor zone shall identify a feasible corridor where one or more future high-voltage electric transmission lines can be built that are consistent with the state's needs and objectives as set forth in the *Strategic Transmission Investment Plan*.³³⁸ The Energy Commission's transmission corridor designation program should also consider the protection and management of natural and working lands to reduce GHG emissions, as directed by Senate Bill 1386 (Wolk, Chapter 545, Statutes of 2016).

This chapter builds on recommendations in the *2016 IEPR Update* relating to statewide energy planning and permitting coordination.

The major topics covered in this chapter and in Appendices E and F include western reliability and planning coordination activities, the status of major transmission projects, minimizing the environmental effects of transmission infrastructure, integrating data gathered and produced in landscape planning efforts, and next steps.³³⁹ While the chapter concludes with recommendations, planning is ongoing on several fronts, which will continue beyond the current IEPR cycle.

The IEPR Lead Commissioner and Siting Lead Commissioner conducted a public workshop with the Governor's Office of Planning and Research on May 24, 2017, in support of this strategic transmission planning. The main topics covered were policy perspectives, projects using interactive data platforms to support collaborative planning, and maximizing existing transmission through advanced technologies and targeted resources. The information presented in this chapter draws on workshop materials, as well as written and oral comments, as appropriate.³⁴⁰

economic reasons defined by the appropriate licensing agency; and 4) where there is a need to construct additional transmission capacity, seek agreement among all interested utilities on the efficient use of that capacity.

338 <http://www.energy.ca.gov/2009publications/CEC-700-2009-011/CEC-700-2009-011-CMF.PDF>.

339 As described below in the section titled "Emerging Issues," expanding interest in, and experience with, retail choice providers is shaping the size, location, technology type, control, and ownership of electricity generation, storage, and demand response. Community choice aggregation (CCA) is a state program that allows cities and counties to partner with their investor-owned utility (IOU) and become the default electricity supplier. Like any other load-serving entity (LSE), a CCA schedules load and supply through the California ISO day-ahead and real-time markets. See Chapter 1 for more information on CCA trends.

340 The transcripts, WebEx recording, and docketed comments for the May 24, 2017, IEPR Workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies are available at http://www.energy.ca.gov/2017_energypolicy/documents/#05242017.

In addition, the record of several related Energy Commission workshops have been considered in developing this chapter, including:

- April 6, 2017, staff workshop on Environmental Planning Case Studies (Docket Number 17-MISC-03).
- May 12, 2017, IEPR joint agency workshop on the Increasing Need for Flexibility in the Electricity System.
- August 2, 2017, IEPR staff workshop on Environmental Information for Energy Planning.
- Various staff workshops, forums, and webinars for Offshore Wind Energy Planning (Docket Number 17-MISC-01).

Transmission Needed to Support the State’s Clean Energy and GHG Reduction Goals

As noted above, additional transmission or restructuring of the transmission system may be needed to achieve the state’s clean energy goals and reduce GHG emissions by 40 percent from 1990 levels by 2030.

Status of Major Transmission Projects

The California ISO and other entities have identified and approved many transmission projects to meet reliability requirements, provide economic benefits, and support recent policy goals, including the RPS mandate of 33 percent renewable energy by 2020. The *California ISO 2016–2017 Transmission Plan* lists 177 previously approved transmission lines, new substations, reconductoring projects, and other upgrades. The California ISO’s *2015–2016 and 2016–2017 Transmission Plans* determined that projects identified and approved in the previous plans are sufficient to meet California’s 33 percent RPS within the California ISO footprint. Future California ISO planning cycles will focus on moving beyond the 33 percent RPS framework.

The Energy Commission provides annual updates on transmission expansion for delivering renewable energy.³⁴¹ The May 24, 2017, update summarizes 21 major transmission projects approved by the California ISO and other balancing authorities due to the potential of these projects to expand the state’s capabilities to integrate and deliver renewable energy or to provide other critical grid reinforcements, as shown in Table 12 and Figure 29. Material changes in expected grid conditions, such as evolving load growth trends, or cancellations of generation projects, can subsequently force the postponement or cancellation of transmission projects. For more information on the status of the projects shown in Table 12 and Figure 29, see Appendix F.

³⁴¹ For more information, see http://www.energy.ca.gov/renewables/tracking_progress/#transmission.

Table 12: Status of California Transmission Projects to Integrate Renewable Energy

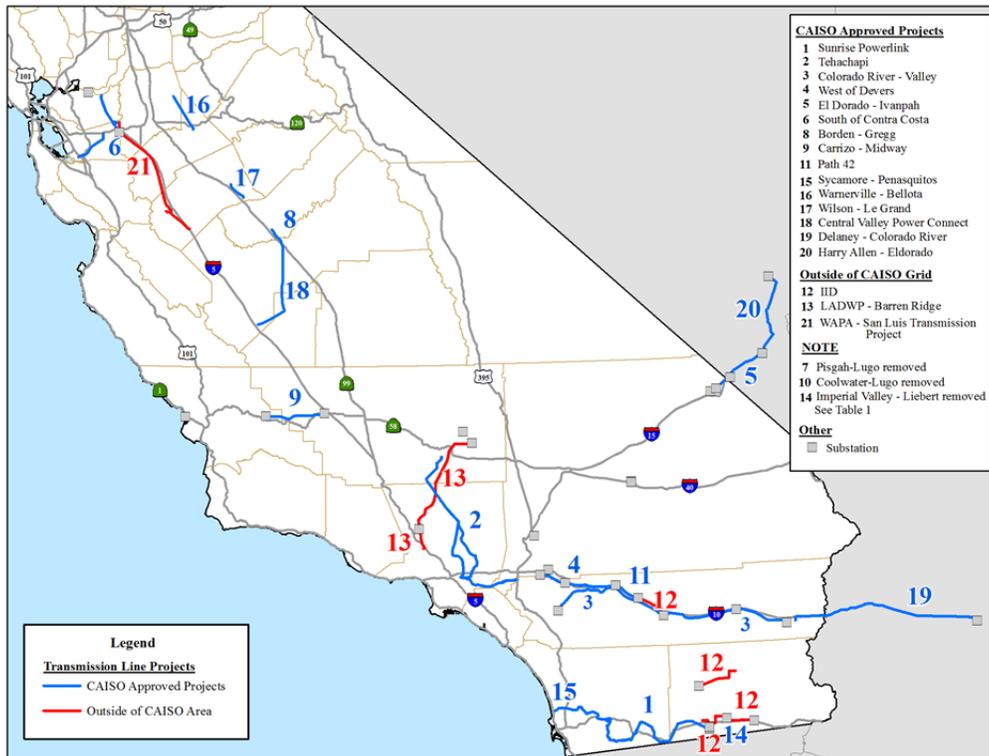
Transmission Project	California ISO Status ³⁴²	CPUC or Lead Agency Permit Status	Construction Status	Actual or Expected In-service Date
1 – Sunrise Powerlink 500 kV Line	Approved	CPCN Approved	Operational	2012
2 – Tehachapi 500 kV Line	Approved	CPCN Approved	Operational	2016
3 – Colorado River-Valley 500 kV Line	Approved	CPCN and PTC Approved	Operational	2013
4 – West of Devers 230 kV Reconductoring	LGIA	CPCN Approved	Engineering/Design	2021
5 – Eldorado-Ivanpah 230 kV Line	LGIA	CPCN Approved	Operational	2013
6 – South of Contra Costa 230 kV Reconductoring	LGIA	CPCN Approved	On Hold	
7 – Pisgah-Lugo 500 kV Line	SCE's Pisgah-Lugo project was identified by the California ISO as being needed for the interconnection of the 850 MW K Road Calico Solar Project. On June 20, 2013, K Road, LLC filed a request with the Energy Commission to terminate the Calico Solar Project. As a result, the Pisgah-Lugo project is not moving forward.			
8 – Borden-Gregg 230 kV Reconductoring	LGIA	NOC/CPCN TBD	On Hold	
9 – Carrizo-Midway 230 kV Reconductoring	LGIA	NOC Approved	Operational	2013
10 – Coolwater-Lugo 230 kV Line	Significant material changes in grid conditions on SCE's application for a CPCN for the Coolwater-Lugo project necessitated withdrawal of this project. On May 21, 2015, the CPUC Commissioners approved the ALJ proposed decision and closed SCE's application.			
11 – Path 42 230 kV Reconductoring	Approved Policy Project	N/A	Operational	2016
12 – IID: Path 42 230 kV Reconductoring and additional upgrades (outside CAISO grid)	N/A	IID/SCE/BLM Joint Final Mitigated Negative Declaration Adopted	Construction suspended	
13 – LADWP: Barren Ridge 230 kV Line (outside CAISO grid)	N/A	LADWP/US Forest Service. BLM Joint Final EIR/EIS Adopted	Operational	2016
14 – Imperial Valley-Liebert 230 kV Line	California ISO selected Imperial Irrigation District (IID) as project sponsor. On July 8, 2014, the IID Board of Directors adopted the final mitigated negative declaration. The California ISO received notice from IID on November 24, 2015, exercising its right to terminate the approved project sponsor agreement. As the project depended on IID's participation, the project has been cancelled.			
15 – Sycamore-Penasquitos 230 kV Line	Approved Policy Project with Reliability Benefits	CPCN Approved	Planning/Design	2018
16 – Warnerville-Bellota 230 kV Reconductoring	Approved Policy Project	NOC Approved	Engineering/Design	2022

³⁴² In 2012, the Federal Energy Regulatory Commission (FERC) approved the California ISO's revised generator interconnection procedures known as the Generator Interconnection and Deliverability Allocation Procedures (GIDAP). Before the GIDAP, both the Generator Interconnection Procedures and the TPP identified large-scale network upgrades. With FERC's approval of the GIDAP, the TPP is now the primary vehicle for identifying the large-scale network upgrades associated with the interconnection of renewable generation necessary to achieve the RPS. The Large Generator Interconnection Agreement (LGIA) projects were approved by the California ISO through the Generator Interconnection Procedures prior to the GIDAP.

Transmission Project	California ISO Status ³⁴²	CPUC or Lead Agency Permit Status	Construction Status	Actual or Expected In-service Date
17 – Wilson-Le Grand 115 kV Reconductoring	Approved Policy Project	NOC Approved	Engineering/Design	2020
18 – Central Valley Power Connect (formerly Gates-Gregg 230 kV Line)	Approved Reliability Project with Policy Benefits	Continued CAISO Study	On Hold	
19 – Ten West Link 500 kV Transmission Line Project (Delaney-Colorado River 500 kV Line)	Approved Economic Project with Reliability and Policy Benefits	CPCN Filed	Competitive Solicitation Process	2020
20 – Harry Allen-Eldorado 500 kV Line	Approved Economic Project with Reliability and Policy Benefits	N/A (lines is located entirely in Nevada)	Competitive Solicitation Process	2020
21 – San Luis Transmission Project	N/A	Western Area Power Administration/San Luis & Delta-Mendota Water Authority Joint Final EIS/EIR Adopted	Engineering/Design	2022

Source: California Energy Commission, May 2017, Transmission Expansion for Delivering Renewable Energy, http://www.energy.ca.gov/renewables/tracking_progress/documents/transmission_expansion_projects.pdf.

Figure 29: Map of Approved Transmission Projects in California to Help Integrate Renewable Energy



Source: California Energy Commission – Siting, Transmission and Environmental Protection Division, Cartography Unit

As discussed in Chapters 1 and 2, SB 350 requires large publicly owned utilities (POUs) to file IRPs with the Energy Commission and load-serving entities to file IRPs with the CPUC by January 2019. Through their IRPs, filing entities will demonstrate how they plan to meet the electricity sector’s share of the 2030 GHG reduction target and other goals, including achieving 50 percent RPS and ensuring reliability. Going forward, the information developed in the IRPs will be used in transmission planning.

Update on Multistate Transmission Project Proposals

The *2015 IEPR* covered five proposed major multistate transmission projects that are in various stages of permitting and could be on-line in the early 2020s.³⁴³ Since that time, as part of the RETI 2.0 process, the Western Interstate Energy Board (WIEB) identified 12 proposed transmission projects (including those discussed in the *2015 IEPR*) that could deliver high-quality renewable resources to California and provide other benefits such as relieving congestion and

³⁴³ The five projects are the Centennial West Clean Line Transmission Project, the Southwest Intertie Project, the SunZia Transmission Project, the TransWest Express Transmission Project, and the Zephyr Power Transmission Project. See pp. 95–97 of the *2015 IEPR*, available at http://www.energy.ca.gov/2015_energypolicy/index.html.

enhancing reliability. The status of these projects is included in the *RETI 2.0 Western Outreach Project Report*.³⁴⁴ See also Appendix F for more information.

Congestion on Major Paths

Consistent with Senate Bill 1565 (Bowen, Chapter 692, Statutes of 2004) mandates, previous *IEPRs* have addressed congestion³⁴⁵ on major transmission paths³⁴⁶ identified by the California ISO. However, recent analyses have not identified sufficient congestion within or into the California ISO to justify new transmission upgrades. The historical analysis of congestion in the California ISO *Annual Report on Market Issues & Performance* found that “the frequency and impact of congestion was higher in 2016 than 2015 on most major interties connecting the ISO with other balancing authority areas, particularly for interties connecting the ISO to the Pacific Northwest and Palo Verde.”³⁴⁷ The California ISO *2016–2017 Transmission Plan* forecast congestion within and into California for 2026, including only renewable generation needed to meet the 33 percent RPS requirement. The California ISO found, “The congestions are not significant for justifying an upgrade, based on either the studies in previous planning cycles or engineering judgment.”³⁴⁸

In the *2016–2017 Transmission Plan*, the California ISO looked closely at congestion on the California-Oregon Intertie and ties between the California ISO and the Imperial Valley. The study found increased California-Oregon Intertie congestion relative to other studies but not enough to justify upgrades. For the Imperial Valley, the study did not identify significant congestion. For both the California-Oregon Intertie and the Imperial Valley, the *2016–2017 Transmission Plan* recommended further study with the applications of modeling enhancements.³⁴⁹

Existing forecasts by the California ISO have relied largely on resource portfolios developed to meet 33 percent RPS targets primarily under “full capacity deliverability status” interconnection

344 Published in October 2016 and available at http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf.

345 The term “congestion” refers to situations where transmission constraints reduce transmission flows or throughput below levels desired by market participants or government policy (for example, to comply with reliability rules). A high degree or level of transmission system utilization alone does not necessarily mean congestion is occurring. Congestion can arise only when there is a desire to increase throughput across a transmission path, but such higher utilization is thwarted by one or more constraints. Transmission congestion has costs—they may induce higher costs for consumers on the downstream side of the transmission constraint if the consumers’ electricity supplier(s) must rely on higher-cost generation sources, and they may make it more difficult to achieve policy goals such as increased reliance on renewable generation resources. Transmission congestion may also cause reliability problems, where such constraints affect operations by limiting access to reserves.

346 The major WECC transmission paths that are within or tie into California are shown in Figure 103 in Appendix F (Status of Major California and Western Transmission Projects).

347 California ISO, *2016 Annual Report on Market Issues & Performance*, May 2017, p. 177, http://www.caiso.com/Documents/May9_2017_DMM_2016_AnnualReport_MarketIssues_Performance_ZZ17-4.pdf.

348 California ISO, *2016–2017 Transmission Plan*, March 2017, p. 180, http://www.caiso.com/Documents/Board-Approved_2016–2017TransmissionPlan.pdf.

349 *Ibid.*, p. 195.

assumptions. Potential congestion issues related to a 50 percent RPS target have not been fully explored, and “energy-only” interconnection assumptions will factor in those analyses.³⁵⁰

Similar to the situation in California, system loads for the Western Electricity Coordinating Council (WECC) have largely been trending flat to downward on a year-over-year basis, planning reserve margins have been ample, and transmission investment over the past five years has been steady. Generally, when system fundamentals align in this way, the effects of congestion on the system are low. Confirming this expectation, the WECC identifies only four monitored paths with flows at or above 75 percent of the path operating limit for more than 20 percent of the time in 2016.³⁵¹

Peak Reliability (Peak)³⁵² provides reliability services for the vast majority of balancing authority areas in the Western Interconnection and helps drive efficient use of the bulk power system by using state-of-the-art tools and implementing cutting-edge standards and modernization revisions. On June 27, 2017, the Peak-Enhanced Curtailment Calculator ended a parallel operations phase with the retiring WECC Web SAS tool and became the sole analytical tool for managing unscheduled flow on WECC-qualified paths per the unscheduled flow mitigation plan. The calculator uses near real-time inputs from Peak’s supervisory control, data acquisition, and state estimator systems to identify sources of flows contributing to system operating limit exceedance³⁵³ in support of more effective and efficient operation of the Western Interconnection bulk electric system.

In April 2017, Peak deployed a modified system operating limit method to align Western Interconnection procedures with North American Electric Reliability Corporation (NERC) Reliability Standards, which had a compliance date of April 1, 2017. Previous system operating limits were static and established far in advance of the operating horizon. The new standards effectively establish dynamic calculation of system operating limits much closer to real-time operations and allow significant improvements in the operational efficiency of the Western Interconnection. As noted in Chapter 3, the Energy Commission supports operational and system improvements, as well as intrahour scheduling and continued market development, as important ways to increase transfer capability and provide greater coordination between California and the rest of the West.

350 To date, most contracts for renewable energy have required full deliverability of renewable resources during peak conditions. This contractual requirement, which is a prerequisite for obtaining resource adequacy credit, has resulted in costly transmission projects that may result in little or no additional renewable energy being delivered into the system. Many interconnected generators are able to deliver full output most of the time, even without additional network upgrades beyond those required for interconnection. As renewable generation requirements grow, California energy agencies are exploring the value of “energy-only” renewable resources contracts instead of requiring full deliverability. This option has the potential to lower costs and increase the potential for renewable energy generation in many areas.

351 <https://www.wecc.biz/epubs/StateOfTheInterconnection/Pages/Transmission/WECC-Paths.aspx>.

352 Peak Reliability (Peak) was formed as a result of the bifurcation of the WECC into a regional entity (the role served by WECC) and a reliability coordinator (the role served by Peak). The bifurcation of WECC received final approval from the FERC on February 12, 2014. As the reliability coordinator (RC), Peak provides reliability services for the vast majority of balancing authority areas in the Western Interconnection, except Alberta, Canada. For more information, see Appendix E and <https://www.peakrc.com/whatwedo/Pages/default.aspx>.

353 WECC defines the SOL as the maximum flow possible on the path that ensures reliable operations. Thermal, voltage, or stability criteria performance may be impacted if flow exceeds the prevailing path SOL. See <https://www.wecc.biz/epubs/StateOfTheInterconnection/Pages/Transmission/SOL-Exceedance.aspx>.

Opportunities to Support the State’s Clean Energy and GHG Reduction Goals Through Efficient Use of Existing Transmission Grid

California’s renewable energy and GHG reduction goals have driven development of significant amounts of utility-scale renewables in the last decade. Unlike most conventional generation, utility-scale renewable energy projects are often far from load centers and, without transmission upgrades, may trigger congestion on the transmission grid. By following the Garamendi Principles and looking for opportunities to maximize the efficiency of the existing transmission grid before expanding it, energy planners and decision makers can minimize environmental effects associated with construction of additional transmission capacity, expansion of existing rights-of-way, or creation of new rights-of-way. This section identifies three opportunities for maximizing the efficient use of the existing transmission grid: use of advanced transmission technologies, application of transmission “right-sizing,” and increased regional coordination.³⁵⁴

Advanced Transmission Technologies

Flow controllers and advanced conductors are among the advanced transmission technologies that present an opportunity for making efficient use of the existing grid. Both solutions have the potential to increase transmission capacity in existing rights-of-way.

Flow controllers, or distributed series reactors (DSRs), are devices that can be deployed directly onto existing transmission line conductors to route power around transmission constraints by “pushing” and “pulling” power from overloaded lines and onto underused lines. The result is additional transmission capacity on existing transmission paths and increased use of the existing system and rights-of-way without changing out the existing conductor or transmission tower structures. In 2016 Pacific Gas and Electric Company’s (PG&E’s) Electric Program Investment Charge project 1.09C report³⁵⁵ demonstrated the safe and effective operation of DSRs on PG&E’s transmission system to reduce line flow. The project installed 90 DSRs and associated communication and control equipment on PG&E’s Las Positas-Newark 230 kilovolt (kV) line. PG&E reports that the project demonstrated that DSRs can reduce line flow and could be used to reduce transmission congestion. PG&E noted two other findings. First, a proposed line needs to have sufficient conductor and tower strength capable of supporting the DSR devices. Second, many hundreds of units would be required to mitigate any sizable line overload. Nevertheless, PG&E concluded that use of DSRs would be significantly less costly than a traditional transmission upgrade to increase capacity in most scenarios.

In 2017 the California ISO considered the Mission-Old Town flow control upgrade project, which would have installed flow controllers on San Diego Gas & Electric’s (SDG&E) Mission-Old Town

³⁵⁴ Two of these three opportunities—use of advanced transmission technologies and application of transmission right-sizing—were addressed during a panel discussion at the May 24, 2017, IEPR workshop on strategic transmission planning.

³⁵⁵ PG&E, *EPIC 1.09C – Test New Remote Monitoring and Control Systems for T&D Assets, Discrete Series Reactors*, December 2016, https://www.pge.com/pge_global/common/pdfs/about-pge/environment/what-we-are-doing/electric-programinvestment-charge/PGE-EPIC-Project-1.09C.pdf.

and Mission-Old Town Tap 230 kV lines.³⁵⁶ The Mission-Old Town flow control upgrade project would have partially mitigated contingency thermal overloading concerns for the summer of 2018 in the event of delays to other transmission projects under construction. According to a California ISO market notice, it ultimately determined not to grant approval of the project because SDG&E subsequently identified potential engineering and permitting challenges, questioning the ability of the project to meet the June 1, 2018, target in-service date and avoid other schedule effects on transmission projects in the area.³⁵⁷

Reconductoring an existing transmission line with advanced conductors is another way to increase the transmission capacity of the existing grid and reduce line losses. Reconductoring a transmission line involves replacing the existing conductors with newer designs with better design features or increased current carrying capacity or both. Advanced conductors available today tend to be “high-temperature, low-sag” meaning that they have higher ampacity³⁵⁸ without violating sag clearance requirements. Lower sag can equate to less need for new towers. Conventional conductors consist of outer aluminum conductor strands wrapped around a steel-reinforced core. In contrast, advanced conductors typically consist of outer aluminum conductor strands wrapped around a composite core that is lighter weight than the traditional steel core. This enables additional aluminum conductor strands to be wrapped around the core without increasing the total weight. These higher-capacity conductors can be used to reduce congestion where transmission towers cannot easily or cost-effectively be replaced.

Several California utilities have used advanced conductors to increase line capacity in existing rights-of-way. For example, Southern California Edison reconducted its Rector-Vestal and Magunden-Vestal 200 kV lines using high-temperature, low-sag conductors, and the Sacramento Municipal Utility District (SMUD) reconducted some of its transmission lines with advanced conductors. SMUD has observed that there are cases where reconductoring with advanced conductors is less likely to be cost-effective. Much of SMUD’s system uses all-aluminum conductors with lighter support structures, and these structures would need to be replaced to use advanced conductors.³⁵⁹ Thus, there are limitations to applying advanced conductors.

In addition to flow controllers and advanced conductors, the conversion of alternating current transmission lines to direct current holds the potential for increasing the transfer capability of the existing transmission grid. SDG&E submitted such a project as a proposed interregional transmission project to the California ISO, Northern Tier Transmission Group, and WestConnect in early 2016.³⁶⁰ This alternating current to direct current conversion project proposes to convert

356 California ISO, “Pacific DC Intertie Upgrade and Mission-Old Town Flow Control Upgrade,” April 2017, http://www.caiso.com/Documents/Agenda_Presentation_Mission-OldTown_PacificDCIntertieUpgradeProjects.pdf.

357 California ISO, Market Notice titled “Mission-Old Town and Pacific DC Intertie Upgrade Projects Update,” May 23, 2017, http://www.caiso.com/Documents/Mission-OldTown_PacificDCIntertieUpgradeProjectsUpdate.html.

358 *Ampacity* is the maximum amount of electric current a conductor or device can carry before immediate or progressive deterioration.

359 May 24, 2017, IEPR workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-13/TN217924_20170607T144655_Transcript_of_05242017_IEPR_Lead_Commissioner_Workshop_on_Strat.pdf, pp. 135–135.

360 The relevant planning regions for this particular project are the California ISO and WestConnect.

a portion of the existing 500 kV Southwest Powerlink to a multiterminal, multipolar high-voltage direct current (HVDC) system with terminals at the North Gila and Imperial Valley 500 kV substations and the Miguel 230 kV substation. SDG&E reports that this HVDC conversion project may increase the San Diego import capability by 500 to 1,000 MW or more.

Transmission Right-Sizing

A second opportunity for maximizing the efficiency of the existing transmission grid is through transmission right-sizing. Where appropriate, right-sized transmission projects can reduce future costs and environmental impacts and make efficient use of existing (and new) rights-of-way. Existing transmission rights-of-way are not only highly valuable assets, but should be viewed as a scarce resource that should be managed as efficiently as possible in meeting state climate change and energy goals as new transmission rights-of-way are extremely difficult to site. Right sizing is also receiving growing consideration given the forecast uncertainties created by such emerging trends as the significant growth of community choice aggregation and the shift to DER in California.

When the concept of transmission right-sizing was first described in the *2011 IEPR*, and brought up again by stakeholders in the *2014 IEPR Update*,³⁶¹ *right-sizing* or “upsizing” referred to building transmission lines that have greater capacity than needed over the short-term planning period (10 years) to accommodate longer-term electricity growth or connect new generation development for the future or both. Allowing projects to be upsized beyond current needs could also maximize the value of land associated with already necessary transmission investment and avoid future costlier upgrades to accommodate future need and development.

In the *2015 IEPR*,³⁶² the concept of right-sizing was expanded beyond 10 years to see if needed projects should initially be built larger or built such that they can easily be made larger in the future. Thus, right-sizing evolved to include designing future flexibility into transmission projects so they can be scalable or upgradable in the future. The *2015 IEPR* recommended that the state develop a set of right-sizing policies through the *2016 IEPR Update* process.

As part of the *2016 IEPR Update*, the *2016 Environmental Performance Report of California's Electrical Generation System*³⁶³ (*2016 EPR*) noted that a good right-sizing policy would essentially expand the analysis of large transmission facilities and look beyond a 10-year planning horizon to determine whether a proposed transmission line or project should be sized larger to meet needs more than 10 years out. The *2016 EPR* cautioned that a blanket extension of the California ISO's transmission plan beyond the current 10 years is likely not reasonable because transmission planning requires location-specific load and resource forecasts that are less accurate

³⁶¹ California Energy Commission, *2014 IEPR Update*, February 2015, <http://www.energy.ca.gov/2014publications/CEC-100-2014-001/CEC-100-2014-001-CMF.pdf>.

³⁶² California Energy Commission, *2015 IEPR*, February 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-01/TN212018_20160629T154356_2015_Integrated_Energy_Policy_Report_Full_File_Size.pdf.

³⁶³ Bartridge, Jim, Melissa Jones, Eli Harland, Judy Grau. October 2016. *Final 2016 Environmental Performance Report of California's Electrical Generation System*, California Energy Commission. Publication Number: CEC-700-2016-005-SF. http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-03/TN214098_20161018T145845_Staff_Report_Final_2016_Environmental_Performance_Report_of_Cal.pdf.

as the planning horizon is extended. There is an inherent tension between promoting right-sizing through a transmission planning horizon longer than 10 years and the forecast uncertainties that may result in an unnecessary right-sizing recommendation.

To avoid spending resources on studies with uncertain outcomes, the *2016 EPR* suggested that right-sizing analyses should be limited to large transmission projects found needed in the 10-year transmission plan to see if there could be a need for a larger project. It further suggests establishing a reasonable size threshold of 200 kV and above or 115 kV and above in constrained areas for the longer-term analysis to ensure the state's longer-term transmission needs are being met without overburdening the transmission planning agencies.

A right-sizing policy could also be applied through the alternatives analysis of the environmental review of a proposed project or the CPUC's certificate of public convenience and necessity process. This would require project objectives to be defined in a manner that they include transmission needs beyond 10 years.

In the case of either right-sizing through transmission planning or permitting review of expanded alternatives, right-sizing options would be limited to changes in the specific transmission project that either enlarge the proposed project or build in an option to easily enlarge the project later.

California has already used the concept of transmission right-sizing extensively in Southern California Edison's Tehachapi Renewable Transmission Project and PG&E's Gates-Gregg 230 kV line. These projects included the construction of 230 kV double-circuit towers strung initially with only one circuit and, in the case of the Tehachapi Renewable Transmission Project, the construction of towers built to 500 kV specifications but initially energized at 220 kV.

Regional Coordination

A third opportunity for maximizing the efficiency of the existing transmission grid is through increased regional coordination. The Western EIM and the proposed development of a regional, westwide electricity market are examples of regional coordination. Both are opportunities to use the existing transmission grid more efficiently and are discussed more broadly in Chapter 3.

The state also continues to coordinate with federal agencies on planning activities in the West. Section 368 of the Energy Policy Act of 2005 required the U.S. Department of Energy, the U.S. Forest Service, and the U.S. Bureau of Land Management (BLM), in cooperation with the Departments of Agriculture, Commerce, Defense, and Interior, to designate new right-of-way corridors on western federal lands for electricity transmission, distribution facilities, and oil, gas, and hydrogen pipelines.

In May 2016, the U.S. Department of Energy, U.S. Forest Service, and the BLM (the federal agencies) released the Section 368 Corridor Study.³⁶⁴ The Section 368 Corridor Study reviewed 6,000 miles of designated Section 368 energy corridors on federal land in 11 western states to understand whether they promoted environmentally responsible siting decisions and reduced the

³⁶⁴ Argonne National Laboratory, *Section 368 Corridor Study*, May 2016, http://corridoreis.anl.gov/documents/docs/Section_368_Corridor_Study.pdf.

need for new rights-of-way on federal lands. The Section 368 Corridor Study also evaluated how each corridor was used, the types and the number of projects within them, and identified areas for further study.

In September 2016, the federal agencies began a regional corridor process seeking stakeholder review and comment.³⁶⁵ Beginning with Region 1, which encompasses Western Arizona, Southern Nevada, and Southern California, the federal agencies developed corridor abstracts that identified high-level environmental, land-use, and permitting issues associated with each of the 26 corridors in Region 1.³⁶⁶ As part of the review, the federal agencies provided accessible geospatial data and information for the designated energy corridors.³⁶⁷

In late October 2016, the Energy Commission submitted a letter recommending BLM consider county land-use data and rules as it evaluates 368 corridors.³⁶⁸ The letter further recommended that BLM maintain Section 368 corridors near designated focus areas in the *Desert Renewable Energy Conservation Plan (DRECP)* as those corridors are important to reliably meeting California's energy needs and GHG reduction goals.

The Energy Commission will continue to work closely with the federal agencies in evaluating Section 368 corridors and coordinate state and federal planning efforts to ensure that environmental and land-use issues associated with transmission corridors are appropriately considered and evaluated for potential designation by the Energy Commission. This work could create opportunities to connect federal and state transmission corridors in areas with high renewable energy potential, where future transmission may be necessary.

Landscape-Scale Planning to Reduce GHG Emissions

The dramatic growth of renewable energy projects throughout California over the last decade has helped reduce GHG emissions and improve the environmental performance of the state's electric generation system. As California considers stronger renewable energy goals to meet its GHG reduction goals, landscape-scale planning can help simplify development while reducing adverse effects. Landscape-scale planning for renewable energy and transmission is a proactive approach to identifying opportunities and minimizing potential development impacts when development occurs. It does not determine the need for future renewable energy or transmission.

Landscape-scale planning considers a wide range of potential constraints and conflicts when assessing the most appropriate areas for development and conservation, including, but not limited to, environmental sensitivity, conservation and other land uses, tribal cultural resources, and stakeholder concerns. In a letter to the California ISO initiating the RETI 2.0 process, Energy Commission Chair Robert B. Weisenmiller and CPUC President Michael Picker noted that there is proven value in using science-driven findings and broad consensus planning to assess the relative

³⁶⁵ See <http://corridoreis.anl.gov/>.

³⁶⁶ These abstracts are available at <http://corridoreis.anl.gov/regional-reviews/>.

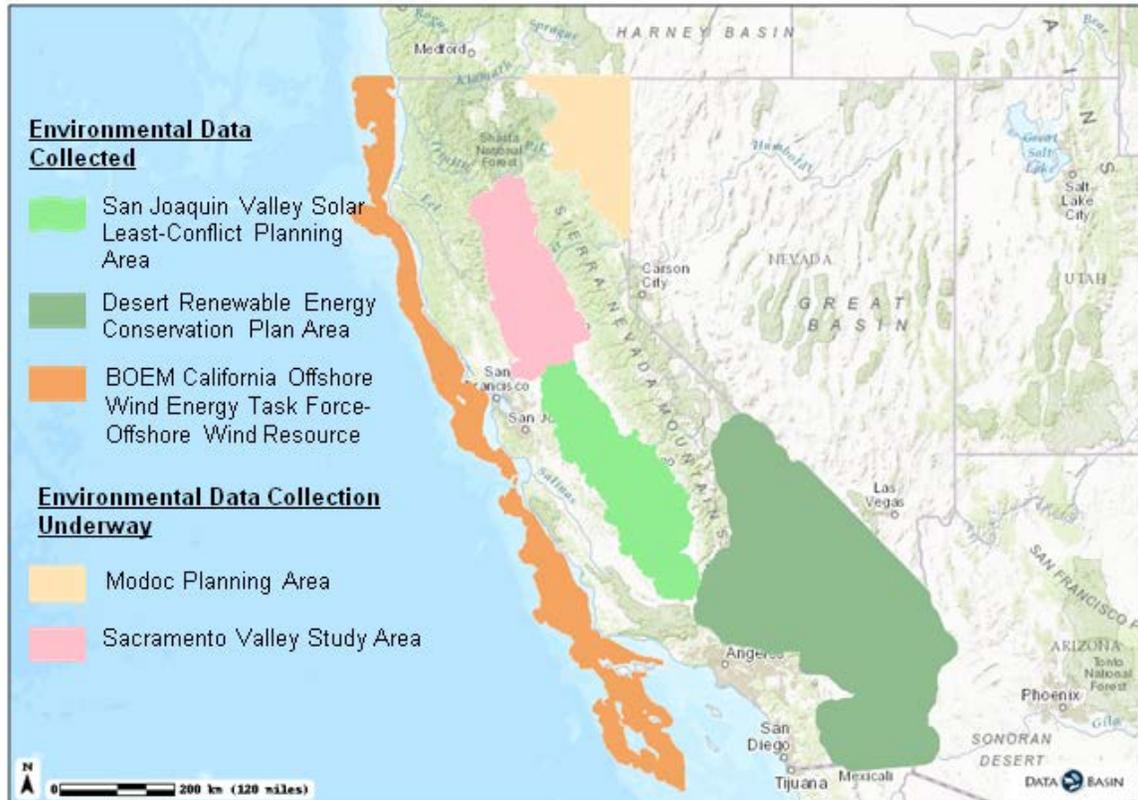
³⁶⁷ <https://bogi.evs.anl.gov/section368/portal>.

³⁶⁸ California Energy Commission, letter from Chair Robert B. Weisenmiller to Stephen Fusilier (BLM Washington Office), *Comments on Region 1 Review of Section 368 Energy Corridors*, October 24, 2016.

potential of different locations for renewable energy, especially in the context of identifying policy-driven transmission lines.

California has engaged in landscape planning for energy and natural resource conservation in multiple geographic areas of the state, as shown in Figure 30. Previous energy landscape-scale planning processes are discussed below.

Figure 30: Areas of Data Collection for Statewide Energy Planning



Source: California Energy Commission. Map information is on Data Basin at: <https://databasin.org/maps/5d75770fa6884b9caf226dcd4478a634>.

RETI 2.0

In September 2015, the California Natural Resources Agency, Energy Commission, CPUC, California ISO, and the U.S. BLM California Office initiated RETI 2.0. RETI 2.0 was a proactive, statewide, non-regulatory planning forum intended to identify constraints and opportunities for new transmission, both within and outside the state, to access and integrate new renewable energy resources and help meet California’s goals. As noted by Energy Commission Chair Weisenmiller, California is “pursuing an integrated strategy, and looking ahead at least 15 years to make sure we’re doing the right things now to develop the options we’ll need then. The RETI 2.0 process is helping the state’s energy agencies, utilities, renewable industry, and residents narrow down our focus on where we might need new transmission.”³⁶⁹

³⁶⁹ California Energy Commission, News Release dated December 16, 2016, “Expanding Transmission to Access Renewables May be Key to Reach State Mandates,” http://www.energy.ca.gov/releases/2016_releases/2016-12-16_RETI_expanding_transmission_reach_state_mandates.pdf.

RETI 2.0 incorporated and built off science, data, and analyses from state landscape planning efforts to better inform stakeholders and decision makers of the potential environmental implications of new energy infrastructure. The final RETI 2.0 report,³⁷⁰ published in February 2017 summarized the high-level environmental and land-use information, identified potential transmission constraints, and offered conceptual solutions throughout California. A subset of recommendations includes the following:

- Develop and study scenarios of future renewable resource procurement that focused on using the existing capacity of the current transmission system.
- Include local land-use information in planning efforts and provide counties tools to assist in planning, decision making, and outreach.
- Continue to identify data gaps, gather data, and update data.
- Assemble existing data sets in useful ways to assess areas for potential environmental implications at a landscape-scale level. By consistently applying existing statewide and regional data sets, the state can improve analysis of the conservation value, landscape intactness, and presence of habitat connectivity in areas throughout the state.
- Complete the interactive environmental report writer tool that could be used in future energy planning to identify and evaluate locations to site renewable energy generation and transmission, as well the environmental context of that location.
- Engage in frequent and meaningful consultation with tribal entities and apprise Native American tribes of existing mechanisms and opportunities for engagement.

As discussed during the May 24, 2017, IEPR workshop, using analytical tools to evaluate complex data is a valuable way for stakeholders and decision makers to collaborate and better understand the environmental implications associated with new renewable energy and transmission infrastructure.³⁷¹

Moving forward, the state is building upon the RETI 2.0 process by integrating the data and best-available science gathered from the different landscape planning efforts, including the *DRECP*, San Joaquin Valley Least Conflict Planning, Modoc Planning Effort, and Sacramento Valley Study, into a single, publicly-accessible, California Energy Gateway.³⁷² The California Energy Gateway is an online, interactive platform that can support state and local planning by offering

370 California Natural Resources Agency, *Renewable Energy Transmission Initiative 2.0 Plenary Report*, February 2017, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN216198_20170223T095548_RETI_20_Final_Plenary_Report.pdf.

371 May 24, 2017, IEPR workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-13/TN217924_20170607T144655_Transcript_of_05242017_IEPR_Lead_Commissioner_Workshop_on_Strat.pdf, pp. 28–33.

372 On April 6, 2017, Energy Commission staff presented a draft California Energy Gateway at the Staff Workshop on Environmental Information for Energy Planning. Documents for that workshop can be found at http://energy.ca.gov/renewables/enviro_info-energy_planning/documents/.

increased transparency and enabling users to collaborate through assembling, displaying, integrating, analyzing, and sharing data.

San Joaquin Valley Least Conflict for Solar PV

The San Joaquin Valley is an important agricultural production area for California and the world, and home to many threatened species and habitats. The San Joaquin Valley's abundant sunshine also attracts solar development, and many solar projects have been built in the valley. Given this, the Governor's Office of Planning and Research (OPR) launched a stakeholder-driven, nonregulatory planning process in June 2015 to identify and recommend least-conflict areas for solar PV development.

As described in *A Path Forward: Identifying Least-Conflict Solar PV Development in California's San Joaquin Valley*, a San Joaquin Valley Gateway was established to gather data and simplify the sharing of information. The stakeholder groups identified more than 471,000 acres of least-conflict lands within the 9.5 million-acre planning area. This information was shared with the tribes, and of the 471,000 least-conflict solar PV development areas identified, 213,000 acres avoid known tribal resource concerns, and several cultural resource management recommendations are contained in the final report.

Desert Renewable Energy Conservation Plan

The *DRECP* is a landscape-scale plan that identifies the most appropriate locations in the California desert for renewable energy development while providing effective protection and conservation of desert ecosystems. The lead agencies for developing the plan included the BLM, U.S. Fish and Wildlife Service, California Department of Fish and Wildlife, and the Energy Commission. The *DRECP* was completed in September 2016 as a BLM Land Use Plan Amendment on 10.8 million acres of public lands managed by the BLM. The Land Use Plan Amendment designates about 388,000 acres of development focus areas and 4.2 million acres of new conservation areas.

During development of the *DRECP*, the lead agencies created the *DRECP* Gateway – an online, interactive platform designed to collect and share the underlying environmental data of the *DRECP*, promote collaboration between agencies and stakeholders, provide access to spatial information, upload content, connect to other data sources, develop maps identifying specific concerns that could then be shared easily, and encourage public comment.³⁷³ The *DRECP* Gateway was also used in developing composite data layers that reflect conservation values and helped determine priorities for habitat intactness and understand locations of important habitat connectivity.

Experience with the *DRECP* Gateway has encouraged and promoted collaboration among a variety of agencies and diverse stakeholders and successfully advanced landscape-scale planning for conservation and renewable development in the California desert. The Energy Commission continues to support the *DRECP* Gateway, and the applications and data it contains will remain

³⁷³ <https://drecep.databasin.org/>.

available to assist planning in California's desert regions and be integrated into the California Energy Gateway.

An important ongoing effort in the desert area is the implementation of steps to achieve the DRECP's biological conservation goals. The *California Desert Biological Conservation Framework*³⁷⁴ is a synthesis of the science and conservation planning information used to develop the DRECP, and includes a high-level analysis of how the 4.2 million acres of public conservation lands in the BLM DRECP Land Use Plan Amendment contribute to the overall biological conservation goals of the 22.5-million-acre DRECP planning area. The *California Desert Biological Conservation Framework* contains key conservation information for desert species and landscapes, provides scientific data and analysis, and outlines approaches to inform targeted conservation actions that could be used to support future conservation and land-use planning by federal, state, and local agencies in the California desert, including preparation of a regional conservation assessment (RCA) or regional conservation investment strategy (RCIS).³⁷⁵

Local Planning Efforts

Local governments have permitted many of the renewable energy projects developed on private land in California and will continue to be important partners in meeting the state's GHG reduction goals. Examples of local planning and permitting being assisted and promoted with the use of interactive data platforms and online environmental data were presented at the May 24, 2017, IEPR workshop.

Kern County

To assist with permitting for infrastructure development, provide environmental data, and engage applicants, Kern County developed an interactive Kern County Gateway to assist with permitting and compliance verification.³⁷⁶ The Kern County Gateway simplifies data review by staff, alleviates county staffing constraints by providing users accessible data and maps, enhances transparency of county actions to the public, and resolves questions on land cover data or other inconsistencies. The gateway has also been integrated with the county's permitting system and software,³⁷⁷ allowing users to generate site plans, flag mitigation measures from the EIR, and provide details on compliance.

³⁷⁴ The California Desert Biological Conservation Framework is available on the DRECP website at <http://drecp.org/documents/#conservationbio>.

³⁷⁵ There are 27 wildlife species and 10 plant species addressed by the California Desert Biological Conservation Framework as part of the biological conservation focus. These species are identified as "Covered Species" in the 2014 Draft DRECP and "Focal Species" addressed in the 2016 DRECP LUPA ROD. See section 3.3 of the Framework for more information: http://drecp.org/documents/docs/conservationbio/files/01-CA_Desert_Bio_Conservation_Framework.pdf.

³⁷⁶ May 24, 2017, IEPR workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-13/TN217924_20170607T144655_Transcript_of_05242017_IEPR_Lead_Commissioner_Workshop_on_Strat.pdf, pp. 37–38.

³⁷⁷ May 24, 2017, IEPR workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-13/TN217924_20170607T144655_Transcript_of_05242017_IEPR_Lead_Commissioner_Workshop_on_Strat.pdf, pp. 78–82.

The Kern County Gateway was also used to support an energy-permitting project environmental impact report on 2.8 million acres in Kern County and is being used to support a Valley Floor Natural Community Conservation Plan/Habitat Conservation Plan that will be fully Web-based and allow users to view available biological studies for specific properties.

Antelope Valley Regional Conservation Investment Strategy

The Regional Conservation Investment Strategy (RCIS) program discussed in the text box is being tested in the Antelope Valley, an area of Northern Los Angeles County that is facing effects from renewable energy development, transportation, housing, and climate change. Local and state agencies, environmental groups, business groups, and others are developing an Antelope Valley RCIS that will guide future actions and allow developers to design and implement projects that avoid effects to species and areas of conservation value.

Antelope Valley RCIS stakeholders are using an online platform to collaborate on conservation prioritization, data analysis, and mapping to identify core and linkage areas for species.³⁷⁸ During the May 24, 2017, IEPR workshop, panelists suggested that a similar data platform could be used in other regions of the state and by local governments to promote stakeholder collaboration to develop and implement an RCIS.³⁷⁹

³⁷⁸ May 24, 2017, IEPR workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-13/TN217924_20170607T144655_Transcript_of_05242017_IEPR_Lead_Commissioner_Workshop_on_Strat.pdf, pp. 74, 86–87.

³⁷⁹ May 24, 2017, IEPR workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-13/TN217924_20170607T144655_Transcript_of_05242017_IEPR_Lead_Commissioner_Workshop_on_Strat.pdf, pp. 57–58.

City of Lancaster

Zero Net Energy Alliance received a state Electric Program Investment Charge grant to develop innovative business models and policy frameworks that overcome adoption barriers for zero-net-energy residential communities and community-distributed energy resources in the city of Lancaster in Los Angeles County. As part of that effort, the grant is funding the development of a distributed generation (DG) screening application that can help identify environmentally preferred areas for DG and demonstrate how the spatial information, factors, and analytical approach could be applied effectively for local DG planning. The application enables users to specify desired environmental and engineering attributes, such as conservation value and available electric grid capacity, to identify areas meeting those criteria. Once the concept is tested in Lancaster, it could be expanded to other areas of California with similar underlying data.

Use of Data Platforms and Analytical Tools in Landscape-Scale Planning

The May 24, 2017, IEPR workshop included two panels that discussed the use of data platforms to guide planning: “Policy Perspectives on

Regional Conservation Framework Pilot Program

In September 2016, Governor Brown signed Assembly Bill 2087 (Levine, Chapter 455, Statutes of 2016), which created the California Department of Fish and Wildlife’s Regional Conservation Investment Strategy pilot program¹ to guide conservation of natural resources and infrastructure planning. The program encourages a voluntary, nonregulatory regional planning process intended to result in higher-quality conservation outcomes and includes an advanced mitigation tool. The program uses a science-based approach to identify conservation and enhancement opportunities that, if implemented, will help California’s declining and vulnerable species by protecting, creating, restoring, and reconnecting habitat and may contribute to species recovery and adaptation to climate change.

The program consists of three components: RCA, RCIS, and mitigation credit agreements.

- An *RCA* is a conservation assessment of important species, ecosystems, protected areas, and habitat linkages at the ecoregion scale and may include more than one ecoregion.¹
- An *RCIS* is a conservation assessment of Focal Species,¹ their associated habitats, and the conservation status of the *RCIS* land base. Conservation actions and habitat enhancements identified in an *RCIS* may be used as a basis to provide advance mitigation under a mitigation credit agreement or inform other conservation investments. An *RCA* is not required to develop an *RCIS*, and any public agency may develop an *RCIS*.
- A *mitigation credit agreement* is an agreement under an approved *RCIS* to create mitigation credits by implementing the conservation or habitat enhancement actions identified in an *RCIS*. Mitigation credits may be used as compensatory mitigation for impacts under the California Environmental Quality Act, the California Endangered Species Act, and the Lake and Streambed Alteration Program.¹

While there is a limit of eight *RCIS* that may be approved by the California Department of Fish and Wildlife before January 1, 2020, Senate Bill 103 (Committee on Budget and Fiscal Review, Chapter 95, Statutes of 2017) exempts from this cap, *RCIS* requested by a state water or transportation infrastructure agency. Senate Bill 103 also removed the January 1, 2020, sunset provision for the Regional Conservation Investment Strategy program.

Using Interactive Data Platforms to Support Collaborative Planning” and “Project Examples – Using Interactive Data Platforms to Support Collaborative Planning.”³⁸⁰ Panelists represented a range of organizations from local and state government, an electric utility, environmental organizations, and the military.³⁸¹

The panels included representatives with a diverse range of expertise and all shared general support, as well as some of the benefits of using interactive data platforms to guide planning. Moreover, panelists offered perspectives and considerations on using data platforms. Some of the more common perspectives and considerations expressed by both panels included the following:

- Consider the scale of planning processes (for example, landscape vs. site-specific).
- Platforms should be fully inclusive of existing data and planning processes.
- Ensure that data platforms are transparent, accessible, and kept current.
- Know your audience and their level of expertise and ability to collaborate.
- Identify funding mechanisms to create and maintain platforms.
- There should be interoperable functionality with other data and information, specifically with systems used by electricity planners.
- Data should be useful and well organized on data platforms.
- Group working spaces for interacting and collaborating should meet the expectations of user groups, including confidentiality.
- Consider if a data platform will eventually be used for plan implementation.
- Limitations of how data platforms can be applied to planning should be transparent.

A major focus of the May 24, 2017, IEPR workshop was exploration of California’s major landscape-scale renewable energy planning efforts and the ways in which those planning processes used interactive data platforms. As discussed earlier, the use of these platforms has led to improved collaboration with federal and state agencies, local governments, tribes, and stakeholders, as well as more robust participation by the public and greater overall transparency in each process.³⁸²

³⁸⁰ For more workshop information, visit http://energy.ca.gov/2017_energypolicy/documents/#05242017.

³⁸¹ Representatives from the following organizations participated as workshop panelists on the data platforms topic: California Energy Commission, California Department of Fish and Wildlife, California Government Operations Agency, Kern County, Southern California Edison, Defenders of Wildlife, Audubon, The Nature Conservancy, American Farmland Trust, and Department of Defense.

³⁸² May 24, 2017, IEPR workshop on Strategic Transmission Investment Planning: Interactive Data Platforms to Support Collaborative Planning and Advanced Technologies, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-13/TN217924_20170607T144655_Transcript_of_05242017_IEPR_Lead_Commissioner_Workshop_on_Strat.pdf, pp. 8-10.

Offshore Wind Planning Efforts

To help support the state's long-term GHG reduction goals, the Energy Commission held a workshop as part of the 2016 IEPR proceedings to explore the viability, potential, opportunities, and challenges of permitting renewable energy offshore California.

In a May 12, 2016, letter to Department of Interior Secretary Sally Jewell, Governor Brown requested that a federal/state government task force be formed to coordinate state and federal planning and permitting of offshore renewable energy. The Bureau of Ocean Energy Management (BOEM) California Intergovernmental Renewable Energy Task Force (California Task Force) was established as a partnership of state, local, federally-recognized tribal governments, and federal agencies to plan for potential offshore renewable energy development in federal waters offshore California. The task force is not a decision-making body but provides a forum to discuss ocean uses, issues, concerns and priorities; exchange data and information; and encourage early and continual dialogue and collaboration opportunities.

To advance the collaboration between the state and federal government, Interior Secretary Sally Jewell and Governor Brown signed an MOU on December 12, 2016, to plan for and implement GHG reduction and renewable energy goals in a cooperative, collaborative, and timely manner. The MOU establishes that the task force will “engage in planning for offshore renewable energy to advance collaborative planning and conservation through data sharing, development and utilization of common data platforms and tools, and proactive stakeholder engagement.” The MOU further specifies that BOEM and the state will “collaborate and engage in a multi-phase process to collect data to inform planning efforts and identify possible areas offshore California that are suitable for potential offshore renewable energy programs” and to use the initial data and information gathered to “identify one or more suitable areas offshore California for BOEM to issue one or more Calls for Information and Nominations regarding wind energy leasing.”

At the first task force meeting convened in October 2016, the group agreed to an outreach and engagement effort that would share information on the multiphase offshore wind planning process, gather initial input, and identify and collect data regarding potential offshore wind energy development areas. California Task Force members also identified the need for tribal outreach that included nonfederally recognized tribes. In early 2017, the state and BOEM began outreach to tribes, academics and researchers, environmental organizations, fishing interests, locally elected officials, and the public. The state also formed the State Tribal Ocean Renewable Energy Working Group to ensure that information and data was shared with, and received from, both federally and non-federally recognized tribes.

Using information gathered from federal and state agencies and during outreach efforts, a California Offshore Wind Energy Gateway was developed.³⁸³ More than 600 datasets on the California Offshore Wind Energy Gateway are informing the planning process and will be used to identify potential offshore wind energy development areas that can be discussed and refined among the task force members, tribes, and stakeholders.

³⁸³ The Offshore Wind Energy Gateway is available at <https://caoffshorewind.databasin.org/>.

Recommendations

- **Build upon the Renewable Energy Transmission Initiative (RETI) 2.0 process and create a California Energy Gateway.** The Energy Commission should continue to build upon the Renewable Energy Transmission Initiative 2.0 process by developing and refining additional analytical tools, creating a California Energy Gateway, and integrating data from previous planning efforts into it.³⁸⁴ The California Energy Gateway will host the data, applications, and information to support continued planning that will contribute to California’s greenhouse gas reduction and renewable energy goals.
- **Continue supporting landscape-scale planning efforts to further reduce GHG emissions.** The Energy Commission should continue supporting landscape-scale planning for energy and infrastructure using interactive data platforms, online environmental data, and providing technical support where appropriate.
- **Continue to explore use of landscape-scale planning tools and techniques.** The Energy Commission should continue to explore and improve the use of landscape scale planning tools and techniques with stakeholders and other agencies to that would:
 - Assess opportunities and constraints for renewable energy across landscapes in concert with local communities and in a public and data-driven process.
 - Interconnect in- and out-of-state transmission pathways identified in RETI 2.0 that would improve import and export of renewable resources.
 - Help alleviate key constraints, such as the Desert Area Constraint identified in RETI 2.0.
 - Connect renewable resource areas.
 - Connect federal Section 368 corridors.

CHAPTER 6: Electricity and Natural Gas Demand Forecast

Background

The California Energy Commission provides full forecasts for electricity and natural gas demand every two years as part of the *Integrated Energy Policy Report (IEPR)* process. The forecasts are used in various proceedings, including the California Public Utilities Commission's (CPUC's) Long-term Procurement Planning (LTPP) process and the California Independent System Operator's (California ISO's) Transmission Planning Process (TPP). The CPUC identified the *IEPR* process as "the appropriate venue for considering issues of load forecasting, resource assessment, and scenario analyses, to determine the appropriate level and ranges of resource needs for load serving entities in California."³⁸⁵ In addition, the Energy Commission provides annual year-ahead peak demand forecasts for the resource adequacy process in coordination with the California ISO and the CPUC.

The Energy Commission's full demand forecast is done biennially, in odd-numbered years. Recognizing the process alignment needs and schedules of the CPUC and California ISO planning studies, the Energy Commission provides an update to the full *IEPR* forecast in even-numbered years. The forecast includes three demand cases designed to capture a reasonable range of demand outcomes over the next 10 years. The *high energy demand* case incorporates relatively high economic/demographic growth, relatively low electricity and natural gas rates, and relatively low committed efficiency program, self-generation, and climate change impacts. The *low energy demand* case includes lower economic/demographic growth, higher assumed rates, and higher committed efficiency program and self-generation impacts. The *mid* case uses input assumptions at levels between the *high* and *low* cases.

2017 IEPR Forecast and Beyond

This year's *IEPR* process remains focused on meeting the goals outlined in the Clean Energy and Pollution Reduction Act (De León, Chapter 547, Statutes of 2015) (Senate Bill 350). Among other requirements outlined in SB 350, the California Legislature set forth the goal of doubling statewide energy efficiency savings by 2030 and establishing strategies and targets to meet that goal. As part of the *2016 Energy Demand Forecast Update*, the Energy Commission evaluated future data needs and forecast improvements to build technical capability for new assessments of statewide energy demand.³⁸⁶ This year's forecast also emphasized the doubling of energy efficiency, continued disaggregation of the forecast, climate change, zero-emission vehicles,

³⁸⁵ Peevey, Michael. September 9, 2004. *Assigned Commissioner's Ruling on Interaction Between the CPUC Long-Term Planning Process and the California Energy Commission Integrated Energy Policy Report Process*. Rulemaking 04-04-003.

³⁸⁶ Garcia, Cary and Chris Kavalec. 2017. *California Energy Demand Updated Forecast, 2017-2027*. California Energy Commission. Publication Number: CEC-200-2016-016-CMF.

photovoltaics, and the peak shift. During the *2017 IEPR* process, forecast staff continued to build upon the work performed in 2016 to enhance forecasting methods, including geographic disaggregation and development of a long-term hourly load forecast, and impacts of SB 350 on the forecast.

Improvements to Forecast Methods

The *California Energy Demand 2018–2030 Revised Forecast* (CED 2017 Revised)³⁸⁷ uses the modified geographic scheme for planning areas and climate zones introduced for *California Energy Demand 2016–2026, Revised Electricity Forecast* (CED 2015),³⁸⁸ which is closely based on California’s balancing authority areas.³⁸⁹ The model inputs were more fully integrated into the sector models in this forecast based on the new geography, rather than relying on mapping of model outputs as previously done. For example, inputs such as appliance saturations and average consumption by end use were developed for the new geographic scheme. The past two forecasts used model outputs based on the older geographic scheme and then mapped those results to the new scheme. The Energy Commission expects to have additional consumption and meter data in 2018 through a Title 20 data regulations rulemaking designed to support future forecast geographic disaggregation. Once the new regulations are in place, Energy Commission staff will work with the utilities to determine the disaggregation level that best serves transmission- and distribution-level analyses.

Community choice aggregators (CCAs) are expected to play an increasingly important role in California’s energy future. This forecast includes projections for 12 CCAs currently operating. More CCAs are expected and a fuller snapshot of these impacts will continue in the next IEPR Update.³⁹⁰ (See “Changes in Electricity Market Structure” in Chapter 1 for more information on CCAs.)

Energy Commission staff developed an hourly load forecasting model for the investor-owned utility (IOU) planning areas. This model incorporates hourly behind-the-meter photovoltaic (PV) generation, hourly load impacts of electric vehicles (EVs), residential time-of-use (TOU) pricing, and additional achievable energy efficiency (AAEE). In addition to the hourly load forecasting, the TOU component is a new modeling effort for the Energy Commission. Staff used the hourly load model to estimate impacts from potential “peak shift” for each IOU, reflecting changes in utility peak hours and load brought on by demand modifier impacts. Extending this analysis to

387 Kavalec, Chris, Asish Gautam, Mike Jaske, Lynn Marshall, Nahid Movassagh, and Ravinderpal Vaid. 2018. *California Energy Demand 2018–2030 Revised Forecast*. California Energy Commission. Electricity Assessments Division. Publication Number: CEC-200-2018-002-SD.

388 See Kavalec, Chris, Nick Fugate, Cary Garcia, and Asish Gautam. 2016. *California Energy Demand 2016-2026, Revised Electricity Forecast*. California Energy Commission. Publication Number: CEC-200-2016-001-V1, pp. 20-26. Available at http://www.energy.ca.gov/2015_energypolicy/documents/#adoptedforecast.

389 A *balancing authority* is an entity responsible for integrating resource plans and maintaining the proper balance for load, transmission, and generation within an area defined by metered boundaries. California includes eight balancing authorities, of which the California ISO is by far the largest.

390 Spencer Olinek, Comments from Pacific Gas and Electric; Danielle Osborn Mills, Comments from the American Wind energy Association.

additional planning areas, as requested in comments from LADWP, will have to wait until the 2019 IEPR.³⁹¹

Staff updated utility efficiency program impacts in the baseline forecast, or “committed” savings, to reflect activity in 2016 and 2017. Expected program impacts beyond 2017 are incorporated in the managed forecasts through AAEE savings. The 2016 updates to Title 24 building standards are included in the CED 2017 Revised baseline, with future likely standards updates also handled through AAEE estimates. For the IOUs, most of estimated AAEE savings are derived from the CPUC’s *2018 Potential and Goals Study*,³⁹² while estimates for publicly owned utilities rely on individual utility adopted goals. Both IOU and publicly owned utility future savings are augmented by staff analysis for SB 350, as discussed later in this chapter in “Managed Forecasts.”

The Title 24 building standards updates expected in 2019 will include requirements for PV installations for new homes as a contributor toward the state’s zero-net-energy goals. Since mandated efficiency improvements from the 2019 Title 24 are part of AAEE and not in the baseline forecast, consistent treatment of PV installations requires that the estimated additional installations from these 2019 updates be treated separately from PV adoptions in the baseline forecast, yielding additional achievable photovoltaic (AAPV) adoption. In addition, the predictive model for PV adoptions now incorporates the impact of residential TOU rates on PV system adoption. Staff agrees with comments by the California Solar Energy Industries Association that residential rate design and potential policy changes to solar tariffs and tax credits (see Chapter 2 for more information) add additional uncertainty in forecasting PV adoption.³⁹³

CED 2017 Revised incorporates a new transportation electricity forecast, which includes light-duty vehicles, medium- and heavy-duty vehicles, public transit, and high-speed rail. Predicted light-duty EV purchases, which include battery electric and plug-in hybrid, were discussed and vetted through the Demand Analysis Working Group (DAWG),³⁹⁴ a technical stakeholder group, and the Joint Agency Steering Committee (JASC),³⁹⁵ and are significantly higher than in previous forecasts, reflecting current trends and more optimistic projections for these vehicles.

Data and Analytical Needs

Assembly Bill 802 (Williams, Chapter 590, Statutes of 2015) confirmed the Energy Commission’s authority to require the submission of individual utility customer usage and billing data. On

³⁹¹ Eric Montag, Comments from Los Angeles Department of Water and Power.

³⁹² Draft report available at ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/DAWG/2018andBeyondPotentialandGoals%20StudyDRAFT.pdf.

³⁹³ Brad Heavner, Comments from the California Solar Energy Industries Association; Damon Franz, Comments from Tesla.

³⁹⁴ The DAWG is a forum for technical discussion and consensus-building on inputs and results for the electricity and natural gas demand forecasts adopted by the Energy Commission. Energy Commission staff convenes DAWG, pulling in forecasting experts at the utilities as well as other stakeholders, to discuss technical details behind the forecast to build consensus. For more information, see <http://www.dawg.info/about-demand-analysis-working-group>.

³⁹⁵ The JASC is an interagency team of management from the Energy Commission, CPUC, California ISO, and CARB, responsible for coordinating activities that contribute toward increasing the granularity of the Energy Commission’s demand forecast.

January 13, 2016, the Energy Commission opened Rulemaking 16-OIR-03³⁹⁶ to consider amending the agency's regulations specifying data collection and disclosure for load-serving entities. These amendments will help the Energy Commission implement SB 350 and AB 802 provisions and clarify existing provisions in the regulations. The Energy Commission will submit its final proposed regulatory language to the Office of Administrative Law in July 2017. The rulemaking includes acquisition of high-priority data by January 1, 2018, including:

- Electricity and gas customer monthly billing data for the five largest electric utilities and the three largest gas utilities.
- Interval meter data for the five largest electric utilities, beginning in 2019.
- Interconnection data for all interconnected devices, including energy storage.
- Behind-the-meter load shape research conducted for planning purposes by the five largest electric utilities.
- Modeling files used by the two largest gas utilities for hydraulic modeling of their transmission and distribution systems.
- Confidentiality designations for new customer data.

Data collected under these regulations will be used for studies that will improve demand forecasting and technical knowledge of the role of energy efficiency in reducing customer demand. It will also allow regional assessments of hourly and seasonal impacts of savings; disaggregation and improvement of energy demand forecasts; improved electricity peak load forecasts, and baselining and improved characterization of energy consumption across customer sectors and end uses. The data will improve local area forecasting, which in turn, will enhance reliability planning. This data collection will focus primarily on the larger utilities (Pacific Gas and Electric, Southern California Edison, San Diego Gas & Electric, Los Angeles Department of Water and Power, and Sacramento Municipal Utility District).

Additional topics to be considered for Phase 2 of the Title 20 data rulemaking include data required to assess progress in reaching energy efficiency savings targets, networked electric vehicle charging, wind performance, and balancing authority information. These topics need further staff analysis and stakeholder discussion. This second phase is anticipated to begin in summer 2018.

Furthermore, SB 350 requires the Energy Commission to establish a process for 16 publicly owned utilities to submit integrated resource plans to the Energy Commission for review by January 1, 2019, and requires the CPUC to establish a similar process for regulated load-serving entities.³⁹⁷ Energy Commission and CPUC staffs are working to ensure proper alignment of both

³⁹⁶ http://www.energy.ca.gov/business_meetings/2016_packets/2016-01-13/Item_05_OIR-Senate_Bill_350/Item%205%20OIR%20Senate_Bill350_final_1-4-16.pdf.

³⁹⁷ To that end, the CPUC issued an order instituting rulemaking (R.16-0-007) in February 2016. An inventory of CPUC proceedings related to SB 350 is available at http://www.cpuc.ca.gov/Senate_Bill350/. The Energy Commission's first workshop to consider a publicly owned utility process was held April 18, 2016. Final guidelines to be adopted in August 2017.

the Integrated Resources and Distributed Resource Planning processes. Chapter 2 provides more detail on the Energy Commission's SB 350 efforts.

Economic/Demographic Outlook for California

California's economy is large and diverse. The state remains a leader in national economic growth.³⁹⁸ Although still a leader nationally, the pace of growth is now steadily slowing down. The Great Recession began in late 2007 and lasted until the summer of 2009, but it was not until 2012 that California's economy showed signs of a recovery. Since 2011, California's gross state product has consistently grown faster than the nation as a whole due to two economically strong regions – Los Angeles/Long Beach/Anaheim (\$930.8 billion) and San Francisco/Oakland/Hayward (\$431.7 billion). However, growth is not expected to continue at the current pace.

Statewide unemployment was down 5.1 percent in January 2017, which is significantly lower than the recession era high of more than 12 percent in December 2009. The lower unemployment rate, although a positive factor in a growing economy, could limit potential future growth in a full employment economy, which the state is very close to reaching. It will also limit further expansion in areas such as personal income, birth rates, homeownership rates, migration into the state, and overall gross state product.³⁹⁹

Moody's Analytics, IHS Global Insight, and the University of California at Los Angeles do not anticipate a recession in the near term for California or the nation as a whole. This position hinges on the uncertainties associated with the Trump Administration's policies. All three forecasting groups expect California's economy to grow at a slow and steady rate through 2019, with California at a higher rate than the nation. Projected growth for the next few years will range from 1.5 to 3 percent gross domestic product (GDP) growth. Those same experts predict the slower pace of growth will be driven by slower growth in the Bay Area's job market, slower growth in California's residential construction, and reduced in-migration and increased out-migration of firms and individuals throughout California.

Income growth has slowed, but it is still above the national average due to the technology sectors in the Bay Area and Los Angeles regions. California continues to attract high-income people, but low- and middle-income people (such as teachers) are leaving California because housing has become too expensive. With the increasing cost of living, California's economy continues to face affordability issues, as seen in the competitive housing/rental markets, increased costs in commercial real estate market/rentals, and high business costs.

³⁹⁸ The Energy Commission uses several sources to develop its economic/demographic outlook including Moody's Analytics, IHS Global Insight, the Anderson Forecast at the University of California, Los Angeles (UCLA), the California Department of Finance (DOF), California Employment Development Department, US Bureau of Labor Statistics, and the U.S. Census Bureau. Information was also presented by economists from these entities at the California Energy Commission's Economic and Demographic Workshop held January 24, 2017.

³⁹⁹ The Labor Market Information Division, *California's Unemployment Rate Falls to 5.1 percent in January*, Press Release, California Employment Development Department. March 3, 2017, http://edd.ca.gov/About_EDD/pdf/urate201702.pdf.

Higher income people tend to reside in coastal regions with amenities such as short distances to the ocean, milder weather, more urban lifestyles, and access to international outlets through international airports and seaports. Millennials and baby boomers alike are attracted to these coastal areas, but coastal areas have little available buildable land, making it less affordable to people of low or middle incomes. Environmental and zoning regulations such as open space protection and historical landmark preservation further limit the amount of land that can be used for affordable housing. Without streamlining some of these environmental/zoning regulations, builders will be unable to build affordable housing in these expensive metropolitan areas. As a result, the coastal region will continue to suffer a housing shortage, and rental costs will continue to increase.⁴⁰⁰ However, one possible form of relief for the affordable housing issue would be to connect the Bay Area and Central Valley through the high speed rail system under development.

Larger populated inland regions such as Sacramento, Fresno, and Riverside are also seeing affordability issues as more people from the coastal regions move inland to seek affordable housing. For example, thousands of San Francisco residents are moving to the Sacramento region each year as homeownership is more easily attainable and affordable than in the Bay Area's real estate market. If affordability issues continue along with increases in the cost of living, California's future growth may be restricted.

California's statewide housing growth in 2016 (net unit growth in completed housing units) was up more than 31 percent from the previous year, and included the addition of 89,000 housing units. The total number of housing units in the state is now more than 14 million. Statewide multifamily units represented 57 percent of unit growth last year, continuing a five-year trend. Multifamily units cost less to build and require fewer workers. This year marks the first time since 1991 that a net of more than 50,000 multifamily housing units were added to California's housing stock in a given year.⁴⁰¹ Builders in Sacramento cannot build enough homes to keep up with demand for several reasons, including shortage of construction workers and rising costs for building materials. These factors constrain builders in building affordable housing. That said, newly built homes sell very quickly, and forecasters expect that 9,600 houses will be built in Sacramento in 2017 – up from 7,206 homes built in 2016.⁴⁰²

Over the years, Title 24 standards for new buildings have reduced energy consumption. However, one potentially offsetting factor is consumer pressure on home builders in terms of the size – smaller (less energy use) vs. larger (more energy use) – and location of houses (dense urban areas vs. rural ones). The differences in housing types and amenities differ substantially among different generations, such as the baby boomers and the millennials. The baby boomer generation generally wants to downsize to multifamily units like condominiums or smaller single-family homes closer to their families. The millennial generation tends to want more energy-efficient and

400 Dr. Jerry Nickelsburg, Senior Economist, June 2017, UCLA Anderson Forecast Seminar.

401 The Demographic Research Unit. New State Population Report: California Grew By 335,000 Residents in 2016. Press Release. California Department of Finance, May 1, 2017. http://dof.ca.gov/Forecasting/Demographics/Estimates/e-1/documents/E-1_2017PressRelease.pdf; Jerry Nickelsburg, California Forecast, UCLA Anderson Forecast and Seminar, June 2017 Los Angeles, California.

402 Sangree, Hudson. "Will Sacramento Avoid Another Housing Boom and Bust?" *The Sacramento Bee*, July 17, 2016.

technology-centric homes, and amenities that can be purchased in highly populated cities like Los Angeles. Moreover, population growth is occurring in the hotter inland areas.⁴⁰³ This trend can be expected to result in increases in electricity consumption in inland areas.

The state's population growth will continue to be relatively slow compared to other nearby states as the demand for housing increases. According to the Department of Finance, California's population grew only 0.85 percent in 2016, adding 335,000 residents to total 39,524,000 as of January 1, 2017. This is the lowest level of growth in many decades, but California is still growing slightly more than the nation as a whole. The largest in and out migration numbers are flowing into and out of Texas, Nevada, Arizona, Washington, and New York. The attraction to these states is primarily due to overall affordability from lower housing costs, allowing first-time homebuyers to enter the market, to lower taxes. By the same token, people come to California to seek opportunities in the high-tech industry.^{404, 405, 406}

Trends in Energy Consumption

Since 2000, California's electricity consumption per capita has remained relatively flat, as shown in Figure 30.⁴⁰⁷ Many factors affect consumption, including population, income, employment, weather, and energy efficiency standards. For example, increased migration into California and hot weather can cause increased electricity consumption, but energy efficiency can help reduce it.

403 The Demographic Research Unit. New State Population Report: California Grew By 335,000 Residents in 2016. Press Release. California Department of Finance, 1 May 2017. http://dof.ca.gov/Forecasting/Demographics/Estimates/e-1/documents/E-1_2017PressRelease.pdf; Jerry Nickelsburg, California Forecast, UCLA Anderson Forecast and Seminar, June and December 2016, Los Angeles, California.

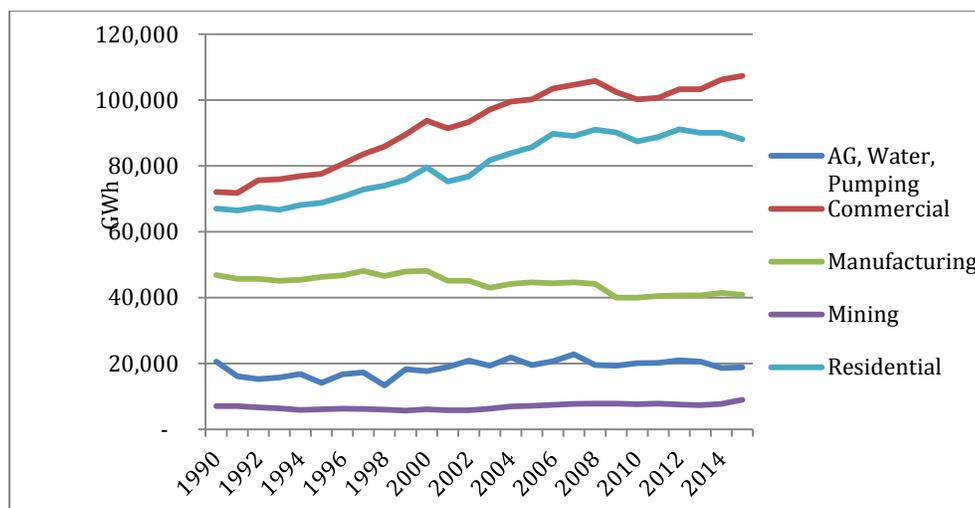
404 The Demographic Research Unit. "New State Population Report: California Grew by 335,000 Residents in 2016." Press release. California Department of Finance, May 1, 2017, http://dof.ca.gov/Forecasting/Demographics/Estimates/e-1/documents/E-1_2017PressRelease.pdf.

405 Nickelsburg, Jerry, *California Forecast*, UCLA Anderson Forecast and Seminar, June and December 2016, Los Angeles, California.

406 *California Trends*, Personal Communication, Chris Lafakis, Moody's Analytics, July 13, 2017.

407 Material from this section is the result of staff analysis of multiyear sector model results and economic/demographic data provided by Moody's Analytics, IHS Global Insight, and UCLA.

Figure 31: Statewide Electricity Consumption by Sector Since 2000



Source: California Energy Commission

California continues to be primarily a service-based economy, which contributes to electricity consumption growth via office and retail space (commercial sector).⁴⁰⁸ Despite growth in the commercial sector, Title 24 standards for new buildings have helped keep energy consumption relatively steady. Although California is a service sector economy, the state is experiencing growth in manufacturing in the auto industry due to local manufacturing of electric vehicles by such companies as Tesla.

Population growth, economic conditions, weather, and energy efficiency programs drive demand for electricity in the residential sector. The upward trend in electricity consumption in the early 2000s corresponds with population growth. It was briefly interrupted by the Great Recession beginning in 2008. With the economy bouncing back, consumption has returned to the prerecession level, followed by a slight decline in the last few years. While it is still too early to indicate with certainty, energy efficiency and technological change may contribute to this decline.^{409, 410}

In the industrial sector, increased fuel prices and end-use efficiency gains drive the declining electricity consumption for the most energy-intensive industries such as petroleum and coal

⁴⁰⁸ The Energy Commission's commercial model relies on economic, engineering and statistical data to forecast consumption. These data include floor space stocks, floor space additions, vacancy rates, energy use intensities (EUIs), fuel saturations, fuel prices, conservation programs, standards savings, and weather data. In addition, changes in fuel prices and weather patterns would cause the forecast to vary from one year to the next. The annual consumption forecast is also affected by the magnitude and interaction of these variables. For example, the main driver of the commercial forecast is the floor space data (stocks, additions, and vacancies); therefore, fluctuations in floor space have a significant effect on the forecast results. These fluctuations are reflected in the increases and decreases seen in the above chart.

⁴⁰⁹ Hurd, Michael D., and Susann Rohwedder. *Effects of the Financial Crisis and Great Recession on American Households*. No. w16407.

⁴¹⁰ National Bureau of Economic Research, 2010.

products manufacturing, chemical manufacturing, food processing, and semiconductor and other electronic component manufacturing.⁴¹¹

Although energy consumption has been relatively flat in previous years in the agricultural sector, the industry may grow in the near future. Some forecasters expect the legalization of cannabis for personal recreational use to have a significant impact on electricity demand in California.⁴¹² However, even in jurisdictions where cannabis has been legal for some time, there are not enough reliable data to predict the magnitude of that impact with confidence. Important driving factors appear to include crop growth, processing environment (indoor, greenhouse, outdoor) and commercial production levels. Staff developed an analysis of the potential ramifications for the electricity grid of cannabis legalization, described in Appendix B of the *CED 2017 Revised* forecast report.⁴¹³ This is the first step in determining how best to incorporate the effects of cannabis growth into the agricultural demand forecasting model, and what data would need to be collected.

California Energy Demand Revised Forecast, 2018–2030

The *IEPR* forecast process began in November 2016, with a request for data from load-serving entities used to inform the staff work. A preliminary version of the forecast was released in late July, with a public workshop held on August 3. Comments from stakeholders during and after this workshop, along with later comments received in October after the workshop on the *Draft 2017 IEPR*, were incorporated into the revised version of the forecast (*CED 2017 Revised*). The IEPR Lead Commissioner held a public workshop on December 15, 2017, to receive public comments on the *CED 2017 Revised* forecast; however, several elements of the forecast (including AAEE and final peak estimates) were still incomplete by the time of the workshop. The forecast now incorporates these missing elements and stakeholders were allowed additional time to comment. The *CED 2017 Revised* forecast report was released for additional public comment on January 20, 2018, with comments due February 2, 2018.

Overall, the *CED 2017 Revised* forecast reflects faster growth in baseline electricity consumption compared to the *2016 IEPR Update* forecast update (*CEDU 2016*) due to significantly higher projections for EVs and a higher forecast for the industrial sector. In addition, staff changed the way that residential lighting savings are accounted for in the forecast, further increasing baseline consumption. Past forecasts have assumed reductions in home lighting use consistent with Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007), which calls for 50 percent reductions in residential lighting by 2018 compared to 2007. By assuming that the AB 1109 requirements were met by 2018 and beyond, past baseline forecasts did not measure lighting

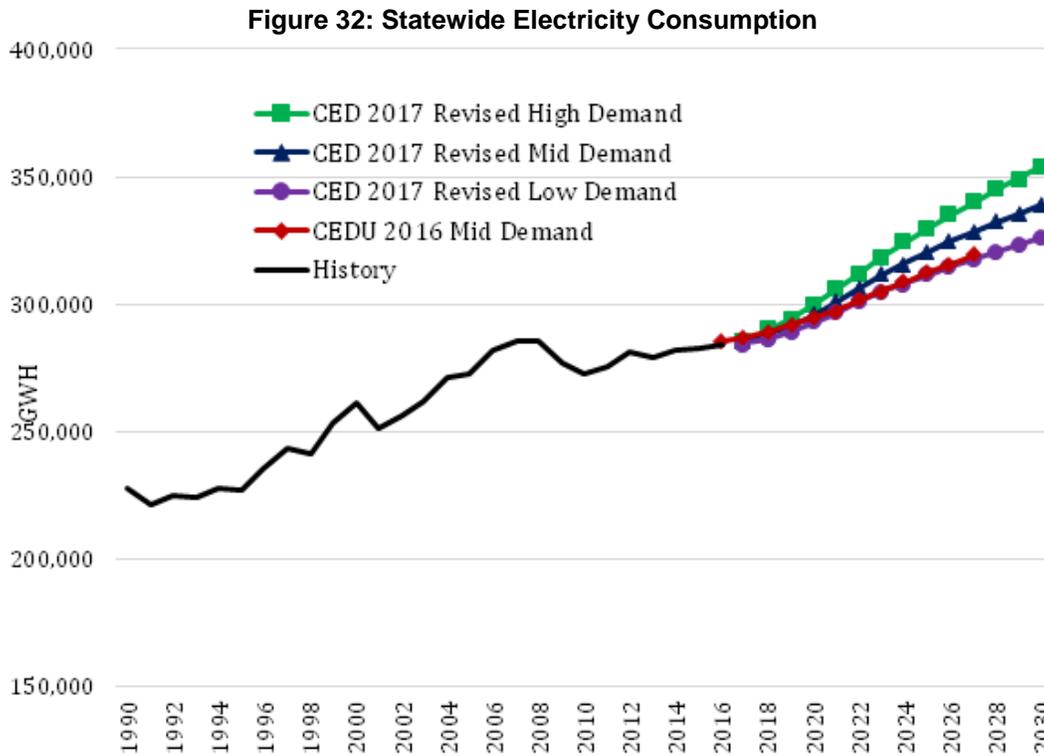
411 Based on the staff analysis of the historical data of industrial energy consumption, the trend of energy rates, and the dollar output data provided by Moody's.

412 Evergreen Economics. *SDG&E Cannabis Agriculture Energy Demand Study Final Report*. CALMAC ID: SDB0301.01; Mills, Evan. Energy Associations. "The Carbon Footprint of Indoor Cannabis Production." *Energy Policy* 46 (2012) 58–67.

413 Kavalec, Chris, Asish Gautam, Mike Jaske, Lynn Marshall, Nahid Movassagh, and Ravinderpal Vaid. 2018. *California Energy Demand 2018-2030 Revised Forecast*. California Energy Commission, Electricity Assessments Division. Publication Number: CEC-200-2018-002-SD.

savings from programs and standards directly. However, given improvements in evaluation, measurement, and verification studies in recent years, staff decided that incorporating future programs and standards targeting lighting would provide a more accurate approach than simply assuming the requirements are met. Because the baseline forecast includes only committed efficiency, lighting savings from programs beyond 2017 that contribute to the AB 1109 goals are not included (are transferred to the AAEE portion), so average lighting use begins to increase in 2018 and later years, driving up growth in residential consumption.

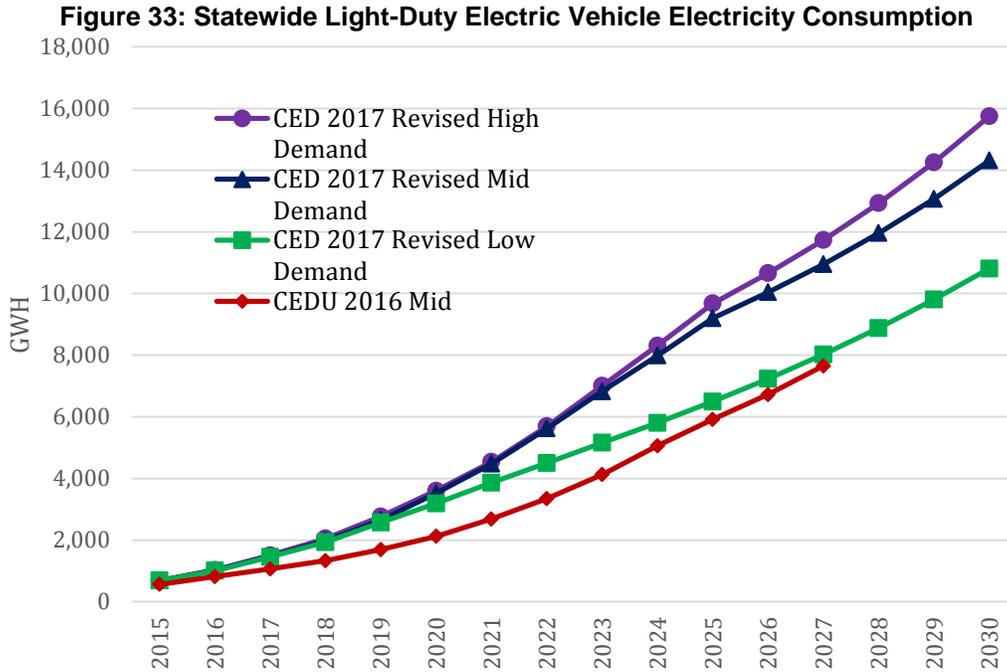
Figure 31 shows historical and projected CED 2017 Revised baseline electricity consumption statewide for three demand scenarios compared to mid baseline consumption projected in the forecast update from the *2016 IEPR Update*. In 2027, consumption in the new mid case is projected to be almost 3 percent higher than the CEDU 2016 mid case, which roughly matches the new low case.



Source: California Energy Commission

The EV forecast incorporates a new vehicle choice survey, completed in spring 2017, and includes projections of pure battery-electric and plug-in hybrid vehicles in both the residential and nonresidential sectors. Three scenarios were developed for CED 2017 Revised, with assumptions consistent with the three demand cases. The new forecasts reflect a more optimistic outlook for EVs by both staff and stakeholders, based on recent trends in California as well as commitments to widespread EV use around the world. (See Chapter 7 section on “Transitioning to Cleaner Transportation.”) This optimism was incorporated in the vehicle choice model through additional vehicle class offerings, higher projections for vehicle range, and a “taste” parameter that put EVs on par with conventional vehicles in terms of general acceptance. Figure 32 shows projected

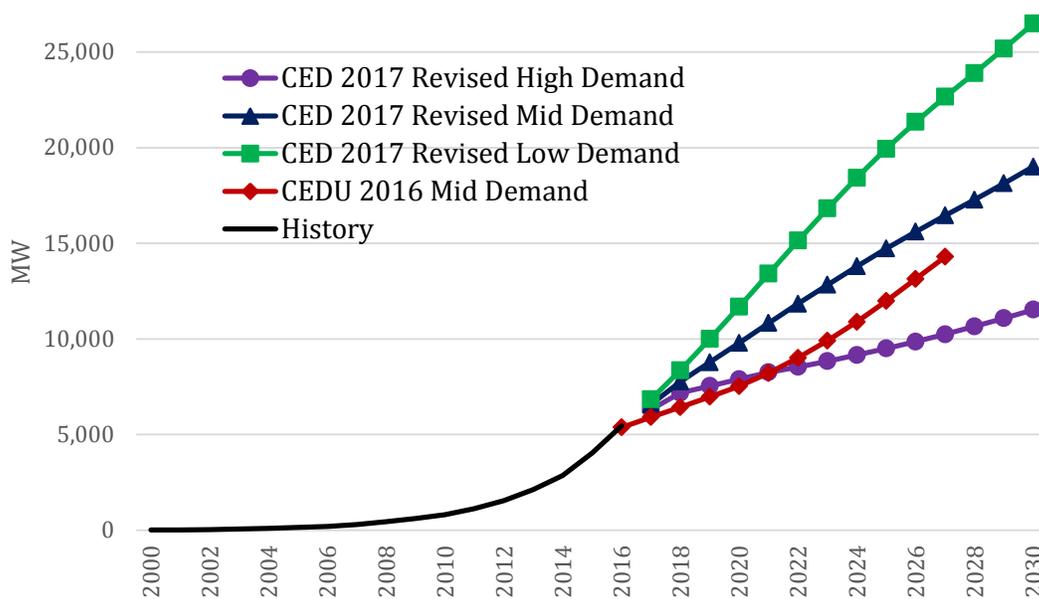
statewide light-duty EV electricity consumption for the three CED 2017 Revised cases and the mid case from *CEDU 2016*. Consumption is higher in all three new cases compared to *CEDU 2016* through 2027, with the new mid case about 3,300 GWh above *CEDU 2016* in this year. Projected EV stock statewide in the CED 2017 Revised high, mid, and low cases reaches 3.9 million, 3.3 million, and 2.6 million vehicles, respectively, by 2030.



Source: California Energy Commission

The key driver behind the peak shift phenomenon is increasing expected adoptions of behind-the-meter PV systems. Historical and projected PV capacities for the three CED 2017 Revised demand cases and the *CEDU 2016* mid case are shown in Figure 33. Projected total installed capacity reaches about 26,500 MW, 19,000 MW, and 11,500 MW in the low, mid, and high demand baseline cases, respectively, by 2030.

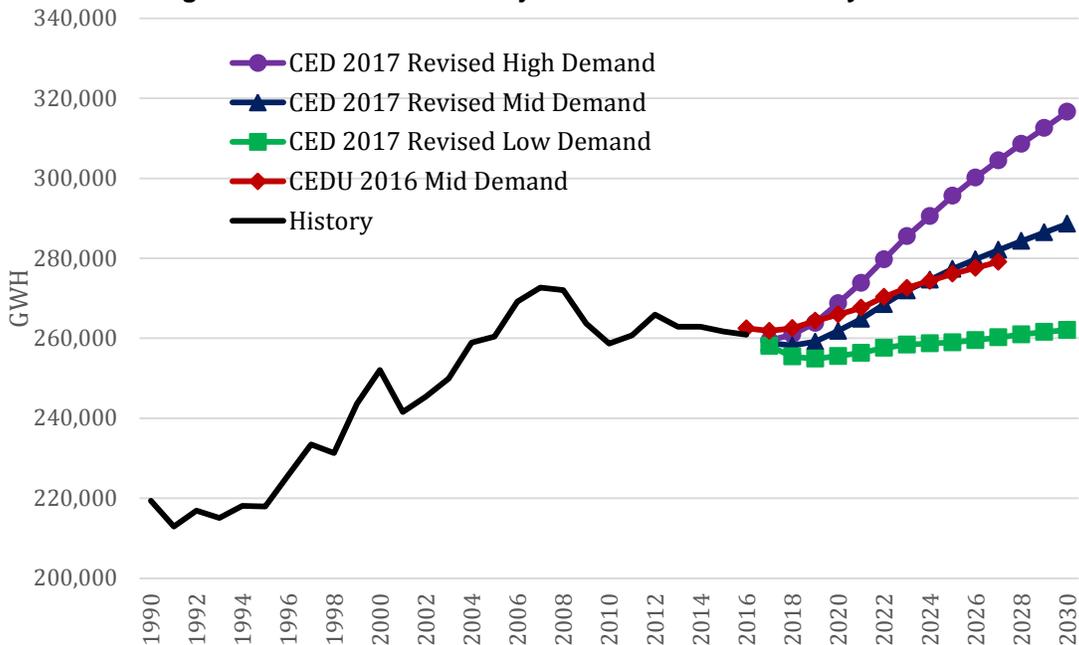
Figure 34: Statewide PV Installed Capacity



Source: California Energy Commission

Projected statewide baseline electricity sales for the three CED 2017 Revised cases and the *CEDU 2016* mid demand case are shown in Figure 34. The increase in projected consumption met with self-generation in CED 2017 Revised because more photovoltaic adoption, along with the 2016 – 2017 efficiency programs, reduces all three new forecast cases below the *CEDU 2016* mid case at the beginning of the forecast period. Growing light-duty EV consumption pushes the new high and mid cases above *CEDU 2016* by 2020 and 2024, respectively. By 2027, sales in the CED 2017 Revised mid case are projected to be around 1 percent higher than in the *CEDU 2016* mid case.

Figure 35: Historical and Projected Statewide Electricity Sales

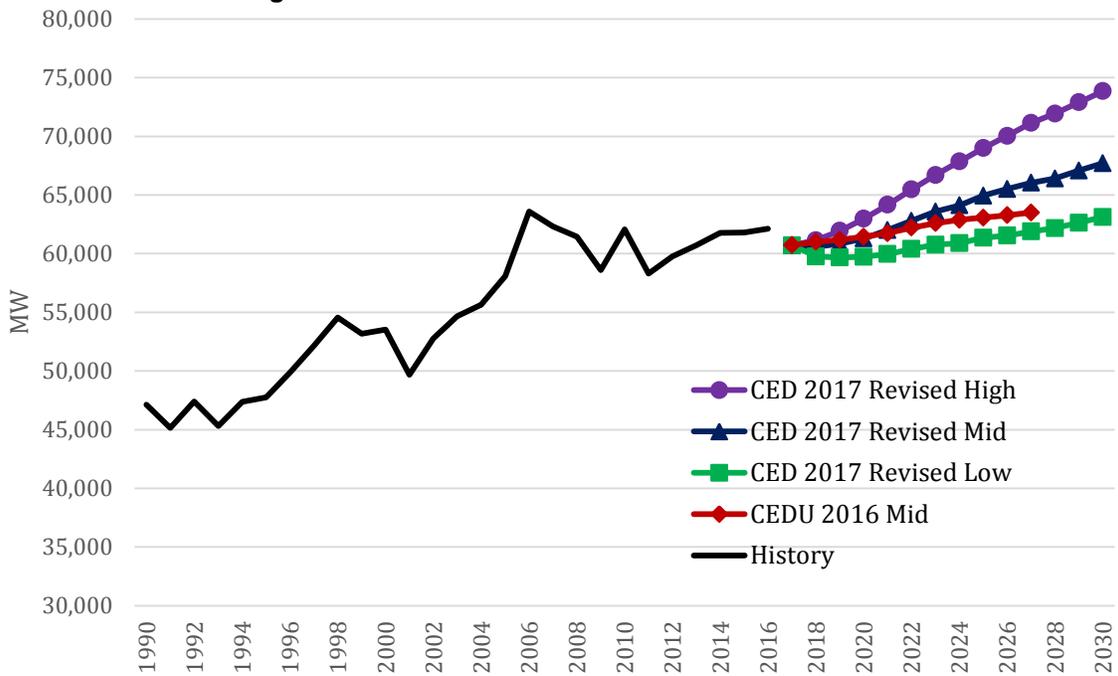


Source: California Energy Commission

Projected *CED 2017 Revised* noncoincident⁴¹⁴ net peak demand for the three baseline cases, adjusted by the peak shift impact for the IOUs and the *CEDU 2016* mid demand peak forecast are shown in Figure 35. Because of the peak shift, net peak demand grows at a faster rate than sales in all three demand cases in the new forecast, and in the mid case pushes above *CEDU 2016* by an earlier year. By 2027, statewide peak demand in the *CED 2017 Revised* mid case is projected to be around 4 percent higher than the *CEDU 2016* mid case. The higher projections for EVs have relatively less impact on peak demand than on consumption and sales, as most recharging occurs during off-peak hours.

⁴¹⁴ Noncoincident net peak demand is the sum of planning area peaks, which may occur at different hours.

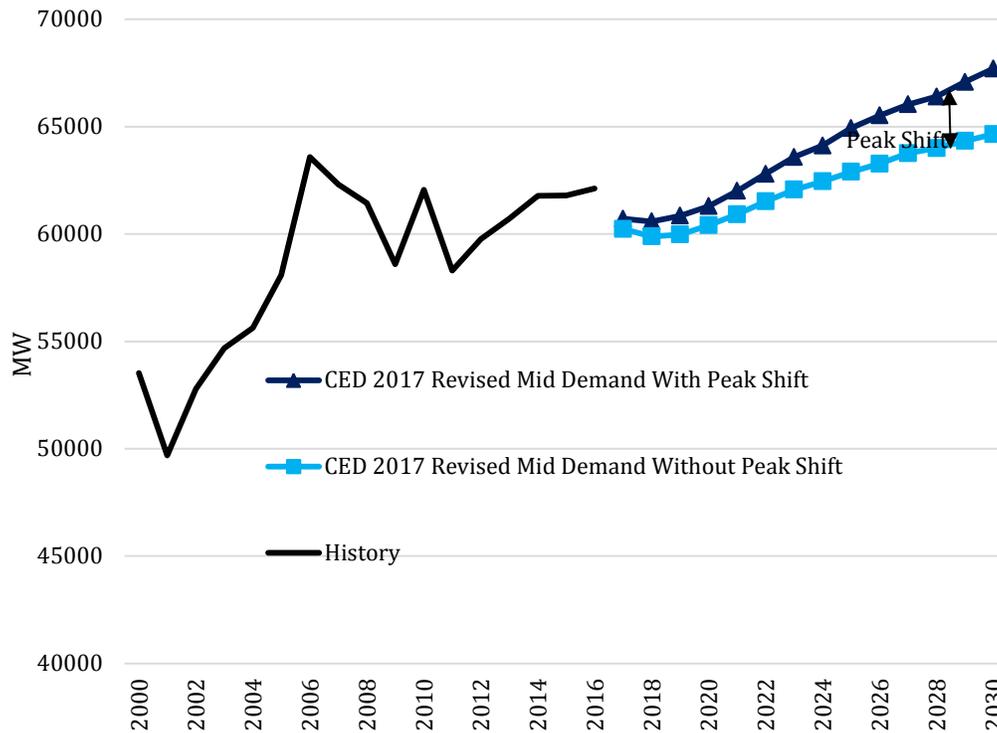
Figure 36: Statewide Noncoincident Peak Demand



Source: California Energy Commission

The impact of the peak shift for the IOU planning areas on statewide noncoincident net peak demand for the CED 2017 Revised mid case is shown in Figure 36. By 2030, the peak shift impact reaches more than 3,000 MW and increases the average annual growth rate for net peak from 0.65 percent to 1.00 percent over 2017 – 2030. Peak shift impacts in the high and low demand cases reach 1,000 MW and 6,100 MW, respectively, by 2030.

Figure 37: Peak Shift Impact on Statewide Noncoincident Net Peak, CED 2017 Revised Mid Case



Source: California Energy Commission

Statewide natural gas consumption demand for the three *CED 2017 Revised* cases and the *CED 2015* mid case⁴¹⁵ is shown in Figure 37. The historical series clearly shows the variability in consumption from year to year, with changes in weather a key contributor to this variability. The figure shows a rather large jump from 2016 to 2017 in the new forecast, a result of the weather adjustment in the residential and commercial models. The year 2016 was very warm in general, with a relatively small number of heating degree days⁴¹⁶ over the year. With heating accounting for almost 50 percent of natural gas demand in the residential and commercial sectors, consumption in 2016 was reduced significantly. From 2017 onward, weather is assumed historically “average” (aside from incremental climate change impacts) so that the number of heating degree days increases relative to 2016, accounting for this jump.⁴¹⁷ Figure 37 also shows a bump upward in the new high case and downward in the low case from 2017– 2018, owing to significant projected industrial sector output growth/decline in this year in these two cases.⁴¹⁸ In 2018 and beyond, growth in the *CED 2017 Revised* mid case is lower than in *CED 2015*, a result of implementation of the 2016 Title 24 building standards updates and a lower forecast for natural

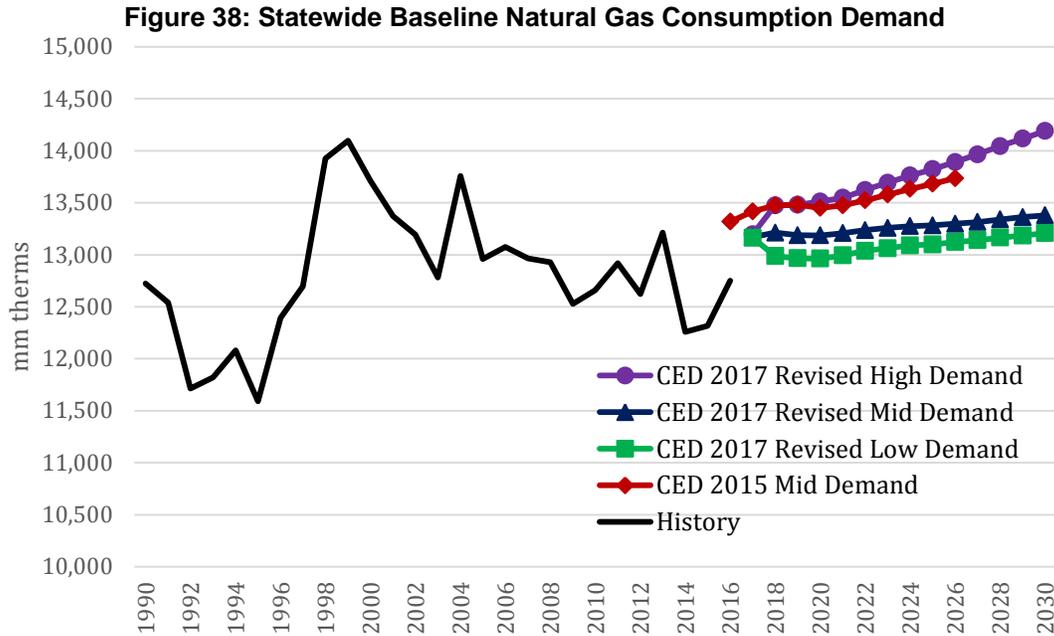
⁴¹⁵ A natural gas end-user forecast was not developed for *CEDU 2016*.

⁴¹⁶ *Heating degree days* is a parameter that is designed to reflect the demand for energy needed to heat a home or building. Heating degree days are calculated using ambient air temperatures and a base temperature (for example, 65 degrees) below which it is assumed that space heating is needed.

⁴¹⁷ The impact of heating degree days is measured through a regression model for residential and commercial consumption. The resulting coefficient for heating degree days is used to adjust consumption.

⁴¹⁸ This is particularly the case with the oil and gas extraction sector, a significant user of natural gas.

gas vehicles. Consumption in the low demand case increases relative to the new mid case over the forecast period as climate change impacts, which reduce consumption, do not affect the former.



Source: California Energy Commission

Climate Change Impacts on Temperatures and Load

To estimate the potential of future climate change to impact electricity and natural gas consumption and peak demand, staff used temperature scenarios developed by the Scripps Institution of Oceanography through a set of global climate change models, where results are downscaled to 50-square-mile grids in California. Multiple scenarios were generated by Scripps, and staff from the Energy Commission’s Research and Development Division chose a “likely” and a more aggressive scenario for use in the CED 2017 Revised mid and high cases, respectively. The low demand case assumes no additional impacts from climate change. The high and low temperature scenarios are applied to weather-sensitive econometric models for residential and commercial sector annual consumption⁴¹⁹ for electricity and natural gas and for electricity peak demand to estimate consumption and peak impacts for each planning area and forecasting zone. The consumption models use cooling and heating degree days for the weather parameter while the peak econometric model uses annual maximum temperatures. Econometric results with the high and mid temperature scenarios are compared to results with no temperature changes to estimate climate change impacts. By 2030, impacts on electricity consumption reach about 1,200 GWh and 1,600 GWh in the mid and high demand cases, respectively. For peak, the corresponding estimates for 2030 are around 800 MW and 1,600 MW. (See Chapter 10 for more information on climate change.)

⁴¹⁹ Other sectors show no significant temperature sensitivity for consumption.

Managed Forecasts

Staff developed managed forecasts, which adjust for additional achievable energy efficiency (AAEE) savings and AAPV under various scenarios for electricity and natural gas for all of the planning areas. For the IOUs, AAEE savings were developed from the CPUC's *2018 Potential and Goals Study*,⁴²⁰ while estimates for publicly owned utilities rely on utility-adopted efficiency goals. Staff developed five AAEE scenarios similar in concept to those used for *CED 2015*.⁴²¹ These scenarios are designed to capture a range of possible outcomes determined by a host of input assumptions, with three AAEE scenarios (high, mid, and low savings) assigned to the appropriate *CED 2017 Revised* demand case(s). The scenarios assigned to a given baseline demand case share the same assumptions for building stock and retail rates. In addition, because of SB 350 goals, staff developed a more optimistic "what if" scenario to be paired with the mid demand case, referred to as high plus savings. These six scenarios are then defined by the demand case and AAEE savings scenario (high, high plus, mid, or low), as follows:

- Scenario 1: High Demand-Low AAEE Savings (high-low)
- Scenario 2: Mid Demand-Low AAEE Savings (mid-low)
- Scenario 3: Mid Demand-Mid AAEE Savings (mid-mid)
- Scenario 4: Mid Demand-High AAEE Savings (mid-high)
- Scenario 5: Low Demand-High AAEE Savings (low-high)

Scenario 6: Mid Demand-High Plus AAEE Savings (mid-high plus)

For the *CED 2017 Revised* forecast, AAEE savings were augmented with additional savings estimated in support of SB 350. The Efficiency Division of the Energy Commission brought on the consulting firm NORESKO for this purpose, to identify and estimate additional efficiency savings opportunities beyond utility programs and future standards typically considered for AAEE savings.⁴²² Initiatives in the analysis included financing programs, Property Assessed Clean Energy (PACE), Local Government Challenge, Local Government Ordinances, Proposition 39, Energy Conservation Assistance Act, Greenhouse Act Reduction Fund (GGRF), Energy Savings Program (Department of General Services), Air Quality Management District programs, benchmarking and public disclosure, Energy Asset Rating, BROs, smart meters and controls, and fuel substitution, as well as additional future ratchets of Title 24 building standards, Title 20 appliance standards, and Federal Appliance Standards.

⁴²⁰ Draft report available at ftp://ftp.cpuc.ca.gov/gopher-data/energy_division/EnergyEfficiency/DAWG/2018andBeyondPotentialandGoals%20StudyDRAFT.pdf.

⁴²¹ Described in pages 54-65. http://docketpublic.energy.ca.gov/PublicDocuments/15-IEPR-03/TN207439_20160115T152221_California_Energy_Demand_20162026_Revised_Electricity_Forecast.pdf.

⁴²² Work is detailed in Appendix B of an Energy Commission Report: Jones, Melissa, Michael Jaske, Michael Kenney, Brian Samuelson, Cynthia Rogers, Elena Giyenko, and Manjit Ahuja. 2017. *Senate Bill 350: Doubling Energy Efficiency Savings by 2030*. California Energy Commission. Publication Number: CEC-400-2017-010-CMF. Available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-06/TN221631_20171026T102305_Senate_Bill_350_Doubling_Energy_Efficiency_Savings_by_2030.pdf Workbooks providing computations and results are available here: <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-06>.

To integrate these projected savings into the traditional AAEE paradigm, an important consideration is disparity between the purpose of the NORESKO analysis (to support SB 350 target-setting) and traditional AAEE projections. SB 350 targets represent savings that could occur if a series of assumptions are consistently pursued through time. Most important is that the assumed funding levels or other indicators critical to the scale of the program effort actually take place. For many of the programs analyzed by NORESKO, there is no assurance of such funding. In contrast, AAEE projections are intended to be used for actual resource procurement to satisfy projected managed energy demand or to replace other sources of generation that will be scaled back through time. In other words, AAEE projections as a supplement to the baseline demand forecast satisfy a statutory requirement that the adopted demand forecast included energy efficiency “reasonably expected to occur.” Therefore, staff developed an approach that sought to adapt the SB 350 analyses by shifting them from “could occur” to “reasonably expected to occur.”

Staff presented a conceptual approach to transforming the SB 350 analyses in this manner in internal discussions and at a DAWG meeting on October 31, 2017.⁴²³ The approach centered around an “energy scaling factor” for programs that would be multiplied against NORESKO SB 350 estimates to generate statewide savings from individual programs. Such savings could then be included in one or more of six AAEE scenarios. This energy scaling factor is a judgmental scalar between zero and one that considers three specific criteria: program scalability likelihood, potential for double counting, and year-specific savings pattern credibility. Program scalability likelihood was intended to assess whether the scale of the program through time matches the utility programs or codes/standards that have made up AAEE in the past. Potential for double counting seeks to determine whether the SB 350 savings projections have fully adjusted for double counting of savings with other programs. Year-specific savings pattern credibility examined the availability of year-by-year estimates in the SB 350 savings analyses. Many programs were assessed by NORESKO using a savings analysis for 2029, with savings for intermediate years between the present and 2029 interpolated using linear or other simplistic methods. No year-by-year assessments were conducted using inputs specific to each intermediate year, because this was not believed to be needed for SB 350 purposes. Traditional AAEE requires a more rigorous year-by-year assessment since the procurement process frequently needs to assess the timing of resource additions. Those SB 350 programs assumed to have a simplistic build-out pattern would receive a lower energy scaling factor. Once these scaling factors were applied to the SB 350 savings estimates, the totals were combined with the “traditional” AAEE.

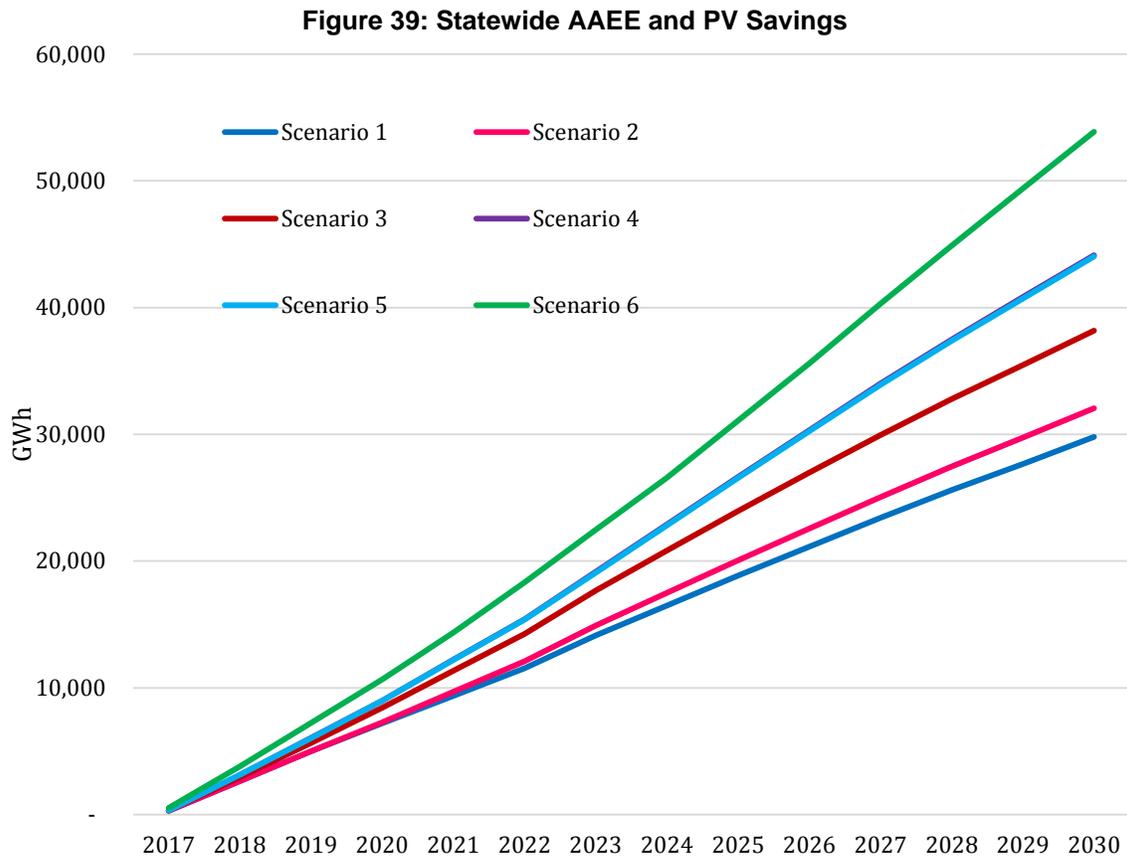
For AAPV, scenarios were constructed to be paired with the six scenarios described above, as follows:

- Scenario 1: Low AAPV
- Scenario 2: Mid-Low AAPV
- Scenario 3 and 4: Mid AAPV
- Scenarios 5 and 6: High AAPV

⁴²³ Mike Jaske, Energy Commission, PowerPoint presentation entitled *Role of SB 350 Energy Efficiency Savings in 2017 AAEE*, October 31, 2017, see http://www.dawg.info/sites/default/files/meetings/2017%20IEPR%20AAEE%20webinar_v4_MJ_10-27-2017.pdf.

Based on stakeholder comments and internal discussions with the Energy Commission’s Energy Efficiency division, staff assumed that Title 24 regulations will induce 70 percent of single family homes to be built with a PV system after 2019 in Scenario 1 and 90 percent in Scenarios 5 and 6, with the average of the additions between these two scenarios (about 80 percent) used for Scenarios 3 and 4. For Scenario 2, staff developed a mid-low scenario by adjusting the mid AAPV so that the compliance rate is reduced from 80 percent to 70 percent. Aside from these new home requirements, PV scenario assumptions are identical to those used in the baseline projections.

Figure 38 shows the total combined electricity consumption savings from AAEE and AAPV by scenario. (Scenarios 4 and 5 appear on top of each other as they are nearly identical.)



Source: California Energy Commission

Choice of Managed Single Forecast Set

The six scenarios discussed above, combining savings scenarios with the baseline forecasts, are managed forecasts that constitute options for a *single forecast set* to be used for planning purposes in Energy Commission, CPUC, and California ISO proceedings. Energy Commission, CPUC, and California ISO leadership have agreed on this forecast set to be used for planning and procurement in the California ISO’s TPP and the CPUC’s IRP, resource adequacy, and other planning processes.

The term “single forecast set” is intended to clarify that what has commonly been called a “single forecast” is not a single number, but actually a set of forecast numbers drawn from the Energy Commission’s demand forecast report, adopted as part of the *2017 IEPR. CED 2017 Revised* contains 6 managed scenarios, as discussed above, which combine baseline forecasts and AAEE-AAPV scenarios. Agreement on a single forecast set includes specification on the use for each component of the set.

The single forecast set is comprised of three components of the IEPR demand forecast:

- 1) A baseline case with its weather variants.
- 2) Two scenarios of AAEE.
- 3) Two scenarios of AAPV.

The combination of a *CED 2017 Revised* baseline forecast plus an AAEE-AAPV scenario depends on the purpose of their use.

- **The selected *CED 2017 Revised* baseline case will be the “mid demand” case for the combined IOU service areas that comprise the California ISO balancing area.**

The mid demand case includes variants for different weather conditions, all of which have been applied consistently by the CPUC and California ISO as follows:

- 1 year in 2 weather conditions – used for system flexibility studies performed by the California ISO for input to the LTPP and for economic studies in the California ISO TPP.
 - 1 year in 5 weather conditions – used for public-policy transmission assessments and bulk system studies in the California ISO TPP.
 - 1 year in 10 weather conditions – used for local capacity requirements and California ISO TPP local reliability studies.
- The Energy Commission, CPUC, and California ISO leadership agree, in principle, that the same AAEE and AAPV forecast scenarios should be applied to the uses described above; however, the state’s ability to characterize and assign the locational attributes of the demand forecast, procurement authorizations, and transmission additions continues to evolve. Due to the local nature of reliability needs and the difficulty of assigning AAEE, AAPV, or demand to specific locations, the agencies’ leadership agrees to use the mid-low AAEE and AAPV forecast (Scenario 2) for local studies.⁴²⁴ **The agencies’ leadership also agrees to use the *CED 2017 Adopted* mid-mid AAEE and AAPV forecast scenarios (Scenario 3) for system-wide and flexibility studies for the upcoming (2018–2019) cycles of TPP and IRP.**

⁴²⁴ See the presentation of Expert Panel member Alan Sanstad before the Energy Commission on May 30, 2013. http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-30_workshop/presentations/03_Sanstad-CEC-May_30_2013.pdf.

The agencies' leadership intends to have future AAEE and AAPV forecasts converge on the use of a single scenario for all studies. To achieve this, the three agencies are collaborating to create more-geographically specific, local-area disaggregation and load-shape impact methods, thereby eliminating the need for a lower AAEE or AAPV forecast for local studies in future planning and procurement cycles.

Recommendations

The Energy Commission should:

- **Continue to study the impacts of legalized cannabis cultivation on the electricity system.** Determine methods to incorporate those impacts into the energy demand forecast going forward.
- **Continue development of hourly load forecasting models and other new analytical methods to support the forecast, as well as assessments related to Senate Bill 350 and Assembly Bill 802.**
- **Support analysis of time-of-use (TOU) rates that will improve hourly demand forecasting.** Analysis of the interaction of residential loads, temperatures, and household characteristics under a default TOU rate will improve the ability of load forecast models to account for the benefits of TOU rates across seasons and climate zones.

CHAPTER 7:

Transportation Energy

Introduction

California is home to 30 million registered cars, trucks, buses, and other motorized on-road vehicles. The state's history has been, in part, a history of the automobile and the associated impacts on personal mobility, land-use planning, and air quality. That legacy lives on today – no sector of California's economy generates more greenhouse gas (GHG) emissions, or uses more energy, than transportation. Transportation fuels and vehicles are also responsible for particulate matter and ozone-forming gas emissions, both downstream from tailpipes and upstream from refineries.

In recognition of these challenges, California has enacted a suite of policies and goals to shift the transportation sector toward cleaner, sustainable fuels and more efficient technology vehicles. These include, but are not limited to:

- Assembly Bill 32 (Núñez, Chapter 488, Statutes of 2006) and Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016): These laws respectively established and expanded the Global Warming Solutions Act of 2006. AB 32 set a goal of reverting to 1990 levels of GHG emissions by 2020. SB 32 set a further reduction goal of 40 percent below 1990 levels by 2030. Based on the *2017 Draft Scoping Plan Update* required by these laws, the transportation sector will require significant transformation to meet its share of these reductions.
- Senate Bill 1275 (De León, Chapter 530, Statutes of 2014): This law established goals of placing at least 1 million zero-emission vehicles (ZEVs), including plug-in hybrid electric vehicles (PHEVs), battery-electric vehicles (BEVs), and fuel cell electric vehicles (FCEVs), in service by 2023. This reflects the pathway toward 1.5 million ZEVs by 2025 set within the *2016 ZEV Action Plan*.
- Executive Order B-32-15: This order required the development of the *California Sustainable Freight Action Plan*, released in July 2016.⁴²⁵ The plan identifies state policies, programs, and investments to improve freight efficiency, transition to zero-emission technologies, and increase California's freight competitiveness.

In support of these goals, California has also established a suite of programs and regulations that variously offer incentives for and mandate the growth of cleaner fuels and vehicles.

- State Implementation Plan: In response to requirements under the federal Clean Air Act of 1970, California's State Implementation Plan describes the state's plan for meeting

⁴²⁵ Office of Governor Edmund G. Brown Jr., *California Sustainable Freight Action Plan*, July 2016. Available at <http://www.casustainablefreight.org/theplan.html>.

ambient air quality standards. The *Mobile Source Strategy* outlines actions within the transportation sector that will allow the state to meet the standards.⁴²⁶

- **Low Carbon Fuel Standard (LCFS):** The LCFS requires regulated fuel providers to reduce the carbon intensity of their dispensed fuel by 10 percent by 2020. Importers and refiners must reduce the carbon intensity of their own fuels or else procure credits from alternative fuels with lower carbon intensities from other providers.
- **Advanced Clean Cars Regulations:** These regulations combined components from the Low-Emission Vehicle regulations and Zero-Emission Vehicle regulations to require development of cleaner light-duty vehicles.
- **Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP):** The Energy Commission administers the ARFVTP, which receives its funding from a surcharge on vehicle registrations. The ARFVTP provides funding for alternative fuel production, alternative fuel infrastructure, and advanced technology vehicles to reduce GHG emissions within the transportation sector. For more information on ARFVTP funding and benefits, see “Appendix D: Benefits Report for the Alternative and Renewable Fuel and Vehicle Technology Program.”
- **Air Quality Improvement Program (AQIP):** The California Air Resources Board (CARB) administers the AQIP, which also receives funding from a surcharge on vehicle registrations. Among the projects created under the AQIP is the Clean Vehicle Rebate Project, which provides an incentive to buyers of light-duty ZEVs.
- **Greenhouse Gas Reduction Fund:** Using funding from the sale of cap-and-trade permits under the state’s AB 32 Cap-and-Trade Program, the Greenhouse Gas Reduction Fund can be used to support projects that lower GHG emissions. In recent years, large shares of this funding (in hundreds of millions of dollars) have been dedicated toward financing lower-carbon transportation fuels and vehicles.
- **Senate Bill 350 (De León, Chapter 547, Statutes of 2015):** Among other provisions, this law requires large privately owned utilities to propose investments to the California Public Utilities Commission (CPUC) that will accelerate transportation electrification. The law also requires publicly owned utilities to consider “transportation electrification” in their integrated resource plans.

With these regulations and policies in mind, this chapter summarizes the results of two stand-alone reports: the *Transportation Fuel Supply Outlook, 2017* and the upcoming *Transportation Energy Demand Forecast 2018–2030*.

The *Transportation Fuel Supply Outlook* identifies some of the current trends in the transportation fuels sector and identifies issues of interest related to transportation fuel supply.

⁴²⁶ More information about the State Implementation Plan, including the *Mobile Source Strategy*, is available at: <https://www.arb.ca.gov/planning/sip/sip.htm>.

The *Transportation Energy Demand Forecast* provides an opportunity to compare the present and forecasted mix of existing fuels and vehicles against the state's aforementioned goals and benchmarks. The forecast reflects a mix of existing policies, current consumer preferences, fuel price cases, and projected market and technological conditions.

Transportation Fuel Supply

For more than 35 years, the Energy Commission has been tasked with collecting a broad set of data from major oil producers, refiners, marketers, transporters, and storers. The Energy Commission combines this unique data set with information available from other sources (such as the California Board of Equalization, U.S. Energy Information Agency, and International Energy Agency) to develop a biennial assessment of transportation fuels as part of the *Integrated Energy Policy Report*. Alternative fuels, including ethanol, biodiesel, renewable diesel, natural gas, electricity, and hydrogen, are also incorporated into the assessment.

For the *2017 Integrated Energy Policy Report (2017 IEPR)*, Energy Commission staff developed the *Transportation Fuel Supply Outlook, 2017* report. Energy Commission staff presented initial findings from the development of the *Transportation Fuel Supply Outlook* at a public workshop on July 6, 2017.⁴²⁷ A staff draft version of the report was released in September 2017, and a final staff version was released the subsequent month.⁴²⁸ This chapter presents some of the key findings of the report.

Recent Fuel Consumption Trends

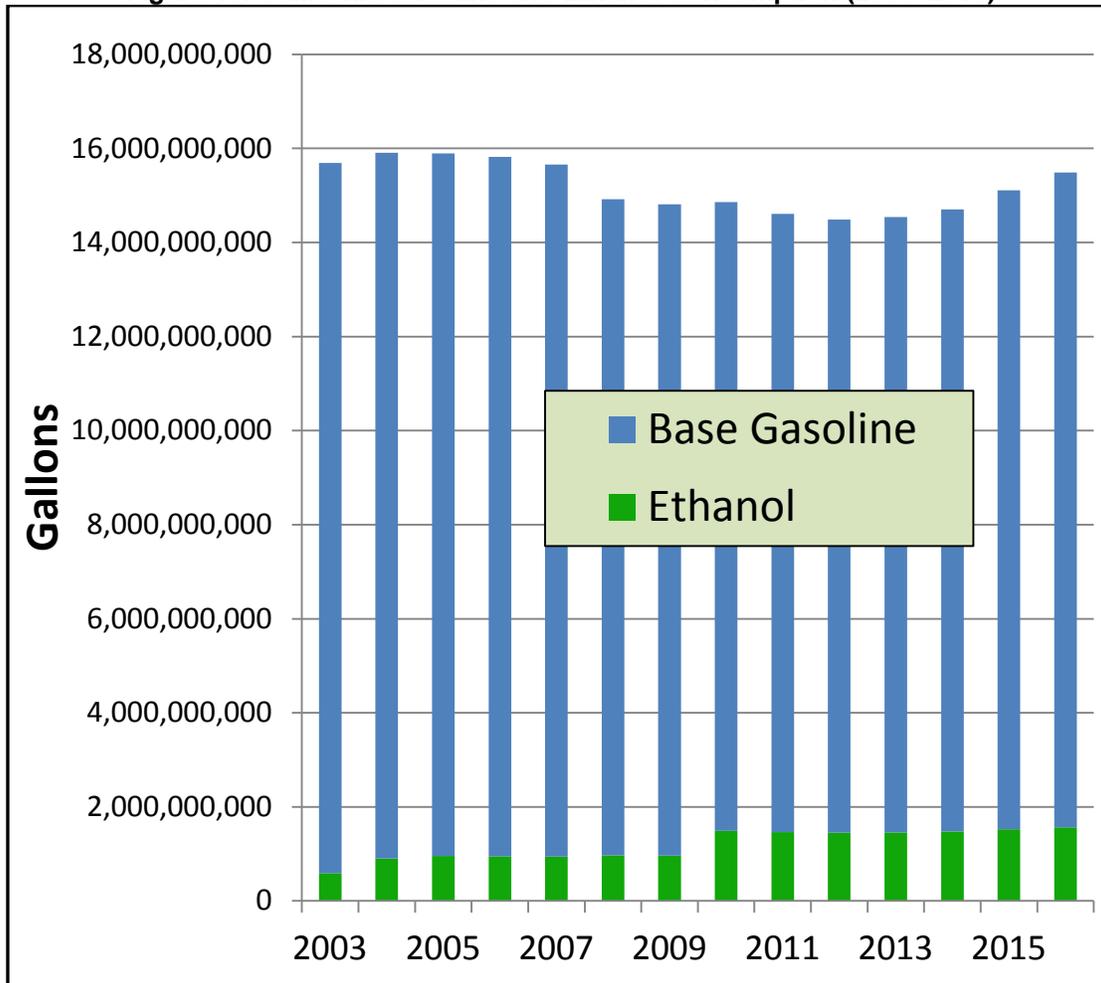
Gasoline has remained the dominant fuel within the transportation sector, with diesel fuel and aviation fuels following. Figures 39, 40, and 41 present trends for these fuels for 2003–2016. Consumption of each of these fuels dipped in 2008 and 2009, likely in response to the economic recession. Diesel and aviation fuel consumption have rebounded above 2003 levels, while gasoline consumption has recovered more slowly.

Since 2003, the ethanol blend in gasoline has increased from about 3.75 percent by volume to 10.1 percent in 2016. (While the regulatory limit on blending ethanol into gasoline in California is 10 percent, additional ethanol can be counted from the sale of E85, which is a fuel blend of 85 percent ethanol and 15 percent gasoline.) On the diesel side, biodiesel and renewable diesel have been spurred on by obligations under the LCFS, representing more than 11 percent of diesel and diesel substitute consumption.

⁴²⁷ Materials from the workshop are available at http://energy.ca.gov/2017_energypolicy/documents/#07062017.

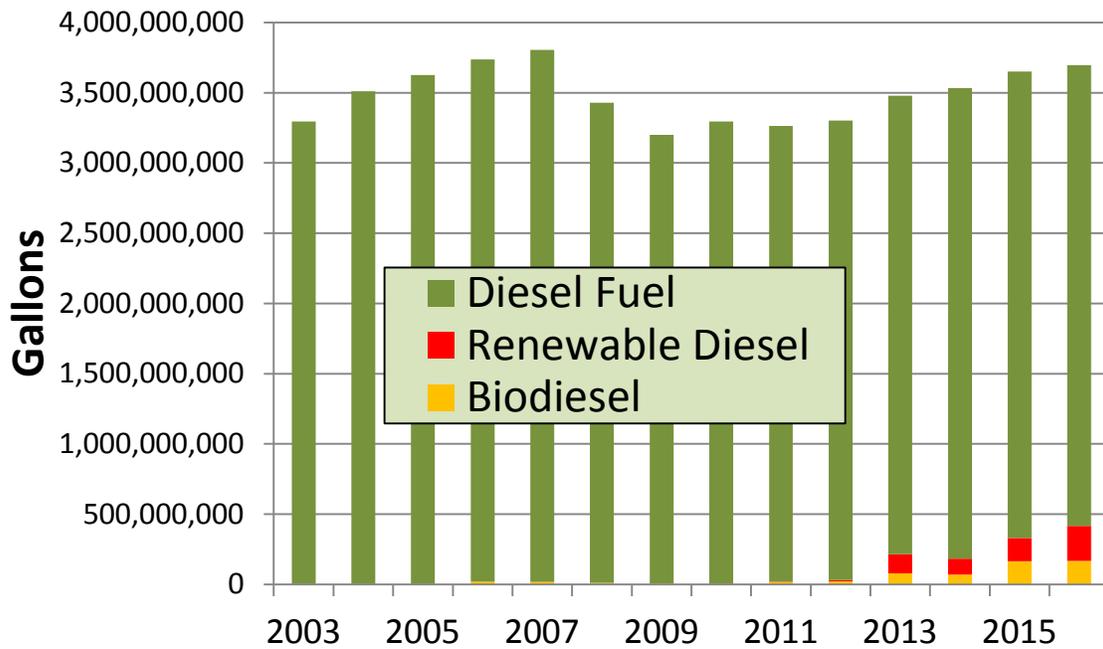
⁴²⁸ Schremp, Gordon, Ryan Eggers. 2017. *Transportation Energy Trends and Assessments, 2017*. California Energy Commission. Publication Number: CEC-200-2017-008-SF. Available at <https://efiling.energy.ca.gov/GetDocument.aspx?tn=221377>.

Figure 40: California Gasoline and Ethanol Consumption (2003–2016)



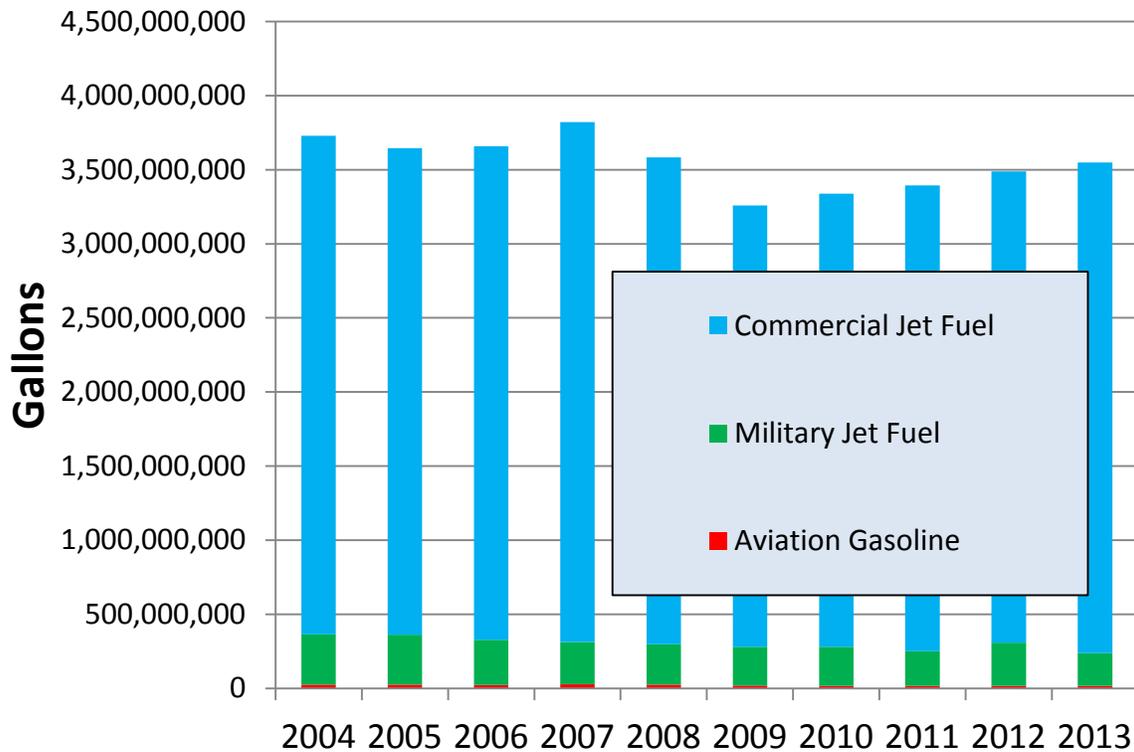
Source: California Energy Commission analysis

Figure 41: California Diesel Fuel, Biodiesel, and Renewable Diesel Consumption



Source: California Energy Commission analysis

Figure 42: California Jet Fuels and Aviation Gasoline Consumption (2004–2016)



Source: California Energy Commission analysis

Other alternative fuels are also included in the *Transportation Fuel Supply Outlook*. Consumption trends of gaseous fuels, including propane, liquefied natural gas (LNG), compressed natural gas (CNG), and hydrogen, are presented in Table 13. (As natural gas grows in the marketplace, a growing portion of it is being sourced from waste-based renewable resources, as discussed in Chapter 8 and Chapter 9.)

Table 13: California Gaseous Fuel Consumption (2003–2016)

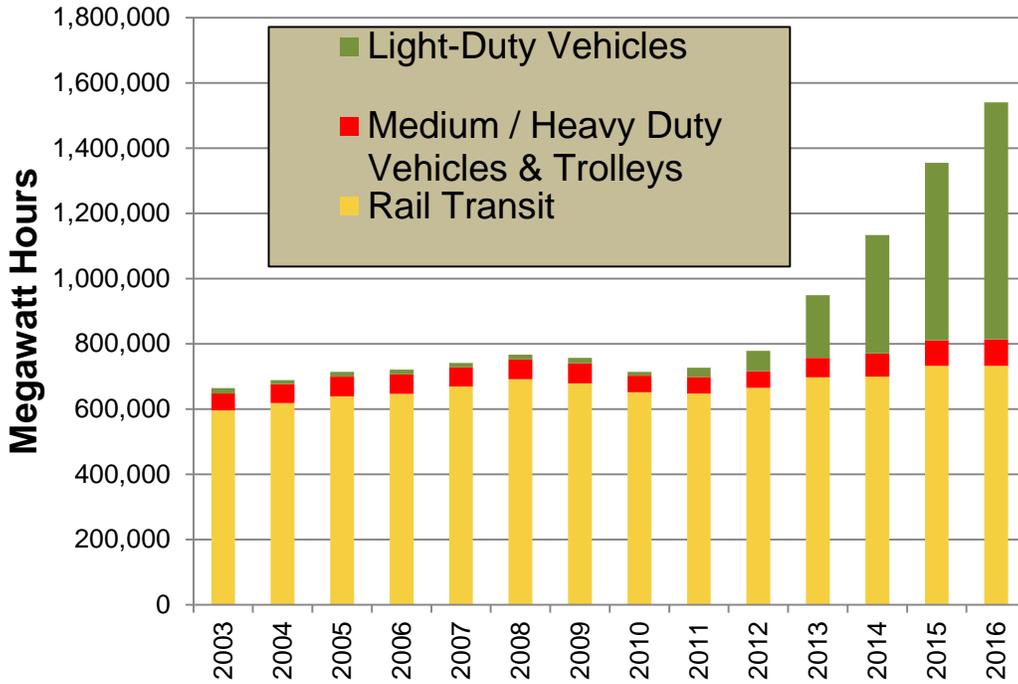
Year	Propane Consumption Gallons¹	LNG Consumption Gallons²	CNG Consumption Therms³	Hydrogen Consumption Kilograms
2003	18,455,500	27,970,031	98,033,540	728
2004	23,317,500	28,307,916	98,291,858	15,555
2005	22,999,500	28,645,800	113,150,176	9,275
2006	19,983,500	28,983,685	117,058,495	17,454
2007	18,316,000	22,400,000	119,325,161	19,987
2008	18,391,000	18,900,000	127,599,355	23,971
2009	22,861,067	29,635,453	139,456,782	38,292
2010	26,632,877	32,356,377	145,186,972	34,096
2011	29,139,991	35,487,647	151,230,879	52,179
2012	33,028,638	30,492,564	160,369,476	73,443
2013	34,755,459	31,868,353	165,759,354	66,276
2014	31,834,779	33,082,102	179,462,285	64,499
2015	25,806,328	34,000,572	181,989,469	62,708
2016	5,793,698	31,605,833	198,408,653	110,575

Preliminary Values

Source: 1) Table 25A- Taxable Distributions of Diesel Fuel and Alternative Fuels, 1937–1938 to 2009–2010 fiscal year data averaged over two years to estimates calendar year values for years 2003 through 2008. 2) LNG data from verbal reports to Energy Commission reporting unit by suppliers. 3) CNG data obtained from the annual *California Gas Reports*. 1998–2016 reports available at <https://www.pge.com/pipeline/library/regulatory/cgr/index.page> 4) National Transit Authority annual reports and California Department of Motor Vehicles fuel cell vehicle registrations. Fuel cell vehicles assumed driven 9,600 miles/vehicle/year and U.S. Environmental Protection Agency Adjusted Combined Cycle fuel economy National Transit Authority Reports, Data Tables, Table 17, Energy Consumption, Other, or Hydrogen Fuels

Finally, an increasing amount of electricity is being used for transportation energy, as depicted in Figure 42. The growth since 2010 is attributed chiefly to the acceleration of light-duty plug-in electric vehicles.

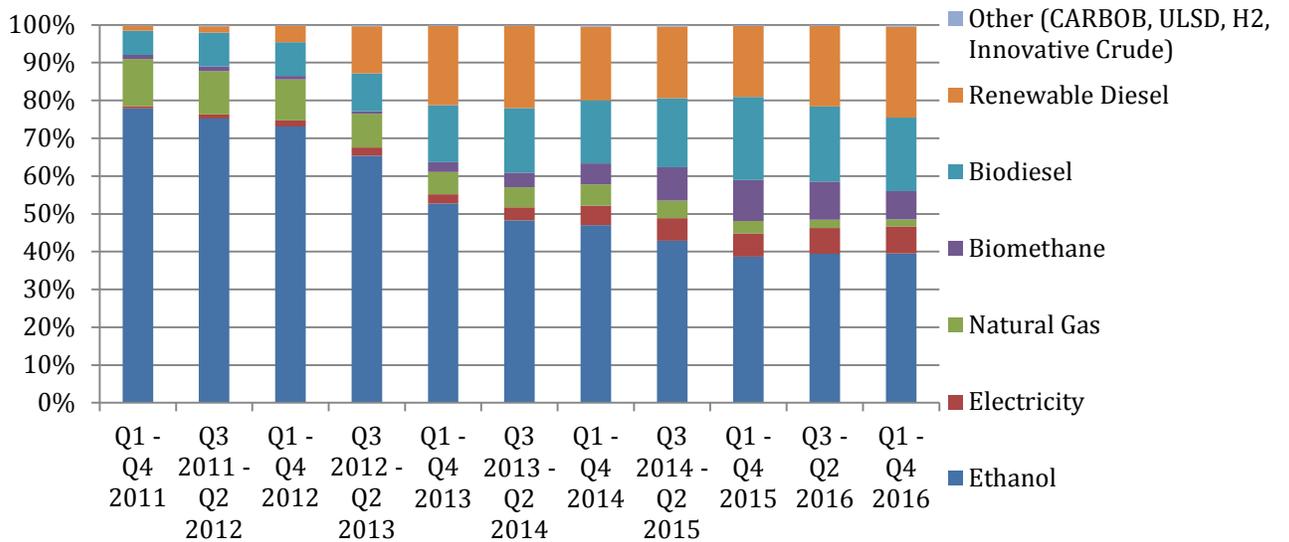
Figure 43: California Transportation Electricity Consumption (2003–2016)



Sources: Federal Transit Administration and California Energy Commission analysis of California Department of Motor Vehicle data

To the extent that these alternative fuels generate GHG emission reductions compared to gasoline or diesel, they are eligible to receive credits under the LCFS. Figure 43 summarizes the share of LCFS credits attributable to each alternative fuel type from 2011 through 2016.

Figure 44: California LCFS Credit Portion by Fuel Type (2011–2016)

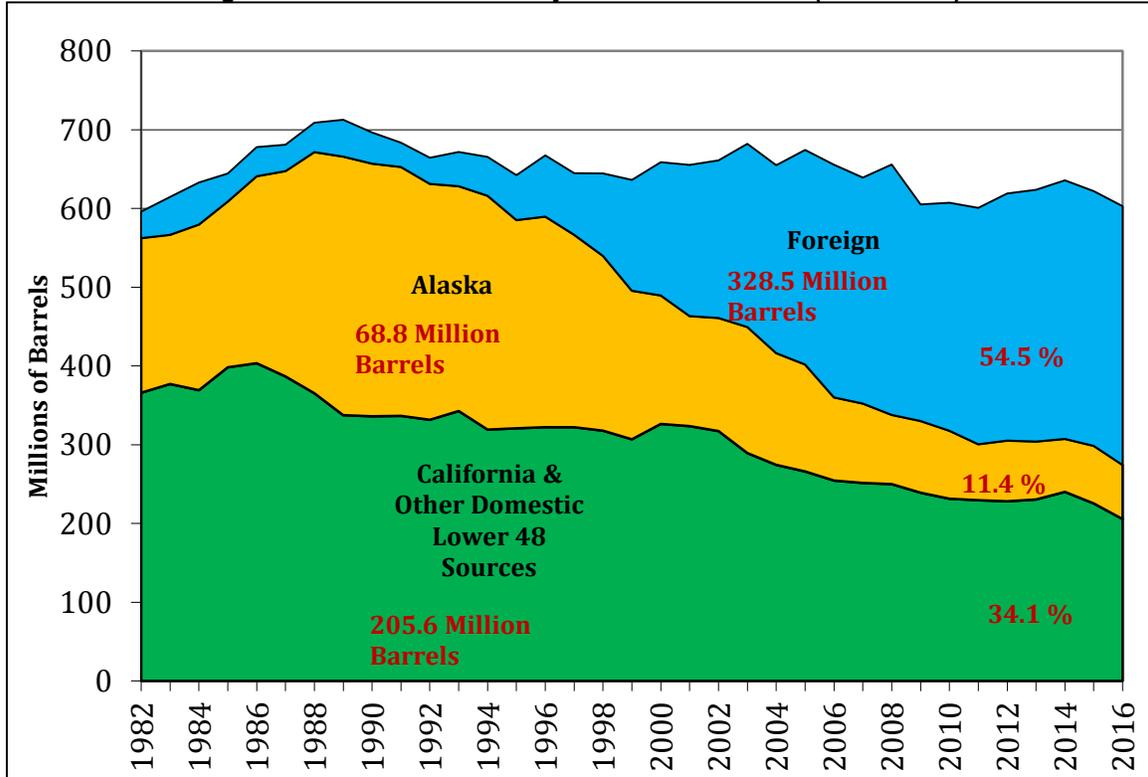


Source: California Air Resources Board

Crude Oil Supply and Price Trends

California continues to be a net importer of crude oil. In-state production peaked in 1985 at about 424 million barrels per year and has since declined to 194 million in 2016. As a result, California refineries rely on foreign sources of crude for more than half of their supply, as shown in Figure 44.

Figure 45: California Refinery Crude Oil Sources (1982–2016)

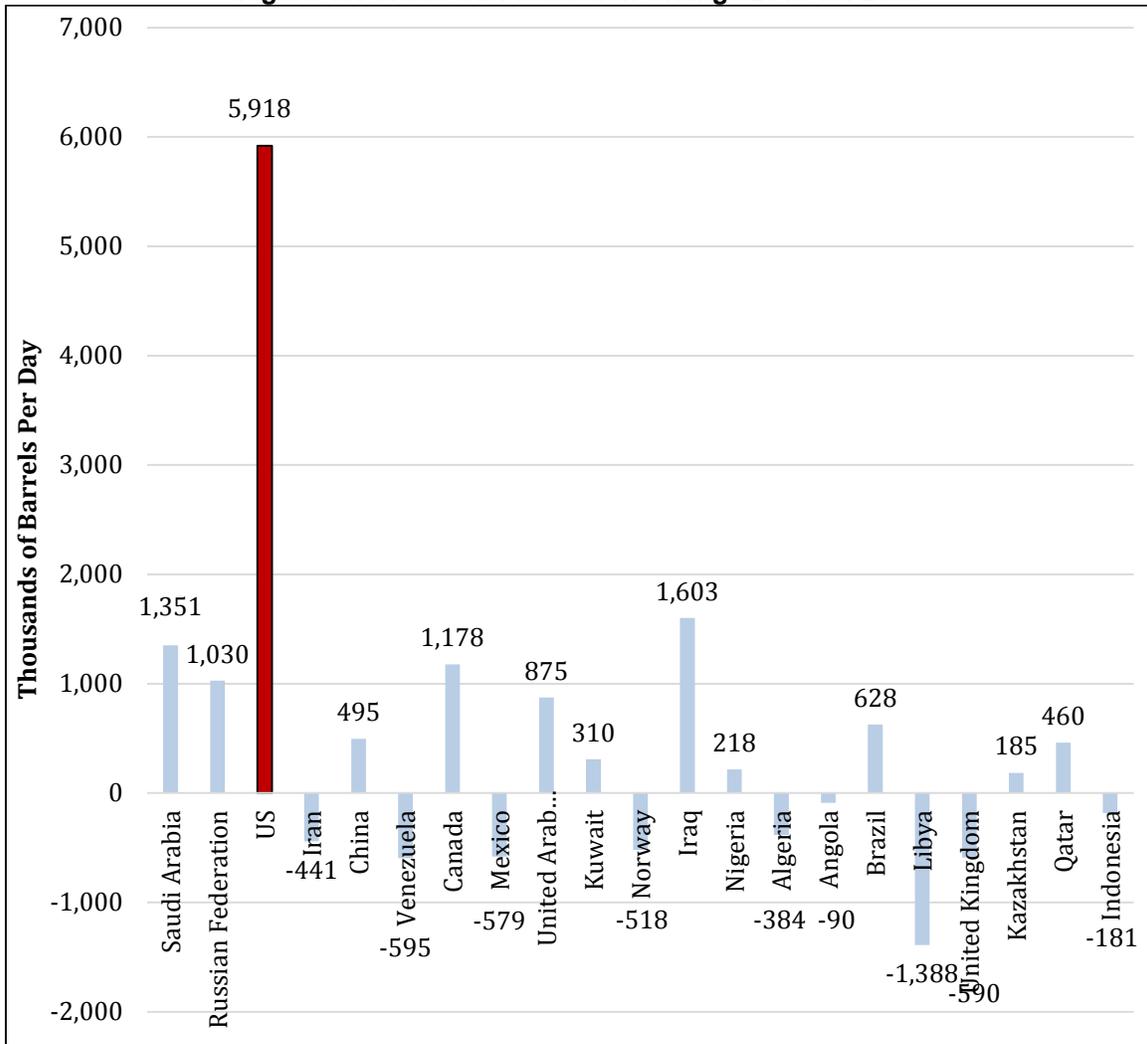


Source: Petroleum Industry Information Reporting Act

While domestic production of crude in California has dropped significantly in recent decades, the opposite has been true in the United States overall. The combination of horizontal drilling techniques and hydraulic fracturing, or “fracking,” has significantly expanded the potential oil resources available within the United States. In particular, tight oil formations in the Bakken basin (North Dakota), Eagle Ford basin (southern Texas), and Permian basin (western Texas) have all seen notable growth in production over the last decade, from fewer than 1 million combined barrels per day in 2007 to 4.4 million barrels per day as of March 2017.

As a whole, production within the United States stood near 8.8 million barrels per day at the start of 2017. The United States has been unique internationally in this growth, as shown in Figure 45.

Figure 46: Crude Oil Production Change 2015 vs. 2008

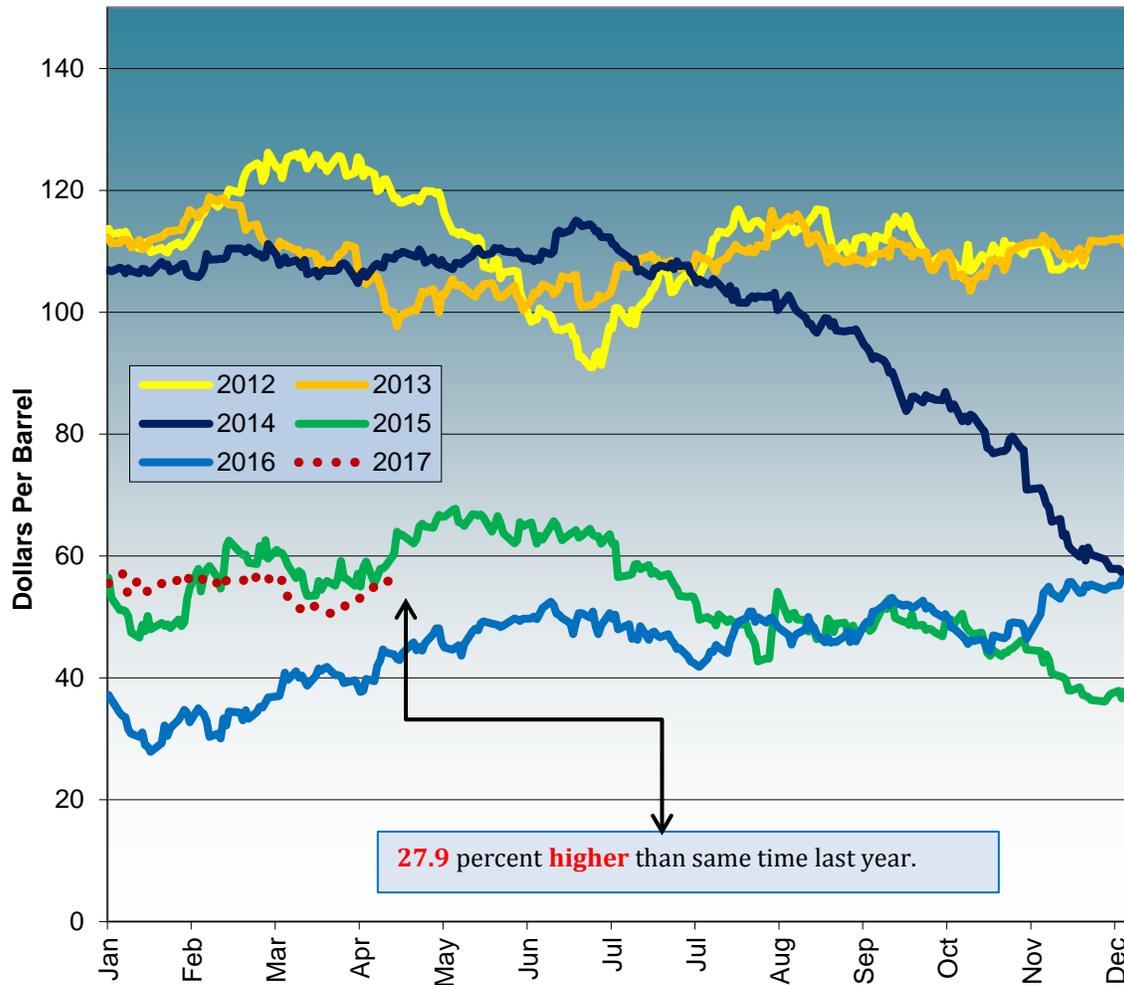


Sources: 2016 BP Statistical Review and Energy Commission analysis

As domestic crude production continued to swell at the start of this decade, an oversupply began to exert downward pressure on international crude prices. This was a result of growing production within the United States, as well as an unwillingness of Saudi Arabia and other Organization of Petroleum Exporting Countries (OPEC) to cut their production to maintain the price. In January 2017, OPEC (and some non-OPEC states) developed an agreement to curtail their production once it became apparent U.S. producers were not sufficiently deterred by lower prices.

The Brent North Sea crude oil price provides a reasonable surrogate for the price of foreign crude oil processed in California refineries. Figure 46 shows the barrel price of crude oil for this benchmark over a calendar year, from 2012 through April 2017.

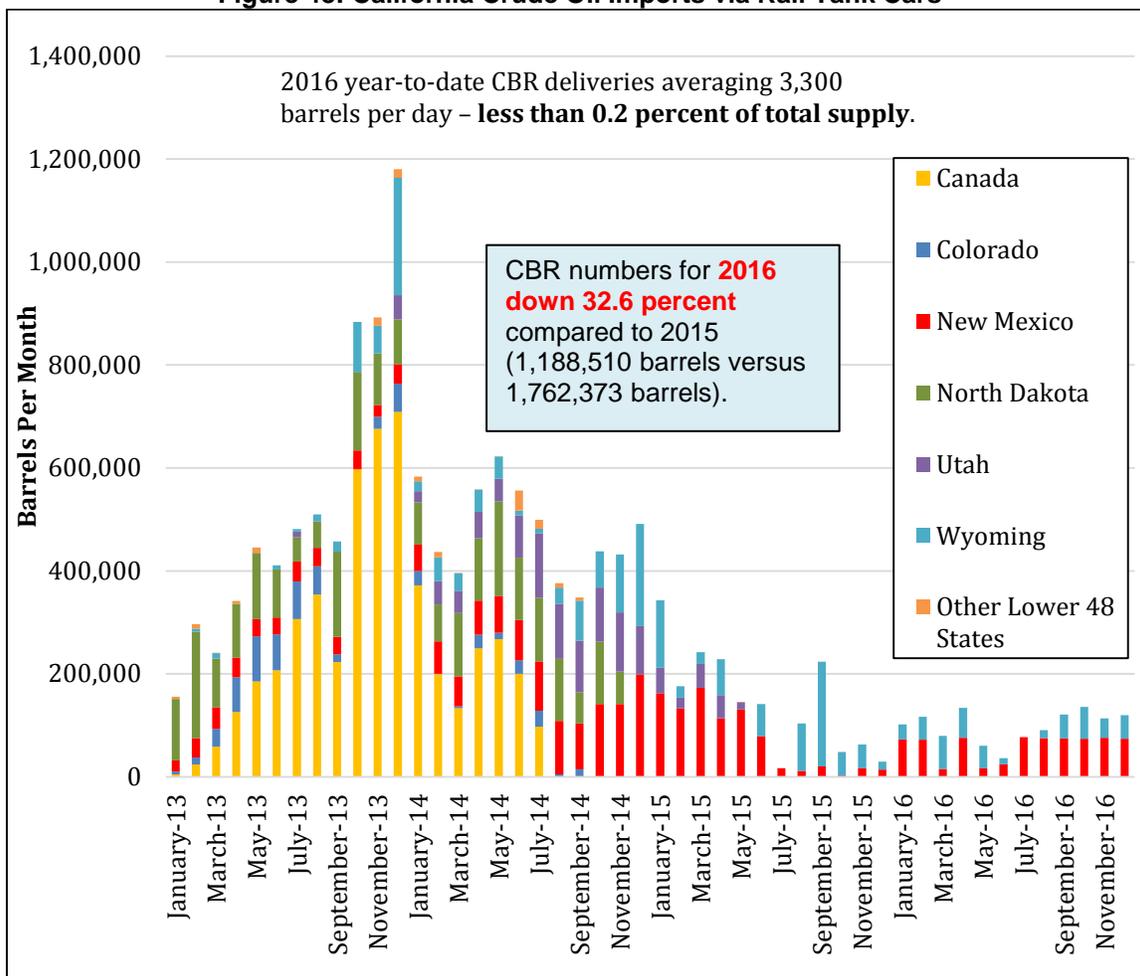
Figure 47: Daily Brent Crude Oil Prices (2012 Through April 18, 2017)



Source: Energy Information Administration

While international crude benchmarks were still running high in the decade’s early years, discounted fuel from the United States remained attractive to California refiners. This discounted fuel, in combination with a lack of crude oil pipeline infrastructure into the state, spurred the growth of transporting crude by rail. However, such deliveries have slowed since the peak in late 2013 as international market prices approached equilibrium with cheaper U.S. production. Figure 47 shows the rate of California crude oil imports via rail in terms of barrels per month.

Figure 48: California Crude Oil Imports via Rail Tank Cars



Source: Petroleum Industry Information Reporting Act data, Energy Commission analysis

Future growth in crude by rail imports would depend largely on increasing the number of receiving facilities constructed within the state, as well as the return of heavily discounted U.S. crude. Construction of such receiving facilities has been the subject of local controversies in California; however, Washington state has several receiving facilities operational, with plans for more. Appendix A of the *Transportation Fuel Supply Outlook* outlines projects in California and the Pacific Northwest.

California Refinery Operations

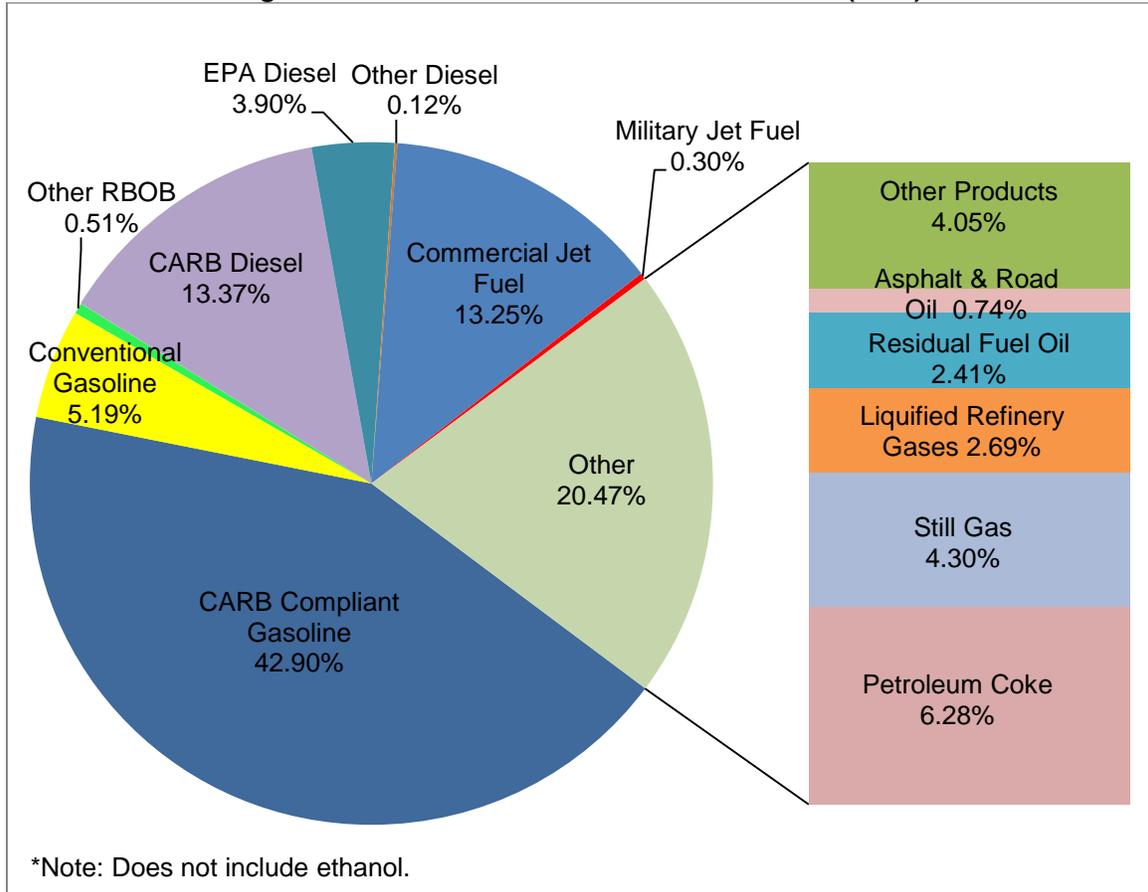
In 2016, California's 15 refineries processed about 1.6 million barrels of crude oil per day.⁴²⁹ Eight of these refineries are in Northern California, processing about 731,000 barrels per day, and seven are in Southern California, processing about 906,000 barrels per day. In terms of fuel outputs, the Northern and Southern California refineries produce roughly comparable proportions of CARB-compliant gasoline, export gasoline, CARB diesel, EPA diesel, and

⁴²⁹ For comparison, California consumed 42 million gallons a day of gasoline, 10 million gallons a day of diesel, and 11 million gallons a day of jet fuel in 2016. If measured in barrels, this would equate to nearly 1.5 million barrels per day of gasoline, diesel, and jet fuel.

commercial jet fuel. Northern California produces a higher share of CARB diesel, while Southern California produces slightly higher shares of EPA diesel and commercial jet fuel.

The combined outputs of all California refineries are shown in Figure 48. These include various compliance mixes of gasoline, diesel, and jet fuels, plus about 20.5 percent “other” refined products and coproducts.

Figure 49: Product Slate of California Refineries (2016)



Source: California Energy Commission

Responses to Significant Refinery Disruptions

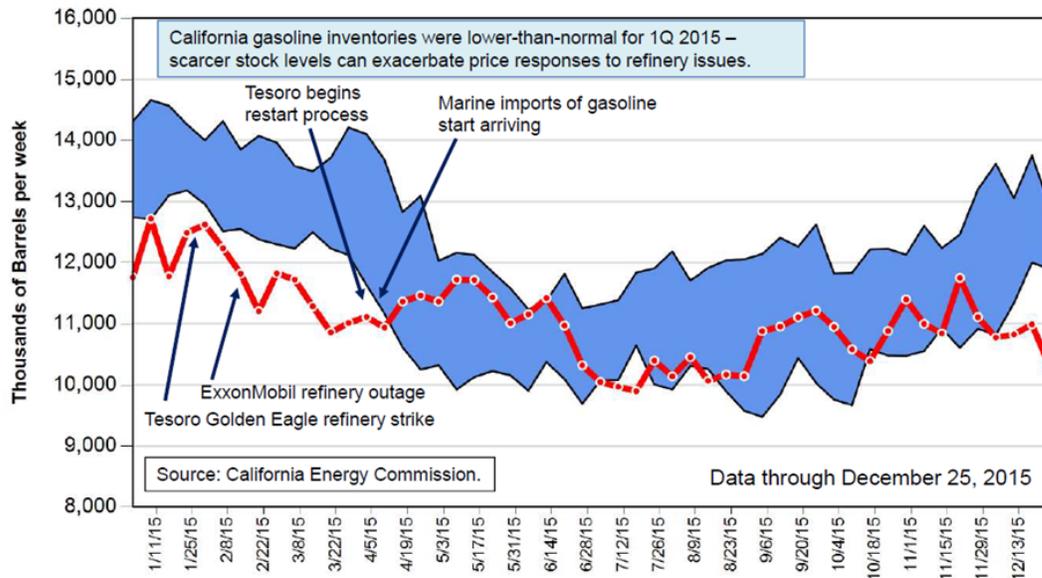
Although California may depend on imports for its share of crude, the state is nearly self-sufficient for its finished gasoline supply and in recent years has been a net exporter of finished diesel fuels. However, planned and unplanned refinery issues in 2015 tested the ability of California’s infrastructure to meet gasoline market demand.

At the beginning of 2015, finished gasoline and gasoline blendstock inventories were already below the five-year range, as depicted in Figure 49. At the same time, the Tesoro Golden Eagle Refinery in Martinez (Contra Costa County) went from a planned maintenance period, to a labor stoppage, to a slowed return to full operation through April. This facility is the fourth largest in California by nameplate capacity.

More dramatically, on February 18, 2015, an explosion at the (then ExxonMobil-owned) Torrance Refinery in Southern California injured two workers. The explosion also damaged the electrostatic precipitator of the refinery, which meant that related gasoline-producing process equipment could no longer operate. Gasoline production would remain offline for roughly 17 months at California’s sixth largest refinery by nameplate capacity.

Figure 50: California Gasoline Inventories Lower Than Normal (Early 2015)

California CARB Gas and Blendstocks Inventories (with 5-Year High-Low Band)



Source: U.S. Energy Information Administration

The pathways for quickly importing finished gasoline or gasoline blendstocks are limited. There are no pipelines for importing gasoline into California; the only existing pipelines connecting California refiners to Nevada and Arizona operate in the reverse direction. Tanker trucks can be quick (a few days, rather than weeks) but could cost double or more than cheaper marine delivery options. Rail tanker cars have few distribution terminals in California that can receive product, and refineries themselves are not configured for it. This leaves delivery from marine vessels as the primary option for importing gasoline or gasoline blendstock.

Unfortunately, the logistics of marine vessel delivery of gasoline are not ideal for responding to sudden price spikes. The timeline for delivery is often in weeks, rather than days. Furthermore, many cargoes of imported gasoline are valued at the average price of gasoline the day before and the day after a delivery is made. This creates significant risk for the importer; for example, a drop in the market price of 10 cents per gallon during the weeks of delivery can equate to a loss of \$1.26 million on a shipment of 300,000 barrels.

In its February 2015 report on refinery maintenance, the U.S. Energy Information Administration noted, “Because the West Coast is relatively isolated from other U.S. markets and located far from international sources of supply, the region is very dependent on in-region production to meet demand.” Unfortunately, several other West Coast facilities were also scheduled for maintenance in February through May 2015. As a result, throughout 2015 California became more dependent on foreign imports of gasoline and gasoline blendstocks.

The lag between higher prices in Southern California and the importation of gasoline and gasoline blendstocks from foreign nations is captured in Figure 50. The black line represents the cost difference of the Los Angeles gasoline spot market price above the similar price in the New York Mercantile Exchange (NYMEX) gasoline spot market. The bars represent the source of California’s foreign imports. As shown, the LA-NYMEX price spread averaged above \$0.30 for most of 2015 (compared to a historical average of \$0.16) and spiked as high as \$0.80 in July 2015. The addition of foreign imports roughly responds to the LA-NYMEX price spread with a one-month lag. For instance, sudden increases in the price spread in February and July were respectively met with significant

Petroleum Market Advisory Committee

In December 2014, the California Energy Commission assembled the Petroleum Market Advisory Committee to help assess petroleum market issues of interest to the Commission. Following the February 18, 2015, Torrance Refinery explosion the committee began exploring the response of the petroleum market to that event. Of primary concern were the three gasoline price spikes that occurred in the first half of 2015. During its meetings, the committee heard from several stakeholders within the gasoline market, including government agencies, traders, retailers, distributors, news organizations, market analysis firms, and environmental and consumer groups. Refinery companies declined all requests for participation. Several policy options were discussed to lessen California’s exposure to these types of events. The committee delivered a report summarizing its work to the Commission on September 13, 2017.

In its report, the committee highlighted that from 2000 through January 2015, the average differential between California and US average gasoline prices could be accounted for by taxes, GHG reduction costs, and the extra cost of producing CARB-grade gasoline. Since the Torrance Refinery fire, however, price differentials have been 10-70 cents per gallon higher than could be explained by these same factors. In June 2017, California gasoline cost more than 75 cents above the national average, of which only about 39 cents could be similarly explained.

The committee’s report also stated that the unexplained cost differentials since the February 2015 fire imply that Californians have paid more than \$12 billion more than they would have if the price differential reflected only taxes, GHG programs, and the extra cost of producing CARB gasoline.

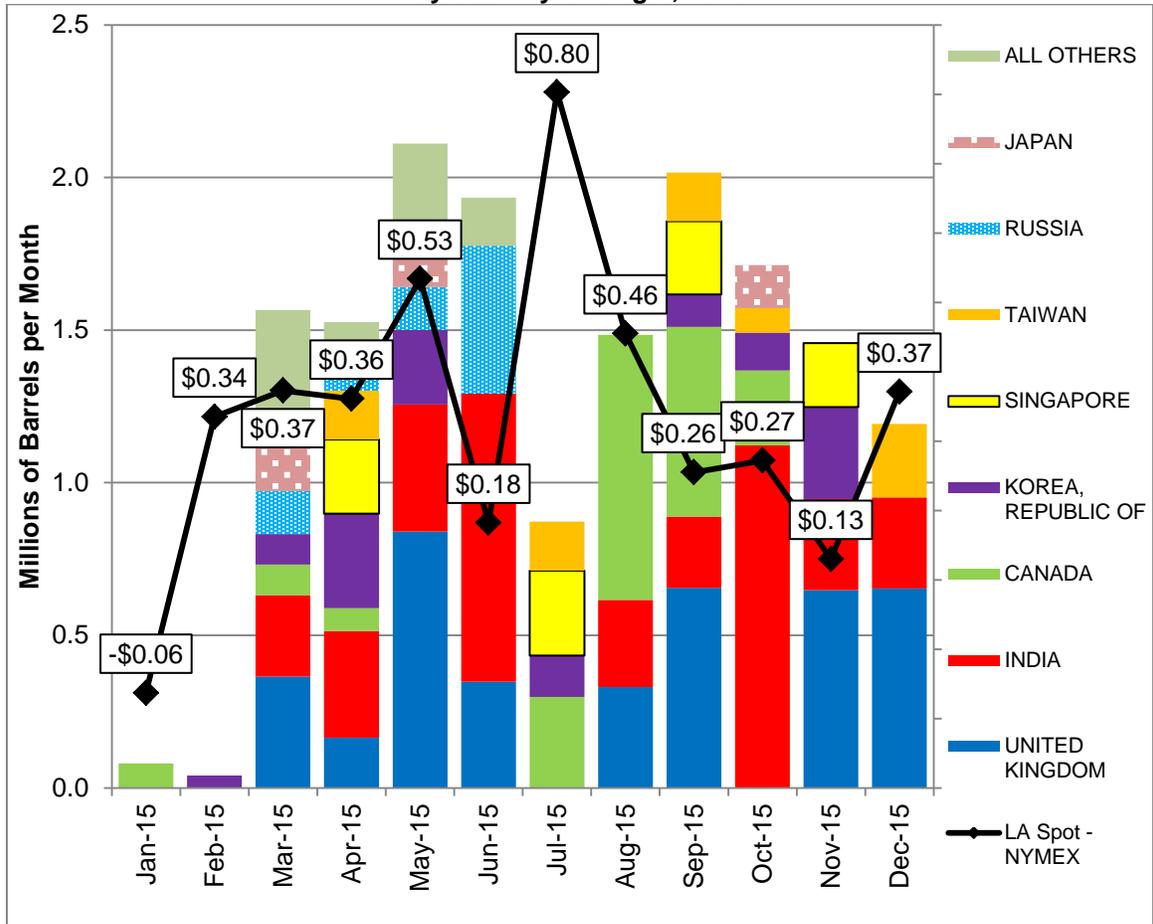
Borenstein, Severin, Kathleen Foote, Dave Hackett, Amy Jaffe, and James Sweeney. Petroleum Market Advisory Committee, 2017. *Petroleum Market Advisory Committee Final Report, December 2014 to November 2016*. California Energy Commission. Publication Number: CEC-200-2017-007.

Meeting transcripts and materials can be found at: http://www.energy.ca.gov/assessments/petroleum_market/.

Additional records and public comments can also be found under Energy Commission Docket Number: 15-PMAC-01.

increases in foreign imports March and August, while a price spread decline in June was followed by a decline in imports in July.

Figure 51: Monthly Foreign Imported Gasoline and Gasoline Blendstocks by Country of Origin, 2015

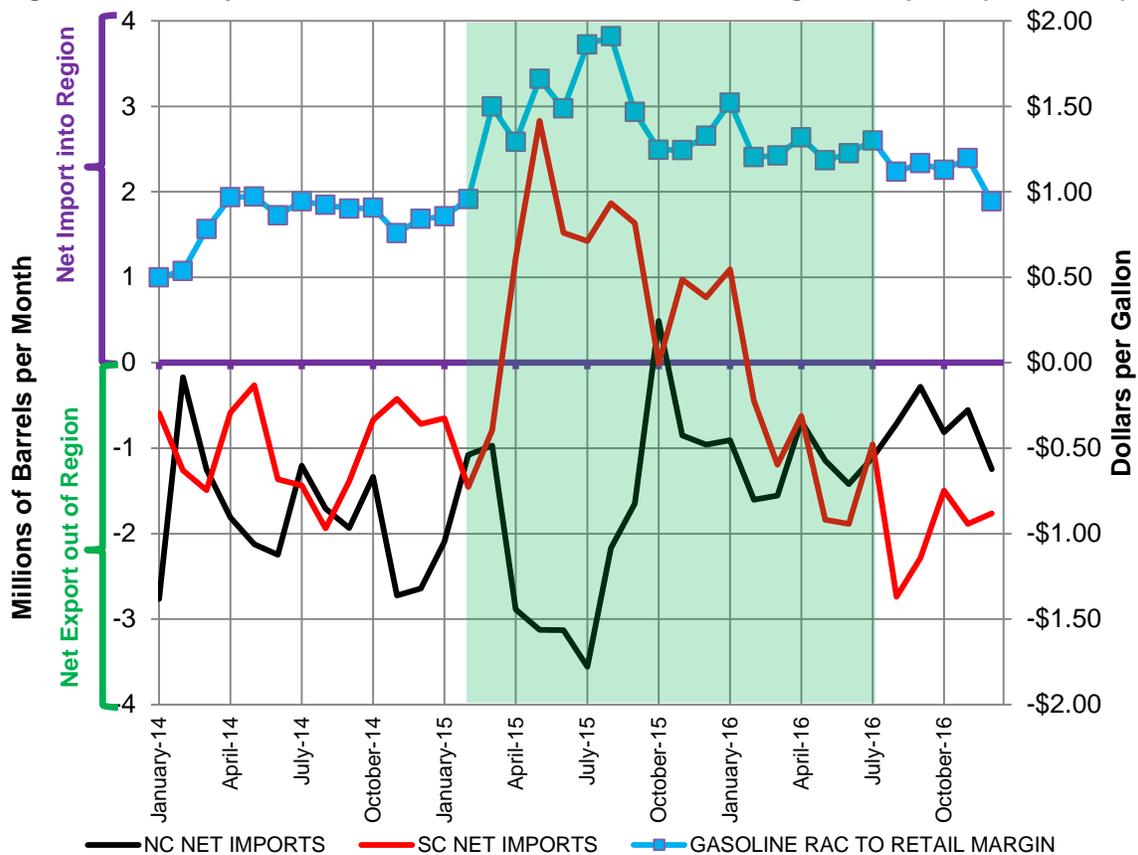


Source: Energy Information Administration

The difference between pretax retail gasoline prices to California's average crude oil prices rose significantly, from a 2014 average of \$0.75 per gallon to a high of \$1.91 in 2015. A reasonable assumption is that some of these costs arose from importing gasoline products from distant locations such as India and the United Kingdom.

Leading up to 2015, Southern California had been trending as a net exporter of petroleum products; however, gasoline production declines at the Torrance Refinery changed that trend drastically. Based on an analysis of import flows, the 2015 gasoline shortage created a shift of roughly 3 million barrels per month (or 126 million gallons per month) in the net import balance of Southern California. Figure 51 shows the drastic impact of this shift in Southern California's net importing on a monthly basis. From January 2014 through January 2015, Southern California (the red line) is a net gasoline exporter (net importing is below zero), until it spikes upward immediately in response to the Torrance disruption.

Figure 52: Monthly Net Gasoline and Gasoline Blendstocks Regional Imports (2014–2016)



Source: California Energy Commission

This rapid shift of roughly 3 million barrels per month represented roughly 10 percent of California’s monthly average gasoline consumption; roughly the same amount of gasoline that the Torrance Refinery would be estimated to produce from the gasoline-production equipment that was offline.

Refinery Supply Concerns

The *Transportation Fuel Supply Outlook* also focuses on a handful of potential refinery supply issues that could impact suppliers in California. However, whether these supply issues would subsequently impact the retail price of refined fuels, and to what extent, is unclear.

Among these supply issues is a proposed rule by the South Coast Air Quality Management District to phase out a specific type of catalyst used with alkylation units, an important source of gasoline-blending components. One potential outcome is a ban on hydrofluoric acid, one of two types of compounds used in the alkylation process in refineries around the world. (Sulfuric acid is the other type of catalyst.) Hydrofluoric acid has the potential to volatilize into a vapor cloud that is very harmful to anyone who comes into contact with it.

Two refineries in California rely on hydrofluoric acid: PBF in Torrance and Valero in Wilmington. If hydrofluoric acid were banned entirely, there could be negative impacts to the supply of

transportation fuels similar to or exceeding the price consequences of the February 2015 explosion at ExxonMobil's Torrance Refinery. If, for instance, there was an inadequate physical footprint for a duplicate alkylation unit, the demolition and construction of a new sulfuric alkylation unit could take at least 18 to 24 months. More broadly, there is uncertainty as to whether the refining company could justify the investment into making the requisite changes; costs of new alkylation units can run in the hundreds of millions of dollars.

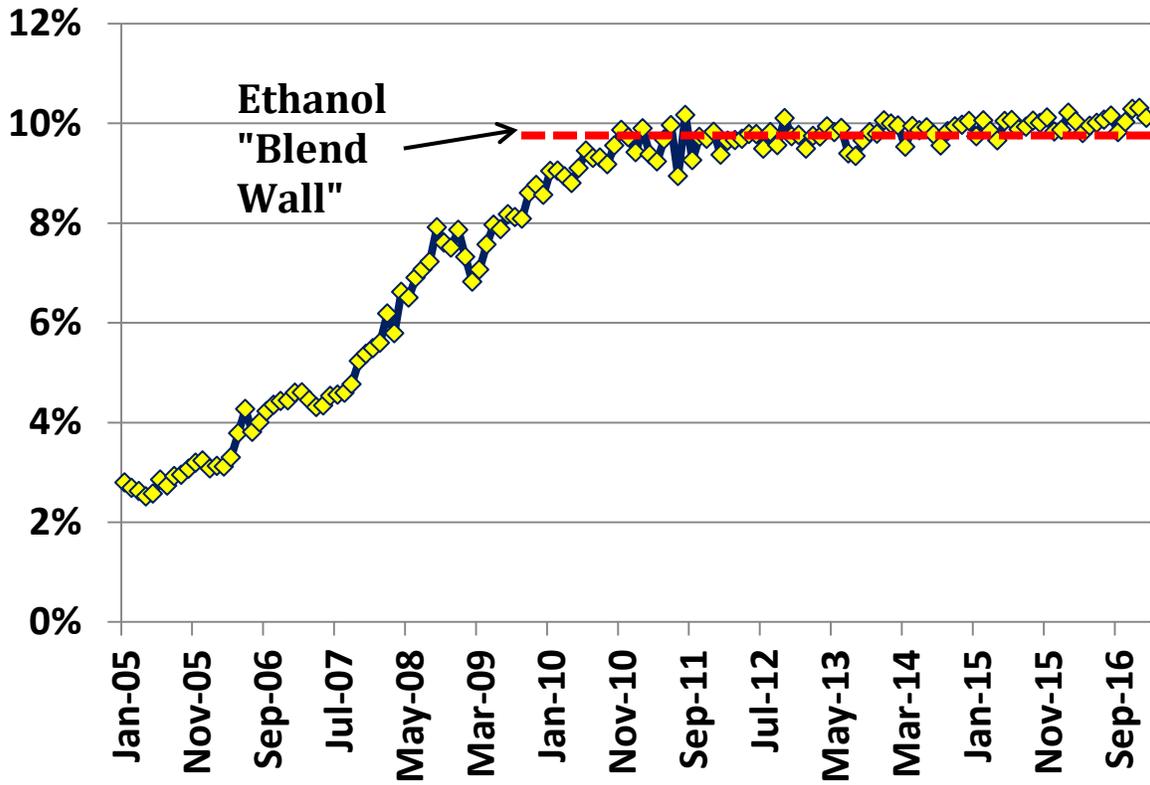
There is also the potential for changing bunker fuel specifications to affect California's refinery operations. Residual fuel oil leftover from the production of gasoline, diesel, and jet fuel is consumed primarily by marine vessels as bunker fuel that has been blended with higher sulfur diesel fuel. Sulfur content limits for bunker fuel are scheduled to be lowered through international agreements via the International Maritime Organization. At a July 6, 2017, IEPR workshop, the group 20|20 Marine Energy presented changes to bunker fuel specifications planned by the International Maritime Organization. A 2020 change has the potential to increase demand for ultralow-sulfur diesel fuel in the vessel bunkering business internationally. In California, however, this would likely reduce demand for that product, as Asian refineries would be able to produce the needed fuel at lower costs. The group 20|20 Marine Energy indicated that this would be a major demand disruption to California refineries regarding bunker fuel production, but global traders would still be able to provide fuel.

Renewable Transportation Fuel Supply

The *Transportation Fuel Supply Outlook* devotes considerable attention to the current market and regulatory status of renewable fuels that are frequently blended with gasoline and diesel – namely, ethanol, biodiesel, and renewable diesel. The amount of biofuel blended into gasoline and diesel has been steadily increasing in recent years. As discussed, more than 80 percent of the GHG emission reductions credited under the LCFS come from ethanol, biodiesel, or renewable diesel.

When measured by concentration in finished motor gasoline, ethanol use has steadily grown from about 3 percent by volume during 2005 to 10.1 percent in January 2017, as shown in Figure 52. The plateau of roughly 10 percent this decade reflects the fact that most states place a regulatory cap on the amount of ethanol that can be blended, often known as the “blend wall.” Nevertheless, sales of E15, E85, and other mid-range blends continue to grow as specialized dispensers expand in the retail market.

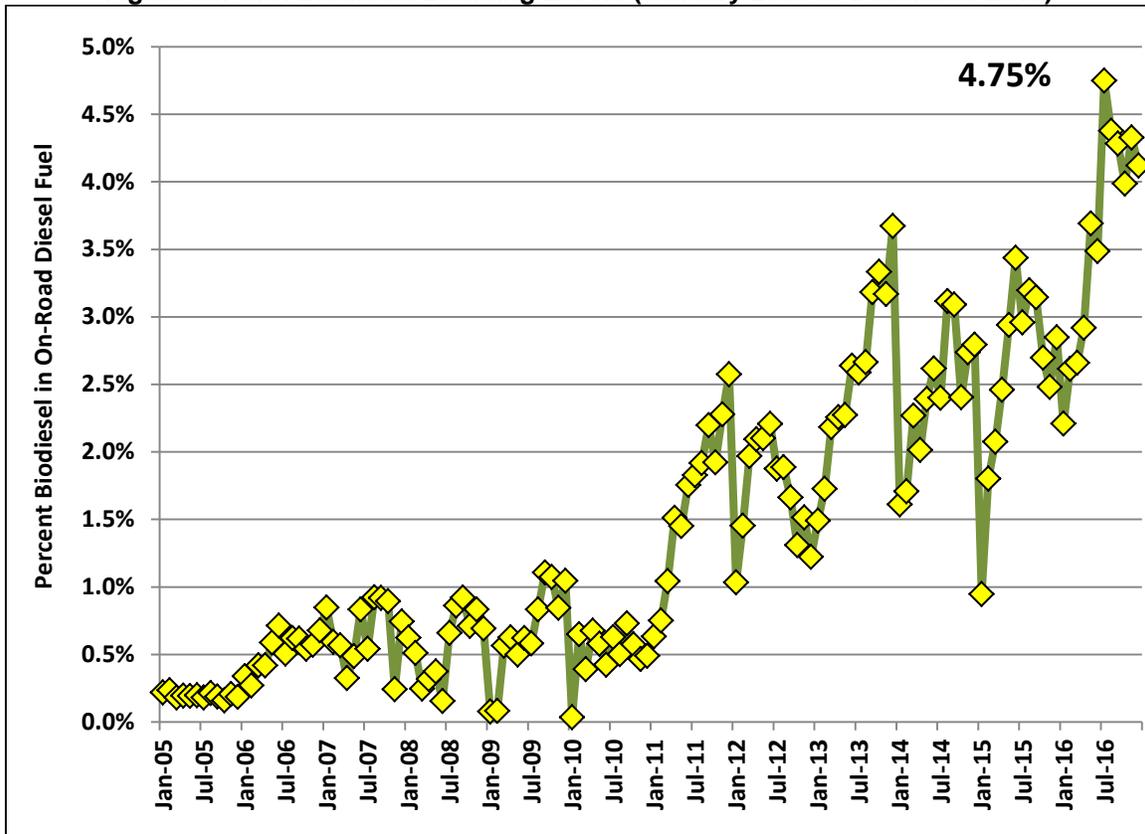
Figure 53: U.S. Ethanol Concentration in Finished Gasoline (January 2005 to January 2007)



Sources: California Energy Commission analysis of U.S. Energy Information Administration data

Biodiesel use within the United States has expanded significantly since 2011, as shown in Figure 53, when a blenders tax credit was reinstated and the Renewable Fuel Standard required minimum biomass-based diesel levels. National use of biodiesel is expected to grow as well, as RFS2 regulations require the use of 2 billion gallons of biodiesel in 2017 and 2.1 billion gallons in 2018.

Figure 54: U.S. Biodiesel Blending Levels (January 2005 to December 2016)



Sources: Energy Information Administration and California Energy Commission analysis

Within California, biodiesel blending limits are the subject of CARB’s Regulation on Commercialization of Alternative Diesel Fuels. The intent of the regulation is to reduce the potential oxides of nitrogen emissions associated with the use of biodiesel. Under the regulation, the maximum concentration of biodiesel would be 10 percent from November through March and 5 percent from April through October. However, there is uncertainty as to whether and how biodiesel distribution entities will be able to switch between these two maximums each year. This uncertainty creates the potential for a blending limit that is effectively 5 percent throughout the year. This will also impact some distributors who dispense biodiesel at a 20 percent blend.

The *Transportation Fuel Supply Outlook* indicates that both ethanol and biodiesel will reach the maximum blend limits in gasoline (at 10 percent ethanol) and diesel (at 5 percent biodiesel) in 2017. As a result, growth may be limited. Renewable diesel, however, will not be limited in this way. The report also outlines feedstock issues associated with biodiesel, which may offer opportunities for biodiesel and renewable diesel with lower life-cycle carbon intensities.

Fuel Price Impacts of Hurricanes

Hurricane Harvey made initial landfall near Rockport, Texas, with sustained winds of 130 mph beginning on August 25, 2017. This storm system yielded the greatest amount of rainfall in history for the continental United States. (See Chapter 10 for information about how climate change increases the risk of major weather events.) Twenty-one refineries on the U.S. Gulf Coast either

shut down as a safety precaution in advance of the initial landfall of the hurricane or closed afterward due to excessive flooding, lack of crude oil access, or lack of ability to send fuel through the normal pipeline and marine distribution infrastructure systems. At the peak on August 30, 2017, nearly 4.6 million barrels per day of crude oil processing capacity was offline.

While major hurricanes like Harvey do not directly impact California's fuel supply (since California does not normally receive gasoline and diesel fuel supplies from refineries along the U.S. Gulf Coast), fuel prices in California can be affected since prices are influenced by changes in the gasoline and diesel fuel futures contract markets. Between August 24 and September 5, 2017, national retail gasoline prices increased 30 cents per gallon, with California retail gasoline prices increasing by just over 14 cents per gallon.

Transportation Energy Demand Forecast

Energy Commission staff developed a preliminary transportation energy demand forecast in June 2017. A public workshop on June 20, 2017, outlined some of these preliminary transportation energy demand forecast results.⁴³⁰ This forecast was integrated into the larger preliminary California energy demand forecast for electricity and natural gas.

Based on feedback following the preliminary forecast workshop and updated inputs, Energy Commission staff subsequently developed a revised transportation energy demand forecast in October 2017. A second public workshop on December 4, 2017, presented the revised transportation energy demand forecast.⁴³¹ To accompany the workshop, staff developed a more comprehensive report on the forecast, titled *Transportation Energy Demand Forecast 2018–2030*.⁴³² The staff report includes a more detailed discussion of the method behind the forecast, as well as more granular results than are covered here.

Forecasting Approach

There are several methods to examine the path for vehicle growth or energy use over time. Some methods begin with a target (such as a quantity of vehicles, fuels, or emissions) and work backward from there to create intermediate goals for the intervening years. Common examples include scenarios generated to demonstrate how a given policy goal or regulation, such as CARB's ZEV regulation compliance scenarios or *Mobile Source Strategy*, can be achieved. These scenarios can create informative benchmarks of desirable progress.

The Energy Commission's *Transportation Energy Demand Forecast* offers an alternative, but complementary, perspective. Staff uses a suite of models (described in Table 14) that incorporate consumer preferences, regulations, economic and demographic trends, projected improvements in technology, and other market factors to forecast transportation energy demand. In this way, the forecast can be used by policymakers to assess progress toward statewide goals.

⁴³⁰ Workshop materials are available online at http://www.energy.ca.gov/2017_energypolicy/documents/#06202017.

⁴³¹ Workshop materials are available online at http://www.energy.ca.gov/2017_energypolicy/documents/#12042017.

⁴³² Bahrenian, Aniss, Jesse Gage, Sudhakar Konala, Bob McBride, Mark Palmere, Charles Smith, and Ysbrand van der Werf. 2017. *Transportation Energy Demand Forecast, 2018-2030*. California Energy Commission. Publication Number: CEC-200-2017-010. Available online at <https://efiling.energy.ca.gov/getdocument.aspx?tn=221893>.

Table 14: Energy Commission Transportation Forecasting Models

Model Category	Model	Description	Key Inputs
Vehicle Demand Models	Personal Vehicle Choice (LDV)*	Generates forecast of household demand for light-duty vehicles by 15 size classes and 10 fuel types, in 3 market segments, based on consumer preferences and behavior.	-Fuel cost -Vehicle attributes and incentives -Household population and income
	Commercial Vehicle Choice (LDV)	Generates forecast of commercial demand for light-duty vehicles by 15 size classes and 10 fuel types, based on consumer preferences and behavior.	-Fuel cost -Vehicle attributes and incentives -Gross state product
	Government (LDV)	Uses rules to grow government LDVs by fuel/technology types, from the base-year stock	-Gross state product - Fuel economy
	Rental (LDV)	Uses rules to grow rental vehicles from the base-year stock	-Gross state product -Fuel economy
	Neighborhood Electric Vehicles	Grows vehicles from the base-year stock	-Gross State Product
	Truck Choice Model (Medium/Heavy Duty)	Uses Argonne TRUCK 5.1 model to project different truck fuel types and technology market penetration	-Fuel cost -Fuel economy -Vehicle prices and incentives
Travel Demand Models	Urban Travel	Predicts choices among travel modes (including auto, bus, rail, and others) and forecasts short-distance personal travel and fuel demand for all travel modes	-Fuel cost -Travel cost -In-and-out of vehicle travel time -Population -Personal income
	Intercity Travel	Composed of two models: one predicts volume of travel, and the other predicts choices among long-distance travel modes (auto, rail, airplane)	-Fuel cost -Travel cost -Departure frequency -Personal income
	Air Travel	Composed of two models: one predicts passenger aviation, and another predicts freight aviation	-Travel cost -Personal income -Population
	Freight Energy Demand (Freight Movement)	Composed of two models: one forecasts vehicle movement and fuel demand for goods movement and modal choice for truck vs. rail; the other forecasts local and regional movement and fuel demand for medium- and heavy-duty delivery, services, recreation and other economic activities	-Fuel cost -Shipment size -Travel time -Gross state product
	Other Bus Travel	Model predicts growth of school buses, demand response (paratransit), and shuttle buses	-Population -Income -Gross state product

Source: California Energy Commission *LDV stands for "light-duty vehicle."

Key Inputs and Assumptions

Energy Commission staff used a variety of inputs and assumptions to generate the forecast results. Different combinations of inputs and assumptions are used to create several plausible demand cases, which are described below.

Common Demand Cases

The transportation energy demand forecast incorporates three demand cases that are designed to be consistent with the larger energy demand forecast discussed in Chapter 6. Major variations include assumptions about economic and demographic trends, and fuel price projections, as shown in Table 15. These inputs and assumptions impact the vehicle and travel demand forecast as measured by vehicle miles traveled, which is correlated with population and income growth and fuel price decreases.

Table 15: Common Electricity Demand Cases Main Inputs

Demand Case	Population	Income	Fuel Prices	
			Petroleum Fuels	Electricity / Natural Gas / Hydrogen
High Demand	High	High	High	Low
Mid Demand	Mid	Mid	Mid	Mid
Low Demand	Low	Low	Low	High

Source: California Energy Commission

The transportation demand cases are designed to be consistent with the demand cases used for forecasting total electricity and natural gas demand, since the results are integrated with the broader California energy demand forecast. For instance, the high transportation electricity demand forecast will be integrated into the high electricity and natural gas demand forecasts.

California Department of Motor Vehicles Data

Vehicle registration data from the California Department of Motor Vehicles (DMV) serve as base-year data for forecasting the growth of various vehicle types within the state. The Energy Commission periodically receives raw vehicle registration data from the DMV and processes the data to disaggregate them, into LDV and MD/HD vehicles. The LDV data is then broken down into, 15 vehicle classes, nine fuel types, model-year vintages, and four market segments.

Fuel Price Forecast

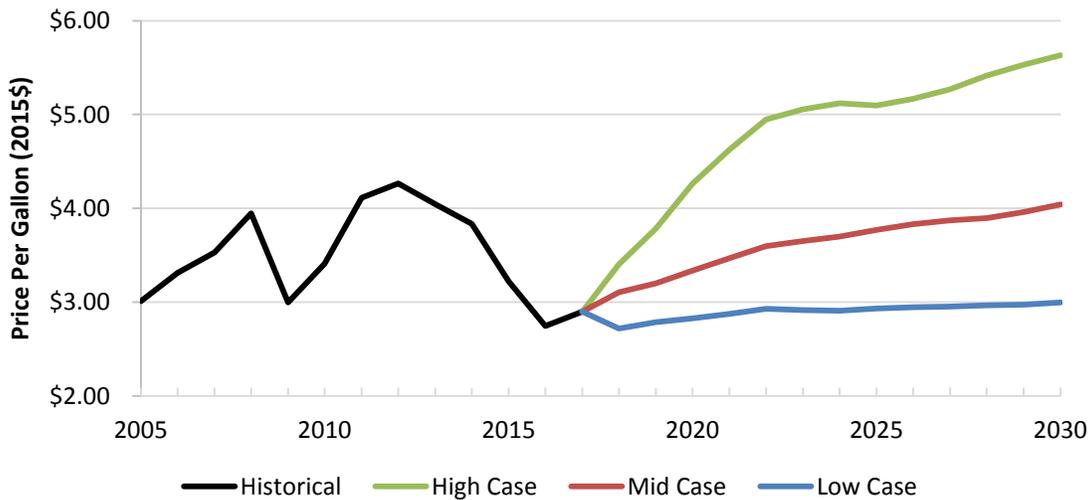
Within the forecast, fuel prices impact the type of vehicles purchased, as well as the total number of miles traveled per year. Specifically, higher prices for a particular fuel makes a consumer less likely to buy a vehicle that relies on that fuel, less likely to use that fuel in a vehicle that can use

multiple fuels, less likely to use that vehicle for travel, and more likely to buy a vehicle with greater fuel economy.

All forecast transportation fuel price cases are developed by the Energy Commission staff (with the exception of the hydrogen prices) but are also based on broader price trends. Fuel price cases for gasoline and diesel reflect the U.S. Energy Information Administration's nationwide forecasts of gasoline and diesel prices in its *2017 Annual Energy Outlook*.

To translate national fuel price forecasts into California fuel price forecasts, the Energy Commission staff considered the historical relationship between annual U.S. and California retail prices. Next, the Energy Commission incorporates changes in state and federal taxes, as well as forecasted changes to the LCFS and the carbon market established under AB 32. The resulting gasoline and diesel prices cases proposed for the low, reference, and high energy demand cases are shown in Figure 54.

Figure 55: California Regular Gasoline Price Cases (2015 Dollars per Gallon)



Source: California Energy Commission

Alternative fuel price forecasts are based on a variety of sources but are usually tied to broader market prices for the fuel outside the transportation sector. For instance, the price cases for electricity in the transportation forecast match the average residential electricity rate used in other sectors of the electricity demand forecast. Similarly, the transportation price cases for compressed natural gas (CNG) reflect the residential, commercial, and industrial price scenarios developed by Energy Commission staff for the natural gas demand forecast. These transportation price cases reflect the relationship among the residential, commercial, industrial, and transportation nationwide forecasts generated by the U.S. EIA. Meanwhile, the price cases for E85 are developed using the energy content ratio of E85 to gasoline, in combination with the Energy Commission's price cases for gasoline in the future.

In developing price cases for hydrogen, the Energy Commission relied on analysis from the National Renewable Energy Laboratory (NREL), which also informs the 2017 version of an

annual hydrogen station assessment by the Energy Commission and CARB required by Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013).⁴³³ This hydrogen price incorporates the utility-level prices for natural gas and electricity developed for the *2017 IEPR*. The price also incorporates the requirement by Senate Bill 1505 (Lowenthal, Chapter 877, Statutes of 2006) to dispense a minimum of one-third renewable hydrogen from publicly funded hydrogen refueling stations.

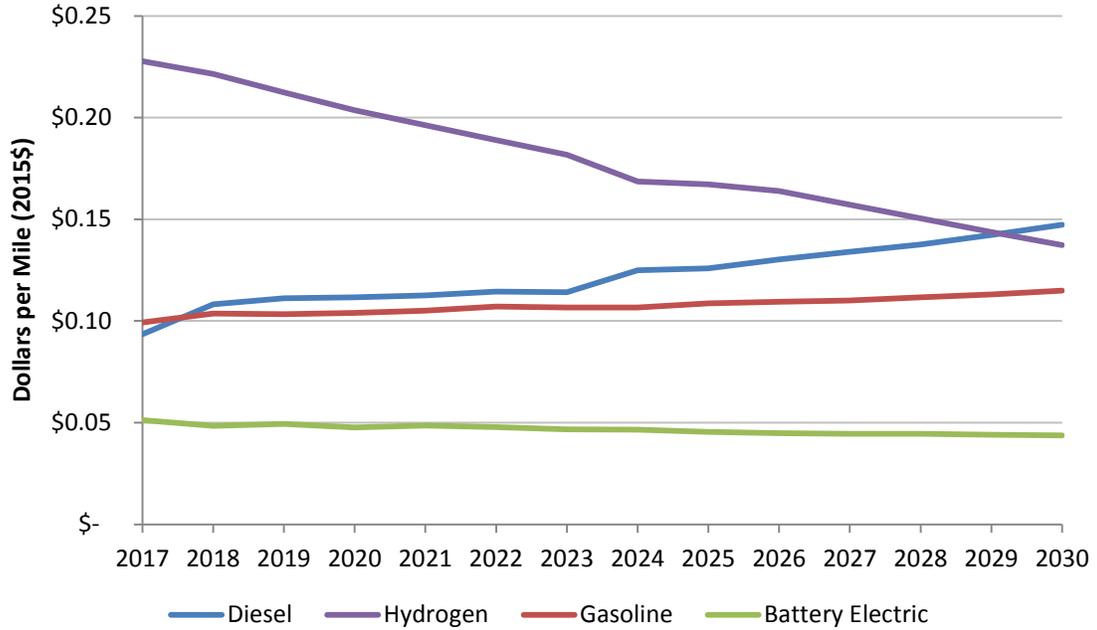
Both conventional and alternative fuel prices can be converted into identical energy units, such as megajoules,⁴³⁴ British thermal units, or gasoline-gallon equivalents. However, such a comparison would overlook the relative efficiencies of different vehicle technologies. For example, a BEV will travel farther than a comparably sized car with a gasoline combustion engine on the same number of megajoules. This is a key feature of the transportation energy demand forecast, which uses cost per mile (not just cost per energy unit) in gauging consumers' preferences for different vehicle options.

Figure 55 compares the approximate cost *per mile* of gasoline, diesel, and several alternative fuels among midsize cars in the light-duty vehicle sector for the reference fuel price forecast. As shown, the cost per mile of electricity remains significantly lower than gasoline or diesel. Based on input from NREL, the cost per mile of hydrogen for fuel cell electric vehicles is expected to decline over time in response to increasing economies of scale for new hydrogen refueling stations. (However, most fuel cell vehicles are being leased with special “free fuel” conditions for a period of several years.)

433 Baronas, Jean, Gerhard Achtelik, et al. 2017. *Joint Agency Staff Report on Assembly Bill 8: 2017 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California*. California Energy Commission and California Air Resources Board. Publication Number: CEC-600-2017-011. Available at <http://www.energy.ca.gov/2017publications/CEC-600-2017-011/CEC-600-2017-011.pdf>.

434 A “megajoule” is 1 million joules. It is the standard unit of work or energy in the International System of Units, equal to the work done by a force of one newton when the point of application moves through a distance of one meter in the direction of the force.

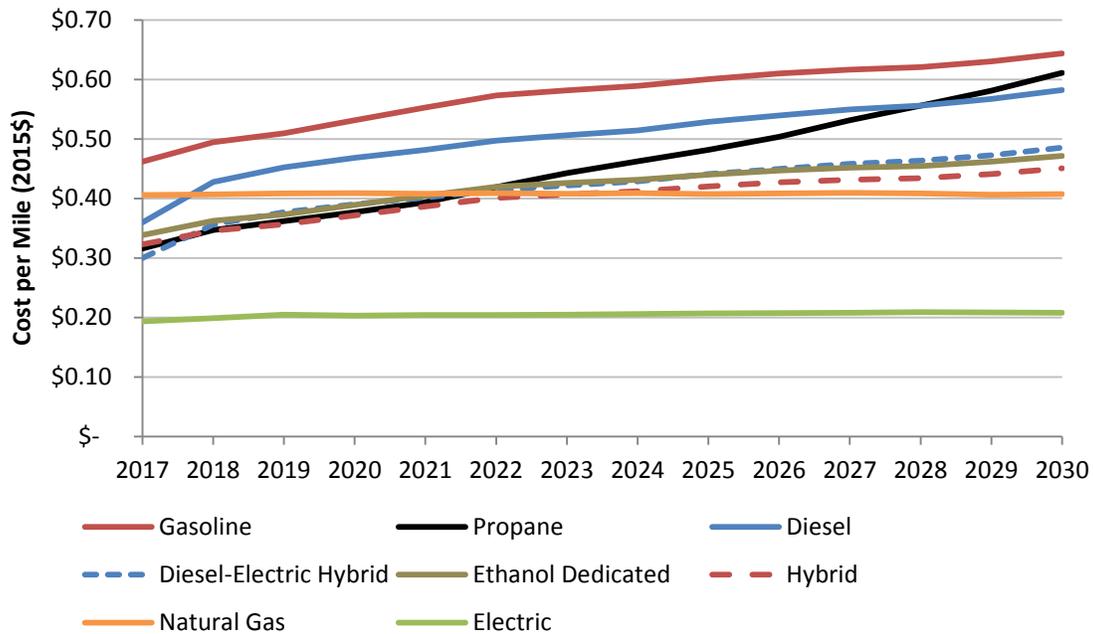
Figure 56: Fuel Cost per Mile Trends for Light-Duty Vehicles (Midsize Cars), Mid Case



Source: California Energy Commission, NREL

Figure 56 shows the cost per mile of various fuels for medium-duty (Classes 4–6) trucks. The cost per mile continues to increase, reflecting the continuous increase in the revised forecast of conventional fuel prices over the forecast horizon (2017–2030), even as there is an increase in fuel economy over the same period. Although the relative positions of gasoline, diesel, and electricity are the same, the costs per mile are higher than in Figure 55 due to the lower overall efficiency of medium-duty trucks compared to light-duty vehicles.

Figure 57: Fuel Cost per Mile Trends for Medium-Duty (Classes 4–6) Trucks, Mid Case



Source: California Energy Commission

Consumer Preferences (Light-Duty Vehicles)

Consumer preferences are a key component in developing the Energy Commission’s forecasts of size and composition of the LDV population. To gauge consumer preferences, the Energy Commission periodically surveys residential and commercial LDV owners. The latest survey was contracted to Resource Systems Group. The main survey data collection phase began in second half of 2016 and concluded in February 2017.

The Commission conducts two surveys, one composed of commercial LDV owners and the other composed of residential LDV owners, depending on the use of a vehicle for “personal” or “commercial” purposes. This survey is done to capture the historically distinct preferences between the two groups. The 2016 survey included both conventional vehicle owners, as well as PEV owners in both commercial and the residential surveys.

In the stated preferences part of the survey, participants are presented with a series of hypothetical vehicles with different attributes and government incentives and asked which one they would choose to buy. The choices help the Energy Commission assess consumer preferences for different vehicle attributes, fuel types, and vehicle classes.

Table 16 highlights some of the recent trends in consumer preferences, comparing the results of consumer surveys in 2017 against those of 2013.

Table 16: Recent Trends in Consumer Preferences for Light-Duty Vehicles

Residential	Commercial
Higher preferences for ZEVs	Higher preferences for ZEVs
Vehicle price is less important	Vehicle price remains the most important attribute
Vehicle range is more important	Vehicle range is more important
Tax credit and rebate are more important, HOV lane access is less important	Tax credits and HOV lane access both important
Fuel economy is less important	Fuel economy is less important
	Acceleration is more important

Source: California Energy Commission

Vehicle Attributes (Light-Duty Vehicles)

Once the survey measured consumers’ preferences for different attributes, fuel types, and vehicle classes, those preferences can be matched against a forecast of vehicle attributes by vehicle class and fuel type that are anticipated to be offered in the market by automakers.

Key vehicle attributes include:

- Range.
- Vehicle price.
- Fuel economy.
- Fuel cost per mile.
- Acceleration.
- Number of makes and models.
- Refueling time.
- Maintenance costs.
- Cargo capacity.

For the 2017 forecast, the Energy Commission contracted with NREL to develop projections of light-duty vehicle attributes that are likely to be available in the market. Given the heightened focus of the *Transportation Energy Demand Forecast, 2018–2030* on vehicle electrification and compliance with CARB regulations for ZEVs, Energy Commission staff specifically revisited and revised assumptions relating to BEV and PHEV prices and electric driving range and generated different scenarios for plug-in electric vehicle (PEV) price and range. For more details on the attributes used to forecast these sales, see the subsequent section “Electrifying Light-Duty Vehicles.”

Medium- and Heavy-Duty Truck Alternative Fuel Penetration Rates

To determine the penetration rates of alternative fuels and advanced vehicle technologies for medium- and heavy-duty trucks, the revised forecast relies on a vehicle choice model developed by Argonne National Laboratory. As constructed, the model is limited to one conventional “base”

fuel (such as gasoline or diesel) and up to three alternative fuel trucks for each class. In response to this limitation, Energy Commission staff assigned alternative fuels and technologies to truck classes based on available indicators of early market introduction. Staff also applied California-specific distributions of vehicle counts for vehicle miles traveled ranges to the model, as well as California-specific fuel prices and incentives for alternative fuels.

Certain truck price and fuel economy forecasts were provided by H-D Systems. Truck prices for alternative fuels were based on an assumption that production reaches high volume by the end of the forecast period, achieving a lower price than the low volume typical during early commercialization. Fuel efficiency is assigned by H-D Systems according to the truck duty cycle most common for each truck class.⁴³⁵

Transitioning to Cleaner Transportation

To meet federal clean air standards, reduce overall GHGs, and reduce petroleum dependence within California, the state must clean up the transportation sector. One way to accomplish this is to electrify transportation, and many rules, regulations, policies, and programs throughout the state are focused on vehicle electrification. This effort is visible outside California as several nations have announced plans to transition their automotive fleets away from relying on gasoline and diesel combustion engines. China, the most populous nation in the world, has proposed to end the sale of gasoline and diesel vehicles, with a date to be determined.⁴³⁶ Leaders in India, the second most populous nation, have proposed 2030 as the year in which all new cars should be electric.⁴³⁷ Norway has set a goal of eliminating gasoline and diesel car sales by 2025, and a similar plan is under consideration in the Netherlands for 2030.⁴³⁸ The Bundesrat in Germany passed a resolution (not legally binding) to ban combustion engines in that country by 2030.⁴³⁹ Leaders in France and the United Kingdom have also announced plans to end the sale of gasoline and diesel vehicles by 2040.⁴⁴⁰

435 H-D Systems is the medium and heavy duty vehicle attributes consultant used for the 2017 IEPR. "Duty cycle" is the pattern of operation, such that refuse trucks that stop at each residence and use energy to process each curbside container are assigned lower fuel efficiency than would be typical for freeway driving.

436 Bloomberg, "China Fossil Fuel Deadline Shifts Focus to Electric Car Race," September 10, 2017, <https://www.bloomberg.com/news/articles/2017-09-10/china-s-fossil-fuel-deadline-shifts-focus-to-electric-car-race-j7fktx9z>.

437 The Times of India, "India Aiming for All-Electric Car Fleet by 2030, Petrol And Diesel to be Tanked," April 30, 2017, <https://timesofindia.indiatimes.com/auto/miscellaneous/india-aiming-for-all-electric-car-fleet-by-2030-petrol-and-diesel-to-be-tanked/articleshow/58441171.cms>.

438 Electrek, "The Dutch Government Confirms Plan to Ban New Petrol and Diesel Cars by 2030," October 10, 2017, <https://electrek.co/2017/10/10/netherlands-dutch-ban-petrol-diesel-cars-2030-electric-cars/>.

439 ArsTechnica, "Germany's Bundesrat Votes to Ban the Internal Combustion Engine by 2030," October 10, 2016, <https://arstechnica.com/cars/2016/10/germanys-bundesrat-votes-to-ban-the-internal-combustion-engine-by-2030/>.

440 Bloomberg, "U.K. Joins France, Says Goodbye to Fossil-Fuel Cars by 2040," updated July 26, 2017, <https://www.bloomberg.com/news/articles/2017-07-25/u-k-to-ban-diesel-and-petrol-cars-from-2040-daily-telegraph>.

Policies, Regulations, and Incentives

California has implemented a range of regulations and incentives to advance its clean transportation goals. Several of these regulations and incentives are incorporated into the transportation forecast and vary between light-duty vehicles and medium- and heavy-duty vehicles.

California's ZEV regulation and the federal Corporate Average Fuel Economy (CAFE) standards apply to LDVs. The effects of several LDV incentives were also factored into consumers' vehicle choices. Incentives included in the analysis are the state rebates from the Clean Vehicle Rebate Project administered by CARB, the federal income tax credit, and access to the state's high-occupancy vehicle lanes.

Among medium- and heavy-duty vehicles, several regulatory requirements were incorporated into the revised forecast. CARB's truck and bus regulations, for instance, require diesel particulate filters and also updating to 2010 or newer engines on a schedule beginning in 2015, with a provision for alternative compliance by fleets. The revised forecast also accounts for fleet requirements in the South Coast area, which require the procurement of lower-emission and alternative fuel vehicles for transit buses, refuse trucks, and certain other fleets.

For transit buses, the forecast also assumes a significant expansion of zero-emission buses within the forecast period. This expansion is in line with CARB's Innovative Clean Transit goal of transitioning all transit buses to zero-emission technologies by 2040. This assumption is justified on the basis of battery-electric buses being cost-competitive with diesel-electric buses, capital costs for transit being borne largely by federal grants, and the reduced costs of fuel and maintenance.

Inputs and Assumptions of PEV Scenarios

California's transportation sector is quickly transforming due to clean vehicle policies, industry investments, and market pressures from changing consumer preferences. The Energy Commission's transportation energy demand forecast must keep pace with this transformation and the Commission must continue robust engagement with transportation sector stakeholders. For this reason, staff formed a subgroup to the Demand Analysis Working Group (DAWG) composed of a diverse set of transportation sector stakeholders to provide input and discuss assumptions and technical issues that affect the transportation energy demand forecast for electrification.

Because of the uncertainties in projecting PEV characteristics over the forecast period, Energy Commission staff created PEV scenarios designed to capture different levels of LDV electricity consumption. These scenarios help determine LDV electricity consumption, which is the major component of transportation electricity demand that is included in the total electricity demand cases. Growth in future transportation electricity consumption is expected to come primarily from light-duty PEVs.

In the first DAWG transportation subgroup meeting, Energy Commission staff generated a set of potential PEV scenarios. Each scenario used one of the three sets of common electricity demand

cases shown in Table 16. Additional inputs and assumptions specific to PEVs were also proposed, including variations in battery price, incentive availability, and recharging convenience. Based on stakeholder feedback, staff narrowed the scenarios for consideration to five (low, mid, high, aggressive, and bookend), which are defined in Table 17.

Table 17: Inputs and Assumptions for PEV Scenarios

	PEV SCENARIOS				
INPUTS	Low	Mid	High	Aggressive	Bookend
PREFERENCES					
Consumers' PEV Preference	Constant at 2017 Level	Increase with PEV Market Growth	Increase with PEV Market Growth	Increase with PEV Market Growth	Increase with PEV Market Growth
INCENTIVES					
Federal Tax Credit	Eliminated after 2019	Decreasing starting 2019	Decreasing starting 2019	Constant through 2030	Constant through 2030
State Rebate	To 2020	To 2025	To 2025	To 2030	To 2030
HOV Lane Access	To 2021	To 2025	To 2025	To 2025 for PHEV / 2030 for EV	To 2025 for PHEV / 2030 for EV
ATTRIBUTES					
Availability of PEVs (in 2030)	PEV models available in 11 of 15 CEC LDV classes	PEV models available in 11 of 15 CEC LDV classes	PEV models available in 11 of 15 CEC LDV classes	PEV models available in 13 of 15 CEC LDV classes	PEV models available in all CEC LDV classes
Vehicle / Battery Price (by 2030)	PEV prices based on battery price declining to ~\$120/kWh	PEV prices based on battery price declining to ~\$100/kWh	PEV prices based on battery price declining to ~\$89/kWh	PEV prices based on battery price declining to ~\$73/kWh	PEV prices reach parity with gasoline vehicles
Avg. Range (2030)	~230 miles	~230 miles	~270 miles	~270 miles	~270 miles
Refuel Time (2030)	15 -21 min	15 -21 min	10-16 min	10-16 min	Same as gasoline
Time to Station (2030)	7-8 min	Same as gasoline	Same as gasoline	Same as gasoline	Same as gasoline by 2025
FORECAST RESULT					
PEV STOCK in 2030	2.6 mil	3.3 mil	3.9 mil	5.3 mil	5.9 mil

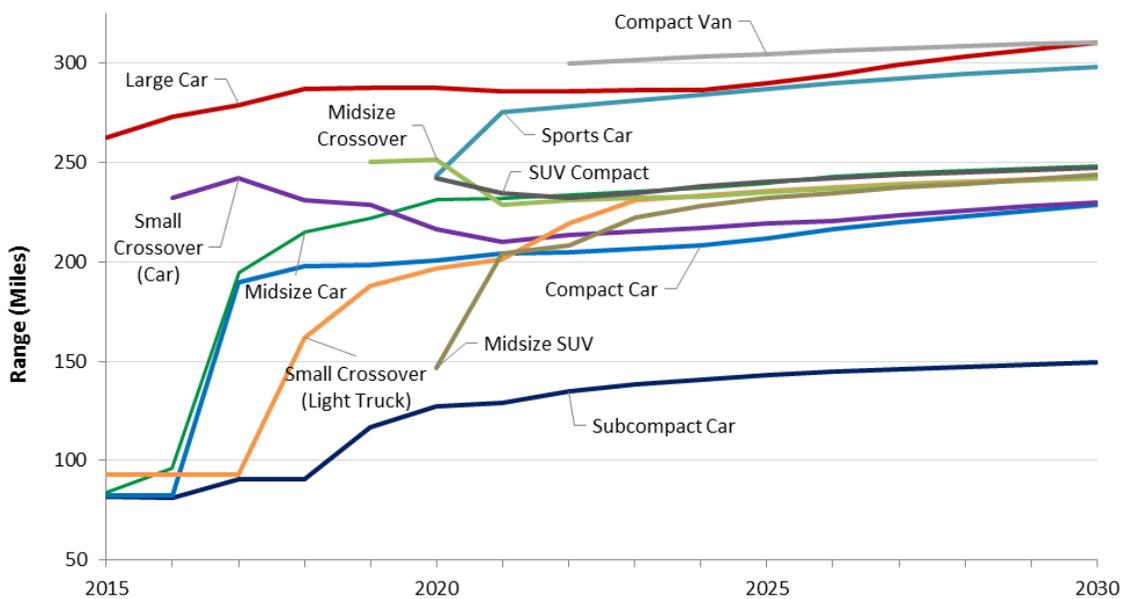
Source: California Energy Commission

The inputs and assumptions for these PEV scenarios range from less favorable to PEV adoption in the low scenario to those more favorable to PEV adoption in the high, aggressive, and bookend scenarios. The high, aggressive, and bookend PEV scenarios used the economic, demographic and fuel price inputs from the high demand case described in Table 16.

Electrifying Light-Duty Vehicles

The *Transportation Energy Demand Forecast, 2018–2030* benefits from a refined focus on LDV electrification, including BEVs, PHEVs, and FCEVs. One of the key attributes of significance for BEV buyers is the expected driving range. In 2015, the range for nonluxury BEVs was limited to 100 miles or fewer. However, beginning with Model Year 2017, several automakers announced plans for more affordable BEVs with increased driving range. Figure 57 depicts the average projected driving range of light-duty BEVs by vehicle class in the mid demand case used in the *Transportation Demand Forecast, 2018–2030*. These projections are based on recent industry announcements, as well as assumptions about long-term manufacturer strategy in response to regulations, projected battery costs, and other market factors.

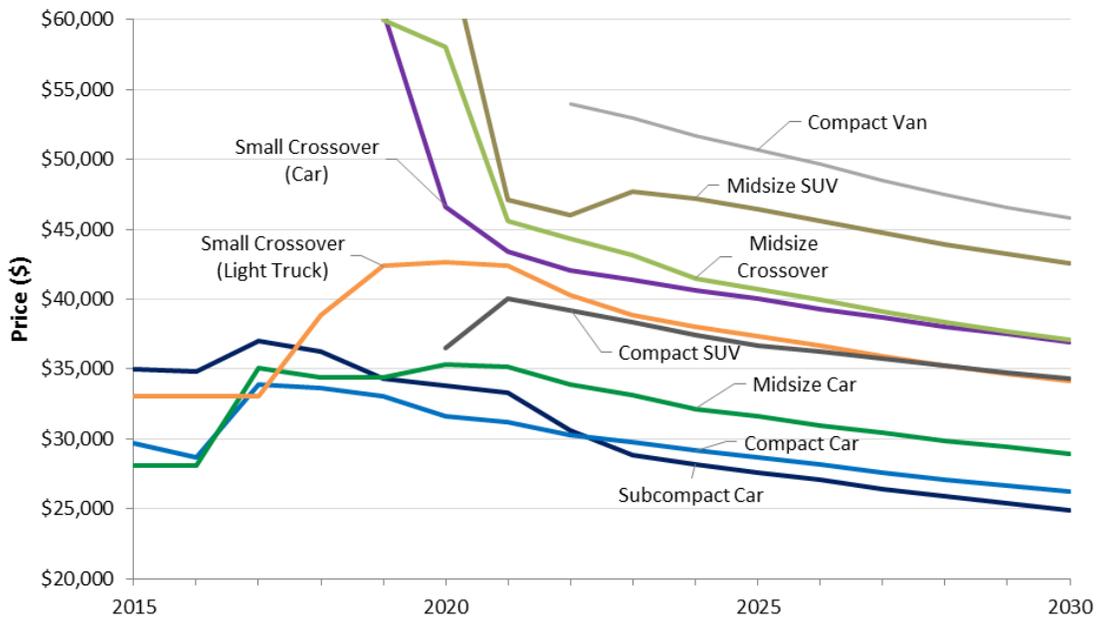
Figure 58: Projected BEV Range by Light-Duty Vehicle Class, Mid Case



Source: California Energy Commission

Similarly, Figure 58 depicts average BEV prices by vehicle class as projected in the mid case within the transportation demand forecast. The rise in average prices between 2015 and 2020 is directly related to the increased driving range of BEVs as forecast in that period. Beyond 2020, the revised forecast anticipates that consumers will demand (and automakers will supply) vehicles with lower upfront costs, in exchange for more modest increases in driving range.

Figure 59: Projected BEV Price by Light-Duty Vehicle Class, Mid Case



Source: California Energy Commission. Note: "Car - Large" price trend is above the displayed axis

Based on the anticipated vehicle attributes and consumer preferences, the transportation forecast includes a range of BEV, PHEV, and FCEV forecasts that can be compared to state policies and benchmarks. For instance, the forecast of BEV, PHEV, and FCEV population from the Energy Commission's transportation forecast can be compared to scenarios from CARB's Advanced Clean Cars Program Midterm Review.⁴⁴¹

In its midterm review, CARB identified a range of low-, mid-, and high-technology scenarios for how automakers might comply with the ZEV regulation. Even in its lowest case, the Energy Commission's forecast for cumulative deployment of BEVs, PHEVs, and FCEVs exceeds the number of vehicles anticipated under CARB's scenarios.⁴⁴² This forecast is shown in Figure 59.

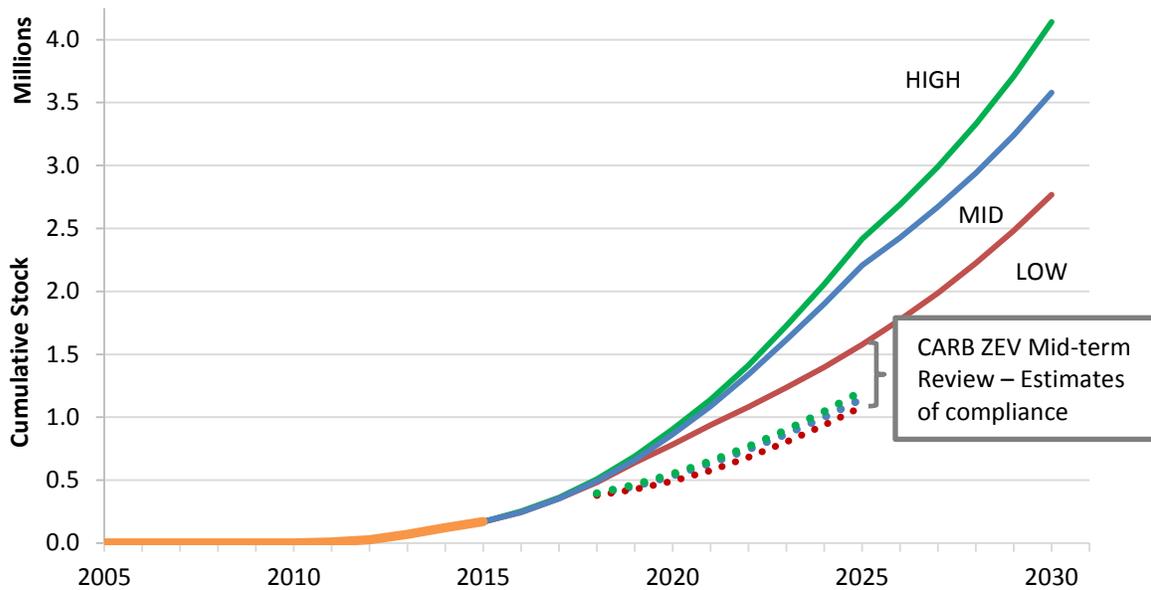
Because compliance with the ZEV regulation is based on a system of credits that vary with vehicle range (and not just vehicle sales), the aggregated vehicle sales numbers are not a measure of compliance. Therefore, Energy Commission staff used a modified version of CARB's 2017 ZEV calculator to confirm that the Commission's forecast did indeed reflect regulatory compliance.⁴⁴³

⁴⁴¹ CARB, *California's Advanced Clean Cars Midterm Review, Appendix A: Analysis of Zero Emission Vehicle Regulation Compliance Scenarios*, January 18, 2017. Available at <https://www.arb.ca.gov/msprog/acc/acc-mtr.htm>.

⁴⁴² To forecast fuel consumption, the Energy Commission forecasts the total vehicle population, including ZEVs. CARB's compliance scenarios in the ZEV Midterm Review calculate cumulative ZEV sales. Total vehicle population will necessarily be lower than cumulative vehicle sales, as the latter doesn't include vehicle retirements. This difference in accounting for ZEVs reflects the differing roles of the Energy Commission and CARB.

⁴⁴³ https://www.arb.ca.gov/msprog/zevprog/zevcalculator/zevcalculator_2017.xlsx.

Figure 60: ZEV and PHEV Forecast Compared to CARB’s Midterm Review Scenarios



Source: California Energy Commission

The transportation forecast results also offer a similar check on progress toward the state’s goal of 1.5 million ZEVs (including BEVs, PHEVs and FCEVs) by 2025 as stated in the *2016 ZEV Action Plan*. The forecast suggests that there may be slightly more than 2.4 million vehicles by 2025 in the high case, about 2.2 million in the mid case, and about 1.5 million in the low case. Taken together, these cases suggest that California could indeed meet its goal of 1.5 million ZEVs.

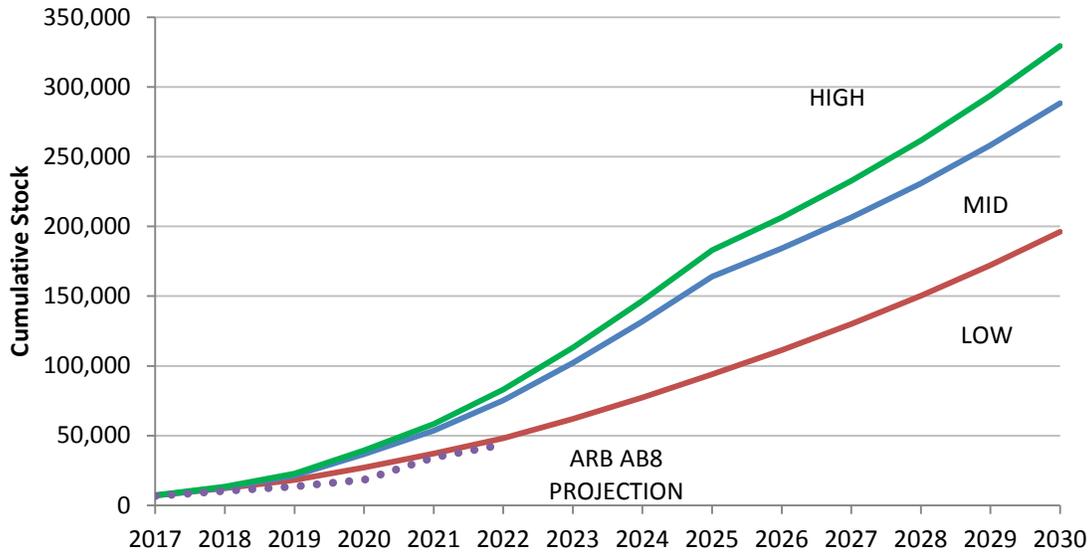
The Cleaner Technology and Fuels Scenario of CARB’s *Mobile Source Strategy* includes a more aggressive assumption of 4.2 million ZEVs deployed by 2030 as a pathway to a longer-term goal of having 100 percent of light-duty sales be zero-emission vehicles. The proposed *2017 Climate Change Scoping Plan Update* includes this interim 2030 target as well.

Results from the forecast, however, suggest that California may be on track to reach 4.14 million ZEVs by 2030 in the high case and just over 3.5 million in the mid case.⁴⁴⁴ This forecast is based on projected consumer responses to current regulations and projected market and technological conditions. If the state aims to meet the 4.2 million vehicle target, the results from the Energy Commission’s forecast suggest that additional measures (such as additional vehicle incentives, regulation, refueling infrastructure development, and increasing consumer awareness) may be needed if the more favorable conditions in terms of fuel prices, economic growth, and technological advancements, as assumed in the high case, do not occur.

⁴⁴⁴ As stated in the previous footnote, the Energy Commission calculates vehicle population, whereas CARB tabulates cumulative vehicle sales.

Finally, results from the forecast can be compared to the automaker surveys of anticipated FCEV deployment conducted by CARB.⁴⁴⁵ As shown in Figure 60, both the automaker survey and the Energy Commission’s forecast anticipate rapid growth in the number of FCEVs as hydrogen refueling stations are successfully deployed.

Figure 61: FCEV Population From Energy Commission Forecast and CARB Automaker Survey Projections



Source: California Energy Commission

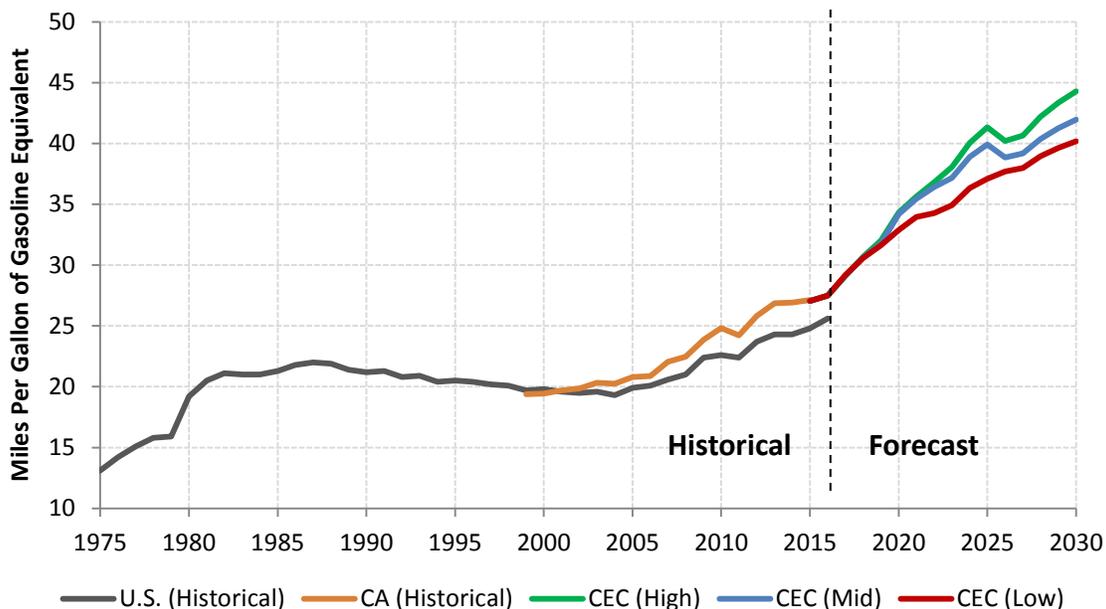
Increasing Fuel Economy for Light-Duty Vehicles

The fleet average fuel economy of vehicles on California roads, as of April 2016, is about 20.4 miles per gallon (MPG) for all fuel types and 20.3 MPG for gasoline and hybrid vehicles. In contrast, the sales-weighted average fuel economy for the new vehicles sold in California in 2015 was 27.0 MPG for all fuel types and 25.1 for gasoline vehicles. The average fuel economy of new LDVs is forecast to rise through 2025 as automakers respond to more stringent CAFE standards.⁴⁴⁶ The increase in fuel economy is primarily a result of increased hybridization and electrification of the statewide vehicle fleet, as well as internal combustion engines becoming more fuel-efficient. Figure 61 shows the average expected fuel economy for new LDVs in California in miles per GGE. The differences in average fuel economy among the high, mid, and low cases are due to differing projections in new vehicle sales composition (for vehicle technology and vehicle class) and case-specific inputs.

⁴⁴⁵ CARB, *2016 Annual Evaluation of Hydrogen Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development*, June 2016. Available at https://www.arb.ca.gov/msprog/zevprog/ab8/ab8_report_2016.pdf.

⁴⁴⁶ An average fleetwide fuel economy of roughly 35-36 MPG is expected to be needed to meet CAFE requirements in 2025.

Figure 62: Historical and Forecasted Sales-Weighted Average LDV Fuel Economy

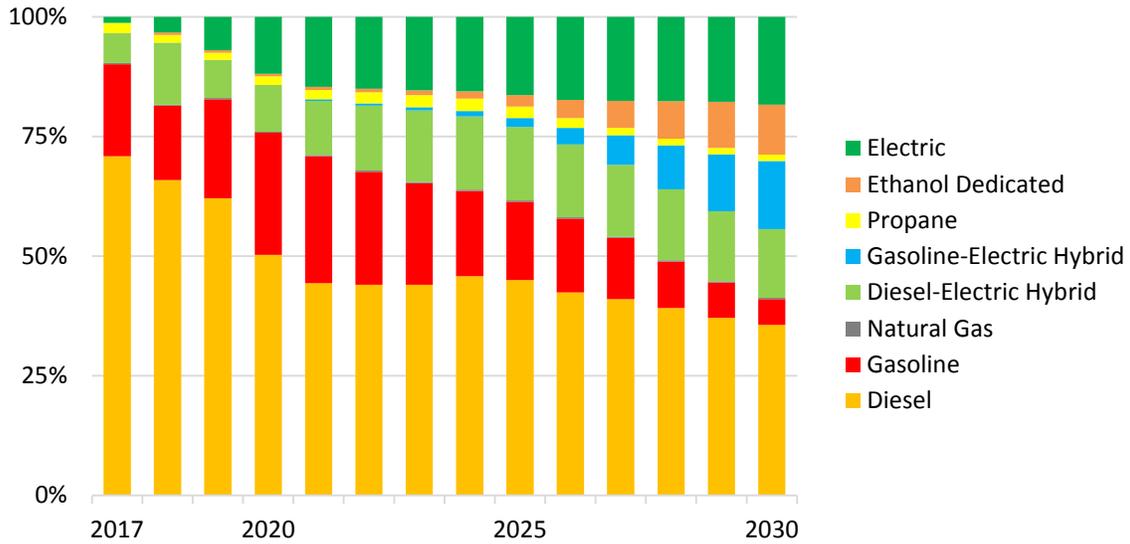


Source: California Energy Commission

Fuel Diversification of Medium- and Heavy-Duty Vehicles

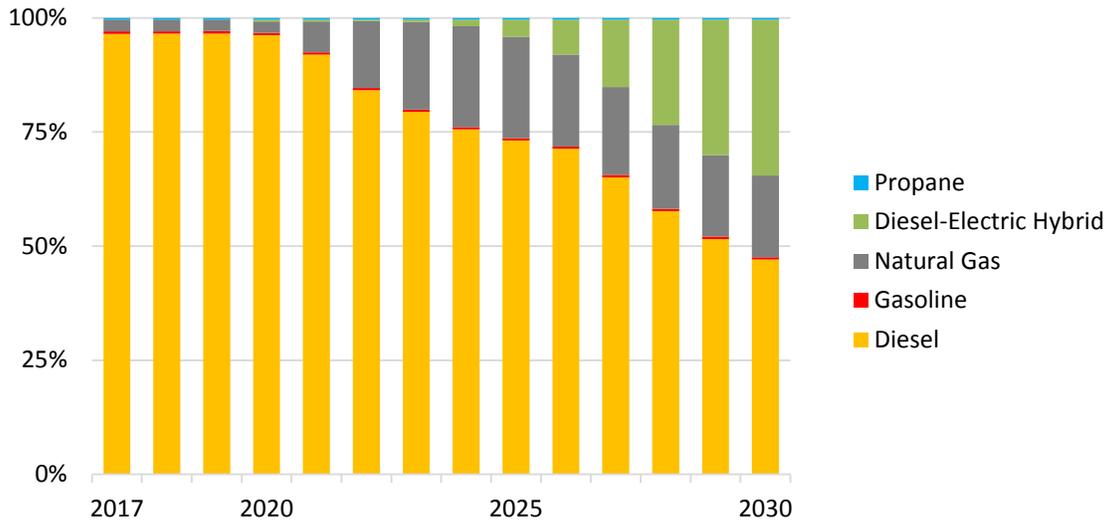
Results from the revised forecast also point to an expansion of alternative fuel and advanced technology vehicles among trucks and buses. As examples, Figure 62 highlights the growth of alternative fuel and advanced technology vehicles in the forecast as a share of new truck sales for both Classes 4 to 6 trucks, and in Figure 63, Class 7 and straight Class 8 trucks. As shown, diesel-electric hybrid options are expected to gain sales shares rapidly throughout the forecast period for Classes 4–6 trucks. In the low demand case (not shown), other alternative fuels show low or no adoption; however, the diesel and gasoline electric hybrids persist with penetration rates similar to the high demand case. For Class 7 and straight Class 8 trucks, revised forecast results indicate natural gas will play a significant role, though conventional diesel options decrease more slowly among these heavier trucks. For drayage trucks, the relatively low incremental cost of catenary electric trucks (when and where catenary infrastructure systems are available) translate to penetration rates greater than 50 percent by 2030 in both the mid and high demand cases.

Figure 63: Medium-Duty New Truck Sales by Fuel or Technology, High Case



Source: California Energy Commission

Figure 64: Heavy-Duty New Truck Sales by Fuel or Technology, High Case

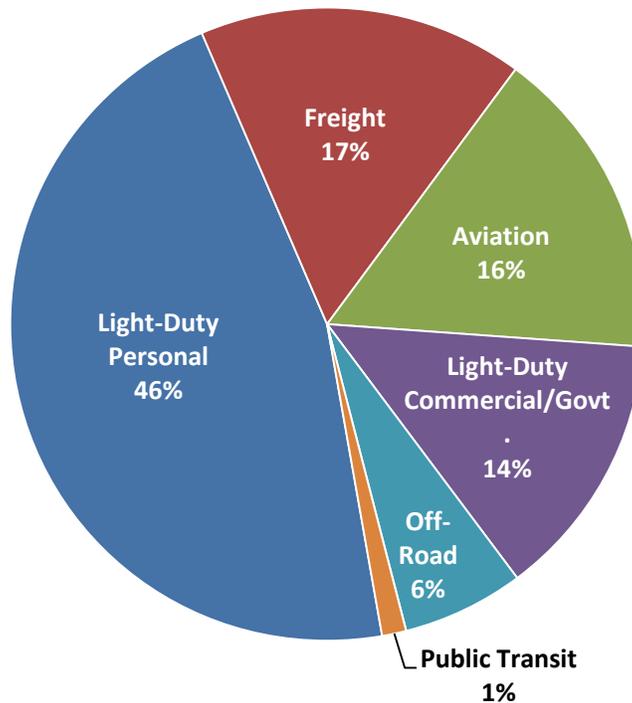


Source: California Energy Commission

Revised Forecast of Overall Fuel Demand

Upon incorporating the aforementioned inputs and assumptions into the various models, the primary product of the transportation energy demand forecast is the amount of energy that will be consumed in the transportation sector. Figure 64 shows the preliminary forecast distribution of total energy consumption in different transportation segments in 2030. More than 90 percent of transportation energy in California is forecast to be used by LDVs, aviation, and freight.

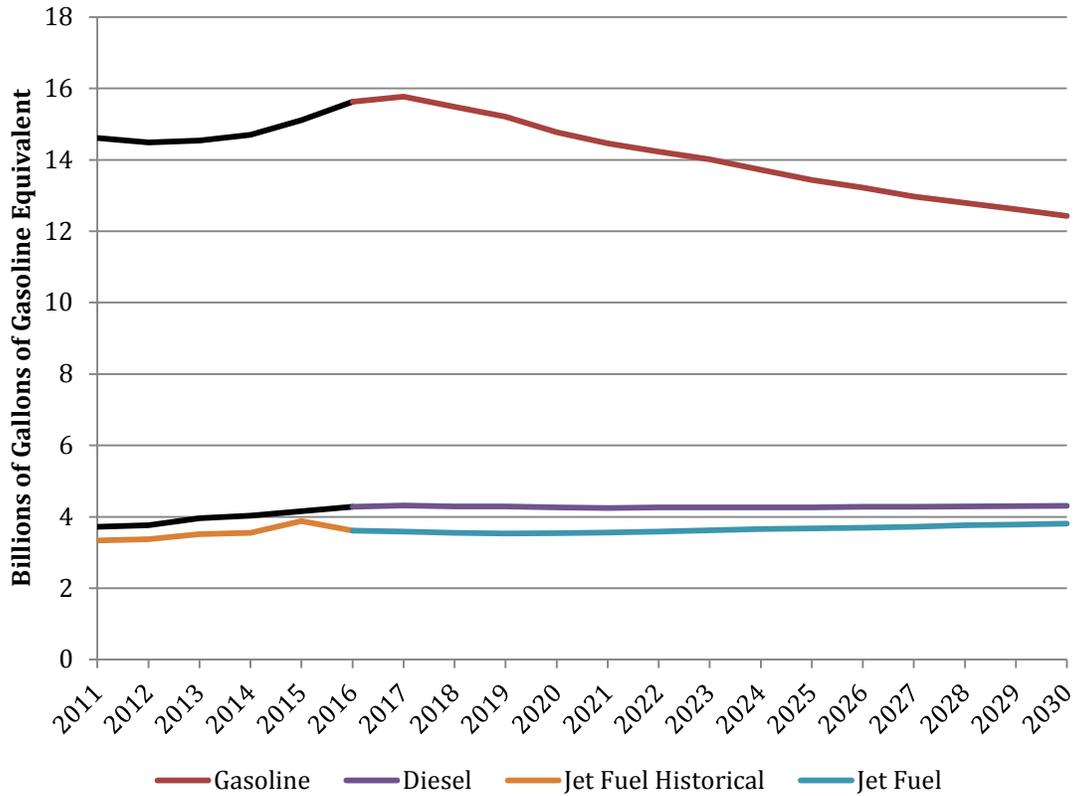
Figure 65: Revised Forecast of 2030 Total Energy Consumption by Transportation Segment



Source: California Energy Commission

Petroleum-based fuels continue to represent the largest shares of transportation fuel demand, both currently and through the forecasted period. However, as shown in Figure 65, demand for gasoline is expected to wane over time, primarily due to increases in fuel efficiency and electrification, both of which are discussed in the “Transitioning to Cleaner Transportation” section.

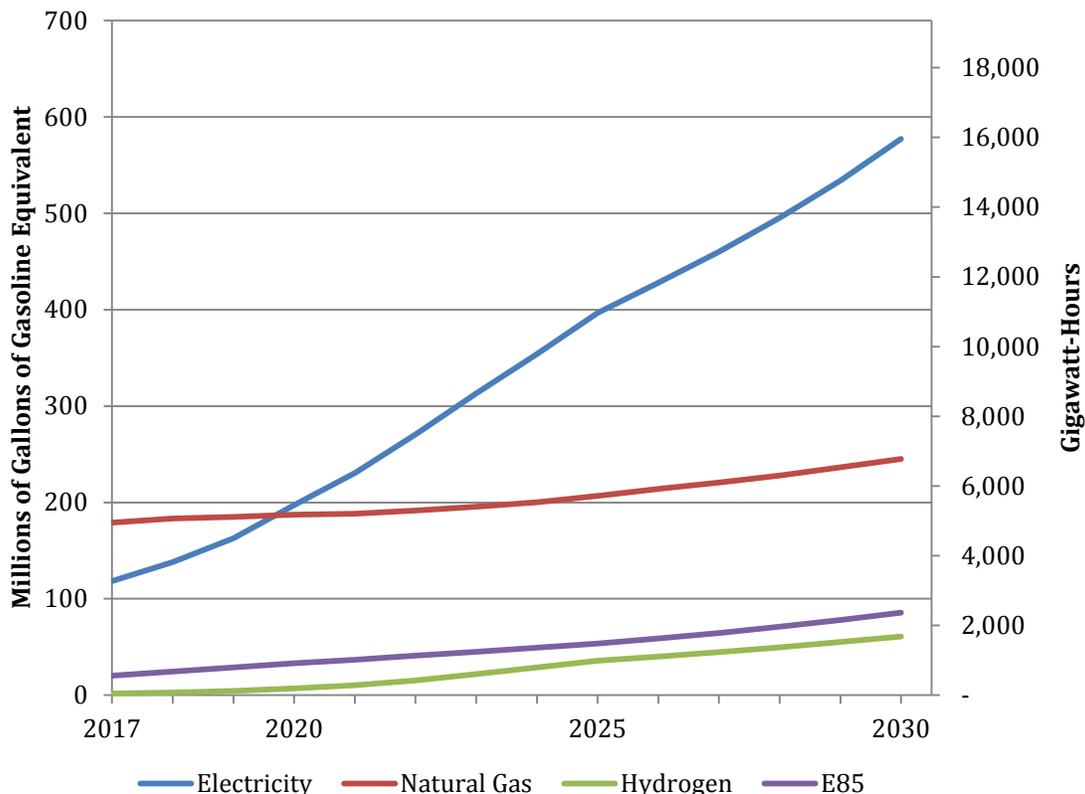
Figure 66: Revised Conventional Fuel Demand Forecast (Mid Case)



Source: California Energy Commission

As the amount of alternative fuel consumed within the transportation sector grows, the role of the transportation sector in the broader forecast becomes increasingly relevant. Figure 66 below shows the increasing demand for alternative fuels within the transportation sector (excluding high-speed rail) in common energy units. The growth in electricity is tied primarily to the electrification of LDVs, while the growth in natural gas reflects increased fuel diversification in trucks and buses. Compared to the billions of gallons of gasoline equivalent consumed or the hundreds of thousands of gigawatt-hours consumed in the larger electricity forecast, these numbers are not large, but they do represent growing sources of demand.

Figure 67: Revised Alternative Fuel Demand Forecast, Mid Case



Source: California Energy Commission

Compared to other transportation fuels, electricity cannot be stored as easily over time. As a result, the timing of electricity demand by electric vehicles is also a key element of incorporating the transportation sector into the larger electricity demand forecast. As described in other chapters of this report, the Energy Commission is working with partner agencies and organizations to determine the current charging patterns of electric vehicle owners, as well as the strategies for how different charging patterns in the future might help address other goals. For instance, the state can use this new electricity load to reshape hourly load curves in ways that promote renewable energy production and grid stability. More information on integrating BEVs and PHEVs can be found in Chapter 3.

The hydrogen used to fuel FCEVs comes primarily from the reformation of methane or biomethane, as discussed in Chapter 9. However, hydrogen can also be produced from excess renewable electricity entering the grid (via electrolysis, discussed in Chapter 3). While the transportation energy demand forecast does not distinguish between renewable and nonrenewable hydrogen, Senate Bill 1505 (Lowenthal, Chapter 877, Statutes of 2006) requires hydrogen refueling stations that receive state funds to dispense hydrogen with a minimum of 33 percent renewable hydrogen on a per-kilogram basis. Sixty-one of the 65 hydrogen refueling stations funded to date by the Energy Commission dispense a minimum of 33 percent renewable hydrogen, and 4 dispense hydrogen from 100 percent renewable sources. On a systemwide basis,

the 65 stations funded by the Energy Commission dispense an average of 37 percent renewable hydrogen.

Recommendations

- **Track and influence global automotive technology to ensure market growth.**
As other major automotive industry participants, particularly China, seek to rapidly electrify their transportation sectors, the Energy Commission and other agencies should pay attention to which vehicles and policies are succeeding in the marketplace. In particular, information about vehicle offerings abroad could help inform expectations of potential vehicle attributes in the future, which directly affects the expectations of the forecast for consumers' purchase decisions.

CHAPTER 8:

Natural Gas Trends and Outlook

Natural gas is a large and important energy source for California. It provides energy to heat homes, cook food, and generate electricity. (See side bar “Natural Gas Use in California.”) Some portion of this will likely remain so even as California moves away from fossil fuels to meet climate goals. (See Chapter 1.)

Natural gas deliveries to California end-users in 2016 averaged about 5.8 billion cubic feet per day (Bcf/d). Statewide, daily consumption in winter 2016 peaked in January at more than 7.3 Bcf/d, whereas, the 2016 summer peak was in August with delivery to end-users at 6.2 Bcf/d. Besides its role for heating and cooking, natural gas-fired electricity is critical to electricity reliability. This is because of its ramping flexibility and black-start capability, both of which are important in supporting California’s shift to renewable generation. (See Chapter 3).

Natural gas, however, is a fossil fuel. It is made primarily of methane, a potent greenhouse gas (GHG), and produces carbon dioxide, the predominant GHG, when combusted. As the state works to reduce GHG emissions to 40 percent below 1990 levels, it will need to transition away increasingly from fossil fuels, including natural gas. Renewable gas may be able to serve some portion of California’s natural gas use. (See Chapter 9 for more information.)

California is also emphasizing natural gas safety. The explosion of a Pacific Gas and Electric (PG&E) high-pressure pipeline in San Bruno in September 2010 and the major gas leak that occurred at the Aliso Canyon natural gas storage facility in October 2015 represent incidents that must never happen again.

This chapter covers natural gas market trends in California, the United States, Mexico, and Canada. It begins with an overview of natural gas trends and issues in California. The chapter provides detailed information on pricing and supply, resources and production, and demand, including an examination of Mexico’s demand growth as it could impact supplies to California. The safety of the natural gas system remains a high priority and is discussed. The chapter also highlights efforts to more closely coordinate natural gas and electricity operations. It also explores the development of gas liquefaction facilities that would help export liquefied natural gas from the United States. Finally, the chapter explores shifting away from natural gas as part of the state’s efforts to meet its climate goals, although there may be a growing niche role for natural gas in the transportation sector.

Natural Gas Use in California

Natural gas serves more than 10.5 million homes, about 445,000 businesses, about 37,000 factories and industrial consumers, and more than 640 electric generating units. The average California home consumes about 100 cubic feet of natural gas per day, or about 30 therms per month.¹ 32 percent of the natural gas used in California is used to generate electricity.

1 U.S. Energy Information Administration and Quarterly Fuel and Energy Report

California Overview

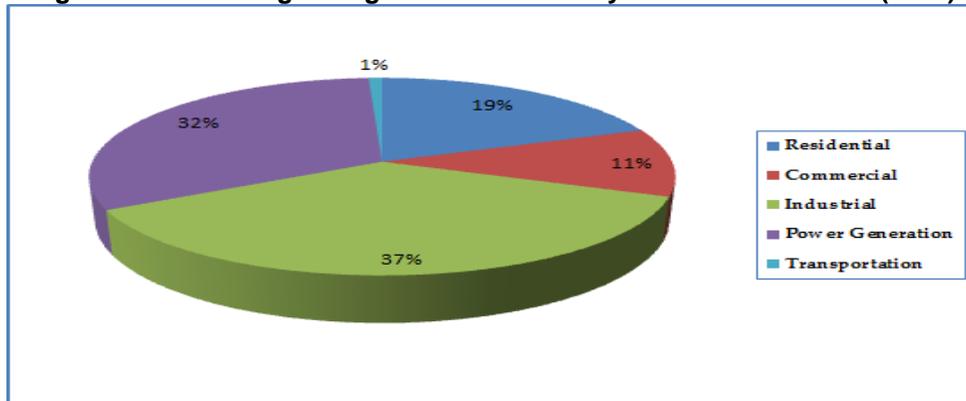
California's natural gas demand and supply trends are ever-changing, both due to state policies and market forces. State policies such as the California Air Resources Board's (CARB's) Short-Lived Climate Pollutant Reduction Strategy, require reductions in methane emissions. In addition, aggressive energy efficiency programs and increased renewable energy generation are reducing total natural gas demand as well as reshaping its hourly use profile. (See Chapters 1 and 2 for more information on the RPS and energy efficiency.)

On the supply side, robust production, largely from shale resources, has resulted in abundant natural gas supply and more stable prices. This is true even while in-state natural gas production continues to decline, with the consequence that the state continues to increase its reliance on imports from outside California.

Over the last 10 years, statewide consumption has varied between 5.7 billion and 6.4 billion cubic feet of natural gas per day, depending on weather and the economy. Total natural gas consumption in the United States in this same period, however, grew by 2.4 percent per year. As will be described later, some of this growth is due to the switch to natural gas-fired generation as a replacement for coal.

Figure 67 shows the breakdown in demand across the state's five end-use sectors – residential, commercial, industrial, power generation, and transportation for 2016.

Figure 68: Percentage Usage of Natural Gas by Sector in California (2016)



Source: U.S. Energy Information Administration

Note that 32 percent of the natural gas used in California generated electricity. This translated to 50 percent of the gigawatt hours produced in California during 2016 being produced with natural gas.⁴⁴⁷ This is actually less gas than would have been used in the past: thermal efficiency improvements in the state's natural gas power plants allow these power plants to generate 27 percent more energy using nearly 2 percent less natural gas than they could 15 years ago.

Gas-fired units provide ramping capacity to follow load changes during the day and to meet demand when renewable generation is not available. It is also often the only resource available for

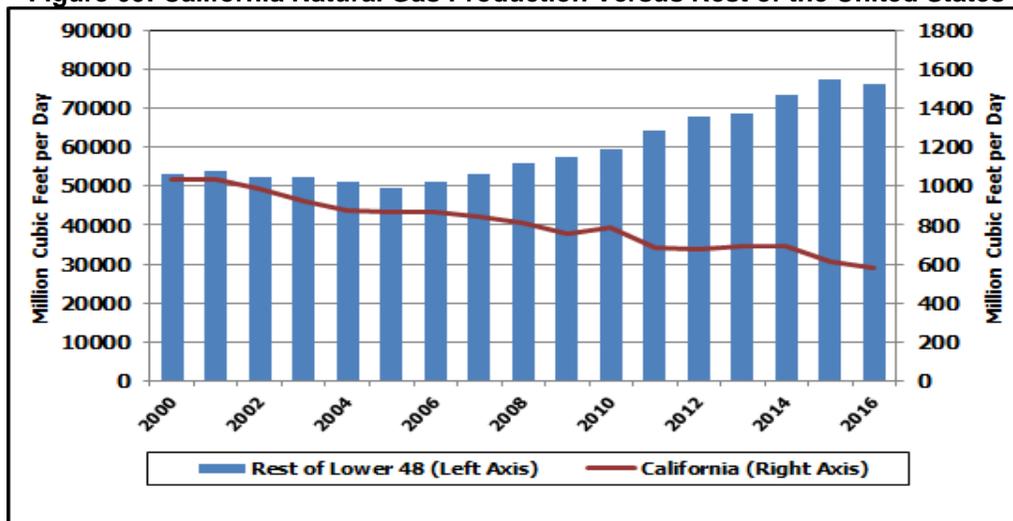
⁴⁴⁷ Calculated from http://energy.ca.gov/renewables/tracking_progress/documents/installed_capacity.pdf.

blackstart capability (for example, to re-start the electric grid after an outage) or that can replace imports should a transmission line need to be de-energized or go out of service in a wildfire. Natural gas-fired generation must continue to transform itself into an enabler of increasing levels of renewable generation and California's power plants are moving in that direction. (See Chapter 3.)

In terms of supply, technological advances have led to an abundance of natural gas supplies and reduced commodity prices for consumers. A decreasing portion of those gas supplies are produced in California, as drilling economics are more favorable elsewhere. In 2000, in-state sources provided 600 million cubic feet per day (MMcfd), or about 15.5 percent of California's consumption. That share peaked at more than 16 percent in 2002; by 2016, in-state sources provided less than 10 percent. Figure 68 shows California's natural gas production declining while it increased in the rest of the United States.

The Energy Commission expects this trend to continue. California's dependence on natural gas imports and the state's location at the end of several major interstate pipelines raise concerns about pipeline and supply reliability even while continent-wide, supplies are robust and prices are much more stable than in years past. These reliability concerns have been heightened by the situation in southern California around the status of Aliso Canyon.

Figure 69: California Natural Gas Production Versus Rest of the United States



Sources: U.S. Energy Information Administration, California Department of Oil, Gas, and Geothermal Resources

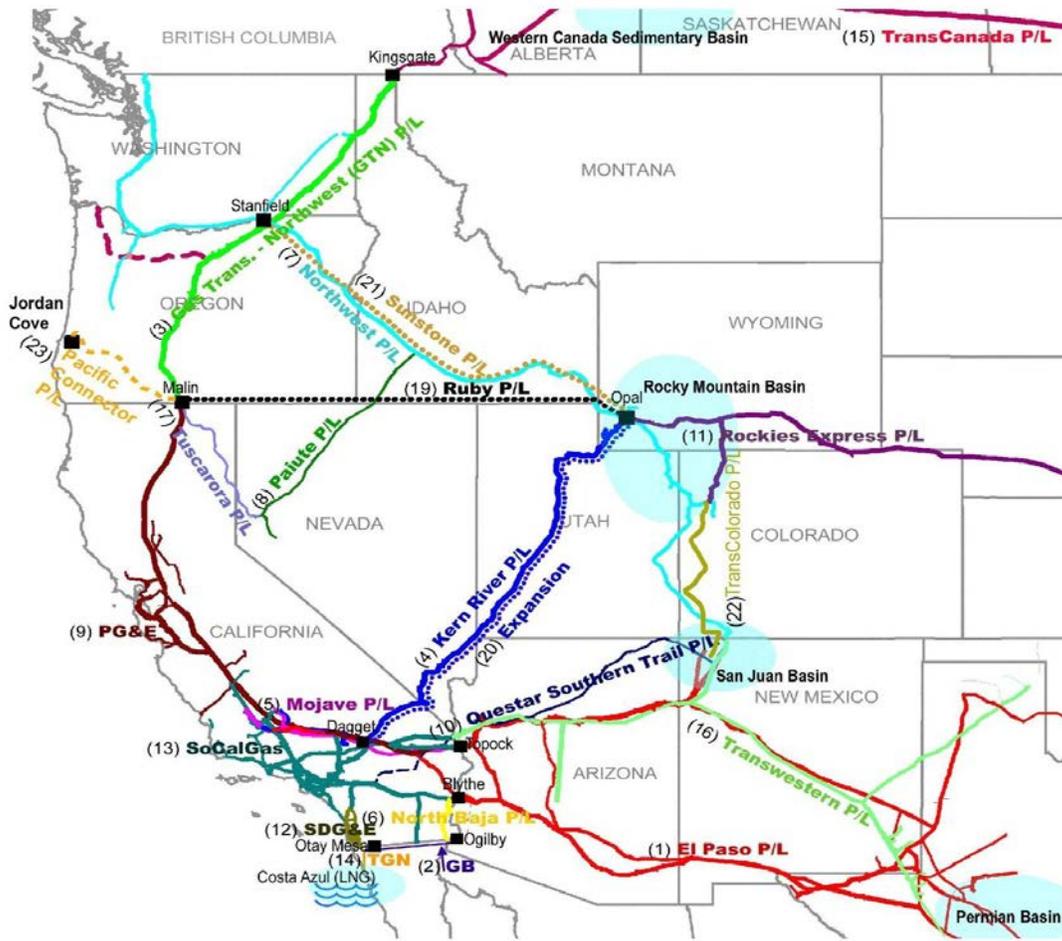
Today, most of the natural gas consumed in California originates from the following out-of-state sources:

- Western Canadian Sedimentary Basin (Alberta and British Columbia, Canada)
- Permian basin (west Texas and southwestern New Mexico)
- San Juan basin (northwestern New Mexico and southwestern Colorado)
- Rocky Mountain region (Wyoming and surrounding states)

Producing basins located a thousand or miles of miles from California provide 90 percent of its natural gas; as such, California relies on infrastructure located out-of-state to bring in the gas supplies consumers need.

That out-of-state infrastructure is provided by several interstate pipelines: Gas Transmission Northwest, Kern River Gas Transmission, El Paso Natural Gas, Ruby Pipeline, Transwestern, and Southern Trails Pipeline. These are shown in Figure 69.

Figure 70: Western North American Natural Gas Pipelines



Western North American Natural Gas Pipelines Legend	
1.El Paso Natural Gas	13. Southern California Gas Company
2.Gasoducto Bajanorte (GB)	14. Transportadora de Gas Natural (TGN)
3.Gas Transmission Northwest (GTN)	15. TransCanada Pipeline
4.Kern River Pipeline	16. Transwestern Pipeline
5.Mojave Pipeline	17. Tuscarora Pipeline
6.North Baja Pipeline	18. Unused
7.Northwest Pipeline	19. Ruby Pipeline
8.Piute Pipeline	20. Kern River Expansion
9.Pacific Gas and Electric Company	21. Sunstone Pipeline
10.Questar Southern Trail Pipeline	22. Transcolorado Pipeline
11.Rockies Express	23. Pacific Connector Pipeline
12.San Diego Gas & Electric Company	

Source: 2016 California Gas Report

Investor-owned utilities own most of the pipeline delivery capacity inside the state. Since the natural gas pipeline explosion in San Bruno in 2010 and reducing methane emissions from natural gas infrastructure, the California Public Utilities Commission (CPUC) authorized increased revenue requirements for PG&E, Southern California Gas and Electric (SoCalGas), and

San Diego Gas & Electric (SDG&E) with the aim of improving natural gas infrastructure safety. These higher revenue requirements unavoidably result in higher costs to deliver natural gas.

Natural Gas Price Projections

Energy Commission staff uses the North American Market Gas-Trade model (NAMGas) to simulate the behavior of natural gas producers in supply basins and natural gas consumers in demand centers.⁴⁴⁸ The structure of the model also includes representations of intrastate and interstate pipelines, liquefied natural gas (LNG) import and export facilities, and other infrastructure.

The model encompasses the regions of the continental United States, Alaska, Canada, and Mexico. Staff developed three cases using common assumptions across all of its differing analyses for the *2017 IEPR*, including, for example, the electricity demand forecast (see Chapter 6.) This assures that the analyses conducted by different staff groups use consistent assumptions. These three cases are known as the “common” cases, denoting- high, mid, and low demand. For the gas market outlook, NAMGas uses inputs and assumptions (for example, increased energy efficiency and renewable generation and varying amounts of coal-fired electrical generation retirements) that will have an impact on the natural gas market. Also, assumed values for proved and potential reserves⁴⁴⁹ in North America appear on the supply side of the NAMGas model.

The model provides projections on prices and supply of natural gas for California and the continental United States for 2017–2030. The model results indicate that natural gas prices at Henry Hub,⁴⁵⁰ after strong growth between 2017 and 2021, will rise at about 1.9 percent per year between 2021 and 2030. Although prices in July 2017 are hovering around \$3.00 per thousand cubic feet (Mcf), staff expects that, by 2030, prices will climb to about \$4.50 per Mcf. During the same time frame, natural gas production will continue to grow, reaching about 30 trillion cubic feet by 2030.

Price Impacts in Southern California

The Energy Commission has been monitoring daily natural gas spot market prices, watching for impacts since the Aliso Canyon gas well leak. To date, staff has not detected major adverse price impacts for southern California. While there does seem to have been an increase in the volatility of daily spot prices at the SoCalGas Citygate, the impact at the border pricing points has been minimal. Citygate volatility increased with the rupture and associated outage of SoCalGas Lines 4000 and 235-2 that began on October 1, 2017. The Energy Commission views this volatility as being caused by the pipeline outages and not by the reduced operating status Aliso Canyon. Energy Commission staff is continuing to monitor for price impacts. This type of impact would not show up in staff's price modeling in NAMGas since staff currently produces only annual natural gas prices.

⁴⁴⁸ NAMGas is built using the MarketBuilder platform that the Energy Commission licenses from Deloitte.

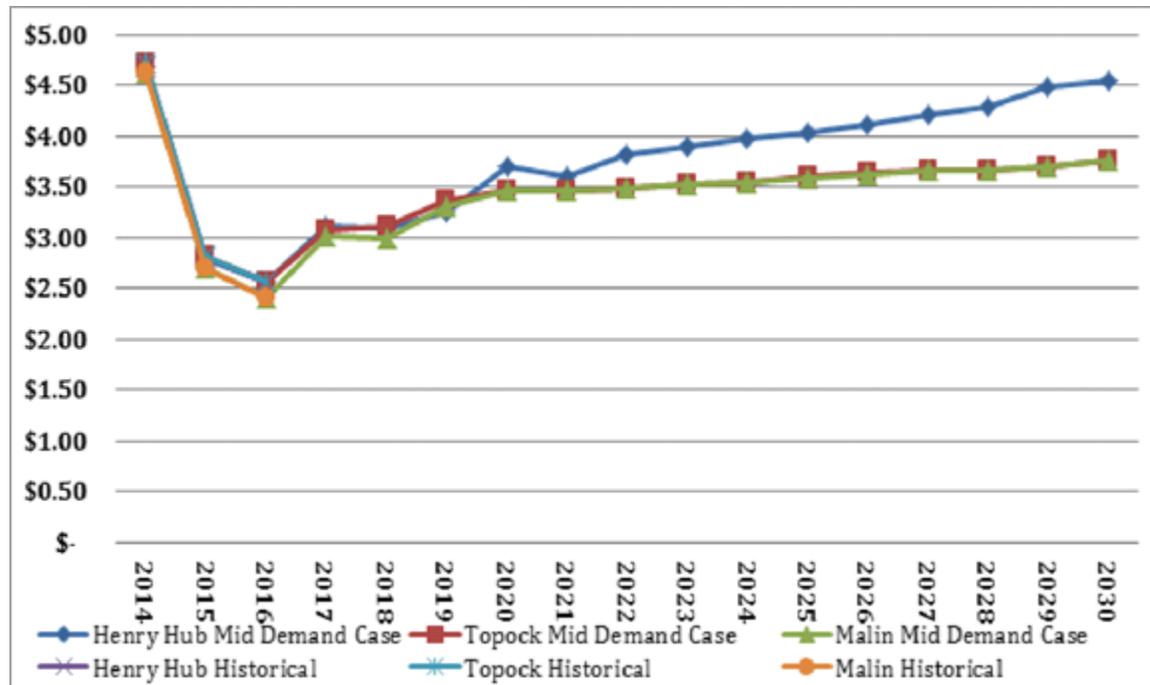
⁴⁴⁹ In general, the gas industry categorizes reserves as either proved or potential, and the natural gas resource base consists of proved plus potential reserves. Proved reserves tend to have a high degree of recovery certainty. Production of potential reserves is more costly, and recovery tends to be less certain.

⁴⁵⁰ The benchmark for natural gas prices in North America is Henry Hub, a gas trading and pipeline interconnection point near Erath, Louisiana. Henry Hub is also used to price the New York Mercantile Exchange natural gas futures contracts and the delivery point specified should a contract result in physical delivery.

Prices at the California border trading locations of Malin (Oregon) and Topock (Arizona) exhibit trends similar to that at Henry Hub. A large portion of supply delivered to California is priced and transacted on these two trading points. Throughout the forecast, Topock prices remain consistent with those for Malin and, by 2030, climb to about \$3.75 per Mcf.

Figure 70 shows the backcasted (2014–2016) and forecasted reference prices (2017–2030) for the Henry, Malin, and Topock hubs compared to actual prices for 2014–2016.

Figure 71: Mid Demand Case Prices for Henry, Topock, and Malin Hubs (2016\$/MCF)



Source: California Energy Commission Natural Gas Unit

California’s location at the end of interstate pipelines may give rise to price impacts. This is because pipeline extensions into Mexico or demand increases in other states, all else equal, would reduce supply available to California. Further modeling scenarios can discern how these changes may affect California natural gas prices.

The full results of the modeling efforts, method and the calculations appear in the *2017 Natural Gas Market Trends and Outlook* report.⁴⁵¹

Natural Gas Sources and Production

Natural gas produced from underground reservoirs. It originates from five general accumulation, or formation, types:

- Low permeability shale⁴⁵²

⁴⁵¹ California Energy Commission. 2017. *2017 Draft Natural Gas Market Trends and Outlook*. California Energy Commission. Publication Number: CEC-200-2017-009-SD.

⁴⁵² *Permeability* measures the ability of natural gas or crude oil to flow through a porous rock formation.

- Tight sandstone
- Conventional (limestone or sandstone)
- Coal-bed methane
- Crude oil deposit (associated gas)

Each natural gas accumulation type or deposit can produce dry or wet gas.⁴⁵³ Wet gas accumulations produce, along with methane, natural gas liquids such as propane, ethane, or butane. These liquids typically yield a higher number of Btu's per cubic foot than methane. Most gas is processed to remove these liquids and they are sold into customized markets.

In the last 20 years, technological innovations such as hydraulic fracturing⁴⁵⁴ (commonly known as *fracking*) and horizontal drilling have dramatically changed the landscape for natural gas supply in North America. As a result, the U.S. now produces more natural gas than it uses.

Potential Impacts of Seismic Events

While fracturing is the technique responsible for abundant supply and stable prices for natural gas, it is not without concern. In the eastern parts of the United States, horizontal drilling and multistage hydraulic fracturing require large quantities of water – sometimes tens of millions of gallons. While most wells today are fractured to one degree or another, even in California, most of the wells in California are vertical. Water usage for fracking in vertical wells dwarfs that of horizontal wells. As a result, a typical fracking job in California uses much less than elsewhere in the country, and averages between 100,000 and 200,000 gallons of water.⁴⁵⁵

Hydraulic fracturing also produces large quantities of wastewater, which field operators inject into deep wells for disposal. Several states, including Ohio, Oklahoma, and Arkansas, have experienced increased frequency of seismic events (earthquakes greater than 3.0 on the Richter scale). It is widely thought that deep underground injections of fracking wastewater are causing this seismic activity. Whether wastewater disposal in California could cause similar seismic events here is unclear. The California Council on Science and Technology's (CCST) assessment of hydraulic fracturing stated that well stimulation techniques currently used in California produce small increases in pressure that will not produce damaging earthquakes. They viewed disposal of produced water into injection wells, however, as a serious potential hazard.⁴⁵⁶

Seismic concerns also arise with respect to California's gas storage infrastructure. The Santa Susanna fault traverses Southern California's Aliso Canyon gas storage field. CCST's recent report

⁴⁵³ *Dry gas deposits* are natural gas accumulations with less than 0.1 gallons of liquid per thousand cubic feet; *wet gas deposits* have more than 0.1 gallons of liquid per thousand cubic feet.

⁴⁵⁴ *Hydraulic fracturing* involves the pumping of a sand-laden viscous fluid, into a well/wellbore to create fractures in a rock formation that stimulate the flow of natural gas or oil, increasing the volumes that can be recovered. Wells may be drilled vertically hundreds to thousands of feet below the land surface and may include horizontal or directional sections extending thousands of feet.

⁴⁵⁵ <http://ccst.us/publications/2015/vol-I-chapter-3.pdf>.

⁴⁵⁶ CCST, "An Independent Scientific Assessment of Well Stimulation in California," July 2015. p.48. Found at <http://ccst.us/publications/2015/2015SB4summary.pdf>.

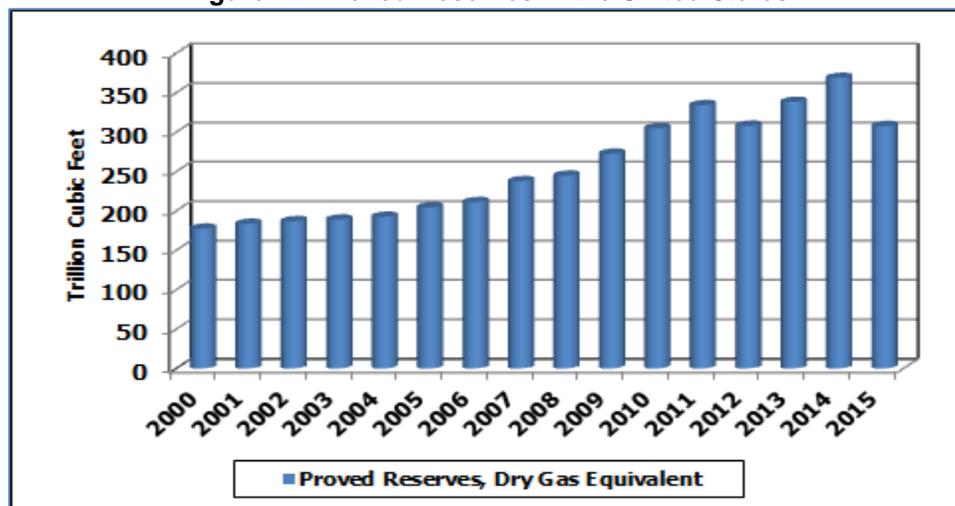
on underground storage notes that detailed risk analyses related to this fault and Aliso Canyon are underway.⁴⁵⁷ It suggests that additional site-specific technical or geological studies may be needed at some other storage facilities, especially in Southern California. The Energy Commission plans to conduct research, in close coordination with the CPUC and the Division of Oil, Gas, and Geothermal Resources, to assess the seismic risks of underground natural gas storage and develop new and advanced seismic risk assessment methods and models.⁴⁵⁸

U.S. Sources and Production

The ability to produce abundant shale gas resources pushed the United States, in 2011, to the number one spot natural among gas-producing countries.⁴⁵⁹ Natural gas production in the United States, climbing since 2005, reached more than 75,000 MMcfd, reaching record levels and, by 2016, 60 percent of dry natural gas production originated from this formation type. With consumption of only about 70,000 MMcfd of natural gas per day, the United States is increasingly able to export natural gas.

Figure 71 displays proved reserves in the United States. In 2005, proved reserves stood at 200 trillion cubic feet. These grew to reach a peak at more than 350 trillion cubic feet in 2014.

Figure 72: Proved Reserves in the United States



Source: U.S. Energy Information Administration

The Potential Gas Committee⁴⁶⁰ estimated that, as of January 2015, total (proved plus potential) reserves in the United States climbed to 2,884 trillion cubic feet, up from 2,073 trillion cubic feet

457 CCST, with funding from the CPUC, *Long-Term Viability of Underground Natural Gas Storage in California An Independent Review of Scientific and Technical Information, Full Report*, January 2018, p. 19. See http://ccst.us/projects/natural_gas_storage/publications.php.

458 Dani, Nicole. 2017. *Natural Gas Research and Development Program Proposed Program Plan and Funding Request for Fiscal Year 2017-18* California Energy Commission Research and Development Division. Publication Number: CEC-500-2017-039.

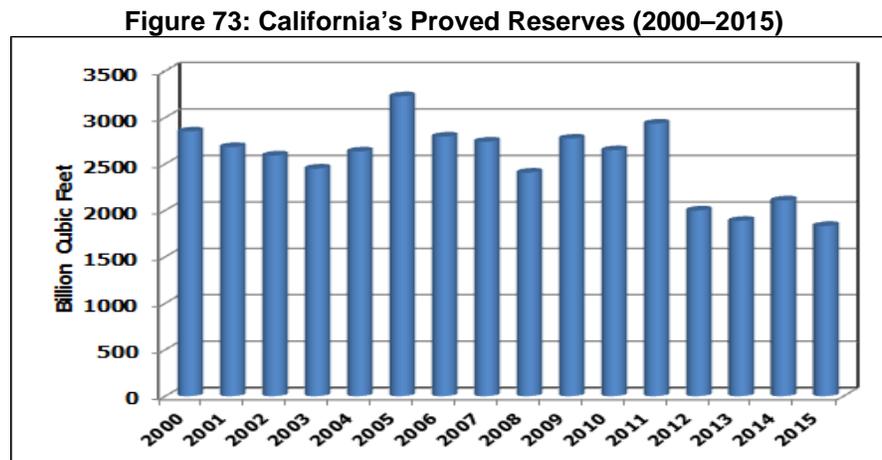
459 U.S. Energy Information Administration.

460 Housed at the Colorado School of Mines (Boulder, Colorado), the Potential Gas Committee "... assesses the future supply of natural gas in the U.S" and publishes its assessment every two years.

in 2008.⁴⁶¹ At the current rate of consumption, the total reserves suggest more than 100 years of available natural gas.

California's Declining Reserves

California natural gas producers are not developing in-state resources in sufficient quantities to alter the downward trajectory of proved reserves. California's natural gas proved reserves (dry gas equivalent) lingered above 2,500 bcf between 2000 and 2011. However, reserves totals have dipped below 2,000 bcf since 2012. California's two identified shales, the Monterey and the Monterey-temblor, have experienced limited testing of potential due somewhat to environmental concerns, the structure of these formations, and basic drilling economics. Figure 72 displays the decline in proved reserves in California.



Source: U.S. Energy Information Administration

Canada Sources and Production

In Canada, the resource base consists of 77 trillion cubic feet of proved reserves and 1,087 trillion cubic feet of potential.⁴⁶² The Canadian oil and gas industry has implemented the same technological innovations seen in the United States. As a result, Canadian production is rising. California has long been a key purchaser of Canadian gas supply.

Natural Gas Demand

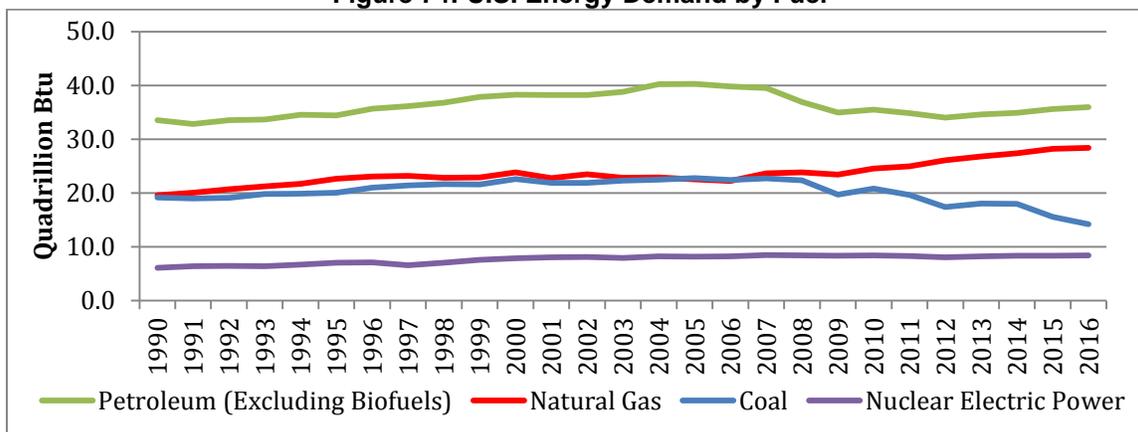
United States Demand

Since 1990, natural gas demand has grown, while coal demand has exhibited a downward trend since 2008 (Figure 73). This decline is mainly due to natural gas-fired electric generation displacing coal-fired generation.

⁴⁶¹ See <http://potentialgas.org/> for information concerning the Potential Gas Committee.

⁴⁶² Information from the Canadian Association of Petroleum Producers.

Figure 74: U.S. Energy Demand by Fuel



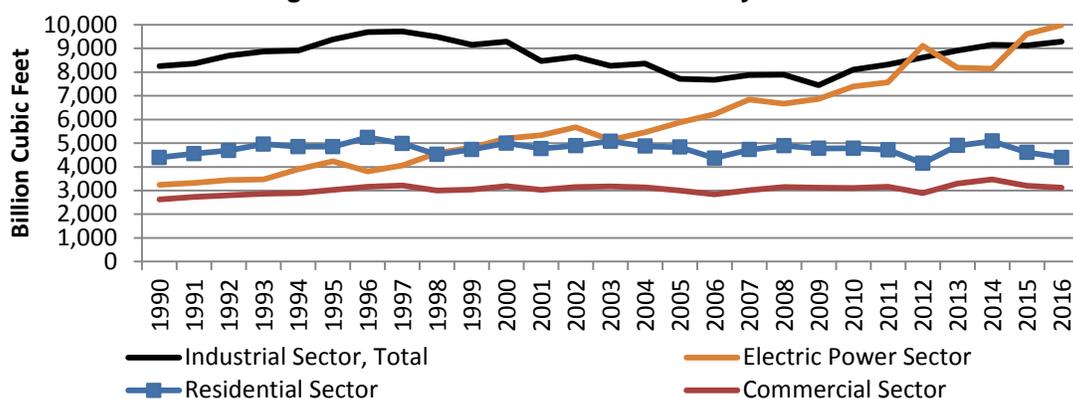
Source: Energy Information Administration, *April 2017 Monthly Energy Review*, "Table 1.3 - Primary Energy Consumption by Source," at <https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T01.03#/?f=A>.

Figure 74 shows natural gas demand by sector. It demonstrates that demand for gas by the industrial sector has grown by 1,173 Bcf or 15 percent since 2010. It also shows a striking increase in demand for natural gas by the electric power sector, where it has more than tripled since 1990. This is primarily due to changing relative fuel prices. As noted in the U.S. Department of Energy’s Reliability report to Secretary Perry: “The biggest contributor to coal and nuclear plant retirements has been the advantaged economics of natural gas-fired generation,”⁴⁶³The U.S. Environmental Protection Agency’s (U.S. EPA’s) regulations, implemented under the authority of the Clean Air Act, added emissions control to coal-fired electric generation, which also increased its cost.⁴⁶⁴ This, along with the higher capital cost of coal-fired generation (relative to gas-fired generation) and consumer desire for cleaner generating technologies are also factors leading to increased use of natural gas in electricity generation across the U.S. The end result is that electric generation from natural gas now exceeds production from coal-fired power plants.

⁴⁶³ Staff Report to the Secretary on Electricity Markets and Reliability, August 2017. At https://energy.gov/sites/prod/files/2017/08/f36/Staff%20Report%20on%20Electricity%20Markets%20and%20Reliability_0.pdf.

⁴⁶⁴ U.S. EPA, “Electric Power Generation, Transmission and Distribution (NAICS 2211).” <https://www.epa.gov/regulatory-information-sector/electric-power-generation-transmission-and-distribution-naics-2211>.

Figure 75: U.S. Natural Gas Demand by Sector

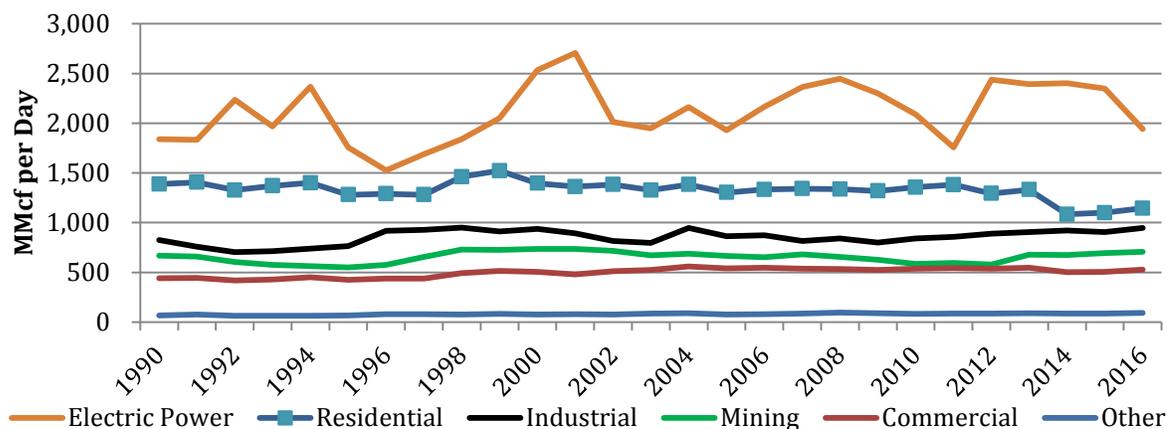


Source: Energy Information Administration, *Monthly Energy Review April 2017*, "Table 4.3 Natural Gas Consumption by Sector," at <https://www.eia.gov/totalenergy/data/browser/index.php?tbl=T04.03#/?f=A>.

California Demand

Figure 75 shows that since 1990, natural gas demand has remained relatively flat in all but the electric power sector. This is despite adding 9.2 million additional residents, a 31 percent population growth.

Figure 76: Annual Daily Average Natural Gas Demand by Sector in California



Source: California Energy Commission, Supply Analysis Office

This flattening of California natural gas demand is due to a combination of policies. First, residential demand declined almost continuously over the period shown, owing to energy efficiency requirements, as embodied in the Energy Commission's Building and Appliance Standards.

The second key change is in the electricity generation sector. Its demand varies depending on temperature and hydro conditions. Economic conditions such as the Great Recession and facilities closures such as that of San Onofre Nuclear Generating Station (San Onofre) also had an impact. Use of natural gas for electricity generation in California is higher today than in 1990, but has not matched its 2001 peak.

The lack of growth in gas demand by electric generation is due to adoption of the Renewables Portfolio Standard (RPS) and the Emission Portfolio Standard (EPS). (For more discussion of energy efficiency standards, see Chapters 2 and 6; for more information on the RPS, see Chapter 2; and for more information on the EPS, see Chapter 1.) The RPS and EPS shifted electricity generation demand away from natural gas to renewable technologies such as solar.

The U.S. Energy Information Administration reported that in 2016 natural gas consumption in the power generation sector in California averaged 1,839 MMcf per day. However, staff's PLEXOS simulations show that in 2017 natural gas demand average only 1,810 MMcf per day – this represents about a 1 percent drop in electric generation natural gas use..

Canada Demand

In Canada, the industrial sector, particularly in the areas of mining and oil and gas extraction, had the highest demand for natural gas in 2015.⁴⁶⁵ Industrial sector natural gas demand has grown from 2005 through 2015 where natural gas is used to provide heat to produce a growing amount of crude oil from oil sands.⁴⁶⁶ Canada's National Energy Board expects the industrial sector to account for the most natural gas demand through 2030.

Power Generation Sector in California and the Western Electric Coordinating Council

Energy Commission staff continues to use the PLEXOS production cost model⁴⁶⁷ to estimate natural gas demand in the power generation sector for the Western Electric Coordinating Council (WECC).⁴⁶⁸ Using PLEXOS, staff developed a WECC-wide production simulation model dataset covering the years 2017–2028 for the three “common” cases for the *2017 IEPR* and one other case with a higher level of additional achievable energy efficiency (AAEE).⁴⁶⁹

California's electricity supply and demand assumptions reflect current policy mandates, such as the state's RPS goals (see Chapters 1 and 2), retirement of once-through-cooling plants (see Chapter 11), and Senate Bill 350 (Clean Energy and Pollution Reduction Act of 2015, De León, Chapter 547, Statutes of 2015) energy efficiency targets (see Chapter 2). For the region of the WECC that is outside California, staff begins with the Transmission Electric Planning and Policy Committee's (TEPPC) 2026 common case.⁴⁷⁰

Figure 76 below shows the PLEXOS simulation results for annual California natural gas use for power generation from the four cases already mentioned.

⁴⁶⁵ Table 2-1, Statistics Canada, *2015 Preliminary- Report on Energy Supply and Demand in Canada*.

⁴⁶⁶ Figure 5.6, National Energy Board, *Canada's Energy Future 2016: Energy Supply and Demand Projections to 2040*.

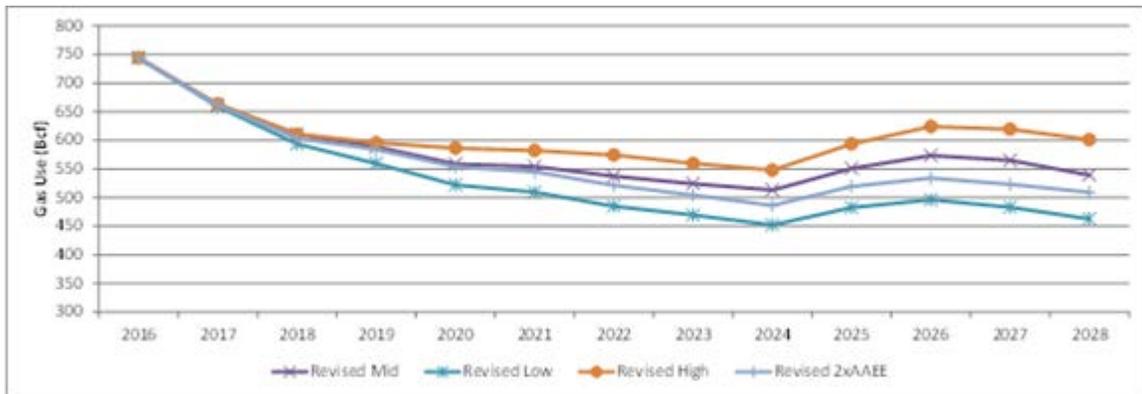
⁴⁶⁷ Platform owned by Energy Exemplar Ltd.

⁴⁶⁸ The WECC region extends from Canada to Mexico and includes the provinces of Alberta and British Columbia in Canada, the northern portion of Baja California, Mexico, and all, or portions of, 14 western states in the United States.

⁴⁶⁹ *Additional achievable energy efficiency* is savings from initiatives that are planned but not yet approved by the utilities or any other entity.

⁴⁷⁰ The TEPPC, a WECC Board of Directors committee, guides WECC's Transmission Expansion Planning (TEP) and working groups consisting of stakeholders throughout the WECC to create this common case on a biennial basis.

Figure 77: California Annual Natural Gas Use for Power Generation for All Cases



Source: California Energy Commission, PLEXOS results

PLEXOS modeling results show that, with the implementation of increased preferred resources and energy efficiency, natural gas generation decreases between 2017 and 2024. Staff, in part, accounts for the increased gas generation between 2024 and 2026 by pointing to the expiration of long-term power supply contracts (purchase agreements) with coal facilities outside California. The Energy Commission, CARB, and the CPUC will continue to develop and implement policies to reduce California’s dependence on natural gas.

The state will experience a significant decrease in electricity imports from coal-fired power plants in 2024–2025. Natural gas-fired power plants will replace some of the lost coal generation.

Natural Gas Infrastructure

U.S. Pipelines

The U.S. natural gas pipeline network consists of an integrated transmission and distribution system that transports natural gas from numerous producing basins to users all over the country via 318,000 miles of gathering, interstate, and intrastate transmission lines and more than 2.2 million miles of gas distribution lines.⁴⁷¹ The pipeline systems of Canada and Mexico connect to this system allowing natural gas imports and exports between the three countries.

Some new pipeline capacity has been built or is planned, primarily in the eastern U.S., to move new shale gas production to regional markets. Some may also be built to deliver gas to LNG export facilities.

California Pipelines

Interstate pipelines provide California with supplies from the U.S. Southwest, Rocky Mountains, and Western Canada.⁴⁷² As Table 18 shows, these interstate pipelines can bring a total of 12.80 Bcf/day to the state. California’s receipt capacity⁴⁷³ totals about 9.8 bcf/day.⁴⁷⁴ In short, the

⁴⁷¹ U.S. Department of Transportation (US DOT) Pipeline and Hazardous Materials Safety Administration (PHMSA) PHMSA. <https://www.phmsa.dot.gov/pipeline/library/data-stats>.

⁴⁷² 2016 California Gas Report, p. 4.

⁴⁷³ The amount of pipeline capacity that can take natural gas supplies from the interstate pipelines.

amount of gas that can in theory reach the state in less than the state's pipeline capacity available to take it away from the receipt points and deliver it inside the state.

Since the state's average consumption is about 5.8 Bcf/day, the difference between interstate and intrastate capacity does not present a problem in meeting demand on an average day. On peak demand days, however, natural gas demand may exceed the combination of supply available from intrastate pipelines and in-state storage. When this occurs, the gas utilities will curtail (halt) gas deliveries to consumers in the industrial and power generation end-use sectors in California.

Table 18: Main Pipeline Systems Serving California (Bcf/day)

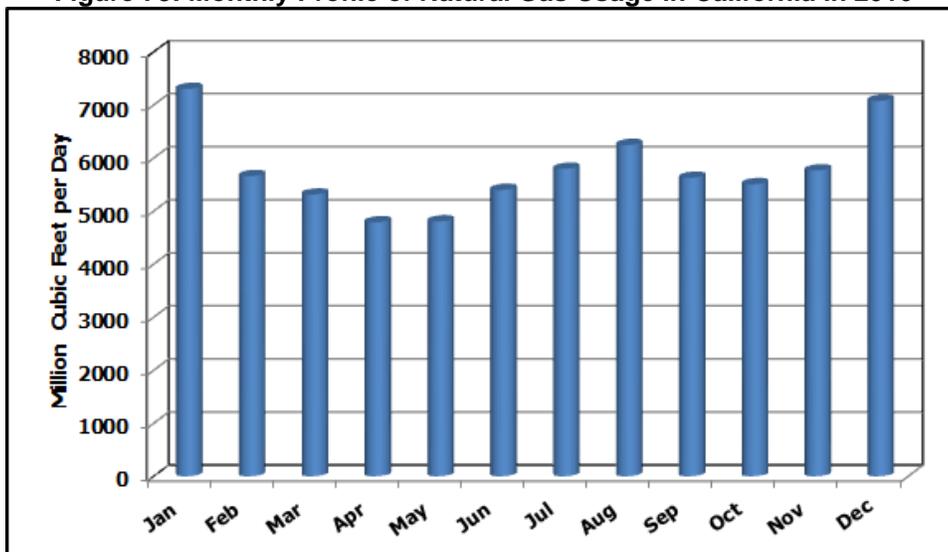
Pipeline System	Maximum Capacity	Average Capacity Utilization Rates (2012-2016)
Gas Transmission Northwest	2.272	51%
Ruby	1.684	46%
Kern River	1.942	77%
El Paso North	2.033	35%*
El Paso South	1.459	35%*
Transwestern	1.150	65%
Mojave	0.976	19%
Southern Trails	0.120	Incorporated into Other in the 2017 California Gas Report Supplement
TGN	0.415	Utilization not reported in the 2017 California Gas Report Supplement
Tuscarora Gas Transmission Company	0.236	Utilization not reported in the 2017 California Gas Report Supplement
North Baja Pipeline System	0.600	Not designed to "serve" California but transports gas from Arizona through California to serve Mexico.
Total	12.89	

Sources: PointLogic, 2017 Supplemental California Gas Report, <https://www.socalgas.com/regulatory/cgr.shtml>.
 *Average capacity utilization rate for both El Paso North and South combined.

Figure 77 displays the 2016 profile of natural gas monthly consumption in California.

474 Estimated using data from the 2016 California Gas Report.

Figure 78: Monthly Profile of Natural Gas Usage in California in 2016



Source: California Energy Commission

Disaggregating the data to examine daily and hourly variation in demand demonstrates two key problems. First, it would show days for which the 9.8 Bcfd of take-away capacity is insufficient to meet all the demand. On those days, California pulls gas from underground storage to cover the deficit. Second, it demonstrates imbalances. Gas flows from production wells at a constant hourly rate and pipeline operators expect gas to be delivered into their systems at this same constant, or, ratable basis. But demand varies hourly. Shippers also sometimes deliver more or less gas than they need on a particular day for various reasons. The difference between hourly demand and constant supply creates what is known as an “imbalance.” Imbalances that get too large strain the natural gas system, allowing the utility system to get either over-pressured (too much gas in the system relative to demand) or under-pressured (too little gas in the system relative to demand). Gas utilities may respond to these imbalances by issuing Operational Flow Orders (OFOs). OFOs instruct market participants (end-use customers and their suppliers) to remedy their imbalances and are an important tool to manage the gas system.⁴⁷⁵

California’s existing combination of pipeline capacity and underground gas storage appears adequate to meet forecast natural gas demand and no general increase in capacity is proposed. SoCalGas and SDG&E, however, have an application before the CPUC seeking permission to build a new 47-mile pipeline to transport natural gas from the Rainbow Pressure-Limiting Station at the Riverside/San Diego County line, south to the Marine Corps Air Station Miramar in San Diego. The proposed pipeline would replace existing transmission Line 1600, which, under this proposal, would be converted to a distribution line. The new line would allow safety testing of the existing Line 1600 and provide a measure of redundancy and additional reliability for gas service into San Diego.

⁴⁷⁵ A key mitigation measure in the Aliso Canyon Reliability Action Plans was to make greater use of OFOs. End-users and their suppliers keeping gas deliveries into the system more closely equal to demand reduces the need for the utility to remedy imbalances by using underground storage. Electric generation ramping up and down during a day contributes to gas system imbalances as does the diurnal demand pattern of most residential consumers.

SDG&E⁴⁷⁶ and SoCalGas⁴⁷⁷ feel strongly that more investments are needed to improve pipeline safety and reliability and asked the Energy Commission to recognize the urgency of these safety risks in the *IEPR*. The Energy Commission takes no position on the merits of this particular project: the evidentiary record on the relative costs and potential safety benefits of any given investment are developed in the appropriate proceeding at the CPUC, not in the *IEPR*. Safety is important and it is clear that the aging gas infrastructure requires upgrades to improve safety, enhance reliability, and reduce GHG emissions.⁴⁷⁸ The Energy Commission has previously funded a number of initiatives in this area. The *2017 IEPR* adds to this by recommending \$50 million in funding to the Energy Commission's Natural Gas Research and Development Program and utility pilot programs to accelerate improved safety, methane control, and climate adaptation for the natural gas system.

Canada

In Canada, planned pipeline infrastructure changes revolve mainly around delivering natural gas to proposed LNG export facilities on British Columbia's Pacific Coast. These changes include the 3 Bcf/day, 416-mile Coastal GasLink Pipeline that would deliver natural gas from the Alberta/British Columbia border to the proposed Kitimat LNG export facility. Canada's National Energy Board has granted approval to the Coastal GasLink Pipeline.⁴⁷⁹

California Storage and Related Issues

Natural gas storage plays an important role in satisfying demand requirements. In the United States, about 400 depleted underground fields now store gas for later use. Storage inventories typically increase during the injection season, April through October, and decrease between November and March, when peak loads and higher prices occur. Daily net withdrawals or injections can occur throughout the year in response to price volatility and/or supply requirements.

In California, the working gas capacity⁴⁸⁰ of natural gas storage facilities connected to the systems of PG&E and SoCalGas totals 371.3 Bcf (Table 19). Natural gas storage facilities (including independently owned) that are interconnected to PG&E's natural gas system have a working gas capacity of 236 Bcf. SoCalGas operates four storage fields that interconnect with its transmission system and have a working gas capacity totaling 135.3 Bcf. Combined, the systems of both gas utilities have a capacity of 237.4 Bcf. In 2016, the U.S. EIA reported that operators injected an average of 341 MMcf per day into California's storage facilities and withdrew an average of 450 MMcf per day.

476 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221739_20171113T135622_Steve_Lango_Comments_Comments_of_SDGE_on_2017_Draft_Integrated.pdf.

477 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221758_20171113T165037_Southern_California_Gas_Company_Comments_SoCalGas_Comments_on_t.pdf.

478 This is embodied in prior *IEPR*'s, a variety of public documents, and CPUC decisions in the San Bruno proceeding and in the Aliso Canyon work.

479 Coastal GasLink Pipeline Project Profile, <https://client.pointlogicenergy.com/#pipeline-project-detail/258>.

480 *Working gas capacity* is the portion of the total storage capacity that field operators use to store natural gas that is cycled to meet demand requirements.

Table 19: Natural Gas Storage in California

	Working Capacity(Bcf)	Maximum Withdrawal Capacity(Bcfd)
PG&E ⁴⁸¹		
Independently -owned/PG&E controlled ⁴⁸²	102.1 133.9	2.2
SoCalGas ⁴⁸³	135.3	3.7
Utility Total	237.4	
California Total	371.3	

Sources: U.S. EIA Natural Gas Annual Respondent Query System (EIA-191 Data through 2015), https://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen

In 2015, a major leak was detected at the Aliso Canyon natural gas storage facility as discussed in the sidebar “Leak at Aliso Canyon” and below in “Natural Gas Pipeline and Underground Storage Safety.” Also see “Natural Gas Electricity Coordination” below and Chapter 11 for more information.

In June 2016, PG&E found indications of a low-level leak at the McDonald storage facility. Flyovers commissioned by the Energy Commission and, later, by

Leak at Aliso Canyon

On October 23, 2015, a natural gas leak was detected from one of the wells at the SoCalGas-owned Aliso Canyon natural gas storage facility. SoCalGas stopped the leak on February 11, 2016, and sealed the well permanently on February 18, 2016. As a result of the leak, Senate Bill 380 (Pavley, Chapter, 14, Statutes of 2016) (SB 380) and DOGGR imposed a moratorium on injections at Aliso Canyon until SoCalGas complies with regulations and meets certain conditions. However, in cases of emergency, withdrawals have been authorized to support regional energy reliability. In a letter from Energy Commission Chair Robert B. Weisenmiller to CPUC President Michael Picker dated July 19, 2017, the Chair wrote, “With the state’s climate target in mind, Governor Brown has asked me to plan for the permanent closure of the Aliso Canyon natural gas storage facility, and I urge the California Public Utilities Commission to do the same.”¹ (See Chapter 11 for more information about energy reliability issues related to Aliso Canyon.)

¹ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN220299_20170721T134102_July_19_2017_Letter_to_California_Public_Utillities_Commission_P.pdf.

⁴⁸¹ California Energy Commission, *Natural Gas Market Assessment, Staff Report*, 2003, p. 51, http://www.energy.ca.gov/reports/2003-08-08_100-03-006.PDF. Accessed July 2017.

⁴⁸² Natural Gas Annual Respondent Query System (EIA-191 data through 2016), Energy Information Administration: https://www.eia.gov/cfapps/ngqs/ngqs.cfm?f_report=RP7&f_sortby=&f_items=&f_year_start=&f_year_end=&f_show_compid=&f_fullscreen.

⁴⁸³ As of May 1, 2017, the working gas inventory of Aliso Canyon is 14.8 Bcf. A July 2017 letter from the Executive Director of the CPUC directed SoCalGas to target a working gas level of 23.6 Bcf while maintaining a level above 14.8 Bcf at all times. This letter is available on the CPUC’s website at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/7-19-17_CPUCLEtrtoR.Schweckere.Reliability.pdf.

PG&E confirmed the leak. This leak forced the temporary closure of McDonald Island. PG&E returned the facility to service in October 2016.

After inspecting the wells per the Division of Oil, Gas, and Geothermal Resources (DOGGR) regulations, the CPUC, in consultation with DOGGR, permitted a resumption of gas injections into McDonald Island. However, storage was limited to 75 Bcf, compared to McDonald Island's 82 Bcf operating capacity. Moreover, the CPUC imposed other conditions on PG&E regarding McDonald Island, including monitoring injection and withdrawal activities, notifying CPUC and DOGGR immediately if other leaks are discovered, and providing daily reports on pressures and volumes.⁴⁸⁴

In February 2017, the CPUC opened a proceeding (Order Instituting Investigation I.17-02-002) to determine the feasibility of minimizing or eliminating the use of the Aliso Canyon natural gas storage facility while maintaining energy and electric reliability for the region. Separately, the CCST prepared the report⁴⁸⁵ requested in the Governor's January 2016 emergency order and in the 2016 budget act addressing the long-term viability of underground storage in California. CCST's report addressed three key questions:

Gas Storage Long-Term Viability Study

The California Council on Science and Technology released on January 18, 2018, its study examining the long-term viability of underground gas storage in California. The study's key findings are:

- The risks of underground gas storage can be mitigated through appropriate and sensible regulation.
- A small list of facilities has relatively higher potential risk compared to others.
- Closing any or all underground gas storage facilities in the near-term would involve replacing underground gas storage facilities with new pipelines or natural gas storage capacity, and require very large investments.
- California's climate policies in future decades could still necessitate the continued use of natural gas storage or storage of biogas, hydrogen, or sequestration of carbon dioxide.
- The state should develop a more complete and integrated plan to understand how the role of natural gas might evolve, assess possible energy portfolios that both meet GHG emission constraints and achieve energy reliability, and consider the potential need for underground gas storage facilities in the future.

1. The risks California's underground gas storage facilities pose to health, safety, environment, and infrastructure.
2. Whether California needs underground gas storage to provide for energy reliability through 2020.
3. How implementation of California's climate policies change the future need for underground gas storage.

484 CPUC Safety and Enforcement Division. Letter to Sumeet Singh Vice President, Asset and Risk Management of Gas Operations for PG&E, Regarding Authorization of Gas Reinjection at PG&E's McDonald Island.

485 CCST with funding from the CPUC, *Long-Term Viability of Underground Natural Gas Storage in California An Independent Review of Scientific and Technical Information, Full Report*, January 2018, http://ccst.us/projects/natural_gas_storage/publications.php.

The report was released on January 18, 2017, and was prepared independently by CCST (see sidebar “Gas Storage Long-Term Viability Study”) without advance review by the Energy Commission or other state agencies. Exactly how to replace Aliso Canyon, consistent with Chair Weisenmiller’s July 19, 2017, letter⁴⁸⁶ to CPUC President Picker, remains to be determined. In that letter, Chair Weisenmiller has committed the Energy Commission to work with the CPUC to develop and assess alternatives. (More about this can be found in Chapter 11.)

Many suggestions from the community and from market participants about alternatives to Aliso have been submitted in response to the joint agency Reliability Action Plans (see Chapter 11, Energy Reliability in Southern California) or in response to the *Draft 2017 IEPR*.⁴⁸⁷ One suggestion came from Gill Ranch Storage, an independent gas storage operator with a facility located in the San Joaquin Valley. Gill Ranch suggested that with some pipeline changes and an expanded interconnection between Northern and Southern California, it might be able to help address reliability issues. It is unclear the suggested changes alone will be sufficient or feasible or how Gill Ranch’s suggestion might fit with other options. Gill Ranch should raise this suggestion in the CPUC proceeding on Aliso Canyon (I.17-02-002), as it may contribute to a portfolio of measures to reduce reliance on Aliso Canyon.

Natural Gas Pipeline and Underground Storage Safety

Natural gas infrastructure safety is paramount. The Energy Commission is committed to doing its part to assist the Governor, the Legislature, and the CPUC in assuring that California’s gas utilities operate safely. Events such as the explosion of a PG&E high-pressure pipeline in San Bruno in September 2010 that killed eight people, injured 58, and damaged or destroyed more than 100 homes or the well blowout at the Aliso Canyon natural gas storage facility in October 2015 that leaked an estimated 109,000 metric tonnes of methane and oil field contaminants into the atmosphere must never occur again.⁴⁸⁸

These incidents resulted in federal and state actions aimed at enhancing the safety of the natural gas infrastructure including pipelines and underground storage. Governor Edmund G. Brown Jr. issued an emergency proclamation on January 6, 2016,⁴⁸⁹ that declared the situation an emergency and directed actions to protect public health and safety and strengthen oversight of gas storage facilities in California.

486 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN220299_20170721T134102_July_19_2017_Letter_to_California_Public_Uilities_Commission_P.pdf.

487 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221725_20171113T112608_Ann_L_Trowbridge_Comments_Comments_of_Gill_Ranch_Storage_LLC_on.pdf.

488 The San Bruno pipeline explosion led to PG&E’s federal conviction on six felony counts, including violation of federal pipeline safety laws and obstructing a National Transportation Safety Board investigation. The Aliso Canyon leak caused reports of adverse physical symptoms, the relocation of thousands of people (including two grammar schools) which caused major disruption to the lives of citizens and concern about impacts to electricity reliability. SoCalGas’ “inventory method” for calculating the leak results in an estimate of 4.62 billion cubic feet of gas emitted; CARB refined this estimate using airborne and other measurements to arrive at 109,000 MT that needs to be mitigated. See https://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_methane_emissions-arb_final.pdf.

489 “Governor Brown Issues Order on Aliso Canyon Gas Leak.” <https://www.gov.ca.gov/news.php?id=19264>.

In June 2016, the federal government enacted the “Securing America’s Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety Act” (SAFE PIPES Act).⁴⁹⁰ The SAFE PIPES Act created the Interagency Task Force on Underground Natural Gas Storage Safety. In October 2016, this task force issued 44 recommendations in the following areas: well integrity at underground natural gas storage facilities, public health and environmental effects from a natural gas leak, and energy reliability concerns in the case of future natural gas leaks.⁴⁹¹ The SAFE PIPES Act also requires U.S. Department of Transportation’s Pipeline and Hazardous Materials Safety Administration (PHMSA) to set minimum safety standards for underground storage facilities while allowing states to go above those standards for intrastate facilities.

Another provision gave PHMSA emergency order authority tailored to the pipeline sector, taking into account public health and safety, network, and customer impacts. The SAFE PIPES Act also ensures that PHMSA provides pipeline operators with timely postinspection information and provides product composition information to first responders after an incident.⁴⁹² Federal regulations in response to the SAFE PIPES Act are in various stages of development.⁴⁹³

The state’s DOGGR issued immediate regulatory changes that at first applied only to Aliso Canyon.⁴⁹⁴ DOGGR subsequently launched a rulemaking to adopt new safety rules for all underground gas storage wells in California. A key highlight of the draft rules is that underground gas storage wells with a single point of failure are now longer allowed to operate. The new rules would also require periodic inspections and testing of individual wells. The public comment period on these new rules ended on July 13, 2017, and final DOGGR action remains outstanding.⁴⁹⁵

California’s large gas utilities are spending more on infrastructure safety. The CPUC approved in the most recent rate cases⁴⁹⁶ for SoCalGas/SDG&E and PG&E, cost recovery for safety enhancements. These enhancements include replacing infrastructure, strength testing, in-line inspections, replacing and automating valves, installing cathodic protection⁴⁹⁷ to protect

490 Protecting our Infrastructure of Pipelines and Enhancing Safety Act of 2016.
<https://www.congress.gov/114/plaws/publ183/PLAW-114publ183.pdf>.

491 *Ensuring Safe and Reliable Underground Natural Gas Storage: Final Report of the Interagency Task Force on Natural Gas Storage Safety*. October 2016.

492 House Transportation and Infrastructure Committee and House Energy and Commerce Committee,
http://transportation.house.gov/uploadedfiles/pipes_2016.pdf.

493 PHMSA, <https://www.phmsa.dot.gov/pipes-act>.

494 More about DOGGR’s work specific to Aliso Canyon can be found at
<http://www.conservation.ca.gov/dog/Pages/AlisoCanyon.aspx>.

495 The rulemaking status and draft rules can be found at
http://www.conservation.ca.gov/dog/general_information/Pages/UGSRules.aspx.

496 *General rate cases* are proceedings used to address the costs of operating and maintaining the utility system and the allocation of those costs among customer classes. For more information: <http://www.cpuc.ca.gov/General.aspx?id=10431>.

497 Cathodic Protection (CP) systems help prevent corrosion from occurring on pipeline exteriors, by imparting a direct current onto the buried pipeline, using a device called a rectifier. As long as the current is sufficient, corrosion is prevented, or at least mitigated and held in check. For more information, please view the PHMSA website at: <https://primis.phmsa.dot.gov/comm/FactSheets/FSCathodicProtection.htm>.

pipelines from corrosion, and particularly for PG&E, making older pipelines piggable (accessible to in-line inspection tools).

The CPUC approved \$636 million worth of investment by SoCalGas for 2016 alone.⁴⁹⁸ In 2017, the CPUC authorized a \$58 million increase from \$375 million to \$433 million in revenue requirements for the operation and maintenance of PG&E's gas distribution system.⁴⁹⁹ This increase comes after a 2016 decision in which the CPUC approved a safety plan consisting of \$850 million.⁵⁰⁰ PG&E, in the Gas Transmission and Storage rate case filed this past November (Application 17-11-009) requests authority to spend upwards of \$785 million for expenses and capital associated with pipeline and storage safety.⁵⁰¹

In 2016, the Energy Commission approved more than \$5 million in the Natural Gas Research and Development program for projects that demonstrate natural gas pipeline safety and integrity management technologies. In November 2016, Energy Commission staff issued *The Natural Gas Research and Development Program Proposed Program Plan and Funding Request for Fiscal Year 2016–17*,⁵⁰² which calls for further research in natural gas infrastructure that has the potential to increase safety and enhance transmission and distribution capabilities of the natural gas system.

Methane Leakage in the Natural Gas System

Short-lived climate pollutants, such as methane, are harmful air pollutants that have a much stronger warming impact than carbon dioxide over the short term. The state can achieve an immediate beneficial impact on climate change by reducing these emissions.

As reported in the Chapter 9, methane accounted for about 9 percent of California's GHG emissions in 2015. The natural gas system is the fourth largest source (about 10 percent of methane emissions), after enteric digestion, manure management, and managed waste disposal sites.

In California, legislation and regulatory decisions are focusing attention on methane leaked from the natural gas system. As such, studies are now attempting to quantify the impact and extent of methane emissions from the pipeline infrastructure that moves natural gas from producing basins to demand regions. Such studies focus on leaks as a result of regular operations; this is different than the catastrophic leak at the Aliso Canyon storage facility.

Completed studies on the natural gas system have estimated leakage rates of about 1.5 percent of the total produced. Further, a synthesis study by J. A. Littlefield, using many of the studies and

498 CPUC Decision 16-06-054

499 CPUC. Decision 17-05-013. Decision Authorizing Pacific Gas and Electric Company's General Rate Case Revenue Requirement For 2017-2019. <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M186/K836/186836115.pdf>.

500 "California Nat Gas Utilities Continue Pouring Billions Into Pipeline Upgrades." *Natural Gas Intelligence*. February 22, 2017.

501 Application No. A. 17-11-009, Tables 3-1 and 3-2. PG&E estimates that its overall rate case request (including other operating and maintenance costs plus capital investment besides the safety programs) represents a 22 percent increase over what it is currently authorized to recover in rates.

502 <http://www.energy.ca.gov/2016publications/CEC-500-2016-063/CEC-500-2016-063.pdf>.

data from the Environmental Defense Fund (EDF) projects, found the emission rate to be 1.7 percent.⁵⁰³ Previous research suggests that to reap the GHG-reduction benefit of fuel switching from coal to natural gas, the amount of emitted methane should not exceed 3.2 percent.⁵⁰⁴

The EDF is coordinating a comprehensive project that examines methane emissions from the natural gas system. The collection of 16 studies is attempting to improve the understanding and characterization of this short-lived climate pollutant. Most participants in the project have completed their studies. However, the EDF is still working on an overarching project synthesis, which expects to develop an overall methane emissions rate across the natural gas supply chain.⁵⁰⁵

Senate Bill 1371, known as “Natural gas: leakage abatement” (Leno, Chapter 525, Statutes of 2014), requires gas companies to report natural gas emissions from the respective facilities and to summarize utility leak management practices, among other things.⁵⁰⁶ Using the data submitted by the utilities, the CPUC and the California Air Resources Board (CARB) will prepare joint annual reports to track and analyze natural gas emissions from transmission, distribution, and storage activities throughout the state.

The CPUC and CARB staff indicated that the information from these reports should be used “...by gas system operators to help determine where emission reductions can be achieved to meet the state’s methane emission reduction goal, while maintaining the safe and reliable operation of the regulated gas storage and delivery systems.”⁵⁰⁷

At its June 15, 2017, meeting, the CPUC approved a decision as part of its SB 1371 proceeding.⁵⁰⁸ This decision included annual reporting for tracking methane emissions; 26 mandatory best practices for minimizing methane emissions; a biennial compliance plan incorporated into the utilities’ annual gas safety plans, beginning in March 2018; and a cost-recovery process to simplify the CPUC’s review and approval of incremental expenditures to implement best practices. The cost-recovery process also included expenditures for pilot programs *and* research and development.

503 Littlefield, J. A. 2017. “Synthesis of Recent Ground-Level Methane Emission Measurements From the U.S. Natural Gas Supply Chain.” *Journal of Cleaner Production.*, Vol. 148, Pages 118–126. <https://doi.org/10.1016/j.jclepro.2017.01.101>.

504 Alvarez, R. 2012. “Greater Focus Needed on Methane Leakage From Natural Gas Infrastructure,” *Proceedings of the National Academy of Sciences*. Vol. 109. No. 17. PAGES 6435–6440. <http://www.pnas.org/content/109/17/6435>.

505 EDF. *Methane Research: The 16 Study Series*. http://www.edf.org/sites/default/files/methane_studies_fact_sheet.pdf.

506 Senate Bill 1371. https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1371.

507 CARB and CPUC Joint Staff Report: *Analysis of the Utilities’ June 17, 2016, Methane Leak and Emissions Reports Required by SB 1371*. p. 3.

508 At this time, only the proposed decision is available on the CPUC’s website at <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M186/K437/186437714.PDF>.

Further, Senate Bill 1383, (Lara, Chapter 395, Statutes of 2016) requires CARB, the CPUC, and the Energy Commission to “...undertake various actions related to reducing short-lived climate pollutants in the state.” (For more information on efforts to reduce short-lived climate pollutants, see Chapters 1 and 9.)⁵⁰⁹

In general, these efforts will result in greater mandatory monitoring on a wider assortment of gas system components than considered previously. Also, new laws and regulations are pushing for better mitigation strategies for emissions from pipelines.

As part of the Energy Commission’s work to reduce short-lived climate pollution, the Energy Commission funds methane emission research through the Natural Gas Research and Development program. This research found evidence that fugitive emissions occur in every subsector throughout the natural gas system, including homes, natural gas vehicle refilling stations, and plugged and abandoned natural gas wells.

An airplane used in one of these research projects was called to action to provide data on the Aliso Canyon gas storage facility leak in Southern California.⁵¹⁰ Data from the research sensors were instrumental in the rapid quantification of methane leakage from the Aliso Canyon facility and helped inform response to the problem.

Other projects related to methane emissions include research to:

Mexico: Potential Impacts From A Changing Market

According to EIA, Mexico holds proved reserves of 15.3 trillion cubic feet and potential reserves (mostly from shale formations) of about 545 trillion cubic feet. Reforms there over the last few years now permit investments into supply and infrastructure by foreign investors. These reforms will likely allow greater natural gas shipments from the United States to Mexico.

Natural gas demand in Mexico (see Secretaría de Energía de Mexico, *Prospectiva de Gas Natural 2016-2030*) grew from 5.09 Bcfd in 2005 to 7.50 Bcfd in 2015. Much of this growth came from the power generation sector, which in 2015 accounted for almost 51 percent of Mexico’s natural gas demand.

U.S. gas exports to Mexico have already increased. EIA data (see <https://www.eia.gov/dnav/ng/hist/n9132mx2A.htm>) shows that exports to Mexico from the United States have increased 322 percent, from 882 MMcfd in 2006 to 3718 MMcfd in 2016.

All else equal, U.S. additional exports to Mexico, particularly those from the Permian basin (West Texas and southeastern New Mexico), can draw away and reduce supply that would otherwise go to southwestern U.S. markets and even California. It could also change the price dynamics that drive southwest U.S. natural gas prices. As has long been shown in staff’s market modeling, the southwest contributes a portion of natural gas supply used in California. Changes in prices for that gas will therefore affect prices to California. Recent data, however, shows production is growing in the Permian basin. This increase in supply should ease concerns about rising natural gas shipments to Mexico potentially reducing gas available to California.

California will need to continue monitoring Mexican market developments as well as the U.S. production and pipelines constructed to support greater exports to Mexico for impacts on supplies that traditionally have been available to California. In so doing, the Energy Commission will continue to work with the Secretaria de Energia, the Comisión Federal de Electricidad and consular officials to provide support as needed on our mutual interests.

509 CARB. *Short-Lived Climate Pollutant Reduction Strategy*. March 2017. https://www.arb.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf, pp. 79-80.

510 Conley, Guido, and Ryerson, American Association for the Advancement of Science, *Science*, “Methane Emissions from the 2015 Aliso Canyon Blowout in Los Angeles, CA,” March 2016.

- Characterize fugitive emissions from commercial buildings in California.
- Identify super-emitters using a NASA/JPL sophisticated infrared camera deployed in a research aircraft.
- Study the potential impacts of subsidence (vertical and horizontal changes in elevation due to groundwater extraction during the drought) to the natural gas system and methane emissions from abandoned wells.

The most recent CPUC-approved natural gas research plan also includes a large field study to deploy new monitoring technologies to identify and quantify emissions from the natural gas system on a near-real-time basis. The hope is to find a cost-effective system or systems that may be deployed to identify intermittent leaks and super-emitters, allowing the design of programs to substantially curtail methane emissions from natural gas.

The data and associated studies will be used to deliver the publicly available annual joint staff report to analyze the utilities' emission reports. Also, this work will improve understanding of the amount of emissions from utilities' facilities and pipelines.

Natural Gas-Electricity Coordination

The constrained use of gas storage at Aliso Canyon and long-term plans for permanent closure, widespread deployment of variable renewable resources, and the proposed retirement of many coal-fired power plants signal the need for greater coordination between the natural gas market and the electricity sector. (See Chapter 11 for a discussion of measures to better coordinate natural gas delivery and electricity production in response to operational constraints resulting from the leak at the Aliso Canyon natural gas storage facility. See Chapter 3 for a discussion of the key role natural gas facilities with quick-start and fast-ramping capabilities play in integrating renewable resources.)

With more gas used across the U.S. to generate electricity, multiple actors are engaged in activity to more closely coordinate between natural gas and electricity operations. FERC launched a rulemaking in 2013 that ultimately led to at least a few changes in pipeline gas scheduling processes designed to help generators.⁵¹¹ Department of Energy Secretary Perry's request that FERC adopt a so-called "grid resiliency pricing rule" and associated staff report noted that natural gas does not offer 90-days of on-site physical supply.⁵¹² NERC published its study in November 2017, specifically assessing the risk to bulk power systems from severe disruptions on the natural gas system. Among its recommendations is that electricity planning take into account the risk of losing key natural gas infrastructure. WECC has a study underway assessing the adequacy,

⁵¹¹ See *Coordination of the Scheduling Processes of Interstate Natural Gas Pipelines and Public Utilities*, Final Rule, Order No. 809, 80 Fed.Reg. 23198 (Apr. 24, 2015), FERC Stats. & Regs. 31,368 (2015).

⁵¹² FERC issued its ruling in Docket RM18-1-000 on January 8, 2018. Its order opens a new rulemaking (RM18-7-000) and proposes to establish a definition of "resiliency." It also directs regional transmission organizations (RTOs) and independent system operators (ISOs) to respond within 60 days as to whether the proposed definition of resiliency should be adopted. It directs the RTOs and ISOs to answer 19 questions related to adverse event risk evaluation and planning, what studies the RTOs and ISOs have done, whether different generation technologies are affected by resiliency events differently, and what attributes of the bulk power system contribute to resilience.

security, and risks associated with the natural gas infrastructure and the ability to serve the evolving Bulk Electric System.⁵¹³ Several of the other regional reliability operators such as the Midwest Independent System Operator and New England's Independent System Operator have performed similar assessments pertinent to characteristics in their own regions.

In California, the leak at Aliso Canyon and the facility's restricted operations caused a particularly intensive effort to assure that the gas system does not lead to electricity blackouts. In that effort, the Energy Commission and CPUC are working with the California Independent System Operator (California ISO) the Los Angeles Department of Water and Power (LADWP), and SoCalGas to assess risks, develop mitigation measures, monitor and coordinate gas and electric operations. The effort, described in more detail in Chapter 11, has resulted in changes in SoCalGas' balancing rules, in changes to which power plants the California ISO dispatches when the gas system is under stress, and in LADWP obtaining South Coast Air Quality Management District approval to burn diesel fuel as a last resort to maintain electricity service. The California ISO can also provide advance direction to power plants about gas system conditions to help power plants better match their gas supply purchases with their actual usage. The coordination activities include regular conversations about the conditions affecting the two systems so that appropriate advance action can be undertaken. One key finding made by the team was how important it now is to understand hourly gas demand, how it changes over the course of the day, and how the gas system matches constant hourly receipts with variable hourly gas demand.

The Environmental Defense Fund (EDF) has suggested that California implement a "natural gas imbalance market" (GIM) as a way of reducing the utilities' reliance on gas storage to manage imbalances.⁵¹⁴ As explained above in the "California Pipelines" discussion, imbalances occur due to differences between gas supplies the utilities receive into their systems and the gas actually used by their customers. During the gas day, the utility uses pipeline inventory and then storage to make up these differences. Gas-fired electric generators typically operate and use natural gas in only certain hours of the day, which inevitably creates imbalances. The Joint Agency Technical Assessments behind the Aliso Canyon Reliability Action Plans highlighted how Aliso Canyon was used to remedy imbalances and suggested tighter balancing rules to reduce reliance on gas from storage.⁵¹⁵

513 <https://www.wecc.biz/Administrative/Gas-Electric%20Interface%20Study%20RFP.pdf>.

514 Comment letter from Environmental Defense Fund and Skipping Stone, June 5, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217837_20170605T093823_Tim_O'Connor_Comments_Comment_letter_from_EDF_and_Skipping_Stone.pdf, pp. 6–10.

515 The CCST study on gas storage also highlights this key use of underground gas storage.

EDF's concept for a GIM is intended to allow the market to develop solutions to reduce hourly imbalances, doing so in a way that yields greater market efficiency and transparency.⁵¹⁶ For example, market participants with excess supply in a given hour might be able to sell that excess gas to others needing more that day. A market price on hourly imbalances might induce other participants to enter the market with solutions for those imbalances, such as firing additional compressors to pack pipelines with more gas. It would be particularly interesting to see if blockchain technology can be used to help manage hourly natural gas imbalances or to help apply advanced metering infrastructure data to improve utility forecasts of core gas demand.⁵¹⁷

Independent Storage Operators

Some of the natural gas storage in California is owned and operated by the two large gas IOUs, PG&E and SoCalGas. Much of the value the independents provide is to enhance liquidity in the market; most of their customers are large customers and natural gas marketers who use storage on a shorter-term basis to hedge price risk or arbitrage price volatility, whereas the IOUs use storage to assure reliability. California may be at the cusp of changes on how independent gas storage (which first joined the market in 1996) is used. First, the new study from CCST as to the viability of underground gas storage may cause rethinking of where storage is wanted or how it is used. Second, operators must implement the new gas storage safety rules developed by DOGGR. PG&E, for example, believes it will cost less to retire two of its gas storage facilities and contract with independent storage for replacement capacity than to bring those facilities into compliance with the new safety rules. It is asking for CPUC approval to implement a new gas storage strategy that would shift some winter reliability protection for core customers over to independent gas storage and that increases cooperation between PG&E and independent storage. Third, hourly and daily gas balancing service is now the domain of the gas utilities. A gas imbalance market as suggested by EDF might result in creating market incentives or mechanisms that could allow independent storage to provide this balancing function, especially with the commitment to retire Aliso Canyon by 2028. Gill Ranch gas storage is also suggesting that with minor pipeline adjustments it might be able to deliver gas to Southern California, where today no independent gas storage exists.

Comments filed after the October 9 workshop expressed skepticism about the GIM proposal.⁵¹⁸ PG&E's comments called the proposal unnecessary given existing market mechanisms. Among those mechanisms are imbalance rules embodied in its current G-Bal tariff, which it has found its customers like. PG&E further pointed out that imbalances are in fact subject to market forces now and same-day trading using PG&E Citygate prices on the Intercontinental Exchange and on the New York Mercantile Exchange. PG&E calling an OFO where penalties are set as a percentage of the market price for natural gas that day does in fact send an immediate market signal.

In additional comments on the *Draft 2017 IEPR*, PG&E listed several factors it recommends be examined when considering EDF's gas imbalance market proposal, including:

- That gas imbalance trading already occurs under the G-BAL tariff.

⁵¹⁶ Greg Lander, Skipping Stone, "Gas Imbalance Market, Conceptual Outline," http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-04/TN221396_20171005T133642_Gas_Imbalance_Market_GIM_-_Conceptual_Outline.pdf.

⁵¹⁷ Basden and Cottrell, "How Utilities Are Using Blockchain to Modernize the Grid," *Harvard Business Review* March 27, 2017.

⁵¹⁸ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-04/TN221600_20171023T155900_Pacific_Gas__Electric_Company_Comments_PGE_Comments_on_the_Draft.pdf.

- How a GIM might affect use of storage for price arbitrage or potentially diminish the value of existing storage assets; what setting up a GIM might cost.
- Differences between existing balancing rules specified in the tariffs for PG&E versus SoCalGas.⁵¹⁹
- That Northern California has storage assets owned and operated by providers independent of the gas utilities, and how the California ISO's gas dispatch tool's ability to incorporate gas constraints into the hourly electric dispatch price and shift generation already.⁵²⁰

PG&E also pointed out that the storage inventory level recommendations articulated as part of the proposal run counter to market-based storage incentives and the current storage market is split between utility and independent storage. (See sidebar, "Independent Storage Operators.") PG&E's own proposal in its 2019 Gas Transmission and Storage rate case is pending before the CPUC.

SMUD is the only other party to file comments on this subject.⁵²¹ SMUD stated that it does not believe a 24-hour market for balancing is useful and views the current practice of calling operational flow orders as sufficient. It is particularly worried about the impact to electric generators. Of course, capturing the cost of imbalances into hourly natural gas prices could allow electricity customers to manage their demand in a way that reduces imbalances.

None of these objections necessarily seem to present insurmountable obstacles to a GIM; rather, they express the view that California's existing approach is adequate. The Energy Commission would like to see the GIM concept more fully expressed and fleshed out in a future *IEPR* cycle or appropriate CPUC proceeding. Why, for example, would a GIM be better than the existing balancing rules? What would be required to implement one? Where would the gas for the afternoon electric generation ramp come from, if not from storage? Ultimately, a GIM may or may not be the solution California needs and it may or may not be feasible. It may also be that the benefits and costs of one differ between Northern California and Southern California. Even so, the concept of a market mechanism that prices hourly imbalances could potentially provide more economically efficient coordination between gas and electric markets than current rules and in so doing support retirement of Aliso Canyon. It is worth exploring more fully.

Liquefied Natural Gas

In the late 2000s, LNG imports into the United States were seen as economic in the face of high prices for gas produced domestically. Prices for domestic supplies dropped, however, with widespread production of gas from shale formations. With the 18 Bcf worth of terminals built to import LNG largely sitting idle,⁵²² producers sought and obtained permission to begin exporting

⁵¹⁹ Key differences between the two systems were documented in CPUC Application Nos. 08-02-001 and 14.06-021 and led the CPUC not to impose the same rules for the two gas utilities.

⁵²⁰ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221734_20171113T143653_Pacific_Gas__Electric_Comments_PGE_Comments_on_2017_Draft_IEPR.pdf.

⁵²¹ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-04/TN221598_20171023T154415_Joy_Mastache_Comments_SMUD_Natural_Gas_Outlook_Comments.pdf.

⁵²² FERC. "North American LNG Import/Export Terminals Existing as of May 1, 2017."

U.S.-produced gas as LNG. Especially with the expansion of the Panama Canal to serve larger ships, the United States is now positioned to become a net exporter of natural gas. With almost 10 Bcfd of export capacity under construction and 7 Bcfd more approved, the United States is expected to become the world's third-largest LNG producer by 2010, after Australia and Qatar. Canada is following along.

Three proposed LNG export facilities in British Columbia, Canada, with a combined capacity of 6.6 Bcfd have received regulatory approval⁵²³ and are in various phases of development.⁵²⁴

The impact of increased LNG exports from North America remains to be seen. According to a 2015 U.S. DOE-funded study, most of the increase will be met by expanded domestic production rather than reduced demand. This study also argues that price impacts will be small.⁵²⁵

At one point, sponsors proposed as many as seven different LNG terminals for California, with several more proposed for Baja Mexico that largely sought to serve the California natural gas market. Of those, only one terminal was built – the Costa Azul terminal in Baja, owned by Sempra. It is connected via pipeline the short distance needed to reach SDG&E's interconnect at Otay Mesa. Little LNG has ever been delivered to that terminal owing to world LNG prices that until recently have been much higher than prices for U.S.-produced natural gas.⁵²⁶ As discussed in the Aliso Canyon reliability action plans (see Chapter 11), some thought has been given as to whether gas at Costa Azul could help reduce stress on the gas system in Southern California. It remains an option and circumstances could yet require its use.

First Steps in Transforming the Natural Gas Sector

One topic that arises as the state works to reduce its GHG emissions and its reliance on methane is how the gas utilities can evolve to participate in a decarbonized future. The Energy Commission discussed the future of natural gas utilities at a joint workshop on renewable gas in June 2017. Steve Malnight, senior vice president of strategy and policy for PG&E, and George Minter, regional vice president of external affairs and environmental strategy for SoCalGas, discussed their respective utility's strategies to reduce short-lived climate pollutants and provided a glimpse into how gas utilities might evolve.

The panelists described how existing infrastructure could support the delivery of renewable gas to end-use customers, particularly for use as a transportation fuel, a concept Mr. Minter termed "gas utility 3.0." (For more discussion of the use of natural gas as a transportation fuel, see Chapter 7.) The concept is that the "gas utility 1.0" was the early days of the gas industry before the late nineteenth century, when providers sold manufactured gas for lighting and heating. This evolved to "gas utility 2.0" when manufactured gas was replaced by naturally-occurring gas produced

⁵²³ Federal Energy Regulatory Commission. "North American LNG Import/Export Terminals Approved as of May 1, 2017."

⁵²⁴ *International Gas Union 2017 World LNG Report*, p. 31.

⁵²⁵ *The Macroeconomic Impact of Increasing LNG Exports*, pp. 12 and 60.

⁵²⁶ See http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-04/TN217277_20170424T125304_US_Gas_Fundamentals_Going_Global.pdf.

from underground geologic formations. Utilities all over the country, including SoCalGas, converted and expanded their distribution system to deliver natural gas. Gas utility 2.0 is the current gas utility system of natural gas delivered by backbone transmission and lower-pressure distribution lines.⁵²⁷

Mr. Minter and Mr. Malnight pointed out that ratepayers would have to fund maintenance and necessary system upgrades as the utilities moved to incorporate greater amounts of renewable gas into their systems. In addition to ratepayer-funded infrastructure and system upgrades, Mr. Minter mentioned that rules must be in place to ensure that the quality of the renewable gas injected into the system meets pipeline specifications. This requirement would safeguard the natural gas system and prevent damage to the infrastructure. The utilities also pointed out that increased use of renewable gas in California requires a robust, transparent market that would encourage investment in this new energy source and provide adequate supplies. The Energy Commission expects SoCalGas, in particular, will aggressively pursue opportunities to develop renewable natural gas owing to its commitment to mitigate the impact of the approximate of 99,650 (+/-9,300) metric tons⁵²⁸ of methane that leaked from Aliso Canyon. Beyond that, the utilities should continue shareholder investments into planning what services they might offer in a California with much lower use of methane. The Energy Commission looks forward to hosting additional discussion on this topic in the *2019 IEPR*.

Recommendations

- **Expand by \$50 million the funding for the Energy Commission’s Natural Gas Research and Development program and utility pilot programs to accelerate improved safety, methane control, and climate adaptation for the natural gas system.** Meeting California’s short-lived pollution reduction targets requires substantial reductions in methane emissions from California’s natural gas infrastructure. Increased funding is needed to fund cost-effective Natural Gas Research and Development projects, including those relating to climate adaptation, safety, and methane emissions mitigation. Also, climate research indicates California’s Central Valley is expected to experience more frequent prolonged periods of drought, which could lead to further groundwater overdraft in areas prone to subsidence. Ensuring the natural gas system can safely navigate these challenges and control methane emissions is a high priority for California.
- **Support additional research into seismic risk to California’s natural gas system**. Greater seismic activity due to disposal of hydraulic fracturing wastewater via underground injection is one area to study and The California Council on Science and Technology’s (CCST) 2015 study agreed such injections could pose an issue. The other area is seismic impacts at underground gas storage facilities. The new CCST study on underground gas storage concurs that additional work in this area would be useful. The Energy Commission should conduct research, in close coordination with the CPUC and the Division of Oil, Gas,

⁵²⁷ History of SoCalGas, <https://www.socalgas.com/company-history>.

⁵²⁸ CARB, *Determination of Total Methane Emissions from the Aliso Canyon Natural Gas Leak Incident*, https://www.arb.ca.gov/research/aliso_canyon/aliso_canyon_methane_emissions-arb_final.pdf.

and Geothermal Resources, to assess the seismic risks of underground natural gas storage in California and develop new and advanced seismic risk assessment methods and models.

- **Continue contingency planning and analyze and coordinate gas-electric impacts on reliability.** The Energy Commission has statutory responsibility for contingency planning in the event of shortages of electrical energy or fuel supplies (Public Resources Code Section 25700). The shifts in electricity generation portfolios and gas infrastructure use mean that the state's electric and natural gas systems are no longer independent of each other. The Energy Commission must continue to assess the natural gas and electricity interface. This includes analyzing the impact of hourly electric generator demand patterns and their impact on the gas system, as well as explicitly analyzing the minimum gas use required by the electric balancing authorities to prevent electricity service disruptions. It also means continuing the effort to hydraulically model the gas system and be able to critically evaluate results produced by the gas utilities, as well as monitoring natural gas and electricity markets, including daily monitoring of electricity and natural gas spot and forward prices. All of these activities are underway.
- **Develop strategies to upgrade the state's aging natural gas infrastructure while reducing reliance on gas and enhancing safety.** These strategies should focus on making infrastructure changes that both reduce fugitive methane emissions and enhance gas system reliability and safety. These strategies, however, must be developed at the same time that California decreases its natural gas use.
- **Coordinate closely with the California Public Utilities Commission (CPUC) to ensure California's continued shift away from fossil fuels, including methane.** The Energy Commission must maintain its coordination with the CPUC to ensure that natural gas demand and usage continue to decline as California shifts away from methane, especially as a power plant fuel. Consistent with Assembly Bill 1257 (Bocanegra, Chapter 749, Statutes of 2013), every four years as part of the *IEPR* the Energy Commission also must "identify strategies to maximize the benefits obtained from natural gas, including biomethane...helping the state to realize the environmental and cost benefits afforded by natural gas." This analysis is done in consultation with the CPUC and other state agencies and will next be developed as part of the *2019 IEPR*.

CHAPTER 9:

Renewable Gas

Short-lived climate pollutants (SLCPs), such as methane, hydrofluorocarbon gases, and anthropogenic black carbon, represent a critical challenge and opportunity in the state's campaign to reduce greenhouse gas (GHG) emissions. Although they do not remain in the atmosphere for as long as carbon dioxide, they are many times more effective than carbon dioxide in trapping heat. For this reason, California has specifically prioritized the reduction of SLCPs as a key strategy in reducing the state's overall GHG emissions. (See Chapter 1 for more information on California's GHG policies and more information on SLCPs and Chapter 10 for California's efforts to adapt to climate change.)

Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) requires that by January 1, 2018, the California Air Resources Board (CARB) shall "approve and begin implementing a comprehensive short-lived climate pollutant strategy developed pursuant to Section 39730 to achieve a reduction in the statewide emissions of methane by 40 percent, hydrofluorocarbon gases by 40 percent, and anthropogenic black carbon by 50 percent below 2013 levels by 2030." SB 1383 also requires the California Energy Commission, in consultation with CARB and the California Public Utilities Commission (CPUC), to "develop recommendations for the development and use of renewable gas, including biomethane and biogas as part of its 2017 Integrated Energy Policy Report." (Section 39730.8 of the Public Health and Safety Code.) The statute states that:

"In developing the recommendations, the Energy Commission shall identify cost-effective strategies that are consistent with existing state policies and climate change goals by considering priority end uses of renewable gas, including biomethane and biogas, and their interactions with state policies, including biomethane and all of the following:

1. The Renewables Portfolio Standard program (Article 16 (commencing with Section 399.11) of Chapter 2.3 of Part 1 of Division 1 of the Public Utilities Code).
2. The Low-Carbon Fuel Standard regulations (Subarticle 7 (commencing with Section 95480) of Title 17 of the California Code of Regulations.)
3. Waste diversion goals established pursuant to Division 30 (commencing with Section 40000) of the Public Resources Code.
4. The market-based compliance mechanism developed pursuant to Part 5 (commencing with Section 38570) of Division 25.5.
5. The strategy [to reduce short-lived climate pollutants]."⁵²⁹

⁵²⁹ California Senate, SB 1383 Short-lived climate pollutants: methane emissions: dairy and livestock: organic waste: landfills, https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383.

The Energy Commission, in partnership with the CPUC and CARB, held a workshop on developing recommendations for the *2017 Integrated Energy Policy Report (2017 IEPR)* on June 27, 2017.⁵³⁰ Participants included state agencies, academic and industry analysts, gas utilities, renewable gas developers, venture capital and financing organizations, and vehicle representatives. More than 20 panelists participated in discussions, and 10 other organizations provided public comment at the workshop. More than 50 written comments were also submitted after the workshop. Information gleaned from the workshop and public comments inform the analysis presented here.

Reducing the use of fossil fuel natural gas is necessary to meet California's long-term climate goals and Governor Edmund G. Brown Jr.'s goals for 2030, identified in his January 2015 inaugural address, of increasing California's electricity derived from renewable resources from one-third to 50 percent, doubling the efficiency of existing buildings and making heating fuels cleaner, and reducing petroleum use in vehicles by 50 percent.⁵³¹ This chapter explores applications for using renewable gas as part of California's strategy to reduce GHG emissions and achieve these goals. As discussed in Chapter 8, natural gas (composed primarily of methane) is used for heating, electricity production, and increasingly in the transportation sector for medium and heavy-duty vehicles. The use of renewable gas in transportation can help achieve the vision of the *California Sustainable Freight Action Plan* to transport freight reliably and efficiently by near-zero emission equipment powered by clean, low-carbon renewable fuels everywhere that zero-emission equipment is not feasible. The use of renewable gas in transportation also supports the vision outlined by the California Sustainable Freight Action Plan, which calls for the use of low-carbon renewable fuels in near-zero-emission equipment (where zero-emission equipment options are not feasible).⁵³²

This chapter identifies cost-effective strategies and considers priority end uses of renewable gas in relation to existing state policies and climate goals. Furthermore, emerging opportunities for resource and technology solutions to reach longer-term SLCP goals are discussed. The chapter closes with the Energy Commission's proposed recommendations as required by SB 1383.

Cost-Effective Strategies

Cost-effective strategies in this context are strategies that yield the lowest cost per SLCP reduction benefit in terms of GHG emissions reduced. The following sections provide an overview of renewable gas sources and the associated potential end uses and summarize the cost-effectiveness of each.

⁵³⁰ Information from the workshop, including transcript and recording, is available at http://www.energy.ca.gov/2017_energy_policy/documents/#06272017.

⁵³¹ Governor Brown's 2015 inaugural address, January 5, 2015, <https://www.gov.ca.gov/news.php?id=18828>.

⁵³² The *California Sustainable Freight Action Plan* specifically references the development and use of renewable gas in near-zero-emission equipment (when zero-emission equipment is not feasible). The plan identifies the capture of dairy biomethane for freight vehicles as one of three key pilot projects to be supported by the state. Additionally, the plan calls for development of a natural gas vehicle research roadmap that includes, among other topics, the production of low-carbon renewable natural gas. For more information see http://www.casustainablefreight.org/documents/PlanElements/Main%20Document_FINAL_07272016.pdf.

In-State Renewable Gas Resource Potential

Renewable gas is gas that is generated from organic waste or from electricity generated by an “eligible renewable energy resource” as defined in Subdivision (e) of Section 399.12 of the California Public Utilities Code or at a “renewable electric generating facility” as defined in Section 25741 of the California Public Resources Code.⁵³³ Renewable gas includes, but is not limited to, biogas; biomethane (also known as renewable natural gas); synthetic natural gas generated from organic waste, or electricity generated by an eligible renewable energy resource or at a renewable electric generating facility; renewable hydrogen; and gaseous products composed of the aforementioned, such as renewable dimethyl ether.”⁵³⁴ Organic waste includes, but is not limited to, food waste, green waste, landscape and pruning waste, nonhazardous wood waste, byproducts of sustainable forest management, food-soiled paper waste that is mixed in with food waste, livestock and animal waste, agricultural waste, wastewater biosolids, and landfilled biomass. Renewable energy resources, as defined in Section 25741 (a)(1) of the California Public Resources Code, include biomass, digester gas, municipal solid waste conversion, and landfill gas, as well as solar thermal, photovoltaic, wind, geothermal, fuel cells using renewable fuels, small hydroelectric generation of 30 megawatts or less, ocean wave, ocean thermal, and tidal current. Policies related to landfill gas capture must be consistent with the SB 1383 organic waste recycling requirements, including for the state to reduce the disposal of organic waste by 75 percent by 2025.

California possesses significant, diverse waste streams and residues that can be used to produce renewable gas. Opportunities exist to capture and beneficially use renewable gas that is now unintentionally produced and emitted into the atmosphere. Methane contributed about 9 percent of the total GHG emissions in California in 2015. Figure 78 summarizes the overall methane emissions inventory within the state from 2015, the most recent year data are available. As shown, the majority of California’s methane emissions are derived from renewable resources such as landfilled waste, livestock manure, and wastewater.⁵³⁵ Over the past 10 years, methane emissions in the state have fluctuated between 39 million and 41 million metric tons of carbon dioxide equivalents (MT-CO_{2e}, 100-year global warming potential [GWP]). Methane emissions from landfills have steadily increased, while emissions from livestock operations have fluctuated, and emissions from wastewater treatment have decreased.⁵³⁶ A 40 percent reduction in methane

533 In the gaseous state of matter at 1 atm (14.696 lb/in²) absolute and 15 °C (60 °F), the reference pressure and temperature for hydrocarbon gas vapor and hydrogen gas measuring devices by the California Department of Food and Agriculture, Division of Measurement Standards. https://www.cdfa.ca.gov/dms/programs/Publications/FRM/2018/3-2018_FRM_Chapter%201_Part_3_3.30-3.40.pdf.

534 The California Hydrogen Business Council urged the Energy Commission to not to inadvertently exclude, or be misinterpreted as excluding, some forms of renewable gas. They proposed changes to the definition of renewable hydrogen, which are mostly consistent with the current definition. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221729_20171113T152855_California_Hydrogen_Business_Council_CHBC_Comments_Comments_of.pdf.

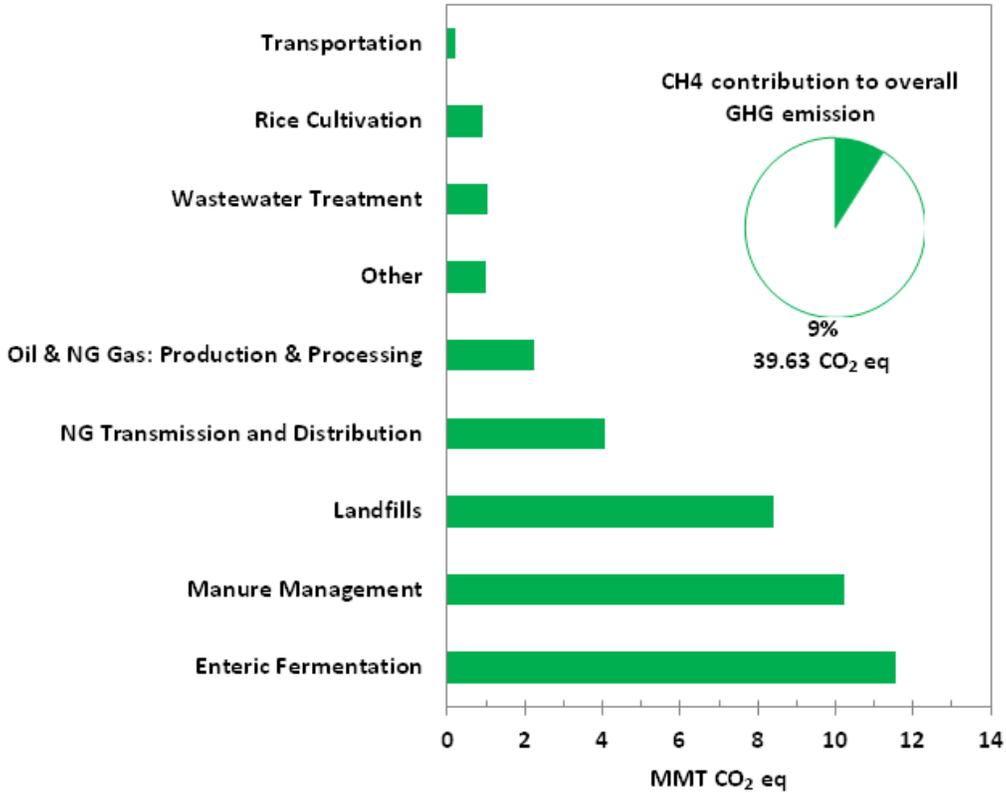
535 Methane emissions from the natural gas system comprise about 10 percent of the state’s methane emissions and are the fourth largest source of methane emissions in California. Based on the CARB’s GHG inventory, methane emissions from California’s natural gas system contribute about 0.9 percent to California’s total GHG emissions, not including methane emissions from the extraction of natural gas in California.

536 CARB. “California Methane Inventory for 2000-2015 – by Category as Defined in the 2008 Scoping Plan.” June 2017, https://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_2000-15ch4.pdf.

emissions from 2013 levels, as mandated by SB 1383, would equate to reducing California’s methane emissions level down to 23.90 million MT-CO₂e (100-year GWP).

Renewable electricity may also be used to produce renewable gas. Productively using excess renewable energy to electrolyze water and produce hydrogen as a source of renewable gas (power-to-gas) is one potential option to help manage the grid as discussed in Chapter 3, “Opportunities to Use Excess Energy.”

Figure 79: 2015 California Methane Emissions Inventory (100-Year GWP)



Source: California GHG Emission Inventory- 2017 edition, released June 6, 2017

Dairy and Other Livestock Wastes

According to CARB’s SLCP inventory, dairy manure, dairy enteric, and nondairy livestock emissions of methane are responsible for more than half (55 percent) of in-state methane emissions. Enteric emissions are expelled directly from animals (such as by burping) and are therefore difficult to capture, but dairy manure is often collected into storage ponds and lagoons, allowing for easier emissions capture. These manure methane emissions are largely driven by how manure is stored and not how it is collected and can be mitigated by a variety of methods, including solids-liquids separation, converting flush systems to scrape, and building digesters to produce biomethane. The manure from a single milking cow (140 pounds of manure daily) can

produce roughly 21,601 standard cubic feet of biomethane in a year, assuming 100 percent conversion.⁵³⁷

California boasts the largest dairy industry in the United States and is home to more than 1,400 registered dairies, with nearly 1.8 million milk cows and heifers.⁵³⁸ However, California has lost nearly 600 dairies within the last 10 years due to higher labor and regulatory costs, low milk prices, and out-of-state competition. Among the remaining dairies, there are only about 980 dairies with a herd size greater than 500 (the minimum size generally considered economical for a stand-alone dairy digester project).⁵³⁹ As of September 2017, there are only 18 dairies that capture and use their methane emissions. Two of these sites are temporarily offline, and one is undergoing repairs.⁵⁴⁰ All these sites have covered lagoon anaerobic digesters, made by covering existing storage lagoons and adding mixing systems. They also all use the produced renewable gas to generate electricity, while one additionally produces a transportation fuel. These digesters capture and destroy less than 2 percent of the statewide lagoon methane. At least 10 other dairy digester systems have been shut down due to economic conditions and/or more stringent air quality regulations. However, as of December 2017, there are three new dairy digesters under construction, with 18 more dairy digesters expected to be developed with \$35 million in total funding awarded in October 2017 from the California Department of Food and Agriculture's (CDFA) 2017 Dairy Digester Research and Development Program, which received 36 applications. CDFA has since received an additional \$99 million from the Greenhouse Gas Reduction Fund in 2017, of which \$65 million to \$80 million is expected to fund the development of even more dairy digester projects. According to stakeholders representing Subgroup #2: Fostering Markets for Digester Projects at the January 8, 2018, Dairy and Livestock Greenhouse Gas Reduction Working Group meeting, it is conceivable to have 100–120 dairy digester projects operating within the next 4 to 5 years.⁵⁴¹

Solid Waste Landfills

Landfills are the second largest sector source of methane emissions in California. Landfills emit methane from the natural decomposition of buried organic waste. More than 1.2 billion tons of waste (more than one-third is organic based upon current disposal rates) have accumulated in California's 370 landfill sites. Although many locations have been retired or idled, leaving only 126 active and permitted landfills accepting solid waste in 2015, organic material can continue to

537 Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. *An Assessment of Biomass Resources in California, 2013 – DRAFT*. Contractor report to the California Energy Commission. PIER Contract 500-11-020.

538 California Department of Food and Agriculture. *California Dairy Statistics Annual 2016*, March 2017. https://www.cdfa.ca.gov/dairy/pdf/Annual/2016/2016_Statistics_Annual.pdf.

539 Sustainable Conservation. *Greenhouse Gas Mitigation Strategies for California Dairies*. July 2015. http://suscon.org/pdfs/news/pdfs/GHG_Mitigation_for_Dairies_Final_July2015.pdf.

540 Boccadoro, Michael. "California Manure Methane Emission Reduction Efforts: An Overview." August 2017, Presentation at the Dairy and Livestock Working Group: Dairy Digester Subgroup #2. <https://arb.ca.gov/cc/dairy/documents/08-10-17/dsg2-dairy-sector-presentation-081017.pdf>.

541 Boccadoro, Michael, J. Lucas, R. Schuhard. "SB 1383 Dairy & Livestock Greenhouse Gas Reduction Working Group Meeting", January 2018, Presentation at the SB 1383 Dairy & Livestock Greenhouse Gas Reduction Working Group Meeting. https://arb.ca.gov/cc/dairy/documents/01-05-18/subgroup_2_digester_presentation_01-05-18.pdf.

emit methane for more than 50 or even 150 years after being placed into the landfill. Today, roughly 30 million to 35 million tons of waste is added each year to California's landfills, down from more than 40 million per year before 2007.⁵⁴² Though plans and progress for increasing prelandfill organics diversion are encouraging, the pre-existing volumes and ongoing additions of organics in landfills will continue to emit methane. The California Biomass Collaborative estimates that nearly 55 percent of the landfill gas extracted from California's landfills is used to generate power, and 45 percent is flared. (See the later section on flaring.)⁵⁴³

The majority of California's renewable gas is supplied from out-of-state landfill-gas-to-renewable-natural-gas (LFG-to-renewable gas) projects, totaling 654 projects in the United States with the potential for 405 more as of March 2017. Although other states have been able to develop LFG-to-renewable gas projects economically to serve the California market, there is only one landfill that produces renewable natural gas in the state. As of June 2017, California has 63 operational landfill gas projects, but only the Altamont landfill produces renewable gas for transportation (specifically, refuse trucks); the other 62 landfills generate electricity or heat or both from LFG.⁵⁴⁴ The Energy Commission has provided grants to at least three landfill gas projects through its EPIC program over the past decade.

Municipal Solid Waste (MSW) and Urban Organic Wastes

A concurrent approach to reducing landfill methane emissions is diverting organic wastes from the municipal solid waste stream before they enter the landfill. Organics diversion is critical to reducing methane emissions, reducing water polluting leachate, and increasing the state's reliance on landfilling as a waste management strategy. About 0.24 and 0.13 tons of methane can be emitted per dry ton of food waste and green waste, respectively. Under SB 1383, CalRecycle must adopt regulations no sooner than January 1, 2022, that achieve a 50 percent reduction in the level of the statewide disposal of organic waste from the 2014 level by 2020 and a 75 percent reduction by 2025. In 2014, 37.4 percent (11.5 million tons) of California's disposal stream was organic waste.⁵⁴⁵

Organics can either be separated at the source, such as by using specific collection bins, or separated from the mixed waste stream. CalRecycle estimates that in 2014, roughly 60 percent of statewide disposal resulted from waste materials that had been processed through material recovery facilities (MRFs) or transfer stations. This provides an opportunity for organics separation and diversion at these facilities. As of 2015, there were 161 active MRFs and 471 active transfer stations within the state, recovering and sorting mixed waste materials. Estimates

542 California Department of Resources Recycling and Recovery (CalRecycle). *State of Disposal and Recycling in California: 2017 Update* August 2017. http://www.calrecycle.ca.gov/Publications/Documents/1612/2017%20State%20of%20Recycling%20and%20Disposal%20Report_01612.pdf.

543 UC Davis. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*. June 2016. <https://www.arb.ca.gov/research/apr/past/13-307.pdf>.

544 U.S. EPA Landfill Methane Outreach Program. "Landfill Gas Energy Project Data." June 2017. <https://www.epa.gov/lmop/landfill-gas-energy-project-data>.

545 CalRecycle. *State of Disposal in California: Updated 2016*. February 2016. <http://www.calrecycle.ca.gov/publications/Documents/1556/201601556.pdf>.

suggest that the annual throughput at both MRFs and transfer stations (15.3 million tons and 25.1 million tons, respectively) is well below the total statewide handling capacity (36.1 million tons and 60 million tons).⁵⁴⁶

Specific to food waste, around 5.5 million tons is disposed each year in California. The two most prevalent treatment pathways for separated food waste are composting and anaerobic digestion. In California, there are roughly 25 operational food processing and urban-waste anaerobic digestion projects that produce mostly electricity, though a few have begun producing renewable gas for transportation fuel.⁵⁴⁷ About half of these projects are at food processing facilities, while the remainder are sited mostly at MRFs or transfer stations. From 2014 to 2017, CalRecycle awarded \$24 million in grants from the Greenhouse Gas Reduction Revolving Loan Program for six organic waste digester projects. For funding year 2017–2018, CalRecycle appropriates another \$40 million for grants for organic waste digester and compost projects. Over the past decade, the Energy Commission awarded grants to seven commercial-scale organic waste digester projects through its ARFVTP program and another seven through its EPIC program.

Wastewater Treatment Plants

There are more than 900 wastewater treatment plant (WWTP) facilities in California, managing nearly 4 billion gallons of wastewater generated every day.⁵⁴⁸ From this system, large amounts of wastewater biosolids (sludge) are produced. Anaerobic digestion has become an accepted process for large wastewater treatment operations seeking to reduce the amount of biosolid waste. Many large WWTPs are already generating between 40 to 70 percent of their onsite energy needs from biogas generated through anaerobic digestion. Roughly 1.15 standard cubic feet of biogas is generated per 100 gallons of wastewater inlet flow with methane content of 65 percent. In California, there are roughly 141 WWTPs that have anaerobic digesters and 59 that utilize their biogas, although mostly to generate electricity.⁵⁴⁹ Overall, WWTPs are one of the smallest sources of methane emissions and represent the smallest technically available source of renewable gas. Methane emissions from WWTPs have also decreased over time, although the overall GHG emissions of these facilities have remained constant, which indicates increased rates of renewable gas utilization or flaring or both.

Although WWTPs contribute a small fraction of methane emissions, these facilities offer significant opportunity in the form of codigestion of solid organic waste. *Codigestion* refers to the anaerobic digestion of multiple feedstocks, such as the addition of food waste to a wastewater digester. Many of the largest plants have excess volume capacity, are close to population centers, and could potentially obtain and process significant amounts solid organic waste. The U.S.

546 CalRecycle, *State of Disposal in California: Updated 2016*, February 2016, <http://www.calrecycle.ca.gov/publications/Documents/1556/201601556.pdf>.

547 California Biomass Collaborative. "CBC Facilities Database, March 2015." http://biomass.ucdavis.edu/files/2013/09/cbc-facilities-database_March_2015.xlsx.

548 American Society of Civil Engineers. *California Infrastructure Report Card: A Citizen's Guide – 2012*. February 2012. Available at http://www.ascecareportcard.org/citizen_guides/Citizen's%20guide%202012_Revised.pdf.

549 California Association of Sanitation Agencies. "2015 Fact Sheet, December 2015." <http://casaweb.org/wp-content/uploads/2015/12/2015-Biosolids-Fact-Sheet-cm.pdf>.

Environmental Protection Agency estimates that the nearly 140 wastewater treatment facilities with anaerobic digesters in California have an estimated excess capacity of 15–30 percent.⁵⁵⁰ The California Association of Sanitation Agencies estimates that existing infrastructure at government-owned WWTPs could accept up to 75 percent (7 million wet tons) of the food waste stream being landfilled. CARB carried out a geospatial analysis indicating that food waste and wastewater treatment excess capacity are spatially correlated throughout California. The analysis found that all food waste from landfills could theoretically be consumed by wastewater treatment plants within 30 miles. Codigestion could potentially reduce the investment cost of developing organics diversion projects and provide side benefits, such as decreasing waste hauling distances, increasing water recovery, and generating a renewable supply of fertilizer and soil amendments. Anaerobic digestion projects can help support the goals of Senate Bill 7 (Steinberg, Chapter 4, Statutes of 2009) to reduce urban per-capita water use in California by 20 percent by December 31, 2020, as well as Governor Brown’s Executive Order B-29-15 water-saving measures. Marginal additions of food waste can also greatly increase renewable gas production at WWTPs. Demonstrations by the sanitation districts of Los Angeles County have shown that adding 10–12 percent food waste (on a volume basis) can more than double the biogas production of a WWTP. CARB’s *SLCP Strategy* identifies WWTP codigestion as a potential strategy. The Energy Commission has provided grants to at least six wastewater digester projects through its ARFVTP and EPIC programs over the past decade.

Forest Biomass

The Placer County Air Pollution Control District and bioenergy developer stakeholders from the Bioenergy Association of California also called for state agencies to prioritize, or at least further support, underused feedstock resources such as forest biomass from wildfire hazard zones.⁵⁵¹ Reduction of open-air wood combustion, open pile burning, and catastrophic wildfires eliminates the risk of long-term methane from decomposition, as well as the risk of short-term black carbon emissions from combustion. These projects, however, are not yet economically feasible and require further process developments to reduce costs and improve efficiencies.

Technological breakthroughs are needed to make bioenergy systems environmentally sustainable and economically viable. To this end, and to respond to the Governor’s 10-30-2015 Proclamation of a State of Emergency⁵⁵² to protect communities against unprecedented tree die-off, the Energy Commission issued a grant solicitation in 2016 to fund research and demonstration activities to advance bioenergy electricity generation, with two groups focused on using feedstock from sustainable forest management, as defined by the CPUC BioMAT program.⁵⁵³ Supported technologies include mobile, modular gasification systems that can be located at the closest point to biomass-residual removal with interconnection capability and gasification technology

550 U.S. Environmental Protection Agency (2016).
<https://www3.epa.gov/region9/waste/features/foodtoenergy/wastewater.html>.

551 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-10/TN220230_20170717T082126_Shannon_Harroun_Placer_County_Air_Pollution_Control_District_Co.pdf.

552 https://www.gov.ca.gov/docs/10.30.15_Tree_Mortality_State_of_Emergency.pdf.

553 http://www.cpuc.ca.gov/SB_1122/.

demonstration projects in the 2 to 3 MW range that use woody biomass from designated high hazard zones⁵⁵⁴ for wildfire. The solicitation projects will be active in 2018, with results and system commissioning expected around 2020–2021. The Energy Commission has also previously provided grants for at least 12 forest biomass-to-energy projects through its EPIC program over the past decade.

Commercially available technologies that can convert forest biomass into renewable gas may be cost-effective in terms of GHGs and SLCPs reduced when factoring in the avoided cost and impacts of wildfires, which are the largest source of black carbon emissions in the state (roughly 67.5 percent).⁵⁵⁵ However, there is no universal answer to whether fuels reduction treatments with bioenergy production will always create a net-carbon benefit. Forest managers will need to evaluate fuels treatments on a case-by-case or regional basis to determine net GHG outcomes, although it may be difficult to properly estimate.⁵⁵⁶ Analysis generally involves simulating large, intense fires across a given landscape before and after treatment. However, available fire spread and size models are based on historical fuel conditions, and have been unable to duplicate the large fires presently being experienced in California, therefore underestimating the potential benefits from treatments.

In-State Renewable Gas Potential

When assessing how much renewable gas can be developed in California, it is necessary to distinguish between what is technically available versus what is economically feasible at this time.

Technical potential refers to the amount of renewable gas resources that physically exist and can be converted or used with commercialized technologies. Certain conversion and end-use processes may not be technologically mature enough and require further demonstration to reduce risks and costs before widespread market adoption.

Economic potential takes the analysis a step further and recognizes that not all resources can be cost-effectively retrieved or converted or may not generate sufficient or stable revenues to spur private-sector development. Economic potential refers to what is actually commercially viable when factoring in economies of scale of transporting the resource to market, cleaning and processing it, and myriad other associated requirements. For this chapter, economic potential will be used to assess priority resources and end uses.

In-State Renewable Gas Technical Potential

There are many technology pathways that can produce renewable gas, including anaerobic digestion, gasification, pyrolysis, and electrolysis. The most prevalent and commercially available production pathway for renewable gas is anaerobic digestion, which produces a renewable natural

554 The high hazard zone map is available at <http://egis.fire.ca.gov/TreeMortalityViewer/>. (Select boxes for Tier One and Tier Two high hazard zones in the Layer Visibility Legend to view the high hazard zones.)

555 California Air Resources Board. “Short-Lived Climate Pollutant Inventory.” June 2017. <https://www.arb.ca.gov/cc/inventory/slcp/slcp.htm>.

556 Winford, E. M., and J. C. Gaither Jr. (2012). “Carbon Outcomes From Fuels Treatment and Bioenergy Production in a Sierra Nevada Forest.” *Forest Ecology and Management*. 282: 1–9.

gas RNG).⁵⁵⁷ In the absence of oxygen, organic waste materials are broken down by microbes to produce biogas – a mixture consisting primarily of carbon dioxide and methane. Typical anaerobic digestion feedstocks include municipal solid waste organics, food waste, wastewater, and livestock manure. Lignocellulosic compounds, such as wood wastes, are difficult to nearly impossible to anaerobically digest and are thus not used in digester systems. Thermochemical technologies such as gasification and pyrolysis can technically process lignocellulosic waste but are still in the stages of pilot and demonstration testing and are not yet proven economically feasible. Gasification is the process by which organic material is broken down in a controlled environment at high temperatures (typically more than 700 degrees Celsius), without combustion, into simple gases and other byproducts such as tar and ash. At lower temperatures of 200–650 degrees Celsius and in the absence of oxygen, pyrolysis converts organic material into bio-oil, gas, and char products. These thermochemical and other emerging technologies are discussed later in this chapter. Conversely, anaerobic digestion has been widely integrated into numerous California waste systems and is a reasonably mature technology. For example, many wastewater treatment plants incorporate anaerobic digesters as part of their treatment process, while anaerobic digestion is a natural occurrence in landfills and dairy manure lagoons.

The UC Davis Biomass Collaborative compiles, develops, and verifies data sets from numerous references to create a geographic database of California biomass resources and biomass-powered energy production plants. Its assessment of California biomass resources has been used as a basis for numerous published studies, as well as the *U.S. DOE 2016 Billion-Ton Report*.⁵⁵⁸ The Biomass Collaborative estimates the total in-state potential to produce renewable gas (in terms of renewable natural gas [RNG], also known as biomethane) to be 351 billion cubic feet (Bcf) of RNG per year. This estimate includes resources from animal manure (dairy and poultry); municipal solid waste; landfill gas; wastewater treatment plants; fats, oils, and greases; agricultural residue; and forestry and forest product residue.⁵⁵⁹ However, lignocellulosic feedstocks require future development and commercialization of thermochemical conversion technologies. For nonlignocellulosic feedstocks, which can be used in commercially established anaerobic digestion systems, the technical potential is estimated to be 92.9 Bcf of RNG per year. Based upon compiled data from UC Davis, the U.S. DOE, National Petroleum Council, and American Gas Foundation, ICF International estimated in-state technical potential for nonlignocellulosic feedstocks to be between 60.9 and 130.8 Bcf of RNG per year.⁵⁶⁰ A report by Dr. Amy Jaffe from the UC Davis Institute of Transportation Studies (UCD ITS) similarly uses an estimate that conventional

⁵⁵⁷ *Renewable natural gas* (RNG) is biogas that has been upgraded to meet pipeline quality natural gas standards, including the standards adopted pursuant to subdivisions (c) and (d) of Health and Safety Code Section 25421 for injection into a common carrier pipeline and GO 58-A. Alternatively, renewable natural gas can be produced from biomass through gasification to bio-syngas, followed by methanation and upgrading.

⁵⁵⁸ https://energy.gov/sites/prod/files/2016/12/f34/2016_billion_ton_report_12.2.16_0.pdf.

⁵⁵⁹ Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. *An Assessment of Biomass Resources in California, 2013 – DRAFT*. Contractor report to the California Energy Commission. PIER Contract 500-11-020.

⁵⁶⁰ Sheehy, Phil (June 27, 2017) “Potential to Develop Biomethane, Biogas, and Renewable Gas to Produce Electricity and Transportation Fuels in California.” Presentation at Joint Agency Workshop on Renewable Gas.

California sources of renewable gas could technically provide up to 90.6 Bcf of RNG per year.⁵⁶¹ The UCD ITS' study delves into an assessment of the state's economic RNG potential, which is discussed in the following section. Depending on the resource, the levelized cost of using these resources for renewable gas production can be upward of \$6.75–\$29/MMBtu.⁵⁶²

In-State Renewable Gas Economic Potential

Assuming a natural gas market price of \$3/MMBtu, the Low-Carbon Fuel Standard (LCFS) credit price of \$120 per metric ton of carbon dioxide equivalent (MT-CO₂e), and a renewable identification number (RIN) credit price of \$1.78 per D3 RIN, UCD ITS estimates the economically viable renewable gas production potential to be 82 Bcf per year (90.5 percent of the technical potential).⁵⁶³ (The LCFS is discussed further in Chapters 1 and 7.) The study considers renewable gas production to be economically viable when it can be sold for less than the net cost of fossil natural gas (including revenue from LCFS credits). This equates to an RNG production cost less than or equal to \$30.37/MMBtu for landfill gas, \$34.16/MMBtu for wastewater treatment plants, \$39.16/MMBtu for municipal solid waste, and \$71.25/MMBtu for dairies. A limitation of the study is that it assumes all renewable gas is transported via pipeline. However, there are circumstances where renewable gas may not need to be transported or can be transported via other modes. Onsite fueling can be economically feasible, depending on the availability of fleets nearby. This is particularly true for the refuse industry, where renewable gas is produced at the collection fleet's waste drop-off site. In other cases, onsite power generation might be economically feasible in terms of logistics or ability to procure capital financing. For example, many wastewater treatment facilities offset a portion of their electricity consumption using biogas generators. Distribution by on-road gas transport trucks instead of pipeline is another potential option when high pipeline costs are prohibitive.

Table 20 summarizes the amounts of biomethane that could be developed from various feedstocks, both in terms of technical availability and economic feasibility under existing market and policy conditions. The amounts are shown in Bcf and MMBtu. The amount of economically feasible biomethane estimated in Table 20 can be compared to recent natural gas demand in various sectors. For instance, if it were used exclusively within the transportation sector, 82 Bcf (or 623 million diesel gallon equivalents [million DGE]) of biomethane could displace the equivalent of 19 percent of the 3.3 billion gallons of diesel consumed in 2016. This assumes, however, that sufficient natural gas vehicles would be available to use the fuel. In fact, as of 2016, actual use of compressed natural gas (CNG) and liquefied natural gas (LNG) in the transportation sector was closer to just 170 million DGE per year.⁵⁶⁴ Even with the significant growth of natural gas anticipated by the transportation energy demand forecast as discussed in Chapter 7, natural

561 Jaffe, Amy Myers, Rosa Dominguez-Faus, Nathan C. Parker, Daniel Scheitrum, Justin Wilcock, and Marshall Miller. 2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*. Institute of Transportation Studies, University of California, Davis, research report. UCD-ITS-RR-16-20.

562 The estimates in this paragraph only entail renewable natural gas, and do not include other types of renewable gas such as renewable hydrogen.

563 American Society of Civil Engineers. *California Infrastructure Report Card: A Citizen's Guide – 2012*. February 2012. Available at http://www.ascecareportcard.org/citizen_guides/Citizen's%20guide%202012_Revised.pdf.

564 Based on consumption of diesel, CNG, and LNG from Chapter 7.

gas demand by 2030 is expected to remain near 300 million DGE in the mid case.⁵⁶⁵ In comparison, if it were used exclusively for electricity generation, 82 Bcf of biomethane would be equivalent to 12 percent of the roughly 708 Bcf of conventional natural gas used for in-state electricity generation in 2016. Alternatively, if it were dedicated for uses within the combined industrial, commercial, and residential sectors, the 82 Bcf would represent nearly 4 percent of 2016 natural gas use.⁵⁶⁶

⁵⁶⁵ Based on mid case for natural gas from Chapter 7, originally in gasoline gallons equivalent.

⁵⁶⁶ The 2016 California daily natural gas usage was 6.072 billion cubic feet per day based upon the 2016 *California Gas Report* prepared by the California gas and electric utilities.

Table 20: Annual Technically Available and Economically Feasible Biomethane Renewable Gas Production Potential From California Biomass Resources

Feedstock	Amount Technically Available	Renewable Gas Potential From Amount Technically Available [UC Davis California Biomass Collaborative]		Renewable Gas Potential From Amount Technically Available [ICF]		Economically Feasible Renewable Gas Potential* [UCD ITS]	
		(Bcf)	(million MMBtu)	(Bcf)	(million MMBtu)	(Bcf)	(million MMBtu)
Animal Manure (Dairy & Poultry)	3.4 MM BDT	19.5	18.9	12.3-18.7	11.9-18.7	10.1	9.8
Municipal Solid Waste (food, leaves, grass fraction)	1.2 MM BDT	12.7	12.2	22.5-50.1	21.8-48.4	16.3	15.8
Municipal Solid Waste (lignocellulosic fraction)	6.7 MM BDT	65.9	63.7				
Landfill Gas	106 Bcf	53	51.2	22-54.8	21.3-53.0	50.1	48.4
Wastewater Treatment Plants	11.8 Bcf	7.7	7.4	4.1-7.2	4.0-7.0	5.6	5.4
Fats, Oils, and Greases	207,000 tons	1.9	1.8	N/A	N/A	N/A	N/A
Agricultural Residue (Lignocellulosic)	5.3 MM BDT	51.8	50.1	29.6-32.5	28.6-31.4	N/A	N/A
Forestry and Forest Product Residue	14.2 MM BDT	139	134	14.5-44.9	14-43.4	N/A	N/A
Total		351	339	104.9-208.3	101.4-201.4	82	79.4

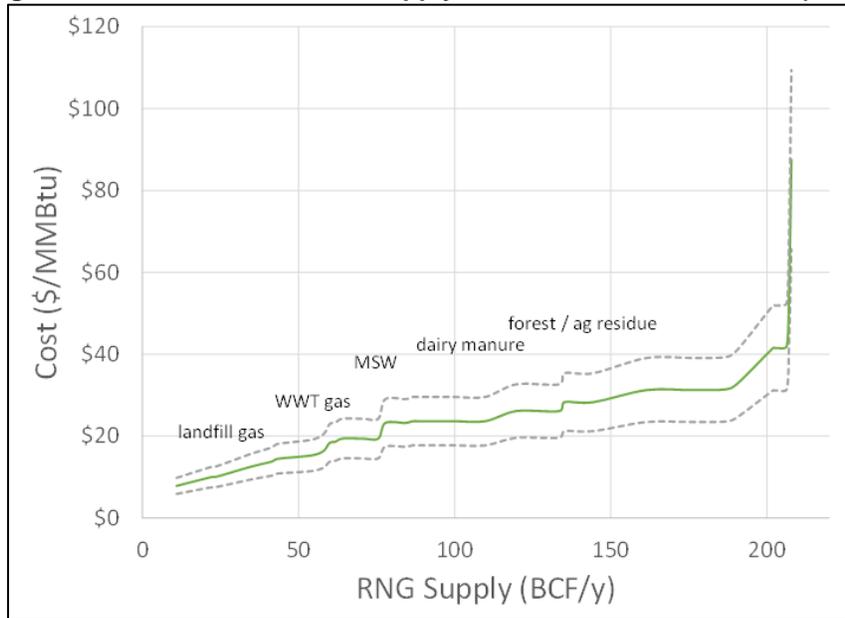
*Economically feasible renewable gas is determined at a natural gas market price of \$3/MMBtu, LCFS credit price of \$120/MT-CO₂e, and RIN price of \$1.78/gallon of ethanol equivalent.

Source: Williams, R. B., B. M. Jenkins and S. Kaffka (California Biomass Collaborative). 2015. *An Assessment of Biomass Resources in California, 2013 – DRAFT*. Contractor report to the California Energy Commission. Contract 500-11-020; Sheehy, Phil (Forthcoming 2017) Design Principles for a Renewable Gas Standard. ICF International; and Jaffe, Amy Myers, Rosa Dominguez-Faus, Nathan C. Parker, Daniel Scheitrum, Justin Wilcock, Marshall Miller .2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*. Institute of Transportation Studies, University of California, Davis, Research Report UCD-ITS-RR-16-20.

ICF’s assessment is based upon reviews of studies by the California Biomass Collaborative, UC Davis ITS, the American Gas Foundation, the Department of Energy’s Billion Ton Study, and other resources. Figure 79 shows the supply curve for combined sources of renewable gas from all sources, assuming ICF’s high-end estimate of total technical supply. For each feedstock, ICF calculated the levelized cost of energy (LCOE) using equipment capital costs, operations and maintenance, and financing (5 percent discount rate and 20-year financing period). The dashed gray lines represent a 25 percent uncertainty range. The RNG production costs are not stacked

perfectly as shown in the figure but illustrate the relative costs of RNG production from various feedstocks.

Figure 80: California Potential Supply of Renewable Natural Gas (RNG)



Source: Sheehy, Phil (Forthcoming 2017). *Design Principles for a Renewable Gas Standard*. ICF International

UCD ITS takes a step further by creating supply curves from a spatial engineering economic analysis. The cost analysis for stationary resources (landfills and WWTPs) takes the resource potential at a given location and calculates the cost of producing renewable gas from that supply point. For dairy manure, a clustering analysis was performed for dairies to capture the potential for aggregating biogas in a local pipeline network for centralized upgrading and injection. The Geospatial Bioenergy System Model was used to optimally locate and size renewable gas production facilities based on the costs of procuring, transporting, and converting the resource to renewable gas.

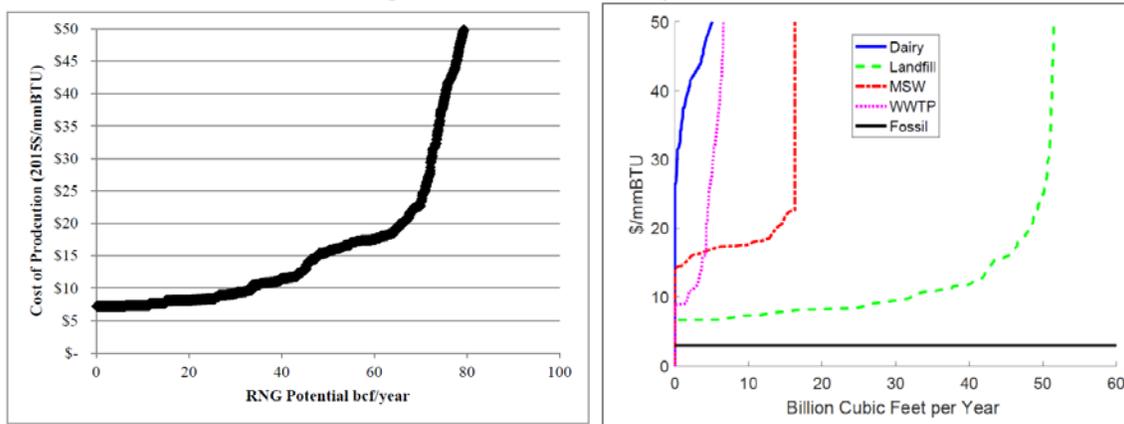
Figure 80 presents UCD ITS' supply curve for combined sources of renewable gas derived from anaerobic digestion and then splits the supply curve by source. At a specific level of production for each resource type, the costs sharply curve upward, which is not present in ICF's analysis. The upward curves represent smaller or remote sources that are prohibitively expensive due to significantly higher collection or pipeline interconnection costs.

UCD ITS's study finds that although renewable gas production may be economically viable up to 82 Bcf per year, costs of production are shown to increase significantly beyond 70 Bcf per year as smaller and more dispersed projects are developed. Figure 81 further divides the UCD ITS' supply curve by major cost components. The lowest costs are found for facilities with large gas production that are also near a natural gas transmission pipeline.⁵⁶⁷ Identical to ICF's findings,

⁵⁶⁷ Transmission pipelines, commonly referred to as California's "backbone" natural gas pipeline system, are large, high-pressure pipelines that transport gas into lower-pressure distribution pipelines that serve the majority of end use customers. Only some large noncore (large commercial and industrial) customers take natural gas directly off the transmission pipeline system.

landfills and WWTPs initially provide the lowest cost options, as expected due to existing renewable gas production infrastructure that avoids the cost of digester construction. However, some WWTPs may require digester upgrades to handle higher solids content, and landfills may need upgrades to the associated gas collection systems to improve gas quality. These costs were not included in the analyses. After a certain degree of landfill and WWTP renewable gas development, MSW and dairy projects begin to become cost-competitive options. As solid waste and dairies represent the largest source of methane emissions, they can provide some of the lowest cost incentive options to the state in terms of GHG emissions reductions. A 2016 analysis of the Greenhouse Gas Reduction Fund by the California Legislative Analyst’s Office assessed the Dairy Digester Research and Development Program to cost the state \$8/MT-CO₂e and Organics Composting/Digestion Grants to cost \$9/MT-CO₂e.⁵⁶⁸ By comparison, Clean Vehicle Rebates cost \$46/MT-CO₂e, single-family solar photovoltaics cost \$209/MT-CO₂e, and the truck and bus voucher incentives cost \$452/MT-CO₂e.⁵⁶⁹ See the following section, “Economic Assessment of Renewable Gas End Uses,” for discussion of the economics of dairy digester projects.

Figure 81: California Potential Supply of Renewable Natural Gas (RNG) Derived From Anaerobic Digestion, Overall and by Feedstock Source

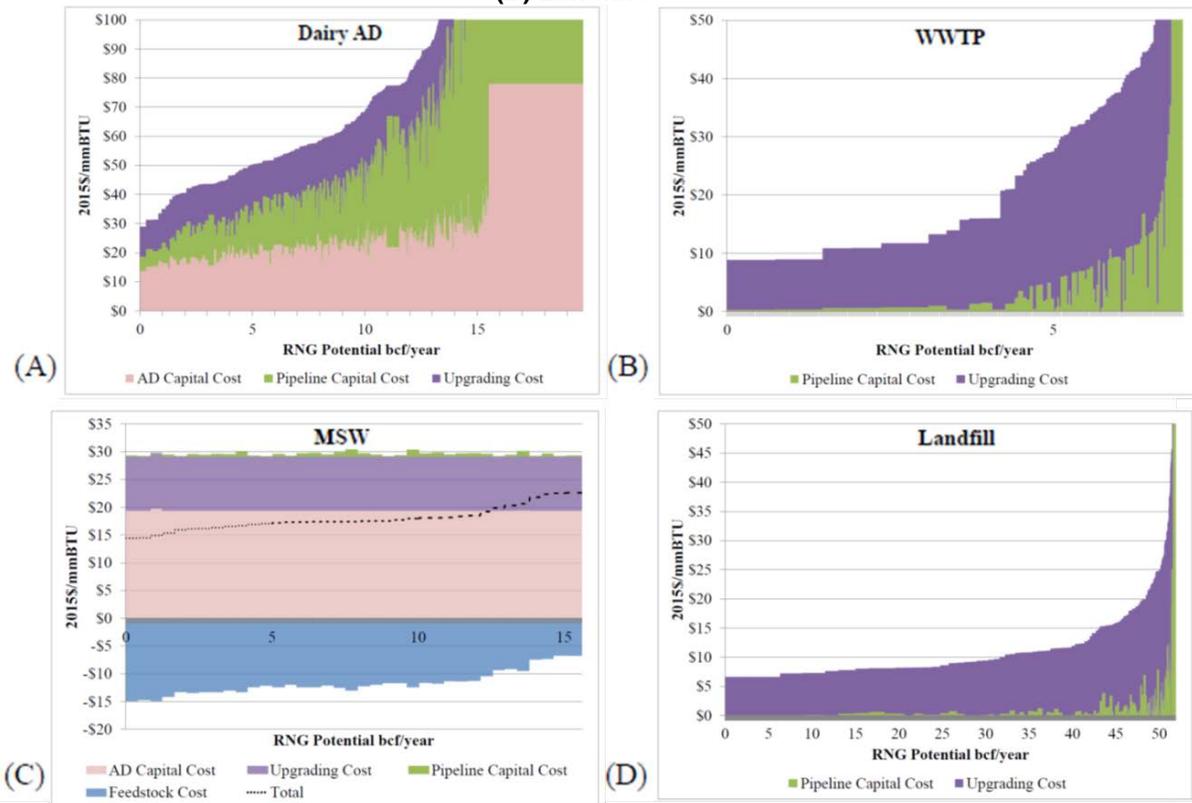


Source: Jaffe, Amy Myers, Rosa Dominguez-Faus, Nathan C. Parker, Daniel Scheitrum, Justin Wilcock, and Marshall Miller. 2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*. Institute of Transportation Studies, University of California, Davis, Research Report UCD-ITS-RR-16-20; and Jaffe, Amy Myers, Nathan C. Parker, Rosa Dominguez-Faus, Daniel Scheitrum, Justin Wilcock, and Marshall Miller (June 27, 2017) *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*. Presentation at June 27, 2017, joint agency workshop on Renewable Gas.

⁵⁶⁸ The Legislative Analyst’s Office calculated costs as the amount of cap-and-trade funds awarded to a program divided by the total estimated GHG emission reductions from the projects that receive cap-and-trade funds.

⁵⁶⁹ California Legislative Analyst’s Office. *Administration’s Cap-and-Trade Report Provides New Information, Raises Issues for Consideration*. April 2016, <http://www.lao.ca.gov/Publications/Report/3445>.

Figure 82: Supply Curve and Component Cost for (A) Dairies, (B) WWTPs, (C) MSW, and (D) Landfills



Source: Jaffe, Amy Myers, Rosa Dominguez-Faus, Nathan C. Parker, Daniel Scheitrum, Justin Wilcock, and Marshall Miller. 2016. *The Feasibility of Renewable Natural Gas as a Large-Scale, Low Carbon Substitute*. Institute of Transportation Studies, University of California, Davis, Research Report UCD-ITS-RR-16-20.

Energy Commission staff is gathering information from in-state facilities to assess the estimated costs for producing biomethane. These facilities include those producing biomethane from dairy waste, organic waste diverted from landfills, wastewater, and landfill gas to produce fuels for transportation use and to generate electricity. The cost information compiled to date is presented in tables throughout the remainder of this chapter.

Production facility costs consist largely of the feedstock preprocessing equipment, the digester or gas collection system, biogas cleanup and handling equipment, and the associated engineering, permitting, and construction costs. Table 21 provides cost ranges for the four main types of biogas production facilities. Cost estimates are adjusted to compare production capacity in one MMBtu-per-year increments. Anaerobic digestion is a mature technology, but cost reductions can be expected from economies of scale and volume.

Table 21: Non-levelized Production Facility Capital Cost Ranges by Type

	Capital Cost Range (\$ per MMBtu per Year Capacity)							
	Food / Urban / MSW ⁵⁷⁰		Dairy		Wastewater*		Landfill	
	Low	High	Low	High	Low	High	Low	High
Organics Collection, Separation, and Processing Equipment	\$9.5	\$21	\$3	\$18	\$16	\$42		
Digester Technology	\$68	\$103	\$7	\$ 85	TBD	TBD		
Gas Collection System							\$2	\$13
Biogas Clean Up Equipment	\$19	\$29	\$20	\$55	\$19	\$40	\$14	\$37
Facility Engineering, Construction, and Permits	\$117	\$177	\$20	\$40	\$25	\$104	\$12	\$20
Subtotal Cost	\$219	\$331	\$50	\$230	\$110	\$160	\$28	\$70
Contingency (7 percent)	\$15	\$23	\$3	\$16	\$8	\$11	\$2	\$5
Biomethane Plant Total Cost	\$236	\$355	\$53	\$246	\$118	\$171	\$29	\$75

*Note: Wastewater treatment plants may already have an existing digester as part of the treatment system, so associated digester technology and construction costs may be excluded or far less for a renewable gas project at such facilities.

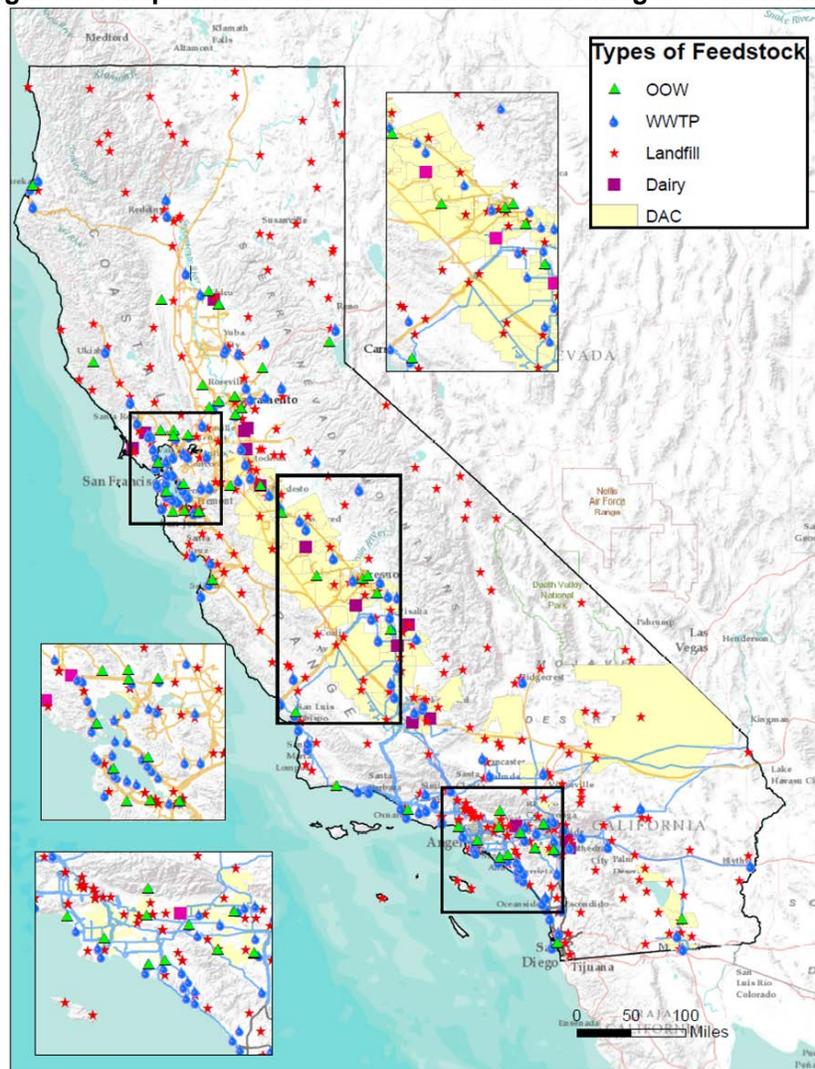
Source: California Energy Commission

The location and disposition of California’s resources vary significantly and are factors in determining economic viability. Figure 82 captures the existing bioenergy sites of landfill, WWTP, dairy farm, and other organic wastes identified in available databases.⁵⁷¹ Overlaid are regions of the state identified as “disadvantaged communities” under the CalEnviroScreen tool. Significant overlap between the resources sites and the overlay underscores a need to be especially sensitive to local air, water, and land pollution that could be generated (or abated) by renewable gas projects, as well as the possibility for expanding economic development in distressed regions. It is critical to reach out and work with local communities when considering and developing bioenergy projects. For information on efforts to increase the access to and benefits from clean energy resources for low-income and disadvantaged communities, see the Chapter 2 discussion of “Addressing Barriers Faced by Low-Income Residents and Disadvantaged Communities” and the Chapter 1 discussion of “Access to Clean Technologies.”

570 Reflects cost range for different types and sizes of biomethane production plants designed to produce RNG for transportation fuels from organic waste diverted from landfills. Includes regional, centralized plants with modular units and organic waste delivered to the plant location for both onsite vehicle use and interconnection to a natural gas pipeline. Also includes smaller community-scale biomethane production plants to fuel vehicles onsite and not to connect to the natural gas pipeline.

571 Landfill site information collected from the U.S. EPA Landfill Methane Outreach Program, <https://www.epa.gov/lmop/landfill-gas-energy-project-data-and-landfill-technical-data#states>; WWTP information collected from the California Biomass Collaborative, <http://biomass.ucdavis.edu/tools/california-biomass-facilities-reporting-system/>; dairy farm information collected from U.S. EPA’s AgSTAR program, <https://www.epa.gov/agstar/livestock-anaerobic-digester-database>; other organic waste information collected from California Biomass Collaborative (available at above link) and communication with CalRecycle.

Figure 83: Map of Waste Resources and Disadvantaged Communities



Sources: California Energy Commission, California Biomass Collaborative, U.S. EPA, and CalRecycle

Several recurring themes were present in stakeholder written comments related to the technical and economic potential of renewable gas resources. Among the comments, some stakeholders expressed a need for a consistent and accurate accounting of feedstock resources. The Bioenergy Association of California and its members stated that preferably, state agencies would develop policies based upon a common assessment of total feedstock resource potential, rather than current feedstock economic viability.⁵⁷² The economics of renewable gas production are based on today's policy and market circumstances, which are expected to change over time as policies and incentives go into effect. Having an accepted method for assessing current and future economic feasibility would encourage maximizing the development and use of California's in-state renewable gas potential. As a solution, the University of California, Riverside, suggested

⁵⁷² http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-10/TN220137_20170713T094913_Julia_A_Levin_Comments_Bioenergy_Association_of_California_Comm.pdf.

developing a working group to create a reliable, consistent framework for feedstock collection, procurement, and supply throughout the state.⁵⁷³

To minimize environmental impacts, the Sierra Club recommended prioritizing the diversion of waste streams before developing a market for repurposing the resulting emissions.⁵⁷⁴ Upstream diversion of organics away from the solid waste system can have a high SLCP reduction benefit among all options. The U.S. EPA's Food Recovery Hierarchy identifies source reduction as the most preferable option in terms of sustainability.⁵⁷⁵ A CARB staff analysis found that common waste treatment through composting and landfilling for 100,000 tons of municipal organic waste per year can emit 55,399 MT-CO₂e (including 1,432 metric tons of methane).⁵⁷⁶ Reducing and diverting organics directly from sources can eliminate methane and other GHG emissions entirely from waste treatment systems. However, converting the organic waste into biomethane transportation fuel through high solids anaerobic digestion can reduce methane emissions by 84 percent (1,268 metric tons of methane) and have a GHG reduction credit of 3,643 MT-CO₂e per year over the life cycle. The cost-effectiveness of a biomethane project incentive, regardless of the benefits of technology advancement, is about \$41 per MT-CO₂e (or \$118 per metric ton of methane), given \$3 million ARFVTP grant funding for a typical anaerobic digestion project running for 20 years. This equals a credit of \$1.69, or \$22.71 per ton of waste diverted, depending on the basis of methane or GHG reduction, respectively. Converting organic waste to displace fossil energy can offer a cost-effective opportunity for SLCP reduction in the current waste treatment system.

Priority End Uses for Renewable Gas

Renewable gas has been used, or proposed for use, as a substitute for conventional natural gas in several energy sectors. The most commercial-ready end uses are electricity generation, natural gas vehicle fuel displacement, and pipeline natural gas displacement.

At the June 27, 2017, joint agency workshop on Renewable Gas, workshop discussion and stakeholder comments revealed that determining the best destination for renewable gas is not one size fits all; the best end-use outcome can depend on a variety of factors, including feedstock, location, and timing. Priority end uses of renewable gas may evolve as California approaches 2020, 2030, and 2050 goals; as markets transform; and technologies advance. However, the state must seek near-term priorities and the most cost-effective solutions at this time to ensure achieving the 2030 SLCP reduction goals.

⁵⁷³ http://doCKETpublic.energy.ca.gov/PublicDocuments/17-IEPR-10/TN220210_20170714T162936_Arun_Raju_Comments_University_of_California_Riverside__Renewabl.pdf.

⁵⁷⁴ http://doCKETpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221756_20171113T165901_Katherine_Ramsey_Comments_Sierra_Club_Comments_on_the_Draft_201.pdf.

⁵⁷⁵ <https://www.epa.gov/sustainable-management-food/food-recovery-hierarchy>.

⁵⁷⁶ <https://www.arb.ca.gov/fuels/lcfs/2a2b/internal/hsad-rng-rpt-062812.pdf>.

A broad coalition of stakeholders,⁵⁷⁷ including the California Roundtable on Agriculture & the Environment, Bioenergy Association of California, American Biogas Council, Organic Waste Systems, Victor Valley Wastewater Reclamation Agency, and Clean Energy, voiced a need for state agencies to increase and extend multiyear funding for renewable gas projects.

In addition to support, stakeholders also expressed concerns with increasing the renewable gas market. Written public comments reflected a need to promote public awareness of renewable gas projects. Stakeholders from environmental justice organizations, including the Center on Race, Poverty & the Environment; Leadership Counsel for Justice and Accountability; Food & Water Watch; Community Alliance for Agroecology; Comité ROSAS; Committee for a Better Shafter; Committee for a Better Arvin; Delano Guardians; Greenfield Walking Group; and the University of North Carolina Center for Civil Rights,⁵⁷⁸ discussed air quality and groundwater contamination impacts. They believe such impacts will increase with the construction and operation of anaerobic digesters in disadvantaged communities. These groups also pointed out the potential for reducing renewable gas emission sources before they even become an issue, such as by applying alternative manure management methods.

PG&E suggested working with local governments and environmental justice groups in disadvantaged communities to consider the local impacts, as well as air quality and economic benefits, of renewable gas projects and to develop emissions and air standards.

Renewable gas projects can play a role in minimizing the impacts of fossil fuel generation and transportation on disadvantaged communities and create opportunities for this segment of the population to have access to cleaner alternatives. However, as discussed in Chapter 2, when working toward achieving statewide clean energy equity goals, it is imperative to engage with local residents and community groups to identify and reinforce key local priorities and address any impacts of renewable gas projects.

Time is an often overlooked factor influencing project cost – the longer it takes to develop a project, the more costs will be incurred and opportunity lost. Figure 83 summarizes an example of a biomethane project development timeline. Due to unexpected project delays, actual project implementation can take much longer – as long as three to five years.

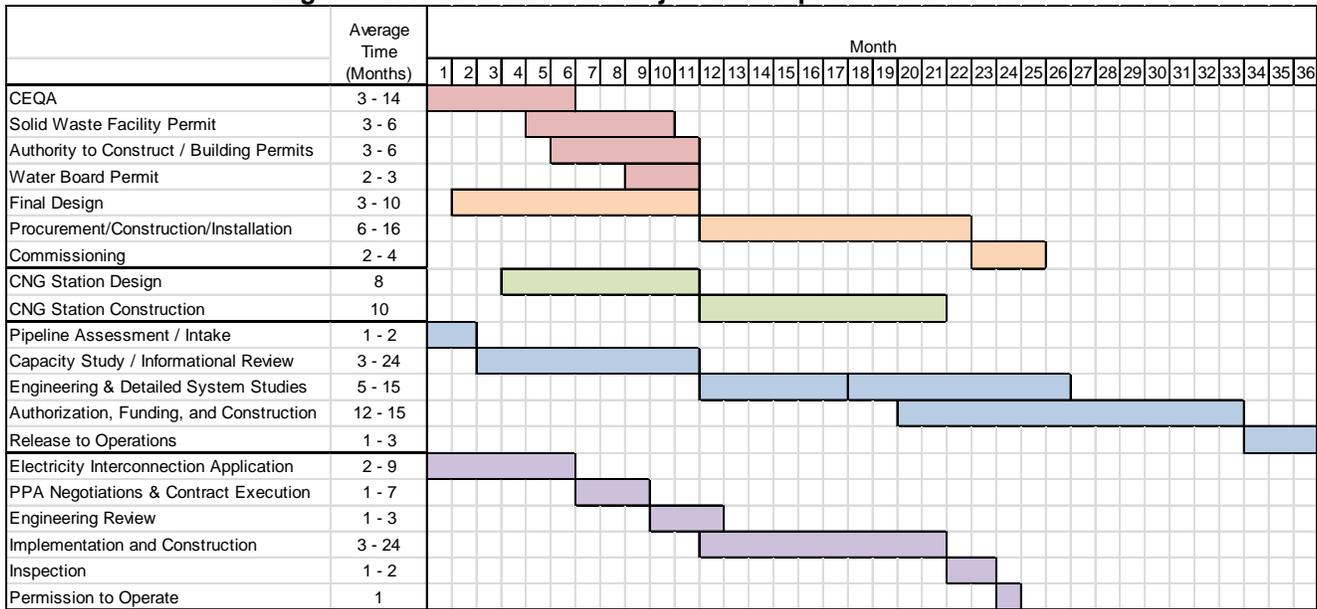
In written comments, Fulcrum Bioenergy suggested that one way to shorten the project implementation period might be to address location, siting, and permitting challenges. They voiced a need for streamlined California Environmental Quality Act reviews and permitting outcomes that are more transparent to reduce the excessive financial risk of renewable gas demonstration projects.⁵⁷⁹

⁵⁷⁷ Stakeholder comments are available online under Docket 17-IEPR-10, Renewable Gas, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-10>.

⁵⁷⁸ Ibid.

⁵⁷⁹ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-10/TN220208_20170714T155116_Graham_Noyes_Comments_Fulcrum_BioEnergy_Comment_RE_1383_Joint_A.pdf.

Figure 84: Renewable Gas Project Development Time Frames



Source: California Energy Commission

Several stakeholders suggested that California should focus on near-term opportunities that maximize GHG emissions reduction benefits.⁵⁸⁰ The California Roundtable on Agriculture & the Environment suggested developing a cohesive statewide agenda for renewable gas production; crossing all sectors, including agriculture, forestry, and municipal waste; conducting research to properly account for ancillary environmental, economic, and public value benefits created by renewable gas projects; and assessing and addressing any impacts of renewable gas development when enacting SB 1383 solutions. Dairy Cares, the Agricultural Energy Consumers Association, and the Agricultural Council of California disagreed with enacting additional regulations. Agricultural Energy Consumers Association and Agricultural Council of California stated in a joint letter that “implementing a mandatory renewable gas standard would be duplicative, add additional complexity to existing legal and regulatory requirements, and unnecessarily increase costs for California’s natural gas consumers. The Agricultural Energy Consumers Association and the Agricultural Council’s members face significant leakage risks due to domestic and international competition for agricultural production and processing. We are very concerned that further natural gas rate increases will expose our members to additional leakage risks, driving employment out of California and raising emissions in uncapped jurisdictions.”⁵⁸¹

Transportation Fuel

With upgrading, biogas can be used in CNG or LNG vehicles. In 2015, there were 20,963 natural gas vehicles registered in California, 80.6 percent of which belonged to the medium- and heavy-duty vehicle (MHDV) sector. Table 22 provides the existing stock of natural gas MHDVs in

⁵⁸⁰ Stakeholder comments are available online under Docket 17-IEPR-10, Renewable Gas, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-10>.

⁵⁸¹ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-10/TN219932_20170627T134729_6617_Letter_from_California_Roundtable_on_Agriculture_The_Envi.pdf.

California by market sector and vehicle class. As shown in Chapter 7, the Energy Commission anticipates a growing share of natural gas fuel within the transportation sector, particularly in MHDVs. Dr. Jaffe's study corroborates growth potential in the transportation sector yet notes that while interested in attractive fuel cost differentials and demand for cleaner transportation from customers, the trucking industry has to date been mostly reluctant to take the plunge on expensive equipment upgrades to natural gas. As mentioned above, the economically feasible potential of biomethane resources within the state, total and individually for some feedstock types, exceeds the demand for natural gas in the transportation sector, both currently (roughly 19 million MMBtu) and in the Energy Commission's forecast for 2030 (nearly 40 million MMBtu). (See Chapter 7 on "Preliminary Forecast of Overall Fuel Demand.") For this reason, the further growth of natural gas vehicles (particularly medium- and heavy-duty trucks) is critical to taking full advantage of the state's available resources. When paired with low-NO_x natural gas engines, renewable natural gas can support a growing fleet of vehicles with significant NO_x and GHG emissions reduction advantages. Refueling infrastructure is also an important factor in ensuring NGV market growth. As of August 2017, there are 326 CNG refueling stations (174 public) and 45 LNG refueling stations (19 public) in California.⁵⁸² Of the public CNG stations, only 53 are accessible by Class 8, 53-foot trucks.

⁵⁸² U.S. Department of Energy. Alternative Fuels Data Center. Accessed August 2017, https://www.afdc.energy.gov/fuels/natural_gas_locations.html.

Table 22: Number of On-Road Medium-Duty/Heavy-Duty Natural Gas Vehicles Operating in California by Key Market Sectors and Vehicle Class

Sector	Number of Natural Gas Vehicles	Notes
Transit (Heavy-Duty)	6,500	Flattening recent growth
Refuse (Heavy-Duty)	2,500 – 4,000	Increasing recent growth
Drayage (Heavy-Duty)	1,200 – 1,500	Most located in Southern California
Over-the-Road Delivery (Heavy-Duty)	200 – 500	Overall population is 175,000+
Delivery (Medium-Duty)	200 – 500	Most in a few large fleets
Total	10,600–13,000 for select sectors listed above	Less than 1 percent of California’s 1,500,000 MDHD vehicle population
Vehicle Class	Number of Natural Gas Vehicles	
Class 4	548	
Class 5	32	
Class 6	507	
Class 7	2,257	
Class 8	13,547	
Total	16,891	

Source: CALSTART. “Overview of California’s Medium- and Heavy-Duty Natural Gas Vehicle Market - For the Dairy Working Group Digester Committee.” Presentation at Dairy and Livestock Subgroup #2: Fostering Markets for Digester Projects meeting. September 2017. Gladstein, Neandross & Associates. “Importance of Growing the Heavy-Duty Vehicle Market in the Success of Dairy Digester Development.” Presentation at Dairy and Livestock Subgroup #2: Fostering Markets for Digester Projects meeting. September 2017.

As explained in its written comments, Clean Energy believes that biomethane used as a transportation fuel in near-zero-emission, heavy-duty trucks delivers the greatest reduction in GHG emissions and provides the best air quality benefits. However, as Calgren Renewable Energy stated in its written comments, producer and user-specific challenges, such as access to pipeline and transmission lines for distribution; renewable gas proximity to vehicle fleets and user accessibility to ultra-low-emission, heavy-duty trucks; inability of renewable gas to compete in the electricity market; and project cost and economies of scale, may dictate what choices are made for biomethane, biogas, and renewable gas end use. The California Natural Gas Vehicle Coalition urged that California should continue research to understand the feasibility of producing more

renewable gas as a transportation fuel despite these challenges.⁵⁸³ North American Repower, Coalition for Renewable Natural Gas, and Cambrian Energy suggested that state agencies encourage truck development and in-state manufacturing by increasing funds for research, development, and demonstration of near-zero-emission heavy-duty trucks. The Energy Commission has supported research and development of these technologies, such as by funding the development and on-road demonstration of Cummins Westport's low-NO_x natural gas vehicle engines for the medium- and heavy-duty truck market. In September 2015, one of these Cummins Westport natural gas engines became the first to receive emission certifications from both the U.S. EPA and CARB at the 90 percent NO_x reduction level of 0.02 grams per brake horsepower-hour. As of January 2018, Cummins Westport offers 6.7L, 8.9L, and 12L natural gas engines certified at this low NO_x standard.⁵⁸⁴ North American Repower, the Coalition for Renewable Natural Gas, and Cambrian Energy additionally specify in their written comments that state agencies should either restructure or align programs to support renewable gas development in California with programs to deploy low-NO_x natural gas trucks and buses. Agencies should reconsider eligibility of fleet conversion or "repower" options for incentive funding. The Energy Commission has provided significant support for the deployment of natural gas vehicles through various monetary incentive programs. The current Natural Gas Vehicle Incentive Project provides incentives to purchasers of natural gas vehicles on a first-come, first-served basis at varying levels, depending on the gross vehicle weight. Incentives for natural gas vehicles are also available from other agencies. CARB's draft fiscal year 2017–2018 funding plan for Clean Transportation Incentives includes low-NO_x natural gas vehicles as an eligible powertrain under the \$188 million Clean Truck and Bus Voucher project. The Carl Moyer Memorial Air Quality Standards Attainment program is administered by local California air districts and provides an average of \$1.2 million annually in incentives for natural gas vehicles. SoCalGas and Lyle Schlyer of Calgren Renewable Energy also supported accelerating market adoption of near-zero-emission heavy-duty natural gas trucks.⁵⁸⁵

Other renewable gases may also serve as alternative transportation fuels, such as renewable hydrogen for fuel cell electric vehicles (FCEVs). (See the "Renewable Hydrogen" section later in Chapter 9.) FCEVs play an important role in helping meet multiple policy objectives, including having 1.5 million zero-emission vehicles on California roads by 2025, set forth by Executive Order B-16-2012 and guided by California's *ZEV Action Plan*. As directed by Assembly Bill 8 (Perea, Chapter 401, Statutes of 2013), the Energy Commission has provided funding (\$20 million per year) for the construction, operation, and maintenance of hydrogen refueling stations and will do so until at least 100 stations are publicly operational. The Energy Commission and CARB annually report on the progress of hydrogen fuel cell vehicle and refueling station

583 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221732_20171113T144809_Thomas_Lawson_Comments_CNGVC's_comments_on_2017_IEPR.pdf.

584 <http://www.cumminswestport.com/press-releases/2018/cummins-westport-receives-2018-emissions-certifications-for-isx12n-natural-gas-engine>.

585 Stakeholder comments are available online under Docket 17-IEPR-10, Renewable Gas, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-10>.

development in California and on the time and cost needed to attain 100 hydrogen refueling stations in California.^{586, 587}

On-Site or Grid Connected Electricity Generation

In general, the most commonly performed beneficial use of biogas is for electricity production using reciprocating engines. This electricity can be used onsite or sold to the local electrical utility. In addition to the generated electricity, waste heat can be used in a combined heat and power setting to supply heat to digesters and buildings. Microturbines can also be used in place of reciprocating engines; these typically have higher capital cost, but can be less costly to operate and maintain, and generally have lower emissions as well. Fuel cells are another more electrically efficient alternative to gas combustion electricity generation technologies, producing zero air emissions and having a quick start-up. Fuel cells can be more capital cost-intensive, though, and are less tolerant to biogas contaminants, requiring higher-quality gas cleaning. Nevertheless, CARB-certified distributed generation technologies, such as microturbines or fuel cells, can significantly reduce NO_x emissions compared to internal combustion-based power generation. Biogas-driven fuel cells can be tweaked to additionally produce renewable hydrogen, which may be extracted for use in other applications. The process of producing power, heat, and hydrogen from fuel cells is known as *trigeneration* (See the “Renewable Hydrogen” section later in Chapter 9.) Certain types of fuel cells can also be directly powered by renewable hydrogen, requiring lower temperatures than the biogas-powered counterparts.

Fuel cell projects that generate electricity for on-site use are eligible for funding under the Self-Generation Incentive Program (SGIP).⁵⁸⁸ For 2017, the use of biogas provides an additional \$0.60 per watt of capacity on top of the baseline \$0.40–\$0.60 per watt incentive, for a current total of up to \$1.20 per watt.

Generating electricity using in-state renewable gas assists with meeting the state’s waste stream reduction requirements, brings environmental and public health benefits, and reduces short-lived climate pollutants. Recognizing these benefits, California’s Renewables Portfolio Standard (RPS) program considers facilities that generate electricity using digester and landfill-derived biomethane, as well as municipal solid waste-derived biogas, as eligible for the RPS, if certain criteria, including environmental and public health criteria, are met. Additional information on RPS requirements for facility certification can be found in the Energy Commission’s *Renewables Portfolio Standard Eligibility Guidebook*.⁵⁸⁹

In-state electricity generation from renewable gas has faced several barriers that have decreased cost-competitiveness. For this reason, the Bioenergy Market Adjusting Tariff (BioMAT) was

586 CARB, 2017 Annual Evaluation of Fuel Cell Electric Vehicle Deployment and Hydrogen Fuel Station Network Development, August 2017, https://www.arb.ca.gov/msprog/zevprog/ab8/ab8_report_2017.pdf.

587 Baronas, Jean, Gerhard Ahtelik, et al. 2017. Joint Agency Staff Report on Assembly Bill 8: 2017 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California. California Energy Commission and California Air Resources Board. Publication Number: CEC600-2017-011. <http://www.energy.ca.gov/2017publications/CEC-600-2017-011/CEC-600-2017-011.pdf>.

588 See <http://www.cpuc.ca.gov/sgip/> and https://www.selfgenca.com/home/program_metrics/.

589 <http://www.energy.ca.gov/renewables/documents/#rps>.

created to support small in-state bioenergy generators of less than 3 megawatts capacity that export electricity to the state's largest three investor-owned utilities. The BioMAT program offers up to 250 MW cumulatively to eligible bioenergy projects, which includes electricity generation using biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion, through a fixed-price standard contract to export electricity to California's three large investor-owned utilities. Electricity generated under the BioMAT can be counted toward utilities' Renewables Portfolio Standard (RPS) targets (the RPS is discussed in Chapters 1 and 2) and typically includes long-term contracts lasting from 10 to 20 years. The contract price is fixed for the term of the project but varies for each category. Contract prices offered are adjusted based on market acceptance and market depth and are adjusted by time of delivery (meaning payments depend upon when the generation occurs). CPUC Rulemaking 11-05-005 ordered that the participating utility companies may cease the BioMAT program in early 2021, after the end of the 60th month after the beginning of the first program period.⁵⁹⁰ Per CPUC Decision 14-12-081, the CPUC is required to begin a review of the program for any category where the price remains at \$197/kWh for two program periods and may suspend the program while making modifications.⁵⁹¹ On December 1, 2017, Pacific Gas and Electric Company (PG&E) filed a motion to the CPUC to suspend its BioMAT program procurement in accordance with Rule 11.1(e) of the CPUC Rules of Practice and Procedure effective December 31, 2017. Several agricultural groups, including Dairy Cares, the Agricultural Energy Consumers Association, and the California Farm Bureau Federation, have filed responses opposing the suspension. On December 18, 2017, the CPUC issued a ruling denying PG&E's motion to suspend procurement under the BioMAT program, citing that PG&E lacks the unfettered right and would need CPUC permission to suspend its BioMAT procurement.⁵⁹²

Pipeline Injection

Local "tethered" fleets often serve as the customers for this fuel when it is produced in-state. However, the options for use of this fuel multiply when it is converted to renewable gas that complies with utility pipeline specifications. California has about 215,000 miles of natural gas transmission and distribution pipelines, 22 compressor stations, and 25,000 metering and regulating stations. Injection into existing natural gas pipeline infrastructure is an emerging distribution method for renewable gas in California. To inject into the pipeline, the biomethane must adhere to the quality standards outlined by the respective gas utility companies. (For more discussion of pipeline safety issues, see Chapter 7.) Raw biogas must be cleaned of contaminants and then upgraded (have carbon dioxide and other inert gases removed) to create biomethane, which has a methane content closer to that of natural gas.

⁵⁹⁰ CPUC Decision Implementing Senate Bill 1122 (D. 14-12-081).

⁵⁹¹ Ibid.

⁵⁹² CPUC, Administrative Law Judge's Ruling Denying Pacific Gas And Electric Company's Motion To Suspend BioMAT Program Procurement, December 18, 2017, https://pgebiomat.accionpower.com/biomat/doccheck.asp?doc_link=biomat/docs/FIT/2015/documents/e.%20CPUC%20Documents/CPUC%20Ruling_BioMAT%20Motion.pdf.

In response to significant interest in reducing SLCPs and increasing renewable energy development, California has enacted several pieces of legislation aimed at promoting biomethane injection without compromising the integrity of the natural gas system.

- Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012) required the CPUC to set pipeline injection safety standards for biomethane and to promote in-state biomethane production and distribution. The CPUC set human and pipeline safety standards and established a \$40 million incentive program where successful biomethane projects would be eligible for interconnection rebates of 50 percent of pipeline interconnection costs up to \$1.5 million per project. This program was originally to end in June 2020.
- Section 784.1(a) of the Public Utilities Code⁵⁹³ requests the California Council on Science and Technology (CCST) to “undertake and complete a study analyzing the regional and gas corporation-specific issues relating to minimum heating value and maximum siloxane specifications for biomethane before it can be injected into common carrier gas pipelines.” Section 784.1(c) of the Public Utilities Code requires the CPUC to reevaluate the biomethane pipeline injection requirements and standards based on the results of the CCST study.
- Assembly Bill 2313 (Williams, Chapter 571, Statutes of 2016) called on the CPUC to increase the rebate amount to 50 percent of pipeline interconnection costs up to \$3 million per project, or \$5 million for dairy cluster projects, and extended the program to December 2021. The CPUC will examine other options to assist the industry, including whether to allow recovery in rates of the costs of investments, before expiration of the program or exhaustion of rebate funds, whichever comes first.
- Senate Bill 840 (Leno, Chapter 341, Statutes of 2016) required the nonprofit California Council on Science and Technology (CCST) to complete a study analyzing certain elements of the CPUC's biomethane injection standards. As of January 2018, the CPUC's contract with CCST is in progress and expected to be completed by June 2018. Within six months of completion, the CPUC must reevaluate requirements and standards adopted for injection of biomethane into common carrier pipelines and, if appropriate, change those requirements and standards or adopt new requirements and standards, giving due deference to the conclusions and recommendations made in the study.
- Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) requires the CPUC, in consultation with CARB and California Department of Food and Agriculture (CDFA), to direct gas corporations to implement no fewer than five dairy biomethane pilot projects to demonstrate interconnection to the common carrier pipeline system no later than January 1, 2018. Gas corporations may recover the reasonable costs of pipeline infrastructure developed under the pilots. Decision 17-12-004, adopted December 14, 2017, established the Implementation and Selection Framework which defines project components that are eligible for funding; how the solicitation will be developed and

⁵⁹³ <http://codes.findlaw.com/ca/public-utilities-code/puc-sect-784-1.html>.

deployed; the cost recovery approach; how the interagency selection committee will choose winning projects; data that must be provided by the dairy biomethane projects; and how to ensure these pilots contribute to the safe operation of the natural gas system.⁵⁹⁴ Utilities are to issue a draft solicitation for dairy pilots no later than January 18, 2018, with SoCalGas taking the lead to issue a joint utility solicitation, after which the final solicitation is due within 20 days. Proposed pilot projects will be submitted within 110 days of the final solicitation. The data collected from these pilots will provide operational, financial, and environmental insight to assist with the development of policies to support renewable gas.

In addition to legislation, the *California Sustainable Freight Action Plan*, developed in response to Executive Order B-32-15, requires several state agencies to take certain actions to help coordinate progress on three pilot project concepts. The Dairy Biomethane for Freight Vehicles concept proposes to develop a commercial-scale, dairy biogas-to-biomethane project that will fuel freight and other vehicles. The proposed pilot will include implementation of pipeline injection and the construction of a fueling station. At the June 30, 2017, IEPR workshop on Renewable Gas, panelists discussed how existing natural gas infrastructure could support the delivery of renewable gas to end-use customers, particularly for use as a transportation fuel. This evolution in moving from natural gas to renewable gas is a concept called “gas utility 3.0” by George Minter, regional vice president of external affairs and environmental strategy for SoCalGas. (See Chapter 8 on “First Steps in Transforming the Natural Gas Sector.”)

Throughout the workshop, several stakeholders expressed that interconnection with gas and electric utility infrastructure can be costly and lengthy for renewable gas projects. Guidance or assistance, along with government support, can address this challenge. However, utility companies and regulators must balance gas quality with system safety and reliability.

In their written comments, the Agricultural Energy Consumers Association, Agricultural Council of California, and Los Angeles County Department of Public Works stated that California should address the high cost of pipeline interconnection and fuel upgrading. Bioenergy producers, such as Bloom Energy, CR&R, Victor Valley Wastewater Reclamation Agency, Bioenergy Association of California, American Biogas Council, and Organic Waste Systems, suggested accelerating reconsideration of pipeline biogas standards directed by Senate Bill 840, Section 11 to address high costs of pipeline interconnection and meet pipeline gas quality standards. Furthermore, they requested that gas companies make Sempra Energy Rule 30 and PG&E Rule 21 consistent with out-of-state biomethane gas quality standards. They also suggested extending the CPUC’s five dairy pilot projects to other waste feedstock sources.⁵⁹⁵

Utilities, PG&E, and SoCalGas suggested that more investment is needed in distribution infrastructure for renewable gas.⁵⁹⁶ SoCalGas stated that “utility rate-based investment in

⁵⁹⁴ <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K352/201352373.PDF>.

⁵⁹⁵ Stakeholder comments are available online under Docket 17-IEPR-10, Renewable Gas, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-10>.

⁵⁹⁶ Ibid.

additional infrastructure, like biogas upgrading facilities, can also provide important value to California by accelerating the state's ability to meet its 2030 environmental goals, and simplifying the investment needed by developers to transform our organic waste into renewable gas.”

Utilities say they are open to exploring the possibilities of developing a Renewable Gas Standard and utility procurement requirement of a certain percentage of in-state renewable gas that does not result in a measurable increase in natural gas costs for all California consumers. However, they state that several factors must first be explored, including how to maintain equity among core and noncore customers, what are the costs for various types of renewable gas, and how a biomethane procurement requirement would fit with requirements that utilities serving core customers purchase bundled interstate capacity and gas. In the *2017 Climate Change Scoping Plan Update*, CARB assessed that a 5 percent increase in use of renewable natural gas reduces GHG emissions by roughly 2 million MT-CO_{2e} and costs \$300– \$1,500/MT-CO_{2e}, with a social cost of carbon benefit of \$55 million to \$170 million.⁵⁹⁷ The cost estimate was based on sensitivity analysis using the PATHWAYS model. The lower cost range assumes biogas in pipeline, using modeled-delivered prices for biogas. The cost-effectiveness of a strategy using pipeline injected biogas to meet a 5 percent renewable gas procurement requirement was on par with other potential initiatives such as increasing RPS and LCFS obligations to 60 percent and 18–25 percent, respectively. The higher cost range assumes renewable natural gas is provided by hydrogen generated from flexible grid electrolysis, known as a *power-to-gas system*, as discussed in Chapter 3. Power-to-gas was by far the least cost-effective strategy out of the ones considered. (See “Power-to-Gas” section below.) However, power-to-gas is at the initial stages of pilot demonstration in California, with one operational project at the University of California, Irvine, (UC Irvine) that injects 0.24–0.78 percent hydrogen gas by volume into a SoCalGas natural gas pipeline.⁵⁹⁸ Based on utility tariff heating value requirements, mixtures of up to 8.5 percent hydrogen gas by volume may be allowable. Research by the University of Illinois at Urbana-Champaign, supported by SoCalGas and in collaboration with UC Irvine, found that mixtures of hydrogen and natural gas with up to 5 percent hydrogen concentration will accelerate fatigue crack growth in steel pipes, conservatively requiring pipelines to be repaired or replaced every 80 years, as opposed to 100 or more years.⁵⁹⁹ The costs of power-to-gas are further discussed later in this chapter under “Long-Term and Alternative Pathways for Renewable Gas.”

Renewable Hydrogen

In the United States, California is the second largest user of hydrogen, second only to Texas, and is one of the three largest producers with an annual production capacity of more than 1.8 million

597 CARB. *The 2017 Climate Change Scoping Plan Update: The Proposed Strategy for Achieving California's 2030 Greenhouse Gas Target*. January 20, 2017. Pg. 65 – 66. https://www.arb.ca.gov/cc/scopingplan/2030sp_pp_final.pdf.

598 UCI News. In a national first, UCI injects renewable hydrogen into campus power supply. December 6, 2016. <https://news.uci.edu/2016/12/06/in-a-national-first-uci-injects-renewable-hydrogen-into-campus-power-supply/>.

599 M. Dadfarnia and P. Sofronis, Assessment of Resistance of Line Pipe Steels to Hydrogen Embrittlement, November 29, 2016, https://www.google.com/url?sa=t&rct=j&q=&esrc=s&source=web&cd=3&ved=0ahUKEwiOgZyggd3YAhWvmuAKHRHhCCAQFgg0MAI&url=http%3A%2F%2Fwww.aep.uci.edu%2Fdownload01%2FPower-to-Gas%2FFinal_Report_SoCalGas_Project_UIUC.doc&usg=AOvVaw1mrQ4W1bu7KFISGedK_qDP.

metric tons. The vast majority of this hydrogen is produced from natural gas. Displacing petroleum-based fuels with renewable alternatives may allow existing hydrogen production capacity to be dedicated elsewhere for energy. Hydrogen, like methane, can also be developed from renewable resources. As described in Chapter 3, one such pathway is the conversion of excess renewable electricity into renewable hydrogen via electrolysis. (See “Use of Excess Electricity.”) Renewable hydrogen can also be produced from biomethane, biogas, and other biomass-based resources.

On January 30, 2017, Energy Commission staff held a public workshop on Implementation Strategies for Production of Renewable Hydrogen in California. The Energy Commission heard testimony and comments from stakeholders, including hydrogen refueling station developers, technology providers, utility companies, local governments, the U.S. Department of Energy, national labs, and academia, about the need for renewable hydrogen in California. A key takeaway from the workshop was that while renewable hydrogen production technologies are in all stages of development, some commercial off-the-shelf equipment are available with multiple installations and demonstration projects across Europe. However, comments from Nel Hydrogen, ITM Power, and StratosFuel indicated that the high cost of electricity (especially in California) presents a challenge for electrolysis system developers, unless using excess renewable electricity, which provides low or negative price rates. They also testified that waiving grid fees for hydrogen production (such as under Net Energy Metering [NEM 2.0]), could help reduce hydrogen costs. Nel Hydrogen estimated that renewable electricity at less than \$0.05/kWh and hydrogen infrastructure at scale (larger than 50 MW) can achieve a hydrogen vehicle fuel price at pump (\$6.70/kg) equivalent to gasoline.⁶⁰⁰

Fuel cells are the primary technology choice for power generation when using hydrogen gas. Deployment of fuel cells using renewable hydrogen in a distributed generation system can significantly reduce GHGs and local criteria pollutant emissions compared to combustion generators. The Orange County Sanitation District, for example, operates a facility that can use biogas from a wastewater treatment plant to simultaneously produce electricity, heat, and hydrogen, referred to as a trigeneration system. In this system, treated biogas from an anaerobic digester is run through a high-temperature fuel cell, which produces the hydrogen.

Renewable hydrogen also plays a significant role in the state’s development of hydrogen refueling stations for fuel cell electric vehicles. Senate Bill 1505 (Lowenthal, Chapter 877, Statutes of 2006) requires hydrogen refueling stations to dispense a minimum of 33.3 percent renewable hydrogen. As of August 2017, 28 of the 29 California retail hydrogen refueling stations relied on renewable hydrogen sourced from biomethane, biogas, or other renewable gases (as opposed to electrolysis from renewable electricity). As previously mentioned in Chapter 3, the ARFVTP issued a \$3.9 million funding solicitation for projects that produce renewable hydrogen, whether derived from renewable gas resources or renewable electricity. The Energy Commission held a public workshop on July 31, 2017, to discuss draft concepts for the solicitation, and a pre-application workshop on January 9, 2018. Projects are expected to be awarded by May 4, 2018.

⁶⁰⁰ Nel Hydrogen. Renewable Electricity to Hydrogen – California. Presentation at January 30, 2017, Pre-Solicitation Workshop on Implementation Strategies for Production of Renewable Hydrogen in California.

Economic Assessment of Renewable Gas End Uses

In addition to fuel production costs, developers (or their customers) may be responsible for covering additional capital costs related to the end uses of the fuel. As discussed, biogas end uses include transportation fuel, injection into common carrier natural gas pipelines, and electricity generation. Table 23 presents estimates of the capital expenditures associated with using biogas for these end uses.

The sectors in which natural gas vehicles are used the most (refuse and transit) predominantly operate CNG vehicles, rather than LNG. There has been much recent activity in integrating CNG engines into other medium- and heavy-duty vehicle sectors due to CNG's economic advantages of lower costs and greater LCFS credit generation compared to LNG. The two main costs of using biomethane as a vehicle fuel are the costs of installing a CNG refueling station(s) and the cost of buying new CNG vehicles or retrofitting diesel vehicles.

Injecting biomethane into a natural gas pipeline requires the installation of biogas conditioning and upgrading equipment, utility interconnection, and perhaps biogas gathering lines. Interconnection encompasses a point of receipt and pipeline extension from the biogas upgrading facility to an existing common-carrier natural gas pipeline. It is ideal to site the biomethane production facility as close to a natural gas pipeline interconnection point as possible. Biogas gathering lines may be desired for central biogas processing. Such lines can reduce overall costs and reach economies of scale. This method of biogas processing has been proposed for dairy cluster projects. According to a recent report by the UC Davis Biomass Collaborative, levelized costs of \$25/MMBtu can typically be expected for pipeline injection and \$7/MMBtu at a larger scale (for 20 years, 6 percent annual interest). These costs compare to roughly \$3/MMBtu for traditional natural gas. This does not include about \$4/MMBtu for environmental costs of all types of flaring, whether renewable or nonrenewable natural gas. Once injected into the pipeline, transportation costs may be around \$5/MMBtu, not including any costs of leaked gas associated with transportation. Comparatively, releasing fugitive methane emissions directly into the air has an environmental cost of about \$45/MMBtu.⁶⁰¹ Methane leakage issues in California's natural gas system are being addressed by Senate Bill 1371 (Leno, Chapter 525, Statutes of 2014), through which the CPUC approved a biennial compliance plan incorporated into the utilities' annual gas safety plans, beginning in March 2018. (See Chapter 8 on "Methane Leakage in the Natural Gas System.") Safety issues for projects must also be addressed before renewable gas projects are implemented. (See Chapter 8 on "Natural Gas Pipeline and Underground Storage Safety.") Safety standards for biomethane pipeline injection were addressed by the California Office of Environmental Health Hazard Assessment by Assembly Bill 1900 (Gatto, Chapter 602, Statutes of 2012) and are being reevaluated by CCST under Senate Bill 840 (Committee on Budget and Fiscal Review, Chapter 341, Statutes of 2016). Additional similar evaluation processes will be needed to address the injection of hydrogen gas.

⁶⁰¹ Williams, R., C. Ely, T. Martynowicz, and M. Kosusko. *Evaluating the Air Quality, Climate and Economic Impacts of Biogas Management Technologies*. U.S. Environmental Protection Agency, Washington, D.C, EPA/600/R-16/099, 2016.

When using biomethane for electricity generation, interconnection costs play a similar role. For both gas and electricity interconnection, fees must be paid to the respective utility company. These fees fund applications, studies, and testing to determine whether the existing infrastructure and downstream users are compatible with the existing structure or whether modifications are needed.

Table 23: Nonlevelized Capital Cost Ranges for Biomethane Renewable Gas End Uses

		Capital Cost Range (\$ per MMBtu per Year Capacity) *Unless otherwise stated	
		Low	High
CNG Vehicle Fuel	CNG Fueling Station ⁶⁰²	\$17	\$55
	Differential Cost of CNG Heavy-Duty Vehicle (relative to diesel)* ⁶⁰³	\$45	\$68
Hydrogen Vehicle Fuel	Hydrogen Fueling Station ⁶⁰⁴	\$193	\$541
	Differential Cost of Hydrogen Heavy-Duty Vehicle (relative to diesel) ⁶⁰⁵	\$750	\$1,800
Biomethane Pipeline Injection	Biogas Gathering Lines (for centralized cleaning)	\$12.5	\$45
	Biogas Conditioning/Upgrading Equipment	\$14.5	\$75
	Natural Gas Pipeline Interconnect ⁶⁰⁶	\$8	\$35
Electricity Generation	Electricity Generator <ul style="list-style-type: none"> • Stationary Reciprocating Engine • Microturbine • Fuel Cell 	<ul style="list-style-type: none"> • \$23 • \$88 • \$150 	<ul style="list-style-type: none"> • \$105 • \$170 • \$250
	Electricity Interconnect*	\$3	\$26

*Based on fuel use and vehicle activity data from CARB EMFAC 2014, instead of capacity.
Source: California Energy Commission

602 CNG fast-fill and slow-fill capabilities.

603 Cost range of \$43,000 - \$80,500 differential for each natural gas truck compared to equivalent diesel truck model. Cost data from TIAX, ANGA, CARB and AFLEET.

604 Baronas, Jean, Gerhard Achtelik, et al. Joint Agency Staff Report on Assembly Bill 8: 2016 Annual Assessment of Time and Cost Needed to Attain 100 Hydrogen Refueling Stations in California. California Energy Commission. Publication Number: CEC-600-2017-002.

605 Cost range of \$400,000 - \$800,000 differential for each hydrogen fuel cell electric truck compared to equivalent diesel truck model.

606 Cost range to complete pipeline interconnect for one million diesel gallon equivalents (DGE) per year production plant capacity at central regional plant. Assumes additional production modules at central regional plant should not require significant new pipeline interconnection costs.

CARB's SLCP Reduction Strategy (March 2017) includes an assessment of different renewable gas end uses for different dairy operations. The analysis indicates that projects that produce fuel rather than electricity consistently provide the most cost-effective solutions, independent of how manure is managed (Table 24). This is primarily due to the higher revenue provided by LCFS and RIN credits. In fact, no modeled project was revenue positive in the absence of LCFS and RIN credits, demonstrating the importance of continuing the LCFS program (Figure 84). Nevertheless, historically it has been more common for electricity generation projects to secure long-term power purchase agreements of up to 10 to 20 years, whereas fuel projects generally rely on spot-market pricing or 1–3-year agreements for both fuel and credit sales. A proposed strategy is to produce both electricity and fuel, hedging the long-term certainty benefits of electricity generation against the more volatile high-revenue potential of fuel production. However, as discussed in Chapter 1, "Changes in Electricity Market Structure," long-term contracts with utility companies are not available in the electricity sector, except when required of utilities such as under the BioMAT program. For existing biogas electricity generation projects that are not eligible under BioMAT, such as landfill gas facilities that may not get their electricity contracts renewed, there are potential opportunities to switch to producing biomethane transportation fuel. Biogas electricity generation projects may also have the option of directly supplying electricity onsite to a customer, with whom they can enter a long-term contract. Projects may alternatively form contracts with community choice aggregators (CCAs), although there is uncertainty surrounding the ability of CCAs to secure the financing needed for long-term investments. (See Chapter 1 on "Changes in the Electricity Market Structure.")

Sierra Club recommended that state funding agencies should compare the cost-effectiveness of reducing emissions within the waste stream against repurposing the resulting emissions. Another key takeaway from CARB's SLCP Reduction Strategy as shown in Table 24 is that renewable gas utilization projects, whether for fuel or electricity production, can be more cost-effective on a GHG reduction basis than relying solely upon manure management methods that avoid methane emissions, such as conversion to pasture and using manure scrape systems.⁶⁰⁷ However, fuel projects were much more cost-effective than electricity projects, with fuel projects generating more than four times greater revenue. In situations where fuel production is not viable, the next economical option would be to consider alternative manure management methods (such as conversion to pasture). CDFA's 2017 Alternative Manure Management Program is expected to provide \$9.7 million in financial assistance for the implementation of nondigester manure management practices. Two subgroups, formed under the Dairy/Livestock Working Group to address Senate Bill 1383, are investigating how to foster markets for digester and nondigester dairy projects.

When revenue streams are factored in, dairy projects show potential to reduce manure methane emissions at low or negative costs. Although dairy projects may cost the most per unit of energy,

⁶⁰⁷ Alternative manure management methods are nondigester management practices, such as pasture-based management, solid separation of manure solids before entering an anaerobic environment, and conversion from flush to scrape manure collection systems. Alternative manure management methods should be used to reduce methane emissions from manure that is not an economically viable resource for renewable gas (for example, medium and small livestock operations or those operations not sited well for digesters).

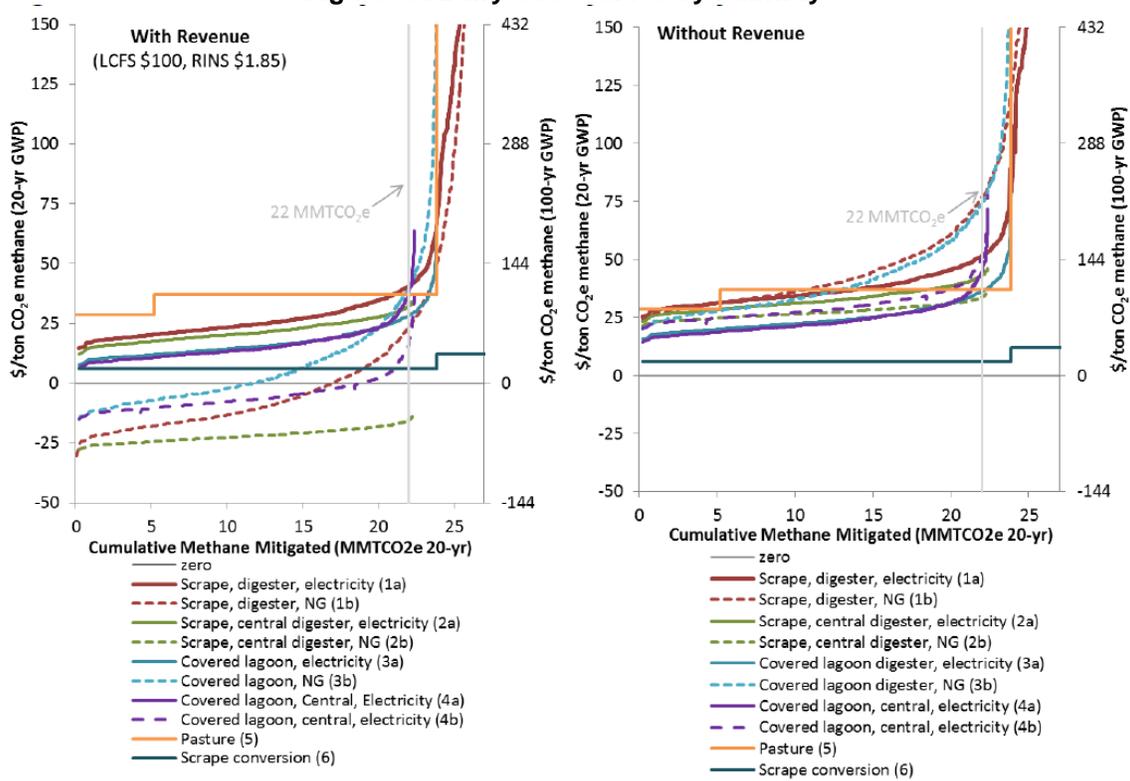
as presented by Dr. Jaffe’s study, they can still be highly cost-effective in terms of cost per GHG emissions avoided, especially when producing a transportation fuel. Analyses indicate that renewable gas end use as a transportation fuel in natural gas vehicles should be prioritized since it provides the most cost-effective GHG emissions reductions with modest capital costs.

Table 24: Economic Analysis for Projects at an Example Flush Dairy With 2,000 Milking Cows Over a 10-Year Period (44,410 MMBtu/yr, all Costs and Revenues in Million Dollars)

Pathway	1a	1b	2a	2b	3a	3b	4a	4b	5	6
	Scrape, Onsite Digestion to Electricity	Scrape, Onsite Digestion to Fuel	Scrape, Central Digestion to Electricity	Scrape, Central Digestion to Fuel	Lagoon, Onsite Digestion to Electricity	Lagoon, Onsite Digestion to Fuel	Lagoon, Onsite Digestion to Electricity with Central Clean-up	Lagoon, Onsite Digestion to Fuel with Central Clean-up	Pasture	Scrape Only
Capital	\$6.9	\$7.2	\$6.8	\$5.3	\$5.1	\$7.2	\$5.7	\$5.9	\$7.2	\$1.6
O&M	\$5.5	\$5.3	\$4.8	\$4.5	\$3.1	\$4.2	\$2.5	\$4.3	\$2.8	\$0.4
Revenue	\$3.6	\$16.0	\$3.6	\$16.0	\$2.6	\$11.4	\$2.6	\$11.4	--	--
10-Year Net Present Value (NPV) and Cost Effectiveness										
NPV (million \$)	-\$8.8	\$3.6	-\$8.0	\$6.2	-\$5.6	\$0.0	-\$5.7	\$1.2	-\$9.9	-\$2.1
\$/MT CO₂e (20-yr GWP)	21	-8	19	-15	13	0	13	-3	29	5
\$/MT CO₂e (100-yr GWP)	60	-24	55	-42	38	0	39	-8	82	14

Source: CARB. *SLCP Reduction Strategy*. March 2017, https://www.arb.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf. Summation may not be exact due to rounding. Capital costs amortized over 10 years with 7 percent interest. Discount rate is 5 percent. Costs normalized to example 2,000-cow dairy. Revenue includes carbon credits for electricity, LCFS value, RINS, and other revenue.

Figure 85: Dairy Cost Curves by Pathway



Source: CARB. *Short-Lived Climate Pollutant Reduction Strategy*, March 2017. Available at https://www.arb.ca.gov/cc/shortlived/meetings/03142017/final_slcp_report.pdf

Renewable Gas Revenue Streams

Renewable gas projects are able to capitalize on a variety of revenue streams in addition to the sale of the fuel itself. Renewable gas projects often rely on these alternative sources of income, including credits and by-products, to be economical. The revenue of a facility depends highly upon the type of energy product that is produced. Table 25 illustrates the types and range of revenue that renewable gas projects may earn by producing CNG vehicle fuel, hydrogen fuel cell vehicle fuel, and electricity.

Table 25: Renewable Gas Facility Revenue Ranges by End Use

		Revenue Range		Current Revenue (End of May 2017)
		Low	High	
CNG Vehicle Fuel	Retail CNG Sales or Fuel Savings (\$/MMBtu) or Henry Hub Pipeline RNG Sales [\$/MMBtu]	\$13.30 [\$2.00]	\$22.00 [\$5.00]	\$22.00 [\$3.00]
	RFS D5 RIN Credits (\$/MMBtu)* or RFS D3 RIN Credits [\$/MMBtu]**	\$9.80 [\$24.40]	\$15.80 [\$36.30]	\$13.00 [\$33.50]
	Cellulosic Waiver Credits (\$/MMBtu) ⁶⁰⁸ (cannot be earned with RFS D3 RINs, but can with D5 RINs if eligible feedstock)	\$6.00	\$26.00	\$15.70
	LCFS Credits (\$/MMBtu) ^{***}	\$1.35	\$46.50	\$4.30 - \$26.80
Hydrogen Vehicle Fuel	Hydrogen Fuel Sales (\$/kg) [\$/MMBtu]	\$7/kg [\$88]	\$18/kg [\$158]	\$10/kg [\$106]
	RFS D5 RIN Credits (\$/MMBtu) ⁶⁰⁹ or RFS D3 RIN Credits [\$/MMBtu]	\$8.40 [\$27.50]	\$11.50 [\$31.60]	\$11.80 [\$30.40]
	Cellulosic Waiver Credits (\$/MMBtu) ^{Error! Bookmark not defined.} (cannot be earned with RFS D3 RINs, but can with D5 RINs)	\$6.00	\$26.00	\$15.70
	LCFS Credits (\$/MMBtu) ^{****}	\$4.40	\$32.20	\$14.70 - \$19.10
Electricity	Electricity PPA (\$/MMBtu) or BioMAT PPA [\$/MMBtu] ⁶¹⁰ or Energy Savings {\$/MMBtu}	\$19.60 [\$37.40] { \$26.40}	\$35.20 [\$57.70] { \$58.60}	[\$37.40 - \$51.50]
	SGIP (\$/W) ⁶¹¹ [\$/MMBtu capacity] (one-time rebate; cannot be earned with BioMAT PPA)	\$1.00/W [\$33.50]	\$1.20/W [\$40.20]	\$1.20/W [\$40.20]
	Cap-and-Trade Offset	11.66/MT-CO ₂ e	13.24/MT-CO ₂ e	\$12.45/MT-CO ₂ e
General	Tipping Fee (for accepting feedstock material)	\$35/ton	\$126/ton	\$45/ton
	Biosolids Compost/Soil Amendment Sales	\$10/ton	\$16/ton	\$0
	Liquid Fertilizer Sales	TBD	TBD	\$0

* Assume 2016 – 2017 current year (2017) D5 RIN credit price range of \$0.76 to \$1.22/RIN.

** Assume 2016 – 2017 current year (2017) D3 RIN credit price range of \$2.19 to \$2.80/RIN.

*** Assume LCFS historical credit range of \$22 to \$122/MT-CO₂e, biomethane CI range of 30.92 to -272.97 gCO₂e/MJ, diesel CI of 98.44 gCO₂e/MJ for 2017, and EER of 0.9 for spark-ignition engines. A range of LCFS revenue at the end of May is shown for a range of carbon intensity pathways at the same credit price.

**** Assume LCFS historical credit range of \$22 to \$122/MT-CO₂e, hydrogen CI range of 47.73 to -12.65 gCO₂e/MJ, California reformulated gasoline CI of 95.02 gCO₂e/MJ for 2017, and EER of 2.5 for light-duty fuel cell electric vehicles. A range of LCFS revenue at the end of May is shown for a range of carbon intensity pathways at the same credit price.

Source: California Energy Commission

608 Cellulosic Waiver Credits may be earned only if choosing to receive D5 RIN credits in lieu of D3 RIN credits. The Cellulosic Waiver Credit price per credit is \$2.00 for 2017, \$1.33 for 2016, \$0.64 for 2015, and \$0.49 for 2014.

609 One kilogram of renewable hydrogen can potentially earn 1.5 RIN credits, based upon calculations from Section 80.1415 of the Renewable Fuel Standard.

610 BioMAT PPA is limited to electricity generation facilities less than or equal to 3 MW capacity (up to 89,671 MMBtu per year, assuming 100 percent capacity factor).

611 Step 1 through Step 3 of the 2017 Self-Generation Incentive Program Handbook, including \$0.60/watt biogas adder. Assumes 100 percent capacity factor.

Vehicle Fuel Revenues

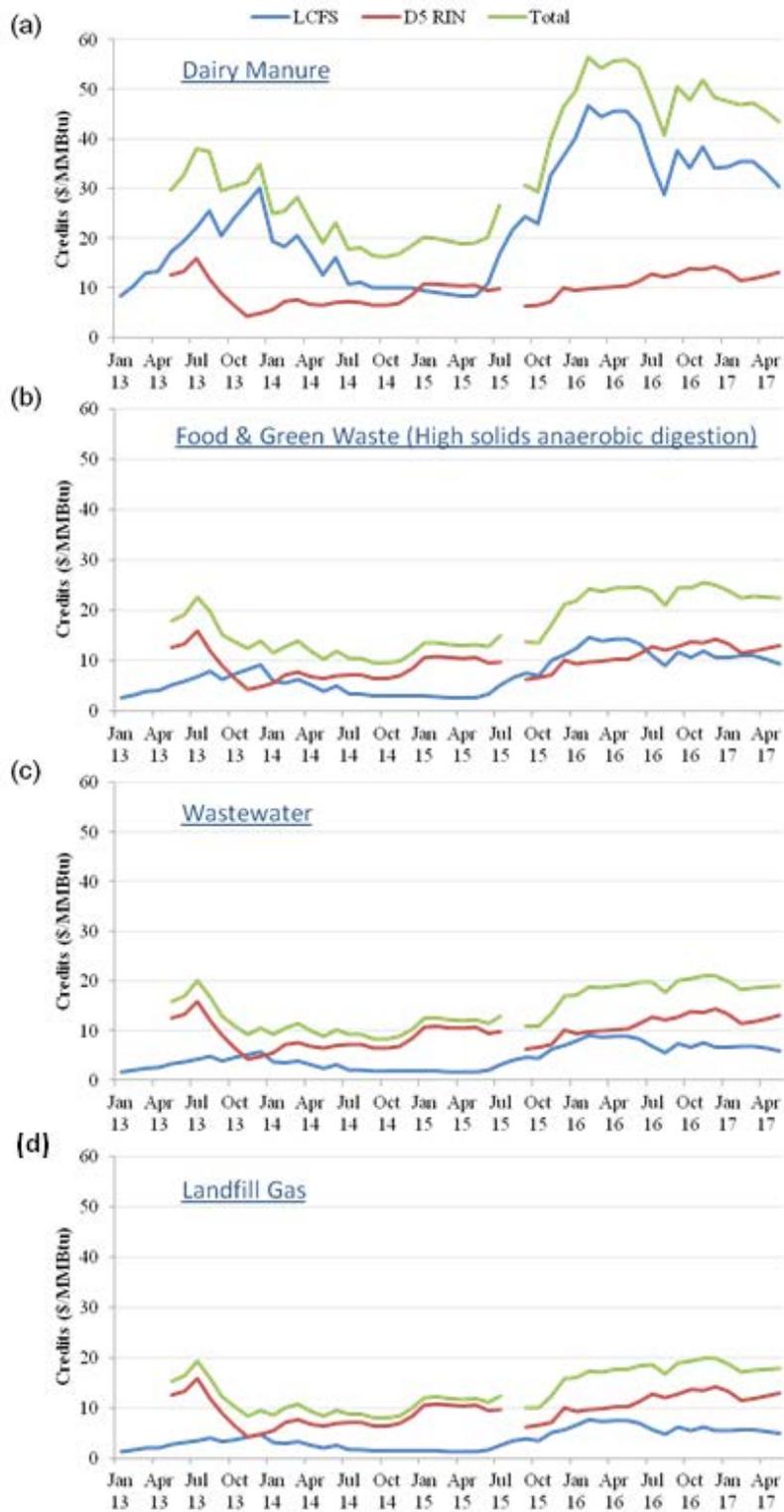
Vehicle fuel production projects are eligible to earn federal RFS RIN credits, as well as California LCFS credits. Many biomethane vehicle fuel projects largely rely on these credits as a major source of income. Both programs create credits for biomethane production through a trading system, but with different obligations. The RFS focuses on mandated renewable fuel consumption volumes nationwide, whereas LCFS regulates the average life-cycle emissions of transportation fuels in the California market.

The credits from these programs are globally tradable as open market commodities. Credits are susceptible to price fluctuations; in addition, they are affected largely by regulatory and policy uncertainty. Often the RIN and LCFS credit revenue is negotiated to be split among the biogas producer (the credit generator) and the biomethane fuel distributor and customer. The biomethane fuel may also be sold at a price below the price of conventional natural gas to negotiate an offtake agreement.

As of spring 2017, nearly 60 percent of the natural gas sold in California for transportation and registered with CARB's LCFS program was in the form of biomethane; however, estimates from LCFS program data are that the vast majority (more than 90 percent) was captured and imported from out-of-state facilities into shared interstate pipelines.

Figure 85 illustrates potential credit for biomethane production under RFS and LCFS. Potential credits are calculated based on historical prices and the rules of RFS and LCFS. Three major types of production pathways are included: biogas from animal waste (primarily dairies), high-strength anaerobic digestion, and upgraded landfill gas. Biomethane from landfill gas earns fewer LCFS credits due to the high carbon intensity; as a result, the combined credit value of the biomethane can be significantly affected by RIN price. Given the uncertain future of RFS, biomethane from landfill gas might be impacted most from an absent (or weakened) RFS, whereas biomethane from dairies would be impacted less.

Figure 86: Historical RIN and LCFS Credits per MMBtu Produced for Four Major Renewable Gas Production Pathways



Source: California Energy Commission analysis. D5 RIN price applied for estimate; LCFS EER=0.90; CI for diesel based on LCFS by years.

Bioenergy developers, utilities, local agencies, agricultural stakeholders, and vehicle manufacturers alike support the LCFS program. The Agricultural Energy Consumers Association and Agricultural Council of California, George Sterzinger with American Waste to Energy, LLC, Debbie Killey, California Bioenergy, CR&R, Genifuel Corporation, Victor Valley Wastewater Reclamation Agency, Bioenergy Association of California, American Biogas Council, Organic Waste Systems, North American Repower, Coalition for Renewable Natural Gas, PG&E, Los Angeles County Department of Public Works, and Fulcrum Bioenergy all provided comments emphasizing the importance of the credit market.⁶¹²

They also requested consideration of the following program revisions:

- Create a mechanism for long-term market certainty for renewable gas by establishing conditions conducive to long-term contracts or long-term guarantees of credit values; establish an LCFS credit reserve and third-party market that provides for long-term contracts and guaranteed credit values; or set a floor of credit price.
- Extend the LCFS program and increase the carbon intensity requirement beyond the 10 percent level.
- Develop a program to encourage LCFS prioritization of California projects.
- Create a mechanism to provide a portion of LCFS credits to end users, not just producers/distributors.
- Provide an LCFS pathway for electric charging from renewable gas.

CARB must follow the Office of Administrative Law rulemaking process to enact any revisions.⁶¹³ However, the Energy Commission supports CARB's LCFS program.

Electricity Generation Revenues

Renewable gas can be used for power generation as renewable electricity. These electricity generation projects can offset current onsite electricity usage or sell their electricity through power purchase agreements with an electric utility company. As mentioned, biomass electricity projects are eligible to earn a financial incentive through California's SGIP, which provides \$1.20 per watt of capacity in 2017.

The BioMAT program offers up to 250 MW cumulatively to eligible bioenergy projects through a fixed-price standard contract to export electricity to California's three large investor-owned utilities. Critically, this contract can be long-term, lasting from 10 to 20 years, and counts toward the utilities' RPS targets. Table 26 summarizes BioMAT program information for California's three major investor-owned utilities. The three categories of projects are defined as follows:

- Category 1: Biogas from wastewater treatment, municipal organic waste diversion, food processing, and codigestion – 110 MW

⁶¹² Stakeholder comments are available online under Docket 17-IEPR-10, Renewable Gas, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-10>.

⁶¹³ Office of Administrative Law, Rulemaking Process, https://oal.ca.gov/rulemaking_process/.

- Category 2: Dairy and other agricultural bioenergy – 90 MW
- Category 3: Bioenergy using by-products of sustainable forest management (including fuels from high hazard zones effective February 1, 2017) – 50 MW

Since the beginning of the program in February 2016, there have been a small number of power purchase agreements contracted under the BioMAT program. Only 2.45 MW (2 PPAs) of Category 1 have been used for P&GE, 2.27 MW for SCE Category 1, and 3.0 MW (1 PPA) for SDG&E Category 1. As of January 2018, there is one 3 MW executed contract with PG&E and two 0.8 MW executed contracts with SCE under Category 2, and none under Category 3. However, there are fewer than five unaffiliated applicants in the statewide pricing queue for Category 1, seven applicants queued for Category 2 (Dairy), fewer than five applicants queued for Category 2 (Other Ag), and fewer than five applicants queued for Category 3.⁶¹⁴ At the August 10, 2017, Dairy and Livestock Subgroup #2 meeting, dairy biomethane project developers vocalized strong intent to use BioMAT in the coming years as their projects become operational. In February 2021, the BioMAT program may expire.

Table 26: BioMAT Program Information for Three Major IOUs

	Program Capacity (MW)			Statewide Price as of December 1, 2017 (\$/MWh)
	PG&E	SCE	SDG&E	
Category 1	30.5	55.5	24	\$127.72
Category 2				
• Dairy	33.5	56.5	0	• \$187.72
• Other Ag				• \$187.72
Category 3	47	2.5	0.5	\$199.72

Source: California Public Utilities Commission

Bioenergy developers and California utilities – Bioenergy Association of California, American Biogas Council, Organic Waste Systems, Victor Valley Wastewater Reclamation Agency, Clean Energy, PG&E, and SoCalGas – suggested opening a proceeding to allow for changes to the RPS and BioMAT to better support and promote bioenergy. Proposed changes may include allowing for procurement of larger or variable-power capacities or creating a mandated ratio of renewable energy from biomass. Also suggested is increasing Self-Generation Incentive Program funding for renewable gas generation and use.⁶¹⁵ Total funding available for renewable generation in SGIP steps 1, 2, and 3 are \$20.7 million, \$20.5 million, and \$20.5 million, respectively. As of January 16, 2018, more than \$7 million has been allocated in step 1.

Additional Renewable Gas Project Revenues

In the case of MRFs, transfer stations, and WWTPs, biomethane facilities may earn revenue from tipping fees by receiving and processing wastes for industries or municipalities.

⁶¹⁴ PG&E. BioMAT Queue Information: Program Period 10-CAT3 (as of January 2, 2018). January 2018.

⁶¹⁵ Stakeholder comments are available online under Docket 17-IEPR-10, Renewable Gas, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-10>.

Projects may also seek to convert liquid effluent into a salable liquid fertilizer and process the digestate biosolids coming out of the digester into a compost or soil amendment product. Likewise, gasification systems may market resulting biochar as a soil amendment. The development of commercial certifications for these commodities is being pursued. If these by-products are not sold, there are disposal fees associated with the associated removal.

In addition to the revenue streams laid out in Table 26, biogas projects may be eligible for various state and federal tax credits and exemption programs. Biogas projects may also be eligible to apply for government incentives, including grants from the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program, CDFA's Dairy Digester Research and Development Program, and CalRecycle's Organics Grants Program.

The role of tipping fees was also a recurring topic in the workshop. Tipping fees vary throughout California (ranging from \$35 per ton to \$112 per ton), which can affect the economic viability of a renewable gas project. The Agricultural Energy Consumers Association and the Agricultural Council of California⁶¹⁶ suggested that increased tipping fees would allow incentives for higher volumes of renewable gas from municipal solid waste.

Long-Term and Alternative Pathways for Renewable Gas

Alternative pathways for converting organic waste resources into renewable gas exist but have not been as widely adopted or demonstrated. These technologies may not present cost-effective strategies for meeting the 2030 goals of SB 1383 at this time; however, they may be beneficial for meeting California's longer-term climate change goals.

Emerging Thermochemical Pathways and Woody Biomass

There are many ways renewable gas can be produced. However, policies and programs have supported mostly anaerobic digestion to date. While anaerobic digestion is effective for feedstocks such as MSW organics, food waste, wastewater, and dairy manure, this widely adopted process cannot readily handle lignocellulosic compounds from wood and green waste.

Organic wastes can be broken down thermochemically under high temperature and/or pressure via gasification or pyrolysis. Gasification and pyrolysis allow the conversion of woody, herbaceous, and other organic material that are difficult or impossible to be digested. The product gas (syngas) can be directly applied for energy generation; used as a hydrogen source for refining, chemical manufacturing, or fuel cell vehicles; or converted into renewable gas. Reacting syngas with certain catalysts will induce methanation, producing methane and water. Compared to biological conversion processes such as anaerobic digestion, these thermochemical methods allow greater conversion yield, improved performance control, fine-tuning, predictability, and a wider range of feedstocks. However, more durable materials and intense processing conditions are needed, which incur higher capital costs. Gasification technologies have been limited to pilot-scale and demonstration-scale projects in California to date.

616 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-10/TN220223_20170714T164531_Michael_Boccardo_Comments_Agricultural_Energy_Consumers_Associ.pdf.

Compared to anaerobic digestion technologies, gasification systems are relatively more capital cost-intensive; however, they allow more rapid throughput, which increases the yield and revenue from the renewable gas product and reduces residue disposal costs. Gasification systems are still in the pilot and demonstration phases and have not been commercially installed in California. As the technology matures, process efficiency enhancements are made, and supply chains are developed, the costs of gasification systems will likely decrease below those costs presented in Table 27. Additional data are needed to assess the cost for gasification in terms of producing transportation fuel and to refine cost estimates for all potential end uses of syngas.

Table 27: Gasification Facility Capital Cost Ranges

Gasification System ⁶¹⁷	Capital Cost Range (\$ Per MMBtu Per Year Capacity)* Unless Otherwise Stated	
	Low (Large-Scale)	High (Small-Scale)
Feedstock Handling Equipment	\$5	\$21
Gasifier Unit	\$48	\$75
Syngas Clean Up Equipment	\$6	\$62
Facility Engineering, Construction and Permits	N/A	N/A
Subtotal Cost	\$135	\$440
Contingency (7 percent)	\$9	\$31
Syngas Plant Total Cost	\$144	\$471
Methanation Unit	N/A	N/A
Fischer-Tropsch System**	\$110,000 barrel/day	\$200,000 barrel/day

*Only required when biomethane is the desired product

**Only required when liquid hydrocarbon-based fuel is the desired product.

Source: California Energy Commission

Stakeholders emphasized the importance of emerging technologies that can support longer term SLCP goals.

In their comments,⁶¹⁸ several renewable gas developers, vehicle manufacturers, and academic institutions, including the University of California, Riverside; Los Angeles County Department of Public Works; Oberon Fuels; Volvo; Coalition for Renewable Natural Gas; Methanol Institute; Fulcrum; and Bioenergy, called for increased focus on and support for emerging conversion pathways. Increased research, development, and demonstration funding was also supported. Comments revealed that government agencies should promote technologies that maximize the greatest levels of GHG emissions reduction benefits at the lowest cost, while preserving the potential to reduce GHG emissions from emerging fuels and transformative conversion technologies not yet fully mature or developed.

Stakeholders, including the BioEnergy Producers Association and California Hydrogen Business Council, indicated that a review of already enacted legislation is needed to ensure that neutral

⁶¹⁷ Reflects cost range for different types and sizes of landfill gas collection systems designed to produce renewable gas for transportation fuels.

⁶¹⁸ Stakeholder comments are available online under Docket 17-IEPR-10, Renewable Gas, <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-10>.

definitions of renewable gas sources and conversion technologies are adopted.⁶¹⁹ Statutory and regulatory policies are not unified in acknowledging the potential role of emerging conversion technologies in producing renewable gas, as these technologies were not well understood during development of state legislation. The Bioenergy Association of California and Clean Energy suggested that corrective action should be pursued to define renewable gas eligibility consistently for funding incentives, potential regulations, and policy proceedings, which would provide a level playing field for these conversion pathways. For example, California Health & Safety Code Section 25420 could be amended to include biogas produced from noncombustion thermal conversion of eligible biomass feedstock consistent with Section 40106 of the Public Resources Code, which would allow access to the pipeline for renewable gas produced from a pathway other than anaerobic digestion. Policy revisions and incentive funding for these newer conversion technologies and fuels could improve private investor confidence to finance these types of projects and could allow open market competition to determine the most cost-effective solutions.

Power-to-Gas

An emerging use of renewable hydrogen is as electricity grid storage and balancing mechanism called power-to-gas (P2G). As discussed in Chapter 3, renewable hydrogen produced via electrolysis can provide a load when wind or solar generation may otherwise be curtailed, and be used later by highly dynamic electrolyzers and fuel cells. Economic analysis was provided from Energy + Environmental Economics (E3) and the National Fuel Cell Research Center.

Other Fuel Pathways

Fast pyrolysis (another thermochemical process) can process organic waste to produce a renewable syngas, which can be an intermediary in producing synthetic methane. Alternatively, other processes such as Fischer-Tropsch can be applied to syngas to produce renewable liquid hydrocarbon fuels, such as biocrude, renewable gasoline, renewable diesel, or renewable jet fuel. Renewable fuels, including renewable gas, are those fuels derived from renewable sources or feedstocks. The fungibility, or interchangeability, of these renewable fuel products with conventional liquid fuels allows for tremendous market penetration potential. Although these conversion processes have been technically viable for more than half a century, they have yet to become economically cost-effective.

Biomethane can also be upgraded into renewable dimethyl ether (DME). DME is a clean-burning fuel with no particulates formation, is suitable for compression ignition engines with modifications, and handles similar to propane, enabling it to rely on existing propane infrastructure. DME has been used for decades as an energy source in other countries but is only now being tested in the United States.

⁶¹⁹ Ibid.

In its written comments, the Union of Concerned Scientists emphasized, “Biomethane represents an important option for low-carbon fuels, but, like all biofuels, its potential supply is limited, so we need to be smart about where we use it.”⁶²⁰

Flaring

Landfills and WWTPs are required to install anaerobic digester systems to capture methane; however, more than half of these sites flare the biomethane, rather than repurpose it. Many dairies that use slurry and scrape systems also capture and flare their biogas. Although flaring both destroys extracted methane that would otherwise create an explosion hazard and reduces GHG emissions, it creates NO_x emissions – often in air basins that are in nonattainment for ozone precursors. Alternatives to flaring can potentially generate less NO_x emissions. For example, as shown in Table 28, microturbines meeting California’s distributed generation standards perform significantly better than flares for both NO_x and volatile organic compounds (VOC) emissions. However, reciprocating internal combustion engines and turbines generate more NO_x emissions than flares.

In addition, while flaring is one method of preventing methane emissions, it does not take full advantage of the economic benefits of using renewable gas as an energy source. Alternatives can generate positive net revenues for the landfill, whereas flare operations constitute an ongoing cost because they generate no revenue. An ICF study indicated the cost of abatement between \$2–\$9/MT-CO_{2e} for cover-and-flare systems at existing dairy lagoons, but costs in California are believed to be much higher than what is presented in the literature, given more stringent regulatory requirements.^{621, 622}

Written comments from multiple stakeholders, including The Coalition for Renewable Natural Gas⁶²³ and Bloom Energy,⁶²⁴ recommend supporting cost-effective systems that use the waste-based sources of fugitive methane to minimize flaring. Although flaring provides immediate and low-cost GHG and criteria pollutant reductions, it throws away the energy potential of a renewable gas resource. Greater emissions reductions can be achieved by instead using the renewable gas in an energy production system and by displacing fossil-derived energy.

620 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-10/TN220161_20170714T105011_Jimmy_O'Dea_Comments_Union_of_Concerned_Scientists_Comments_on.pdf.

621 ICF International, 2013. *Greenhouse Gas Mitigation Options for Agricultural Land and Animal Production within the United States*.

622 Sustainable Conservation, July 2015, *Greenhouse Gas Mitigation Strategies for California Dairies*, http://suscon.org/pdfs/news/pdfs/GHG_Mitigation_for_Dairies_Final_July2015.pdf.

623 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221760_20171113T190549_Nina_Kapoor_Comments_Comments_by_the_Coalition_for_Renewable_Na.pdf.

624 http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221768_20171114T11738_Alia_Schoen_Comments_Bloom_Energy_Comments_on_Draft_IEPR.pdf.

Table 28: LFG Utilization – Most Stringent Emission Limits and Estimated Net Revenue

Extracted LFG Fate	VOC	NO _x	Estimated Costs and Revenues
Landfill Gas Flare	0.009 lb/MMBtu ¹	0.025 lb/MMBtu ²	- \$23,200/yr (annual operating cost) ²
Landfill Gas Turbine - IC Engine	0.005 lb/MMBtu ²	0.036 lb/MMBtu ²	+ \$0.08 per kWh. ³
Landfill Gas Microturbine	0.001 lb/MMBtu ⁴	0.005 lb/MMBtu ⁵	<i>Expected positive net revenue by selling power generation back to the grid.</i>
Landfill Gas Captured and Conditioned for Vehicle Fuel	Regional reductions due to displaced diesel transport	Regional reductions due to displaced diesel transport	Pipeline Injection: Approx. \$5/MMBtu in net revenue ⁵ On-site Fueling Same credit and RIN revenues, but reduced conditioning costs and no pipeline injection costs, resulting in higher net revenues.

Source: California Air Resources Board

Conclusions

Existing state government policies, regulations, incentives, and proceedings have stimulated the success of several anaerobic digester projects using renewable gas from dairy farms, wastewater treatment plants, and projects diverting organic food waste from landfills to produce electricity and transportation fuels. There remains significant, untapped potential to capture value from wasted resources and reduce short-lived climate pollutant and other emissions in California. Two independent studies carried out by UC Davis and ICF International concluded that existing government policies (with some modifications) could support the substantial growth of renewable gas, particularly as a transportation fuel to increase production up to at least 750 million gallons per year (DGE) by 2030. Both studies noted that renewable gas production can generate up to four times the revenue for transportation fuel use compared to electricity from the same renewable gas sources because of the monetary value of credits generated from the federal Renewable Fuels Standard and California LCFS for renewable transportation fuels. As a consequence, projects and policies supporting cost-effective renewable gas development and use in California are important to achieving a significant reduction of methane and help achieve the short-lived climate pollutant goal of reducing methane 40 percent below 2013 levels by 2030.

The aforementioned UC Davis and ICF International studies and workshop comments noted that several challenges might impede achieving the full growth potential and recommended actions to address these challenges. The most notable challenge for renewable gas use within the next 5 to 10 years is the limited number of models and production volume of natural gas vehicles – the most likely near-term transportation option for renewable gas. Vehicle manufacturers produce natural gas transit buses, refuse trucks, package delivery vehicles, and long-haul trucks. Natural gas trucks and buses compete well on fuel price with diesel vehicles, but natural gas trucks and buses cost 15 to 20 percent more than equivalent diesel vehicles and will require incentives to

cover differential costs until vehicle costs reach parity with diesel vehicles. New natural gas engines can also offer a low nitrogen oxide tailpipe emission benefit to help comply with the 2023 National Ambient Air Quality Standards.

State agencies have closely coordinated policies in place or under development to support renewable gas markets. Additional policies may be needed, and agencies may also need to modify, reconfigure, and enhance existing regulations, policies, and programs to fully enable cost-effective commercialization of renewable gas and maximize methane emission reductions. These existing policies and programs will also shape the role of utilities in ensuring the safety and reliability of the natural gas system and determining the extent of their investment in renewable gas projects.

The two independent studies also noted that to achieve full renewable gas growth potential, research and development will be required in several promising yet not commercially available waste conversion technologies to show proof of concept and demonstrate market applications, using a broader range of California waste residue sources and overgeneration of renewable electricity sources that are not suitable for anaerobic digestion. These projects will require additional government investment to explore potential outcomes beyond the next five years.

Recommendations

Senate Bill 1383 (Lara, Chapter 395, Statutes of 2016) requires the Energy Commission to develop recommendations for the development and use of renewable gas, including biomethane and biogas, as a part of its *2017 IEPR*, prepared under Section 25302 of the Public Resources Code. The legislation states, “In developing the recommendations, the Energy Commission shall identify cost-effective strategies that are consistent with existing state policies and climate change goals by considering priority end uses of renewable gas, including biomethane and biogas, and their interactions with state policies, including biomethane and all of the following: (1) The Renewables Portfolio Standard program, (2) The Low-Carbon Fuel Standard regulations, (3) Waste diversion goals established pursuant to Division 30... of the Public Resources Code, (4) The market-based compliance mechanism {Cap-and-Trade}, ...and (5) the strategy [to reduce short-lived climate pollutants developed pursuant to Section 39730].”

The Energy Commission received stakeholder comments suggesting recommendations to focus on near-term opportunities that maximize GHG emissions reduction benefits; prioritize the diversion of waste streams; study the full impacts of renewable gas projects particularly to disadvantaged communities; address challenges related to location, siting, and permitting to reduce project implementation time; increase research efforts to improve emissions reductions and for emerging conversion and fuel pathways; and address the high cost of pipeline interconnection and fuel upgrading. Stakeholders also expressed the need for a consistent and accurate accounting of feedstock resources, more investment in distribution infrastructure, increases and extensions of multiyear state funding for renewable gas projects, and modifications to state programs to provide long-term certainty and growth.

As outlined in this chapter, the Energy Commission has examined recent data, models, and assessments gathered from academia, industry, and environmental groups; stakeholder comments to the *IEPR*; and a review of existing state policies identified in SB 1383. Based on this

analysis and in consultation with other state agencies, including the California Air Resources Board (CARB), the California Public Utilities Commission (CPUC), the California Department of Food and Agriculture (CDFA), and the California Department of Resources Recycling and Recovery (CalRecycle), the Energy Commission identified cost-effective strategies and priority end uses of renewable gas and provides the following recommendations, in no particular order. SB 1383 directs that in consultation with the Energy Commission, state agencies shall consider these recommendations and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of renewable gas, and consider additional policies to support this development.

- **Focus on near-term opportunities that maximize greenhouse gas (GHG) emissions reduction benefits.** State funding agencies – the Energy Commission, CARB, the CPUC, CDFA, and CalRecycle – should focus on cost-effective strategies to develop markets for renewable gas. This *2017 Integrated Energy Policy Report* has revealed that renewable gas produced from anaerobic digestion used as a transportation fuel in near-zero emission, heavy-duty vehicles is the most likely near-term solution. Projects at dairies or using organic waste diverted from landfills offer significant short-lived climate pollutant reductions. Other sources of renewable gas, including power-to-gas or projects using waste woody biomass may also offer additional co-benefits, and deserve further research and demonstration. Attention should be focused on projects that can cost-effectively begin to capture and beneficially re-use methane in the next five years, when the need for short-term climate pollution reduction is at its peak. Moreover, the Energy Commission and the CPUC should expand research and increase natural gas research and development funds for adaptation, safety, energy efficiency, and natural gas engine technologies.
- **Encourage renewable gas for use in state fleets.** For medium-duty and heavy-duty vehicles in the state and local fleets that have no zero-emission options available, the Department of General Services and the state’s education system (University of California and California State University) should seek out cost-effective opportunities to use renewable gas with low NOx natural gas engines.
- **Continue the Low Carbon Fuel Standard (LCFS).** CARB staff should continue to develop amendments to the LCFS that extend GHG emission reduction targets beyond 2020, and strengthen the carbon intensity reduction targets beyond 2020 in line with California’s 2030 GHG reduction requirement enacted through Senate Bill 32.⁶²⁵ CARB should also consider the feasibility of a pathway for renewable gas to electric vehicle charging and hydrogen fuel production under the LCFS.
- **Use a common feedstock collection, procurement, and supply framework.** CARB should organize an interagency team to maintain a statewide feedstock inventory. University of California, Davis (UC Davis) staff should be included in the process and CARB should use the UC Davis inventory as a foundation. Furthermore, CARB should

⁶²⁵ https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32.

amend the LCFS regulation to add trackable unique identifiers to LCFS credits. Credits are not currently associated with either the fuel pathway (all pathways identify feedstocks) under which they were generated, the fuel producer, or a generation date. If credits could be traced back to the pathway, date, and producer, it would be possible to use the credit data to better understand which feedstocks are being used to produce LCFS fuels, as well as the date and location of production.

- **Address California Environmental Quality Act concerns.** CalRecycle and CARB should work with local partners to develop additional tools, such as programmatic environmental impact reports, to assist in developing additional renewable gas production facilities. Moreover, in updating requirements for solid waste facilities through the Senate Bill 1383 regulatory process, CalRecycle should encourage community engagement early in the environmental review for new and expanded solid waste facilities.
- **Prioritize disadvantaged communities.** CARB should work with local governments and environmental justice groups in disadvantaged communities to consider the local impacts, as well as air quality and economic benefits, of renewable gas projects, and develop emissions and air standards. Agencies awarding funding for projects that recycle organic waste and produce renewable gas should mirror Greenhouse Gas Reduction Fund funding criteria for these projects and require applicants to demonstrate engagement with communities within a half-mile radius of the proposed facility.
- **Implement policies to build commercial markets for renewable gas.** The CPUC should continue its efforts to implement dairy renewable gas pilot projects to demonstrate interconnection to the common carrier pipeline system, as outlined in the Order Instituting Rulemaking 17-06-015.⁶²⁶ Following completion of dairy pilot projects, the CPUC should continue to evaluate methods to promote increased use of renewable gas. Under Assembly Bill 2313,⁶²⁷ the CPUC should evaluate the current monetary incentive programs for renewable gas production and pipeline interconnection and consider whether it is prudent reasonable to continue those incentives, which are funded through utility rates. Pursuant to SB 1383,⁶²⁸ CARB should consider additional infrastructure development and procurement policies to encourage dairy renewable gas projects, and state agencies should consider and, as appropriate, adopt policies and incentives to significantly increase the sustainable production and use of renewable gas. Furthermore, Section 784.1(a) of the Public Utilities Code⁶²⁹ requests the California Council on Science and Technology to “undertake and complete a study analyzing the regional and gas corporation specific issues relating to minimum heating value and maximum siloxane specifications for [renewable gas] before it can be injected into

626 <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M191/K136/191136501.PDF>.

627 https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB2313.

628 http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB1383.

common carrier gas pipelines.” Section 784.1(c) requires the CPUC to reevaluate the biomethane pipeline injection requirements and standards based on the results of the California Council on Science and Technology study and under its administrative process, which would include the opportunity for public comment and stakeholder engagement on the conclusions and recommendations of the study.

- **Continue developing mechanisms for long-term market certainty for renewable gas.** CARB staff is developing a pilot financial mechanism as directed by Senate Bill 1383. Two financial methods are under consideration for the pilot: “contracts for difference” and “put options.” Senate Bill 1383 also requires CARB to make recommendations to the Legislature for expanding this mechanism to other sources of biogas.
- **Offer incentives for long-term feedstock supply contracts.** The LCFS offers incentives for but does not require long-term feedstock supply contracts. While regulated entities and trading partners would likely find such contracts to be advantageous under many circumstances, CARB should be open to considering reasonable measures that would further encourage these long-term contracts to provide further stability and certainty to the LCFS credit market. CARB is exploring such measures as part of the dairy working group effort along with the effort to develop a pilot financial mechanism.
- **Determine methods to increase landfill tipping fees.** To accelerate the production of renewable gas, landfill tipping fees should be increased to represent the true cost of disposal. Increases to the \$1.40 Integrated Waste Management tipping fee (state disposal fee) could be used to support the recycling of organic waste.
- **Minimize flaring of landfill gas.** The state should explore mechanisms to encourage landfills to transition from flaring, to capturing and converting renewable gas for use in transportation fuel. CARB should consider requiring landfill gas flares to meet stricter emission standards; those in the recently approved oil and gas regulation would be one mechanism.
- **Consider lessons learned from BioMAT.** The BioMAT program is set to expire February 2021. The CPUC should consider lessons learned from BioMAT and determine next steps.
- **Reduce methane through recycling of organic waste.** Senate Bill 1383 requires CalRecycle, in consultation with CARB, to develop regulatory requirements for cities, counties, and other entities to reduce short-lived climate pollutants and achieve waste reduction goals. To achieve this, CalRecycle and CARB should solicit public feedback in the regulatory process to determine cost-effective strategies for recycling organic waste and technologies for producing renewable gas. CalRecycle and CARB should determine methods for promoting the use of renewable gas from organic waste recycling in the waste sector.

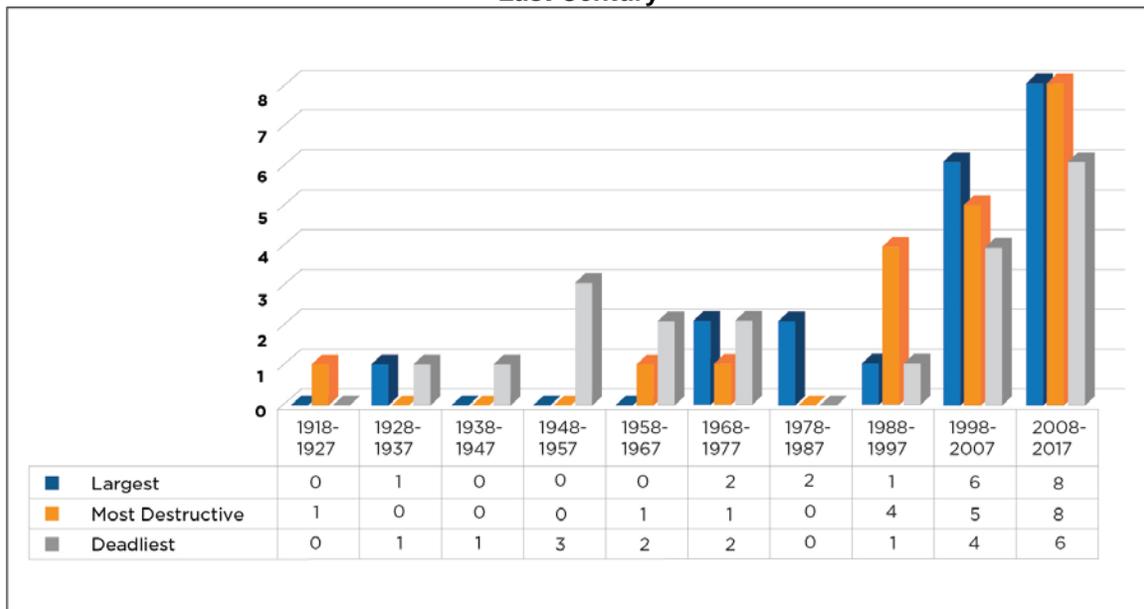
- **The Energy Commission should re-examine the status of renewable gas, including power-to-gas, as part of the Integrated Energy Policy Report in four years.**
- **See the recommendation in Chapter 8 to significantly expand the Energy Commission’s Natural Gas Research and Development program.** Several renewable gas technologies and systems may require further research, development, and demonstration to enable commercialization and reduce costs.
- **See Chapter 3 for further discussion on power-to-gas as a means to use excess renewable generation.**

CHAPTER 10: Climate Adaptation and Resiliency

Introduction

The energy sector (including transportation) contributes more than 80 percent of the annual greenhouse gas (GHG) emissions in California. This sector is also vulnerable to climate impacts, which have implications for energy reliability, affordability, and safety. For example, high temperatures will increase peak electricity demand for space cooling, decrease the efficiency of thermal power plants, reduce the performance of transformers and other electrical equipment, and reduce the energy demand for space heating. Sea-level rise will increase the risks of flooding of petroleum, natural gas, and electricity infrastructure in coastal areas. About half of the 20 largest and most destructive wildfires in California burned in the last decade with seven of the state’s largest, deadliest, and most destructive wildfires in 2017 alone. Figure 86 shows the deadliest and most destructive California wildfires since the early 1900s, clearly indicating the increasing toll that wildfires are having on Californians.

Figure 87: The Largest, Most Destructive, and Deadliest California Wildfires in the Last Century



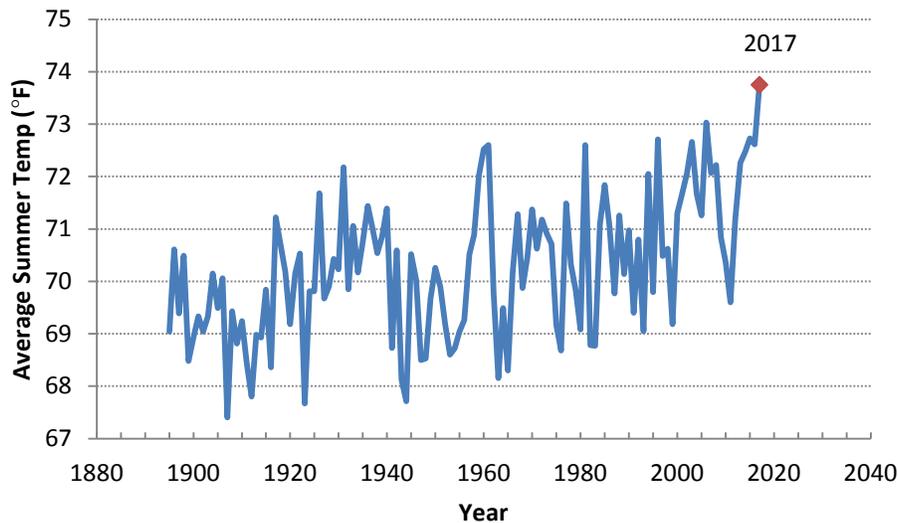
Source: California Energy Commission using data from http://cdfdata.fire.ca.gov/incidents/incidents_statevents. Note: The data for 2017 are preliminary. Last data update: acres (12-26-2017), destruction (12-21-2017), and deaths (11-29-2017).

As anticipated, temperatures in California are going up as a result of climate change. In 2014, California experienced its warmest annual average statewide temperature on record measured since about 1895. The winter of 2014 (December 2014–February 2015) is the warmest on record, while the 2014 summer was not unusually hot. In the summer of 2017, the record for maximum daily temperatures was broken in several cities, including San Francisco. Figure 87 shows the

statewide average summer temperatures (June, July, August). This figure shows that in 2017 California experienced its maximum summertime temperatures on record since 1895. Climate change will continue to produce record-breaking temperatures at local, regional, and statewide levels.

The degree of warming that will materialize in the rest of this century and beyond depends on past and future GHG emissions. It is imperative, therefore, to prepare the energy system for the climate changes already in the pipeline and for the changes expected from global emissions in the next decades.

Figure 88: Statewide Summer Average Temperatures: June, July, and August



Source: California Energy Commission staff using data from the California Climate Tracker

The United Nations Framework Convention on Climate Change⁶³⁰ identifies two responses to climate change: mitigation of climate change by reducing GHG emissions and enhancing sinks, and adaptation (or resilience) to the impacts of climate change. California has adopted the same approach, emphasizing that mitigation and adaptation complement and must reinforce each other. The main drivers of adaptation are rising sea levels, major storms, increasing temperatures, heat waves, wildfires, drought, subsidence, and other climatic changes. Finally, the term “resilience” in this chapter refers to impacts due to a changing climate, while the discussion of resilience in Chapter 3 focuses on the operation of the electricity grid as affected mainly by nonclimatic factors such as the increased penetration of intermittent sources of electricity.

This chapter builds on the discussion on climate adaptation for the energy sector from prior *Integrated Energy Policy Reports (IEPRs)*. This chapter overviews the policy context under which climate adaptation for the energy sector is evolving, summarizes preliminary discussions with community-based organizations and investor-owned utilities (IOUs) on “actionable

630 http://unfccc.int/files/essential_background/background_publications_htmlpdf/application/pdf/conveng.pdf.

science,”⁶³¹ and presents new information about climate projections and the development of climate-relevant parameters. Then it briefly discusses new scientific findings of relevance to the energy sector such as new projections for sea-level rise and the likelihood of achieving the Paris Agreement goal of not exceeding a global average temperature of 2 degrees Celsius (3.6 degrees Fahrenheit) from the preindustrial level. In light of the above information, this chapter presents concepts on how research may help lay the foundation to reduce impacts on disadvantaged communities. This chapter ends with policy recommendations to increase the likelihood of success of climate adaptation for the energy sector.

Policy Context for Adaptation in California’s Energy Sector

A recent article in the science journal *Nature*,⁶³² cosigned by Governor Edmund G. Brown Jr., argues that humanity has only about *three years* to start a robust decline of global carbon dioxide (CO₂) emissions to have a chance of meeting the Paris target of limiting global average temperatures below 2 degrees Celsius from preindustrial levels and pursuing efforts to limit the increase to 1.5 degrees Celsius from preindustrial levels.⁶³³ The authors of the *Nature* article estimate that global emissions cannot surpass between 150 and 1,050 gigatons of carbon dioxide (GtCO₂), after 2016. Governor Brown indicated, “It’s up to you and it’s up to me and tens of millions of other people to get it together to roll back the forces of carbonization and join together to combat the existential threat of climate change.”⁶³⁴ Others

Changes in the Federal Approach to Climate Change

The current administration in Washington D.C. has taken a different approach to climate change—whether in preparation for unavoidable consequences or dissemination of scientific information—from that of the State of California. The decision by the President of the United States to reverse course on the Paris Agreement could dangerously delay global efforts to reduce GHG emissions. Some of the major changes in federal policy could impact California’s efforts to prepare for climate change. Some of these changes are listed below:

- Disbandment of the federal advisory committee put together to assist with the preparation of the *2018 National Climate Assessment* and future assessments jeopardizes the intent of the Global Change Research Act of 1990 to prepare the nation for climate change by delivering these assessments every four years to the President and the Congress.
- The Trump administration recently abruptly ended a study commissioned to the National Academy of Sciences about the potential health effect to people living near coal mines in the Central Appalachia. Research papers have linked these mining activities with health impacts including lung cancer.¹
- The White House has proposed to cut funding for ARPA-E, which is a group in DOE developing new clean technologies and bringing them close to the marketplace. These technologies will be essential for the decarbonization of the U.S. energy system.

1 Hendryx, M., K. O’Donnell, and K. Hom. 2008. “Lung Cancer Mortality Is Elevated in Coal-Mining Areas of Appalachia.” *Lung Cancer*. Volume 62, Issue 1.

Hendryx (2012). Poverty and Mortality Disparities in Central Appalachia: Mountaintop Mining and Environmental Justice. *Journal of Health Disparities Research and Practice*. Vol. 4. Issue 3.

631 *Actionable science* is scholarship with the potential to inform decisions, improve the design or implementation of public policies, or influence public or private sector policies. (<https://www.sesync.org/actionable-science>.)

632 Figueres, C., J. J. Schellnhuber, G. Whiteman, J. Rockström, A. Hobley, and S. Rahmstorf., June 29, 2017. “Three Years to Safeguarding Our Climate.” *Nature*. Vol. 546.

633 United Nations. 2015. Paris Agreement. http://unfccc.int/files/essential_background/convention/application/pdf/english_paris_agreement.pdf.

634 Governor Brown on July 6, 2017, announcing the organization of a Climate Summit Meeting in California late in 2018 that will bring together leaders from around the United States and abroad.

have also made similar arguments about the existential nature of the climate problem that includes the possibility of catastrophic irreversible events.⁶³⁵

Yet, the current administration in Washington, D.C., has been hostile to efforts to protect the planet from a warming climate, prepare its citizens for unavoidable climate impacts, and disseminate scientific information about climate change. The decision by the President of the United States to abandon the Paris Agreement could dangerously delay global efforts to reduce GHG emissions. (See sidebar.) Not addressing climate issues puts California, the nation, the entire world, and future generations at risk of the potentially catastrophic consequences of climate change. California is a world leader in policies to reduce GHG emissions while adapting to the impacts of climate change.^{636, 637} This leadership is crucial for California's economy and the safety and health of its people.⁶³⁸

The safety, reliability, and affordability of California's energy sector are particularly sensitive to climate impacts. At the same time, the energy sector can play a significant role in GHG reductions.⁶³⁹ The immediate reduction of global GHG emissions can help California's energy sector adapt by reducing the frequency of

California Climate Adaptation Legislation

The 2016 *IEPR Update* summarized of the executive orders and legislation pertaining to climate change adaptation.¹ Highlights include the following:

- Senate Bill 379 (Jackson, Chapter 608, Statutes of 2015) requires local hazard mitigation plans to address the impact of climate change, supported by the California Adaptation Planning Guide.¹
- Assembly Bill 1482 (Gordon, Chapter 603, Statutes of 2015) mandated the California Natural Resources Agency (CNRA) to update the state's adaptation plan triennially. An update of this plan, known as the *Safeguarding California Plan* will be finalized in early 2018 following stakeholder input.
- Assembly Bill 2800 (Quirk, Chapter 580, Statutes of 2016) requires the impacts of climate change to be taken into consideration when planning state infrastructure projects. It also requires creation of a working group to develop a report to the Legislature by July 2018 about the engineering standards that should be updated considering future climatic conditions.
- Assembly Bill 398 (Garcia, Chapter 135, Statutes of 2017) extends the California Cap-and-Trade Program and makes "climate adaptation and resiliency" and "climate and clean energy research" eligible to received cap-and-trade funds.

¹ California Energy Commission. 2016. *2016 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2016-003-CMF.

635 Ramanathan, V., Molina, M.J., Zaelke, D., Borgford-Parnell, N., Alex, K., Auffhammer, M., Bledsoe, P., Collins, W., Croes, B., Forman, F., Gustafsson, Ö, Haines, A., Harnish, R., Jacobson, M., Kang, S., Lawrence, M., Leloup, D., Lenton, T., Morehouse, T., Munk, W., Picolotti, R., Prather, K., Raga, G., Rignot, E., Shindell, D., Singh, AK, Steiner, A., Thiemens, M., Titley, D.W., Tucker, M.E., Tripathi, S., Victor, D., and Xu, Y., . 2016.

636 California Energy Commission. 2016. *2016 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2016-003-CMF.

637 UN Climate Change Newsroom Release, "Incoming COP23 President Frank Bainimarama Joins Under2 Coalition Appoints California Governor Edmund Brown Special Advisor for States and Regions," June 14, 2017, retrieved from <http://newsroom.unfccc.int/cop-23-bonn/fijis-prime-minister-and-incoming-cop23-president-joins-under2-coalition/>.

638 *Safeguarding California Plan 2017 Update: California's Climate Adaptation Strategy*, draft report, <http://resources.ca.gov/wp-content/uploads/2017/05/DRAFT-Safeguarding-California-Plan-2017-Update.pdf>.

639 California Energy Commission. 2016. *2016 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2016-003-CMF.

extreme heat and similar events. To help achieve California’s climate and clean energy goals, state programs catalyze investment in new technologies, local planning for preparedness, and cross-jurisdictional sharing to promote a climate-responsive grid.

National and Subnational Context

California continues to expand formal and informal partnerships related to global climate change at home and abroad.⁶⁴⁰ Changes in federal climate change policy make California’s leadership even more important. Among many changes in federal policy, two in particular stand out for California’s energy sector and climate goals:

- The federal administration signaled it intends to withdraw⁶⁴¹ from the United Nations Framework Convention on Climate Change Conference of the Parties 21 (COP 21) “Paris Agreement,” which set a goal of limiting GHG emissions to a point that would theoretically “cap” global temperature increases to no more than 2 degrees Celsius.⁶⁴²
- The Partnership for Energy Sector Climate Resilience would be eliminated under the White House’s proposed budget cuts to the Office of Energy Policy and Systems Analysis in the U.S. Department of Energy.⁶⁴³ However, as of January 2018, the partnership continues its operations. At the same time, in California, SoCalGas and other utilities favor a California version of the U.S. Department of Energy partnership to complement the federal effort.⁶⁴⁴

640 Ibid.

641 <https://www.nytimes.com/2017/06/01/climate/trump-paris-climate-agreement.html>.

642 California Energy Commission. 2016. *2016 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2016-003-CMF.

643 <https://www.greentechmedia.com/articles/read/trump-budget-would-shutter-doe-policy-research-team-epsa>.

644 Comments submitted by SOCalGas on September 12, 2017 to Docket No. 17-IEPR-09.

Yet, strengthened cooperation among national and subnational jurisdictions around the world provides a basis for hope. The Under2 Coalition, formed under the leadership of Governor Brown, includes 205 jurisdictions from 43 countries.⁶⁴⁵ These subnational entities have agreed to limit GHG emissions 80 to 95 percent below 1990, or limit to 2 annual metric tons of CO₂ equivalent per capita, by 2050. In addition, the same day that the federal government announced it intends to withdraw from the Paris Agreement, the governors of California, Washington, and New York formed the United States Climate Alliance, thus pledging to work together to meet the goal of the Paris Agreement. Fourteen states and Puerto Rico have joined the partnership as of October 4, 2017.

State Efforts to Promote Climate Adaptation

In addition to aggressive GHG reduction targets, California is integrating climate adaptation into planning and investment decision-making. The California Natural Resources Agency (CNRA) summarizes the aim of these policies as “ensuring that people, communities, and natural systems are able to withstand the impacts of climate disruption.”⁶⁴⁶

Implications of Out-of-State Extreme Weather and Climate Change

Hurricane Harvey caused catastrophic flooding in Texas and the Louisiana Gulf Coast.¹ This area is home to important oil production facilities, refineries, and storage units. As discussed in Chapter 7 the impact of Harvey to the petroleum system in the Gulf Coast will affect prices of gasoline and diesel fuel in the United States, including California.²

The National Academy of Science issued a report in 2016 titled *Attribution of Extreme Weather Events in the Context of Climate Change*³ reporting advances and research needs for the nascent science of estimating the contribution of climate change to the actual manifestation of weather-related extreme events. This report indicated that it would be very difficult to determine the role that a warming planet would have had, if any, on the events in the Gulf Coast. However, some argue that warmer oceans can result in increased instances of extreme precipitation and may intensify coastal heavy precipitation. Water temperatures in the Gulf of Mexico were between 2.7 and 7.2 degrees Fahrenheit warmer than usual when Harvey started. Two recent studies published in late 2017 make a strong case connecting a warming climate to Hurricane Harvey.^{4,5} One of the studies concluded that “global warming made (Harvey’s) precipitation about 15 percent (8 percent to 19 percent) more intense, or equivalently made such an event (1.5 to 5) times more likely.”

1 It is important to remember the lessons of Gilbert White, father of modern hazard and risk studies, it is not just water that creates catastrophic flooding—rather the hazards in flooding come from how the built environment is planned and executed. See, e.g., White, G.F. 1945. Human Adjustment to Floods. Department of Geography Research Paper no. 29.

2 A recent study found that the likelihood of events such as Hurricane Harvey has increased substantially under the already manifested component of global warming. (Emanuel, K. 2017. Assessing the present and future probability of Hurricane Harvey’s rainfall. Proceedings of the National Academy of Sciences.)

3 National Academies of Sciences, Engineering, and Medicine. 2016. *Attribution of Extreme Weather Events in the Context of Climate Change*. Washington, DC: The National Academies Press. doi: 10.17226/21852.

4 Emanuel, K. 2017. Assessing the present and future probability of Hurricane Harvey’s rainfall. Proceedings of the National Academy of Sciences.

5 Geert Jan van Oldenborgh et al 2017. Attribution of extreme rainfall from Hurricane Harvey. Environ. Res. Lett. 12 124009

645 For the latest statistics, see <http://under2mou.org/>

646 <http://resources.ca.gov/climate/safeguarding/>.

Also, as highlighted in the *2016 IEPR Update*, the Energy Sector Adaptation Working Group – headed by Commissioner Liane Randolph of the California Public Utilities Commission (CPUC) and Chair Robert B. Weisenmiller of the Energy Commission – continues to meet every quarter to discuss how to advance climate adaptation for the electricity and natural gas systems. Other participants in this group from the Governor’s Office of Planning and Research, the CNRA, and the Office of Emergency Services, ensure overall coordination with other adaptation activities.

The energy agencies have also participated in other major climate adaptation activities. They were represented in the Technical Advisory Group created by the Governor’s Office of Planning and Research, created in compliance with Executive Order EO B-30-15, to develop guidelines on how state agencies should protect state infrastructure and plan for a changing climate.

Climate Research and Tools for California’s Energy Sector

This section provides an overview of California’s *Fourth Climate Change Assessment*, as well as two interactive climate information tools (Cal-Adapt and Climate Console) that are being used to inform climate adaptation in the state’s energy sector.

Kicked off in March 2016, California’s *Fourth Climate Change Assessment* is on track to deliver peer-reviewed results in the third quarter of 2018. The assessment includes 15 energy sector studies supported by the Energy Commission. These studies will:

- Develop rigorous, comprehensive climate change scenarios.
- Explore the use of probabilistic forecasts to improve energy sector management and operations as climate diverges from the historical observations that hitherto provided a reasonable basis for planning.
- Investigate regional and local vulnerabilities of the energy system to extreme events such as wildfires, extreme heat, drought, and flooding.
- Explore the interconnectedness of various facets of California’s energy system with other critical sectors and services.

California’s *Fourth Climate Change Assessment* is managed and supported jointly by CNRA, the Governor’s Office of Planning and Research, and the Energy Commission. CNRA is funding research on non-energy issues such as adaptation options to natural ecosystems and the identification of barriers to adaptation. The findings from the Fourth Assessment are scheduled to be available in time to inform development of the *2018 IEPR Update*.

Energy research and development programs administered by the Energy Commission provide statewide information that directly benefits natural gas and electric utility ratepayers. Results are publicly available and helpful for other California adaptation efforts, yet there is an unmet need for climate adaptation research specifically addressing concerns faced by publicly owned utilities’ (POUs’) customers.

One product of Energy Commission-funded climate adaptation research is Cal-Adapt, which makes scientific projections and analyses available as a basis for understanding local climate risks

and resilience options for the energy sector. Released in 2017, Cal-Adapt 2.0⁶⁴⁷ dramatically expands the capacities of the initial (2011) version of Cal-Adapt in five main ways:

- New climate projections
- More powerful and flexible visualizations
- Improved access to data
- A public applications programming interface (API) platform that enables external development of custom tools
- Connection with supporting resources such as the Governor’s Office of Planning and Research Integrated Climate Adaptation and Resiliency Program

The Energy Commission’s Major Adaptation Initiatives

The Energy Commission is fostering climate adaptation initiatives for the energy sector in multiple ways such as:

- Supporting development of a common set of climate scenarios for California for both research and long-term planning. These scenarios have been adopted for California’s *Fourth Climate Change Assessment* and for planning by state and local jurisdictions.
- Supporting studies on climate vulnerabilities and adaptation options for the energy sector including the natural gas, petroleum, and electricity systems in partnership with energy utilities.
- Making the common climate scenarios for research and long-term planning (described above), as well as other scientific results, relevant for energy sector vulnerability assessment and adaptation planning publicly available via Cal-Adapt.
- Supporting consideration of climate scenarios in the Energy Commission’s energy forecasts.
- Providing research leadership for California by leading the Climate Action Team Research Working Group. This group, headed by Chair Weisenmiller, meets every month to coordinate research and to discuss research initiatives.
- Participating in the Adaptation Working Group headed by the CPUC and the Energy Commission. This group meets every quarter.
- Supporting the development and demonstration of clean energy technologies designed to reduce GHG emissions.
- Investigating long-term energy scenarios for all sectors of the economy to inform achievement of GHG emission reduction mandates and development of an energy system less vulnerable to climate impacts.
- Considering climate change in the siting of new power plants and the promulgation of energy efficiency standards.

Visualizations on Cal-Adapt allow users to collect high-resolution climate information by census tract, watershed, climate zones, congressional district, utility service territories, counties, incorporated and census-designated places, and more. Furthermore, users can upload confidential boundary files for use in Cal-Adapt visualizations.

The Cal-Adapt 2.0 new datasets for climate projections, wildfire, snowpack, and a suite of hydrological variables use high-resolution climate projections developed by researchers at the Scripps Institution of Oceanography at the University of California, San Diego. The underlying technique, known as localized constructed analogues (or LOCA), was developed to address the limitations of prior methods with regard to representing temperature extremes and spatial distribution of precipitation. These improvements are critical because extreme temperature and

⁶⁴⁷ <http://cal-adapt.org/>.

precipitation events drive many of the economic and health-related impacts of climate change. The Cal-Adapt use of LOCA and LOCA-derived data align it with the scenarios identified for energy sector planning and research, as discussed in the *2016 IEPR Update*. Data on Cal-Adapt also align with the adaptation guidance for state agencies issued by the Governor's Office of Planning and Research, as directed by Executive Order B-30-15.

California IOUs that participated in the Department of Energy's Resilience Partnership used Cal-Adapt to support vulnerability assessments. More recently, as presented at the August 29, 2017, workshop, SDG&E described how it has used Cal-Adapt for initiatives to support resilient infrastructure, including design of a compressor station in Blythe (Riverside County), as well as investigation of design standards and system hardening. According to Adam Smith from Southern California Edison (SCE), a version of the Department of Energy Partnership to complement the federal effort could better address the fact that the state will need a "California-specific approach" for adaptation.⁶⁴⁸

As a publicly available tool, Cal-Adapt has been adopted by resilience initiatives beyond the electricity and natural gas sectors for which it was primarily developed. For example, the 2017 update of California's general planning guidelines point local governments to Cal-Adapt to support a statutorily required adaptation element of general planning. Similarly, the adaptation guidance from the Governor's Office of Planning and Research directs state agencies to Cal-Adapt as a supporting resource. The Climate Action Team's Research Working Group is exploring how to ensure that Cal-Adapt remains a stable resource to support resilience efforts through support from multiple state agencies or through a public-private partnership.

The California Climate Console⁶⁴⁹ is another tool available for integrating climate change into energy sector planning, with an emphasis on informing the siting of large renewable energy generation projects and transmission infrastructure. The Energy Commission and the Conservation Biology Institute developed Climate Console to provide relevant and actionable climate information that can be used to improve local and landscape-scale planning, landscape conservation, and climate adaptation. It was developed and used for the *Desert Renewable Energy Conservation Plan* – which spans 22.5 million acres in seven counties – to help in identify areas most appropriate for renewable energy development, and areas that are important for the long-term conservation of habitats and species in California's desert. (See Chapter 5 for more information.) Recent additions include statewide coverage of potential vegetation changes, streamflow, climatic water deficit, and the ability to explore the potential climate-driven effects on ecosystem carbon and biomass.

The Sacramento Municipal Utility District and the Los Angeles Department of Water and Power (LADWP), two of the largest POU's in California, are addressing climate adaptation, though many small POU's in California have not done so. At the August 2017 joint agency workshop on Climate

648 Presentation by Mr. Adam Smith. August 29, 2017, IEPR Joint Agency Workshop on Climate Adaptation and Resilience for the Energy System. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-09/TN221244_20170920T104023_Transcript_of_08292017_IEPR_Joint_Agency_Workshop_on_Climate_Ad.pdf. p. 104.

649 <http://climateconsole.org/ca>.

Adaptation and Resilience for the Energy System, a POU representative indicated, however, that tools like Cal-Adapt would allow them to examine the implication of climate change for their facilities.⁶⁵⁰

Actionable Science

Energy sector adaptation research is transitioning from improving general awareness about the potential dangers of a changing climate to the identification of specific, local adaptation actions to inform decision-making for the energy sector. Millions or billions of dollars may be needed to prepare for sea-level rise, major storms, flooding, increasing temperatures, heat waves, wildfires, drought, subsidence due to ground water depletion, changing snowpack conditions, and related impacts. Neglecting to implement climate adaptation measures is likely to be even more costly. Energy Commission adaptation research aims to provide timely information to economically prepare energy systems for climate impacts while responding to diverse needs of utilities and ratepayers, with a particular focus on disadvantaged and vulnerable communities across California.

Climate and climate adaptation research funded and managed by the Energy Commission places a priority on producing results that are “actionable” by end users. Actionable results are important to end users and relevant to their needs and considered rigorous within the scientific community.^{651, 652, 653, 654} In addition, the format and dissemination of results must simplify uptake and meet end users’ specifications. “Actionable” does not necessarily mean “acted on.” In other words, results may be salient to the needs of decision-makers/clients, but circumstances may prevent or delay incorporation into decision-making, policy, or operations.

Energy Commission research programs are designed to provide benefits for IOU ratepayers. Other key stakeholders include investor-owned utilities, the CPUC, and the California Independent System Operator (California ISO). Results also are used by other divisions within the Energy Commission, other state agencies, decision-makers in the executive and legislative branches of state government, local and regional planning organizations, community-based organizations, and the public.

Low-income communities and those communities already shouldering a disproportionate burden of environmental pollution will face the largest challenges preparing for climate change. Multiagency efforts are underway to increase dialogue, understanding, and resources to help meet

650 Transcript of presentation by Scott Tomaszewski representing the Northern California Power Agency. August 29, 2017, IEPR Joint Agency Workshop on Climate Adaptation and Resilience for the Energy System.

651 Cash, D., J. Borck, and A. Patt. 2006. “Countering the Loading-Dock Approach to Linking Science and Decision Making: Comparative Analysis of El Niño/Southern Oscillation (ENSO) Forecasting Systems,” *Science, Technology, & Human Values*. Vol. 31, Issue 4.

652 Pielke, R., and A. Sarewitz. 2005. “Bringing Society Back Into the Climate Debate.” *Population and Environment*. Vol. 26, Issue 3. Pp. 255–268.

653 Dilling, L., and M. Lemos. 2011. “Creating Usable Science: Opportunities and Constraints for Climate Knowledge Use and Their Implications for Science Policy.” *Global Environmental Change*. Vol. 21 Issue 2. Pp. 680–689.

654 Moser, S. C., and L. Dilling. “Communicating Climate Change: Closing the Science-Action Gap.” 2011. *The Oxford Handbook of Climate Change and Society*, Oxford University Press, Oxford Handbooks.

local needs and priorities for climate preparedness. The importance of this work is highlighted in *Safeguarding California 2014, Climate Change Research Plan for California 2015, Safeguarding Implementation Action Plans—Energy Sector Plan 2016, and the 2016 IEPR Update.*

The Energy Commission supports climate change adaptation research for the natural gas system, including three active research projects covering the San Diego region, the rest of Southern California, and Northern

California, covering roughly the geographical regions serviced by San Diego Gas & Electric, SoCalGas, and PG&E, respectively. In addition, the Energy Commission is a strong supporter of research on methods to estimate methane emissions from the natural gas system and on ways to drastically reduce these emissions. Since the natural gas system is underground, it offers some resilience to climate impacts; in fact, following recent extreme weather events such as Superstorm Sandy and Hurricane Harvey, the natural gas system provided an uninterrupted supply of gas that enabled emergency services and heating at critical facilities to continue when other fuel supplies were unavailable. Research is showing, however, that the natural gas system is at risk to other climate-induced impacts, such as ground subsidence after prolonged drought. Additional studies are needed to identify key vulnerabilities and ways to reduce or eliminate them.

The overarching theme of near-term, energy-related climate adaptation research outlined in the *Electric Program Investment Charge: 2018–2020 Proposed Triennial Investment Plan* is to increase the resiliency of the electricity system to climate change and extreme weather events. The CPUC approved the plan on January 11, 2018. In 2017, the Energy Commission and CPUC organized a series of joint meetings and workshops on actionable science for the energy sector, including discussion of best practices and potential research topics relevant to the IOUs and CPUC. (See sidebar “Key Meetings in 2017 That Helped Inform the Energy Commission’s Climate Science Efforts.”)

Key Meetings in 2017 That Helped Inform the Energy Commission’s Climate Science Efforts	
January 25-26, 2017:	The 2017 California Climate Science Symposium, Science to Safeguard California, hosted by the California Natural Resources Agency, California Environmental Protection Agency, and the Governor’s Office of Planning and Research. This included a breakout session titled, “Paradigm Shift: Moving Toward Collaborative Research for Environmental Justice, Equity and Climate Change.”
March 10, 2017:	Meeting on how to help make climate science research more actionable, discussion among Energy Commission and CPUC staff and IOU representatives.
April 11, 2017:	Lead Commissioner Workshop: Customers of Climate Science Research, held by the Energy Commission.
July 6, 2017:	En Banc Hearing on Environmental Justice and Disadvantaged Communities, hosted by the CPUC.
July 13, 2017:	Meeting to discuss climate justice, state agencies met with the Climate Justice Working Group.
August 29, 2017:	Joint Agency IEPR Workshop on Climate Adaptation and Resilience for the Energy System, held by the Energy Commission and CPUC.

While the Energy Commission supports research for the energy system, other state agencies such as the California Natural Resources Agency, the California Department of Water Resources, the California Department of Public Health, the California Department of Food and Agriculture, and CARB support climate studies for the other sectors of the economy.

The Energy Commission held a workshop April 11, 2017, on Customers of Climate Science Research⁶⁵⁵ to aid in developing the *Electric Program Investment Charge 2018–2020 Triennial Investment Plan*. This workshop was organized to strengthen coordination with IOUs, local governments, and other stakeholders and to ensure Energy Commission funding for energy-related climate science research provides actionable results to inform decision-making in California’s electricity and natural gas sectors. This workshop sought agreement from IOUs, local governments, and other user groups on research topics to help meet their needs for climate adaptation planning and implementation. A panel of high-level representatives from the IOUs, a POU, and environmental justice and energy equity advocacy groups provided comments on the presentations by state agency staff, discussed research priorities, and pledged their commitment to work together to prepare the energy sector for a changing climate.

The climate-related energy research program in the approved EPIC investment plan will be addressed through three approaches: investigating risks, increasing climatic knowledge, and boosting resilience. These approaches, and how they respond to the needs for actionable science expressed by end users, are described below.

Investigating Risks

The first initiative aims to improve understanding of risks to the energy sector and identify effective strategies to increase resilience. Topics for this initiative may include development of probabilistic forecasts of hydrological and meteorological parameters relevant for energy planning and operations; studies to detect changing climate conditions in California and to attribute the role of climate change in extreme weather events; and state-of-the science/art climate and sea-level rise scenarios for California’s *Fifth Climate Change Assessment*. PG&E commented at the April 11, 2017, workshop on the need to monitor and study snowpack and streamflow at high resolution because this energy resource varies significantly across time and space. This is also an issue for LADWP and SCE. SCE and PG&E identified a need to account for interdependencies and interactions among climate impacts (for example, identifying risks related to drought followed by severe flood) and across sectors (for example, when Hurricane Sandy triggered power outages that knocked out pumps at gas stations and wastewater treatment plants). PG&E identified a need to account for interdependencies throughout the energy supply chain across sectors and geography. It also recommended coordinating local community vulnerability assessments to include other services besides energy. Further, Melissa Lavinson, vice president of federal affairs and chief sustainability officer for PG&E, indicated that “we’re starting to develop internally what we’re calling our climate resilience screening tool. And we’re going to pilot that with some of our higher-end infrastructure investment projects ... the \$20

⁶⁵⁵ <http://www.energy.ca.gov/research/epic/17-EPIC-01/documents/#04112017>.

million-plus kind of projects, so that we're making sure that we're asking the right questions, ... so that before we make those investments, we've actually addressed the issue of climate change."⁶⁵⁶

This initiative will also develop methods to identify attractive adaptation methods considering deep uncertainty associated with climate change and other stressors. Studies will try to identify win-win strategies that are good options now and under a changing climate in the next 30-plus years, with a special emphasis on options to ease climate change impacts on disadvantaged communities. SCE, San Diego Gas & Electric (SDG&E), and PG&E all requested help at the workshop with developing and evaluating methods for cost-benefit analysis to assist in setting priorities for adaptation strategies.⁶⁵⁷ LADWP and the Asian Pacific Environmental Network (APEN) made suggestions for new equity metrics. LADWP suggested metrics related to adaptation spending, energy services, and outages within disadvantaged communities to look for patterns. APEN suggested metrics such as the percentage of households with air conditioners. APEN also recommended research and additional case studies on sensitivity of disadvantaged communities to power outages and surges, advanced energy storage in disadvantaged communities, identification of key infrastructure in need of reliable electricity (for example, food banks and shelters), and aging or retired energy infrastructure that may pose health and safety hazards. LADWP is using a set of equity metrics developed with input from community organizations that can serve as an example.⁶⁵⁸

Increasing Climatic Knowledge

The second initiative acknowledges the most renewable energy systems depend on climate factors, such as wind and cloud cover, that may be altered with climate change. As California transitions to a low-carbon energy system, the energy sector needs greater clarity about the interactions between renewable electricity generation and climate change. This was also expressed by PG&E among others at the August 29, 2017, workshop in its request for better science on atmospheric river forecasting for hydropower planning. As noted legal scholar and climate adaptation expert Robin Kundis-Craig notes in her principles for climate adaptation, knowledge is the foundation of adaptation and resilience.⁶⁵⁹

656 August 29, 2017, Joint agency workshop on Climate Adaptation and Resilience for the Energy System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-09/TN221244_20170920T104023_Transcript_of_08292017_IEPR_Joint_Agency_Workshop_on_Climate_Ad.pdf, p.203.

657 The U.S. Department of Energy noted at the August 29, 2017, IEPR workshop on Climate Adaptation and Resilience for the Energy Sector that it is a guidance document on adaptation cost-benefit analysis.

658 https://www.ladwp.com/ladwp/faces/ladwp/aboutus/a-financesandreports/au-fr-corporateperformance/au-fr-corporateperformance-emdi;jsessionid=47vjZ6rG1I9hbts5xLORhxy50dLvqM3BhnC2W75hhxH4gyTYcNBt!1227896423?_afLoop=337207535128265&_afWindowMode=0&_afWindowId=null#%40%3F_afWindowId%3Dnull%26_afLoop%3D337207535128265%26_afWindowMode%3D0%26_adf.ctrl-state%3Douzjovw4_4.

659 Craig, Robin Kundis. "Stationarity Is Dead" – Long Live Transformation: Five Principles for Climate Change Adaptation Law," March 2010. *Harvard Environmental Law Review*. 34:1, 9.

Boosting Resilience

The third initiative will integrate climate readiness into electricity system operations, tools, and models to bridge the gap between actionable science and new products to support the effective use of improved technical knowledge from other initiatives and similar efforts. Continued enhancement of Cal-Adapt will be central to this initiative, including with the addition of resilience tools for disadvantaged communities and for leveraging probabilistic forecasts to inform IOU operations and planning. All panelists at the April 11, 2017, workshop requested improvements in Cal-Adapt to enhance usefulness of the tool. There were several comments that Cal-Adapt data should be compatible with management and planning models used by the IOUs and that even integrating it into their GIS databases is a challenge that sometimes requires consultant assistance.

Impacts of 2017 Wildfires

California suffered a devastating outbreak of wildfires in the final months of 2017. Extreme winds in October drove a number of fires through subdivisions and vineyards in the Sonoma-Napa wine region. More than 40 people lost their lives in the fast-moving blazes. Figure 88 shows a satellite photo of the fires. The Tubbs Fire in this outbreak destroyed 5,643 structures, nearly doubling the previous record from the 1991 Tunnel Fire in the Oakland Hills. Between October 8 and 18, more than 359,000 PG&E customers lost electricity at various times.¹

Similarly, Santa Ana winds fanned a series of late season fires in Southern California in December, burning more than 1,000 structures and forcing tens of thousands of residents to evacuate. For the first time in its history, the Santa Ana Wildfire Threat Index issued a purple or "Extreme" wind warning. The Thomas Fire in this outbreak became the largest fire in California's history; at one point, the fire intermittently interrupted transmission lines into the Santa Barbara area, causing outages for more than 85,000 customers.²

The lateness of the fire in the fall did not allow much time for crews to stabilize the burned hillsides before the winter rains began. In January, 2018, an intense storm triggered devastating mudslides from the burned areas above Montecito, causing more than 20 deaths and destroying about 100 homes. The mudslides are also suspected of rupturing a natural gas pipeline, which sparked additional fires. At the request of the Santa Barbara County Fire Department, Southern California Gas interrupted gas service to 3,600 customers in support of emergency response efforts and after 15 days they restored service to 750 customers. The recent mudslides in the area also damaged water and sewage pipes. As a result, the more immediate health and safety hazard stems from the lack of water and sewage and has required residents to evacuate their homes.

These tragic events reflect changes in wildfires observed in recent years as a response to climate change. Fires have been getting larger and more destructive. Nine of the 20 largest California wildfires and nine of the 20 most destructive fires (in terms of structures destroyed) have occurred in the last decade, with 2017 being an especially bad year (as discussed at the beginning of the chapter). Fire behavior has also changed – leading to faster moving, more erratic fires.

The increasing risk from wildfires affects all Californians. Besides the heart-wrenching stories of people who have lost loved ones or their homes and possessions, Californians experience these impacts directly and indirectly. Smoke creates health hazards for vulnerable groups. Homeowners in rural areas have seen homeowners insurance premiums rise and policies become more difficult to obtain. Widespread power outages can result from either direct damage to power lines or from lines being de-energized by utilities during a fire for safety reasons. Californians all pay for the rising costs of fire suppression and restoration in the aftermath. In addition, the emissions from these fires threaten the state's GHG reduction goals. For instance, the 2013 Rim Fire burned 257,000 acres and released between 10 and 15 million metric tons, far more than the state was able to reduce from other sectors. In 2013–2015, wildfires on federal lands in California emitted an estimated 20–25 million metric tons of GHGs (carbon dioxide equivalent) per year.² Estimates for the 2017 fires are not currently available.

1 http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/Oct%209-26%20Unredacted%20Status%20Updates%20from%20PGE%20to%20CPUC.pdf.

2 <https://www.insideedison.com/stories/sce-crews-work-with-first-responders-to-gain-access-to-fire-damaged-areas>.

2 <http://www.sierranevada.ca.gov/our-board/board-meetings/2016dec/aixiwipatchb.pdf>.

Staff from the Energy Commission and the CPUC met with representatives from the IOUs on March 10, 2017. At this meeting, staff from the IOUs encouraged regular communication between researchers and end users such as utilities, so that the science addresses critical needs related to safe, reliable, and affordable energy service; is delivered in a format that can be immediately integrated into existing practices; and delivers pertinent information to the right people at the right time to affect decision-making and produce measurable results.

Moreover, there are several specific “asks” for improving resilience, raised by utilities at the August 29, 2017, IEPR workshop, as well as the April 11, 2017, workshop. Federal regulatory and administrative procedures for permitting transmission line rights-of-way and managing vegetation to reduce fire risk were identified at the August 29, 2017, IEPR workshop as a hindrance to resiliency. Even under today’s climate conditions, many transmission lines are exposed to wildfires. (See the sidebar “Impacts of 2017 Wildfires” and “Wildfires” section in Appendix G.) Risks to public safety due to wildfires are expected to increase with climate change.

Figure 89: Smoke Plumes From the Sonoma-Napa Cluster of Wildfires (October 9, 2017)



Source: NASA, <https://www.nasa.gov/image-feature/goddard/2017/wildfires-running-amok-in-california>, actively burning areas (or hot spots) are outlined in red.

Utilities are required to clear vegetation near lines to minimize line damage from fire in adjacent wildlands and to reduce the risk of transmission infrastructure igniting fires. This win-win strategy is sometimes hampered because of protracted permitting processes to perform this activity. PG&E noted that it can take months to renew existing rights-of-way and vegetation management plans from public land management agencies, especially where lines cross multiple

national forests and other public lands.⁶⁶⁰ Federal legislation is under consideration in the U.S. Senate to address this issue.⁶⁶¹ Similar issues can arise on private lands where permission must be obtained from many land owners. SDG&E obtained a “master special use” permit to combine 70 existing permits for electric facilities within the Cleveland National Forest with potential replacement of certain distribution lines to include fire hardening and undergrounding, or burying lines, of some facilities.⁶⁶²

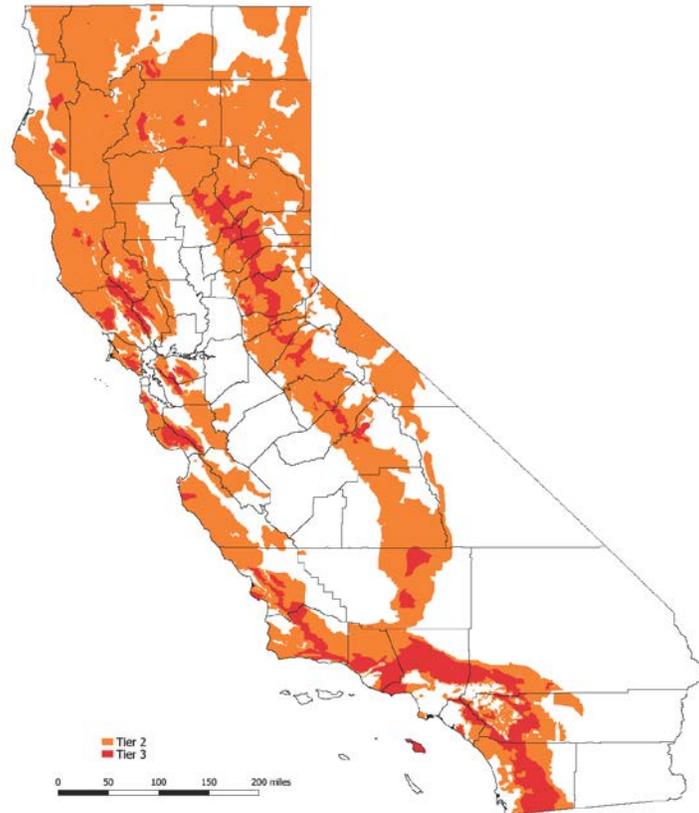
CPUC Rulemaking R.15-05-006 is generating a new high fire-threat district where utility infrastructure and operations will be subject to stricter fire-safety regulations. This new map will be a composite of Tier 1 high hazard zones on the U.S. Forest Service-California Department of Forestry and Fire Protection (CAL FIRE) joint map of Tree Mortality high hazard zones and Tier 2 and Tier 3 fire-threat areas on the CPUC fire-threat map. The CPUC fire-threat map was approved on January 19, 2018. (See Figure 89.)

⁶⁶⁰ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-09/TN221137_20170912T153802_Pacific_Gas__Electric_Comments_Pacific_Gas_and_Electric_Comment.pdf.

⁶⁶¹ S.1460, Energy and Natural Resources Act of 2017, introduced by Senator Lisa Murkowski (R-Alaska) on June 28, 2017.

⁶⁶² http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-09/TN220954_20170830T141705_Brian_D'Agostino_Comments_Master_Special_Use_Permit_in_place_fo.pdf.

Figure 90: CPUC Fire-Threat Map, Draft (January 19, 2018)



Source: CPUC, http://cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Safety/IRT-Approved%20Shape%20B%20Map%2011-17-2017.pdf

The state has anticipated the increased risk of wildfire and its impacts for over a decade through a series of climate change assessments. The First Assessment⁶⁶³ in 2006 projected that the risk of large wildfires could increase by as much as 55 percent. The Second and Third Assessments in 2009 and 2012 continued to refine the fire modeling under different climate scenarios and applied those results for an initial assessment of the vulnerability of the electricity transmission grid.⁶⁶⁴ The ongoing Fourth Assessment is updating the fire projections with the latest climate projections for California. These projections are being used in more sophisticated analysis of potential impacts on electricity, natural gas, and transportation fuel infrastructure and in determining adaptation measures to protect human life, natural resources, and energy infrastructure.

⁶⁶³ http://climatechange.ca.gov/climate_action_team/reports/first_assessment.html.

⁶⁶⁴ http://climatechange.ca.gov/climate_action_team/reports/climate_assessments.html.

Substantive and Procedural Needs for Actionable Resilience Research

As noted elsewhere in this chapter, resilience planning and implementation are not uniform across California. And, as climate impacts can be exacerbated by pre-existing inequities, there is a need to take a deliberate approach to equity in adaptation research to foster robust resilience.

Two events focused on climate change and equity inform the recommendations in this chapter. The first of these was an interactive breakout session at the 2017 Climate Science Symposium titled “Paradigm Shift: Moving Towards Collaborative Research for Environmental Justice, Equity and Climate Change.” That session – which included talks from Chair Robert B. Weisenmiller and Commissioner Janea Scott with the Energy Commission; Ms. Margaret Gordon with the West Oakland Environmental Indicators Project; Nahal Ghoghaie with the Environmental Justice Coalition for Water; and Anne Neville with the California Research Bureau – provided feedback to researchers, local and state government, NGOs, and community representatives on how to move the needle on climate adaptation through research for disadvantaged communities and vulnerable populations. Crucially, full scholarships were arranged for community members to attend and participate in the discussion and the symposium. The session produced extensive feedback and recommendations, which are being incorporated into *Safeguarding California*. Five frequent and overarching points from that session are that, to better address environmental justice and equity concerns in climate research, it is important to:

- Build relationships between researchers and community members through purposefully creating continual opportunities to encourage dialogue.
- Meet people where they are; consider terminology and linguistic and physical accessibility.
- Rely on partnerships with leaders and organizations that are trusted by the affected communities.
- Extend the “life” of research by starting engagement early and having a plan to continue partnerships and training beyond the formal close of the project.
- Make climate research local or locally relevant.

The second event, held July 13, 2017, was a discussion of the Climate Justice Working Group⁶⁶⁵ with state agencies on climate justice. The Climate Justice Working Group presented findings demonstrating who has and will bear the brunt of the impacts of climate change in California. For example, when analyzing extreme heat, Dr. Rachel Morello-Frosch and her research team found:

“Black, and especially Latino and Asian populations are more likely than Whites to live in heat-prone neighborhoods in U.S. urban areas, after controlling for ecologic factors that affect tree growth. Residential segregation increases the likelihood that all racial/ethnic groups will live in heat-prone neighborhoods. Poverty and home ownership do not explain these disparities. Segregation can marginalize populations into neighborhoods

⁶⁶⁵ Attendees included Climate Justice Working Group members and the names of the nonprofits, Resources Legacy Fund (convener of the CJWG), and Dr. Rachel Morello-Frosch, UC Berkeley.

with undesirable built environment characteristics. Climate change adaptation & mitigation should explicitly incorporate an environmental justice perspective to protect vulnerable urban populations.”⁶⁶⁶

The conclusions from these events will inform new adjustments to energy adaptation research (discussed later in this chapter). At Energy Commission workshops in 2017, participants suggested building on existing methods for collaboration in research – such as technical advisory committees and workshops – to develop practices that offered meaningful engagement early and throughout the research. Building and maintaining collaborative processes are key components of some “actionable” research, according to panelists from the APEN and LADWP. These processes are critical to disadvantaged communities’ access to and voice within the development of new climate adaptation and vulnerability research. The suggestions from these meetings were considered in developing the *Electric Program Investment Charge: 2018–2020 Proposed Triennial Investment Plan*.

In September 2017, PG&E announced its first two \$100,000 grants for local government climate resilience initiatives in Northern and Central California. The grants were awarded through PG&E’s Better Together Resilient Communities program.⁶⁶⁷ Also, PG&E announced a pilot program to reduce financial barriers to electric vehicles in disadvantaged communities in California’s Central Valley. The pilot program is offered by PG&E in partnership with Valley Clean Air Now and the International Brotherhood of Electrical Workers Local 684 and 100.⁶⁶⁸

Climate Projections for California and New Scientific Developments

In comments submitted to the *2016 IEPR Update* proceeding, IOUs emphasized the need to have a common set of climate projections for California for long-term planning. Multiyear research funded by the Energy Commission generated a set of California climate projections developed with methods reported in the peer-reviewed literature. These projections were adopted in the final *2016 IEPR Update*, and the Governor’s Office of Planning and Research plans to include them in the forthcoming *California Adaptation Planning Guide*. In 2015, the federal government further tested the method developed by Scripps for the Energy Commission and decided to use this method for the nation as a whole for the *2018 National Climate Assessment*.

Stakeholders and the CPUC are interested in translating the climate projections into information that the energy sector can use in management and planning. To ease this transition, the following sections describe technical considerations for using climate projections to develop climate-relevant parameters and provide some examples.

⁶⁶⁶ Presentation of Dr. Morello-Frosch, “The Climate Gap: Implications for Regulatory Decision-making to Advance Environmental Justice and Sustainability,” July 13, 2017, https://dornsife.usc.edu/assets/sites/242/docs/FacingTheClimateGap_web.pdf.

⁶⁶⁷ PG&E. September 6, 2017. “News Release: PG&E Awards \$200,000 in Grants to Support Local Climate Change Resilience Planning.”

⁶⁶⁸ PG&E. September 19, 2017. “News Release: PG&E Partners with Valley CAN and IBEW to Connect Underserved Communities with Electric Vehicles.”

Using Climate Projections for Energy Management and Planning

The climate projections discussed above include a range of weather and hydrological variables such as ambient temperature (at about 2 meters from the surface), snowpack levels, precipitation, surface wind speed, soil moisture, runoff, solar radiation, and relative humidity. The projections of some of these variables are more reliable than others, and some clear trends can be detected. For example, even though the agreement among models for precipitation is not high, the trend for derived variables that depend on temperature show a clear trend independent of what models are used (for example, fraction of precipitation that would fall as rain instead of snow, snow water equivalent).⁶⁶⁹

Climate Implications for Hydropower Planning and Operation for Climate Resilience

Recent events such as the historic drought and subsequent record rain year are bringing renewed attention to the need to take the changing climate into account in hydropower planning and operation. Such hydropower management practices could have benefitted energy bills⁶⁷⁰ and water security – by, for example, reducing releases from Folsom Dam during a multi-year drought and providing other benefits.

Some researchers have observed that outdated parameters are used for hydropower reservoirs that also have a flood control function.⁶⁷¹ For such reservoirs, the U.S. Army Corps of Engineers sets the operational parameters for how much water a reservoir can store and when.⁶⁷² Those parameters are called “rule curves.” The rule curves for the major dams in California were developed more than 60 years ago. They were based on historically observed climate and do not allow for regular changes in operation based on currently observed weather or short- or long-term weather forecasts.⁶⁷³ Computer models run by Willis and others, as well as separate studies by Georgakakos and others⁶⁷⁴ and funded by the Energy Commission, demonstrate that hydropower dams in California perform better for energy generation, water management, and environmental protection when operational rules incorporate short- and long-term weather and probabilistic climate forecasts. Changes to hydropower rules are necessary to adapt the system to climate change.

⁶⁶⁹ Pierce, D. W., and D. R. Cayan. 2012. “The Uneven Response of Different Snow Measures to Human-Induced Climate Warming.” *J. Climate*, Vol. 26. PP. 4148–67.

⁶⁷⁰ Gleick, P. 2016, *Impacts of California's Ongoing Drought: Hydroelectricity Generation 2015 Update*. <http://pacinst.org/publication/impacts-of-californias-ongoing-drought-hydroelectricity-generation-2015-update/>.

⁶⁷¹ Willis, A. D., J. R. Lund, E. S. Townsley, and B. A. Faber. 2011. “Climate Change and Flood Operations in the Sacramento Basin, California.” *San Francisco Estuary & Watershed Science*. Vol. 9, Issue 2, Article 3.

⁶⁷² Ibid.

⁶⁷³ Ibid.

⁶⁷⁴ Georgakakos, K. P., N. H. Graham, F.-Y. Cheng, C. Spencer, E. Shamir, A. P. Georgakakos, H. Yao, and M. Kistenmacher. 2012. “Value of Adaptive Water Resources Management in Northern California Under Climatic Variability and Change: Dynamic Hydroclimatology,” *J. Hydrology*. Vol. 412–413. Pp. 47–65.

Willis, A. D., J. R. Lund, E. S. Townsley, and B. A. Faber. 2011. “Climate Change and Flood Operations in the Sacramento Basin, California.” *San Francisco Estuary & Watershed Science*. Vol. 9, Issue 2, Article 3, pp. 34–46.

Furthermore, existing rules that allow, but do not mandate, climate considerations may not be sufficient motivation to encourage changes in operation. In a study of Federal Energy Regulatory Commission relicensing on the Yuba River, the author points out that the relicensing process allows the lead agency to incorporate climatic information, but in practice, the agency tends to shy away from doing so, even when relevant climate information is given to it.⁶⁷⁵

There are some positive steps being taken by hydroelectric stakeholders to update operations. The U.S. Army Corps of Engineers has indicated that it would be willing to incorporate atmospheric river forecasts into operations for reservoirs. Similarly, the operations rules for Folsom Dam are being renegotiated and may consider taking weather forecasts into account. And, in California, the Department of Water Resources is partially implementing a decision-support system for reservoir management that incorporates short- and long-term weather forecasts. However, each of these is only a partial solution. Further, because each hydropower dam has an operations manual, a set of stakeholders, and highly specific geography, updating rules will take additional site-specific studies to identify potential risks for continued use of outdated practices and inform decision-making.⁶⁷⁶

The IOUs operate their hydropower units using streamflow forecasts, but the forecasts (based mostly on statistical models) are not performing as well as desired for two main reasons:

- A changing climate is making the reliance on historical data less reliable.
- The water content measurement of the snowpack has significant errors.

The Energy Commission is addressing these concerns with a project installing advanced snow sensors with telemetry capabilities to provide much improved near-real-time estimations of the water content in the snowpack.⁶⁷⁷ PG&E is working very closely with the research teams from the University of California, Berkeley, and the University of California, Merced, on this project.⁶⁷⁸ In addition, the Energy Commission is funding a very promising study that is updating some IOU hydrologic models by using satellite data to determine the spatial extent of the snowpack; the updated models will then be able to better forecast streamflows where hydropower units operated by IOUs are located.⁶⁷⁹

675 Viers, Joshua H. 2011. "Hydropower Relicensing and Climate Change." *Journal of the American Water Resources Association*. Vol. 47 (4). Pp. 655–661.

676 See, for example, Willis, A. D., J. R. Lund, E. S. Townsley, and B. A. Faber. 2011. "Climate Change and Flood Operations in the Sacramento Basin, California." *San Francisco Estuary & Watershed Science*. Vol. 9, Issue 2, Article 3. And see, S. Ziaja. 2017. "Rules and Values in Optimization of California Hydropower." *Natural Resources Journal*. Vol. 57. Pp. 329–360.

677 Avanzi, Francesco. University of California, Berkeley and Merced. In-situ Measurements and Telemetry of the Snowpack to Improve Hydropower Operations in a Changing Climate. Presentation at the August 29, 2017, IEPR Workshop.

678 Freeman, Gary. Pacific Gas and Electric. What Additional Research Could Help the Investor Owned Utilities Cope with Climate Change for Hydropower Operations? Presentation at the August 29, 2017, IEPR workshop.

679 Margulis, Steven. University of California, Los Angeles. Using satellite data and in-situ measurements to improve the estimation of snowpack and snowmelt-driven runoff for hydropower generation. Presentation at the August 29, 2017, IEPR workshop.

Melissa Lavinson from PG&E indicated on August 29, 2017, that relicensing of hydropower units should consider climate change in recognition that hydrological changes are occurring and will continue to change with a warmer climate. She also indicated that PG&E would like to see the use of common data sets and models among agencies. The relicensing process can take about 10 years, but PG&E would like to see a faster process “because in the interim the project just continues to operate as it has operated for decades. So the delay getting through a relicensing process actually delays the implementation of the environmental upgrades.”⁶⁸⁰

New Scientific Developments Relevant to Planning and Research for Adaptation in the Energy Sector

Recent advances in climate science are highly relevant for energy sector planning in California. The sections below review the emerging knowledge in sea-level rise, reductions in carbon emissions needed to keep global temperatures from rising more than 2 degrees Celsius, and the cobenefits of reducing GHG emissions. The sections also review new developments on the social cost of carbon. Understanding the magnitude and rates of sea-level rise and extreme weather events is essential for estimating the vulnerability of energy system assets and adapting to the impacts of climate change. As discussed below, the degree and timing of future emissions reductions also play an important role in determining the impacts of climate change.

Updates From the Recent Scientific Literature on Sea-Level Rise

Scientific consensus is emerging about the contribution of different factors, such as the thermal expansion of the oceans to future sea-level rise.⁶⁸¹ However, scientists are still exploring the extent to which land-based ice in Antarctica is likely to shrink and cause additional sea-level rise.

Modeling calibrated with historical observations over the last several decades suggests that melting of land-based Antarctic ice will raise sea levels up to 12 inches (30 cm) by the end of this century.⁶⁸² However, this type of model cannot explain the large increases in sea levels in the paleoclimate record and does not simulate all the physical mechanisms that are believed to be important to predict such increases. As described in the *2016 IEPR Update*, modeling by Pollard and DeConto⁶⁸³ (including approximations for these physical mechanisms) is able to replicate what the scientific community believes happened before the Ice Age began 130,000 to 115,000 years ago. The projections by Pollard and DeConto for 2100 are an order of magnitude higher than those obtained with models not simulating plausible additional physical mechanisms (such as the linking of atmospheric warming with hydrofracturing of ice shelves and structural collapse of ice cliffs that can trigger rapid sea-level rise). These new projections are also in general

680 August 29, 2017, Joint agency workshop on Climate Adaptation and Resilience for the Energy System, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-09/TN221244_20170920T104023_Transcript_of_08292017_IEPR_Joint_Agency_Workshop_on_Climate_Ad.pdf, p.239-241.

681 Moore, J. C., A. Grinsted, T. Zwinger, and S. Jevrejeva, 2013, “Semi-Empirical and Process-Based Global Sea Level Projections,” *Rev. Geophys.*, 51, pp. 484–522.

682 Ritz, C., T. L. Edwards, G. Durand, A.J Payne, V. Peyaud, and R.C., Hindmarsh, 2015, “Potential Sea Level Rise From Antarctic Ice-Sheet Instability Constrained by Observations,” *Nature*, 3:528(7580):115-8. doi: 10.1038/nature16147.

683 DeConto, R. M. and D. Pollard. 2016. “Contribution of Antarctica to Past and Future Sea Level Rise,” *Nature*, Vol. 531.

agreement with new interpretations of expert elicitations⁶⁸⁴ and model simulations. However, it will most likely take years for the scientific community to reach a consensus about the contribution of Antarctica to sea-level rise in this century.

A growing number of scientific papers suggest the stability of at least some of the Antarctic ice sheets is already in jeopardy or will be in the near future.^{685, 686, 687} At the same time, there are a handful of scientific papers that suggest potential physical mechanisms such as the rapid discharge of freshwater from the top of the snow directly to the ocean without hydrofracturing the ice shelves that would reduce the discharge of ice to the ocean.⁶⁸⁸

The high level of uncertainty about what will happen in Antarctica is because there are physical processes that are not very well understood or there are not enough data to validate physical simulations,⁶⁸⁹ including the modeling work of DeConto and Pollard.⁶⁹⁰ The National Science Foundation and the United Kingdom's National Environmental Research Council are supporting a multimillion dollar, multiyear study in the West Antarctica Ice Sheet. This study – *How Much, How Fast?* – is “designed to improve our understanding of ice-ocean interaction and its impacts on the interior ice sheet dynamics within the framework of the continuing changes in Antarctic climate, oceanic circulation, and ongoing ice flow changes.”⁶⁹¹ The results of this ambitious study may reduce uncertainties associated with the contribution of West Antarctica to sea-level rise in the years to come.

To inform decision makers of advances in sea-level rise science, California's Ocean Protection Council convened a Science Advisory Team (SAT) in early 2017. Led by seven subject matter experts in various aspects of science related to sea-level rise, the SAT developed *Rising Seas in California: An Update on Sea-Level Rise Science*.⁶⁹² Extensive engagement of local governments as well as the public was integral to finalizing this peer-reviewed report, which will provide a scientific foundation for a forthcoming update to the Ocean Protection Council's sea-level rise guidance. The 2018 update to OPC's sea-level rise guidance document is expected early in 2018.

684 Jevrejeva, S., A. Grinsted, and J. C. Moore. 2014. “Upper Limit for Sea Level Projections by 2100,” *Environ. Res. Lett.* 9.

685 Gолledge, N. R., R. H. Levy, R. M. McKay, and T. R. Naish. 2017, “East Antarctic Ice Sheet Most Vulnerable to Weddell Sea Warming,” *Geophys. Res. Lett.* Vol. 44, Pp. 2343–2351.

686 Feldmann, J. and A. Levermann. 2015. “Collapse of the West Antarctic Ice Sheet After Local Destabilization of the Amundsen Basin.” *PNAS*. Vol. 112. No. 46.

687 Alley, K. E., T. A. Scambos, M. R. Siegfried, and H. A. Fricker. 2016. “Impacts of Warm Water on Antarctic Ice Shelf Stability Through Basal Channel Formation.” *Nature Geoscience*.

688 Bell R., W. Chu, J. Kingslake et al. 2017. “Antarctic Ice Shelf Potentially Stabilized by Export of Meltwater in Surface River.” *Nature*. Vol. 544.

689 Scambos, T. A., R. E. Bell, et al. 2017. “How Much, How Fast? A Science Review and Outlook for Research on the Instability of Antarctica's Thwaites Glacier in the 21st Century.” *Global and Planetary Change*.

690 Banwell, A., 2017, “Ice Shelf Stability Questioned,” *Nature*, Vol. 544.

691 Scambos, T. A., R. E. Bell, et al. 2017. “How Much, How Fast? A Science Review and Outlook for Research on the Instability of Antarctica's Thwaites Glacier in the 21st Century.” *Global and Planetary Change*.

692 Griggs, G., J. Árvai, D. Cayan, R. DeConto, J. Fox, H. A. Fricker, R. E. Kopp, C. Tebaldi, and E. A. Whiteman, (California Ocean Protection Council Science Advisory Team Working Group). 2017. *Rising Seas in California: An Update on Sea-Level Rise Science*. California Ocean Science Trust.

The update will speak to an expanded audience, including not only the state agencies who must incorporate sea-level rise considerations into their planning decisions under Executive Order S-13-08, but cities and counties that must comply with SB 379, which requires incorporation of climate change into their planning.

The report uses best estimates of likelihood by a group of experts using numerical experiments and expert elicitation. However, there is still some uncertainty in these estimates. For example, another group of experts based in Europe using more or less the same evidence as the SAT came out with higher sea-level rise projections to the end of this century.⁶⁹³

California's *Fourth Climate Change Assessment* is also using expert elicitation to generate "probabilistic" climate projections. By design, these projections are more precautionary and use new modeling results quantifying the potential rapid demise of Antarctic land-based ice mass. Boston has adopted a similar approach.⁶⁹⁴ The SAT felt that there is a need for more evidence before these new modeling results can be used for regulatory and planning purposes. At the same time, the SAT did not rule out the possibility of rapid increases in sea-level rise with a substantial contribution from Antarctica. To acknowledge this possibility, the team included an extreme scenario of 10 feet regionally in California by 2100, which is close to the upper limit being used for the California Assessment. The SAT suggests that this upper limit should be used for critical long-lived infrastructure.

The new sea-level rise projections are very important to the energy system because the greater the extent of sea-level rise, the greater the proportion of coastal energy facilities (such as substations, pipelines, and refineries) affected. This would change the scope of adaptation measures to be identified and implemented. Prior studies looking at the vulnerability of California's energy system were based on sea-level rise of up to 1.4 meters. The new projections are much higher and include the possibility of up to almost 10 feet (about 3 meters) under an extreme but physically plausible scenario. Ongoing Electric Program Investment Charge-funded research⁶⁹⁵ by ICF is assessing the potential impacts of various sea-level rise projections on the electricity and natural gas sectors in the SDG&E service territory. This assessment will include the costs of disruptions from sea-level rise, the pros and cons of potential adaptation measures, and guidance for designing and siting new energy facilities to account for sea-level rise.

Carbon Budget for Two Degrees Celsius Ceiling

Several scientific publications document that global mean warming is proportional to cumulative carbon dioxide (CO₂) emissions, globally,^{696, 697} regionally,⁶⁹⁸ and within California.⁶⁹⁹ This

693 Grinsted, A., S. Jevrejeva, R. E. M. Riva, and D. Dahl-Jensen. 2015. "Sea-Level Rise Projections for Northern Europe Under RCP8.5." *Climate Research*. Vol. 64:15-23.

694 Boston Research Advisory Group. 2016. *Climate Ready Boston: Climate Change and Sea Level Rise Projections for Boston*. <http://www.bu.edu/earth/files/2016/06/Climate-Ready-Boston.pdf>.

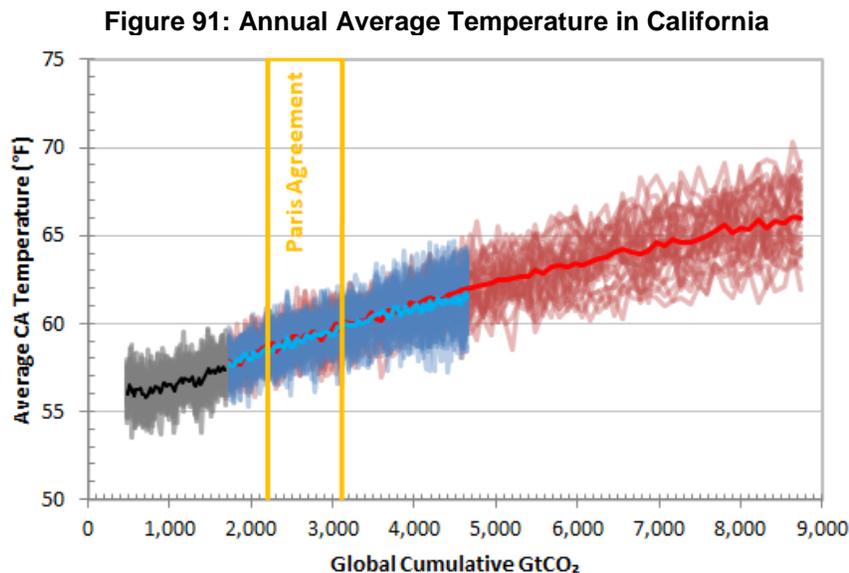
695 D'Agostino, Brian. San Diego Gas & Electric. Status of Research Project About Climate Vulnerability and Adaptation Options for San Diego Gas and Electric: Lessons Learned. Presentation at the August 29, 2017, IEPR workshop.

696 Matthews, H. D., N. P. Gillett, P. A. Stott, and K. Zickfeld. 2009. "The Proportionality of Global Warming to Cumulative Carbon Emissions." *Nature*. 459(7248). Pp. 829–832.

result – that warming scales roughly linearly with cumulative carbon emissions independently of emissions pathway – is also observed in high-resolution downscaled projections (LOCA) for California with regard to snowpack and soil moisture.

The linearity of global temperatures with cumulative emissions has been used to estimate how much more carbon, and therefore CO₂ emissions, could still be emitted to the atmosphere to remain below 2°C warming relative to temperatures before the industrial revolution.

The *2016 IEPR Update* showed that temperatures in California scale almost linearly with global CO₂ emissions. Figure 90 uses this finding to estimate the overall warming associated with additional cumulative CO₂ emissions of 150 and 1,050 GtCO₂ from 2016 that, as indicated before, is the allowed carbon budget that permits compliance with the temperature targets in the Paris Agreement. The vertical lines show the warming expected in California for this range of cumulative CO₂ emissions for the annual average of temperatures. As shown in Figure 90, achieving the Paris Agreement would avoid more severe levels of climate change, but a substantial amount of warming between 1.6 degrees Fahrenheit and 2.8 degrees Fahrenheit above the 1976–2005 average is expected, even if the Paris target is achieved. The red and blue lines in this figure represent the average of multiple outputs from different global climate models with the associated ranges shown in the red and blue areas for the RCP8.5 and RCP4.5 global emission scenarios, respectively.



Source: California Energy Commission staff using data provided by Scripps Institution of Oceanography.

697 IPCC. 2013. "Summary for Policymakers," in *Climate Change 2013: The Physical Science Basis. Contribution of Working Group I to the Fifth Assessment Report of the Intergovernmental Panel on Climate Change*, edited by T. Stoker et al., Cambridge Univ. Press, Cambridge, U.K., and New York.

698 Leduc, M., H. D. Matthews, and R. de Elia. 2016. "Regional Estimates of the Transient Climate Response to Cumulative CO₂ Emissions." *Nature Climate Change*.

699 (See Figure 90.)

The University of California released a report in 2015 titled *Bending the Curve*,⁷⁰⁰ with a roadmap for global action for carbon neutrality showing that it is still possible to safeguard the climate and limit global average temperature below 2 degrees Celsius in compliance with the Paris Agreement. However, the window of opportunity to limit warming in this century below 2 degrees Celsius is almost gone without massive deployment of technologies extracting CO₂ from the atmosphere.^{701, 702, 703}

The impacts to California under a 2 degrees Celsius world would represent the most optimistic scenario for the energy system but still with substantial impacts. For example, the Sierra snowpack, which serves as a natural reservoir for high-elevation hydropower units, would be expected to diminish by less than half, with most models suggesting less than 30 percent loss relative to 1961–1990 baseline. Prior studies suggest that reductions in the snowpack are associated with an increase in streamflows in the winter and reductions in the spring and summer, when hydropower is needed to satisfy peak electricity demand for space cooling. Higher flows in the winter could substantially increase the risk of flooding.

Cobenefits of Reducing GHG Emissions

Reducing global GHG emissions in the near future can also help reduce emissions of air pollutants such as oxides of sulfur, oxides of nitrogen (NO_x), and volatile organic compounds.⁷⁰⁴ An analysis of the public health effects of the Clean Power Plan initiative under the Obama Administration suggest that the plan would have resulted in a public health benefit as high as \$400 billion in 2006 dollars.⁷⁰⁵ Another study found that reducing GHG emissions at the global scale would substantially reduce the intercontinental transport of air pollution from Asia to North America.⁷⁰⁶ This is important because transport of pollution from Asia has been found to seriously limit the ability to comply with air quality standards in California.⁷⁰⁷ A recent study⁷⁰⁸

700 Ramanathan, Veerabhadran, Juliann E. Allison, Maximilian Auffhammer, David Auston, Anthony D. Barnosky, Lifang Chiang, William D. Collins, Steven J. Davis, Fonna Forman, Susanna B. Hecht, Daniel Kammen, C.-Y. Cynthia Lin Lawell, Teenie Matlock, Daniel Press, Douglas Rotman, Scott Samuelsen, Gina Solomon, David G. Victor, and Byron Washom. 2015. *Bending the Curve: 10 Scalable Solutions for Carbon Neutrality and CLIMATE STABILITY*, Executive Summary. Published by the University of California, October 27, 2015.

701 Field, C.B. and K. J. Mach. 2017. "Rightsizing Carbon Dioxide Removal." *Science*. Vol. 356, Issue 6339.

702 Ramanathan, V., Molina, M. J., Zaelke, D., Borgford-Parnell, N., Xu, Y., Alex, K., Auffhammer, M., Bledsoe, P., Collins, W., Croes, B., Forman, F., Gustafsson, Ö, Haines, A., Harnish, R., Jacobson, M. Z., Kang, S., Lawrence, M., Leloup, D., Lenton, T., Morehouse, T., Munk, W., Picolotti, R., Prather, K., Raga, G., Rignot, E., Shindell, D., Singh, A. K., Steiner, A., Thiemens, M., Titley, D. W., Tucker, M. E., Tripathi, S., & Victor, D. *Well Under 2 Degrees Celsius: Fast Action Policies to Protect People and the Planet From Extreme Climate Change*, 2017. Available at <http://www-ramanathan.ucsd.edu/about/publications.php> and www.igsd.org/publications/.

703 Xu, Yangyang, and Veerabhadran Ramanathan. August 2017, Well Below 2°C: Mitigation Strategies for Avoiding Dangerous to Catastrophic Climate Changes. *Proceedings of the National Academy of Sciences of the United States of America*. Vol. 114 No. 39. 10315 – 10323, doi: 10.1073/pnas.1618481114.

704 Shindell, D., J. C. I. Kuylenstierna, E. Vignati, R. van Dingenen, et al. 2012. "Simultaneously Mitigating Near-Term Climate Change and Improving Human Health and Food Security." *Science*. 335: 183-189.

705 Thompson, T. M., S. Rausch, R. K. Saari, and N. E. Selin. 2014. "A System Approach to Evaluating the Air Quality Co-Benefits of U.S. Carbon Policies." *Nature Climate Change*. 4:917-923.

706 Lin, J., D. Pan, S. J. Davis, et al. 2014. "China's International Trade and Air Pollution in the United States." *PNAS*.

707 Parris, D.D., L. M. Young, M. H. Newman, K. C. Aikin, T. B. Ryerson. 2017. "Ozone Design Values in Southern California's Air Basins: Temporal Evolution and U.S. Background Contribution." *J. of Geophysical Research: Atmospheres*.

confirms this finding and suggests that in the United States, the public health benefits of global reductions of GHG emissions are staggering, negating any potential cost associated with mitigation (reduction of GHG emissions). This is because global reductions of GHG emissions also reduce global emissions of conventional air pollutants and of intercontinental transport of pollution to the United States. Other studies have quantified net impact to crop yields reporting similar net positive economic results.⁷⁰⁹ However, GHG reductions are not always associated with similar levels of reductions of air pollutants. For example, if all the CO₂ emissions from power plants in California are eliminated, CO₂ emissions would go down by about 14 percent; however, statewide NO_x emissions would only go down by about 1 percent.

The synergies between methane emissions reductions from the natural gas system and safety should be harnessed. Taking care of safety issues could avoid catastrophic releases of methane to the atmosphere, as with the Aliso Canyon incident. At the same time, the early detection of leaks could bring attention to situations that could become catastrophic without early intervention. For example, current Energy Commission and CARB-sponsored research is measuring methane from various sources, including landfills, industrial facilities, refineries, pipelines, compressor stations, and other infrastructure, using a specially instrumented aircraft. This research has also identified safety issues that were able to be immediately remedied. (See Chapter 8, “California Storage and Related Issues” and “Methane Leakage in the Natural Gas System” and Chapter 11, “2017 Aliso Canyon Natural Gas Storage Facility Energy Reliability Issues” for more information.)

Climate adaptation measures for the natural gas system may also have safety implications. For instance, the Energy Commission funded UC Berkeley to assess potential natural gas pipeline risks related to flooding, soil and debris movement, and sea-level rise in the Sacramento-San Joaquin Delta.⁷¹⁰ Adaptation measures should substantially reduce these risks that could arise with sea-level rise. PG&E partnered with UC Berkeley on this study and will use the results of this and other research to “better understand, plan for, and respond to future climate change risks.”⁷¹¹

Social Cost of Carbon

The social cost of carbon (SCC) is the estimated economic net damage or cost of a unit of carbon dioxide emissions or the climate equivalent of other greenhouse gases emitted to the atmosphere. There have not been major breakthroughs in the literature with respect to SCC, but a major

708 Zhang, Y., S. J. Smith, J. H. Bowden, Z. Adelman, J. West. 2017. “Co-benefits of Global, Domestic, and Sectoral Greenhouse Gas Mitigation for U.S. Air Quality and Human Health in 2050.” *Atmos. Chem. Phys.* 16, 9533-9458.

709 Capps, S., C. Driscoll, H. Fakhrae, P. Templer, K. Craig, J. Milford, and K. Lambert. 2016. “Estimating Potential Productivity Cobenefits for Crops and Trees From Reduced Ozone With U.S. Coal Power Plant Carbon Standards.” *Journal of Geophysical Research: Atmospheres*. Vol. 121, Issue 24.

710 Radke, J. D., G. S. Biging, M. Schmidt-Poolman, H. Foster, E. Roe, Y. Ju, O. Hoes, T. Beach, A. Alruheil, L. Meier, W. Hsu, R. Neuhausler, W. Fourt (University of California, Berkeley). 2017. *Assessment of Bay Area Natural Gas Pipeline Vulnerability to Climate Change*. California Energy Commission. Publication number: CEC-500-2017-008. <http://www.energy.ca.gov/2017publications/CEC-500-2017-008/CEC-500-2017-008.pdf>.

711 http://docketpublic.energy.ca.gov/PublicDocuments/17-EPIC-01/TN216744_20170329T150640_Valerie_Winn_Comments_Pacific_Gas_and_Electric_Current_and_Pote.pdf. For example, from the prior reference “Based on the modeled inundation predictions, researchers and PG&E gas pipeline operators formulated preliminary cost estimates and strategies for avoiding and lessening damage to PG&E-operated natural gas infrastructure.”

review by the National Academy of Sciences suggests important changes on how SCC should be estimated. The National Academy suggests the creation of four interconnected modules: the socioeconomic module, the climate module, the damage module, and the discounting module. This new framework arises out of a disciplinary mismatch in prior SCC work. Past SCC estimations have been done by economists, while the process used to estimate SCC involves simulation of natural systems more in the purview of physical scientists, such as climatologists, agricultural experts, hydrologists, and engineers. The estimation of SCC also requires the simulating of human systems that would also benefit from the participation of social scientists.

The current SCC used by federal agencies is relatively low (for example, \$42 per ton of CO₂ in 2020 in 2007 dollars using a 3 percent discount rate)⁷¹² and does not capture the severity of impacts of GHG emissions predicted by the vast majority of physical scientists. This is due mostly to the nature of the models that were used to estimate SCC that assumes perfect economic markets and perfect adaptation. Some damages are not quantified (such as large biodiversity losses), or the quantification of these damages is subject to debate on ethical and practical grounds.⁷¹³ Finally, some SCC models may not properly consider extreme and irreversible damages, such as the collapse of ice sheets in Antarctica.⁷¹⁴ For all these reasons, some argued that the real SCC must be much higher with, perhaps, a lower bound of \$125 per ton of CO₂.⁷¹⁵

Given the policy relevance of SCC, some prominent economists and lawyers⁷¹⁶ argued their preference for the continued use of SCC in opposition to President Trump's Executive Order 13783 disbanding the Interagency Working Group on the Social Cost of Greenhouse Gases. This executive order ordered federal agencies to monetize climate effects using "the best available science and economics" using appropriate discount rates," which most likely implies a direction to use high discount rates that substantially lower the present value of future damages.

Separately, at the state level, the CPUC recently adopted an interim GHG adder for estimating the cost-effectiveness of distributed energy resources, such as energy efficiency, that do not emit GHGs. The interim GHG adder, which was adopted as part of the CPUC's Integrated Distributed Energy Resources proceeding, is intended to estimate the costs of reducing emissions to achieve the state's 2030 GHG target. The interim GHG adder is set to the Cap-and-Trade Program's Allowance Price Containment Reserve price, while the CPUC's Integrated Resource Planning proceeding engages in modeling to identify the optimal mix of resources and associated marginal costs to reduce GHG emissions in the electric sector. These values represent costs for abatement and not avoided damages, as is the case with SCC.

712 <https://19january2017snapshot.epa.gov/climatechange/social-cost-carbon.html>, accessed on August 30, 2017.

713 Ackerman, F., E. A. Stanton, C. Hope, and S. Alberth. 2009. "Did the Stern Review Underestimate U.S. and Global Climate Damages?" *Energy Policy*. Vol. 37. Pp. 2717–2721.

714 Weitzman, M. .L. 2013. "Tail-Hedge Discounting and the Social Cost of Carbon." *J. Econ. Lit.* Vol. 51. Pp. 873–882.

715 Van den Bergh, J. C. J. M. and Botzen, W. J. W. 2014. "A Lower Bound to the Social Cost of CO₂ Emissions." *Nature Climate Change*. Vol. 4. Pp. 253–258.

716 Revesz, R., M. Greenstone, M. Hanemann, M. Livermore, T. Sterner, D. Grab, P. Howard., and J. Schwartz. August 18, 2017. "Best Cost Estimate of Greenhouse Gases." *Science*. Vol. 357. Issue 6352. Pp. 665.

Identification of Climate-Relevant Parameters for the Energy System

For this chapter, *climate relevant parameters* are actionable weather or climate metrics used for the design, management, operation, or planning of the energy system. For example:

- To estimate the amount of energy (megawatt-hours) that would be required for a certain period for space cooling in homes and buildings, climate forecasters in energy utilities and within the Energy Commission uses a parameter called *cooling degree days* (CDDs).
- To determine the peak electricity generating capacity (megawatts) that should be available for the hot months of the year, forecasters may use the 95th percentile of the maximum temperatures (“1-in-20”) measured in a given meteorological station (or weighted average of multiple stations) in the last 30 years.
- To select specifications for the wires to be used for transmission lines, engineers usually use the maximum temperature measured along the path where the wires will be installed. This is done to ensure that the combination of multiple factors, including ambient temperatures, does not result in levels of sagging that could create safety problems.

These are examples of climate-relevant parameters. Such parameters are usually estimated using historical data from meteorological stations or inferred from an existing network of stations.

Using *only* historical data to achieve robust and safe outcomes for the energy sector, however, is not reliable under a changing climate. For example, the 2006 heat wave experienced in California is assumed to be a highly unusual event with a very low probability of occurring in the future (perhaps a 1-in-500 year event or higher than the 99th percentile) based on historical data. Yet multiple studies have shown climate change will substantially increase the odds of this type of event in the future.⁷¹⁷

How, then, can energy stakeholders develop more robust climate-relevant parameters? One option is using, as a guide, scientifically vetted climate projections. As discussed above, California has a set of peer-reviewed climate projections. These climate scenario projections can be used to estimate how energy-relevant climate parameters would change in the future in California. Also, sensitivity analysis can be conducted by studying the sensitivity of each parameter to the choice of global climate model and emissions scenario.

Energy Commission staff is working with practitioners in the energy sector to identify climate-relevant parameters. Ideally, climate-relevant parameters would be defined in quantitative ways (such as the standard equation for calculating CDDs for specific locations for different time frames for example, annually or during only the hot months of the year). In some cases, the climate parameters are not that obvious. In these cases, qualitative descriptions are adequate as long as these descriptions can be translated in quantitative terms to estimate the probability of similar events occurring in the future. The 2006 heat wave may be an example where a qualitative

⁷¹⁷ Rahmstorf, S. and D. Coumou. 2011. “Increase of Extreme Events in a Warming World.” *Proceedings of the National Academy of Science of the USA*. 5pp. doi:10.1073/pnas.1101766108.

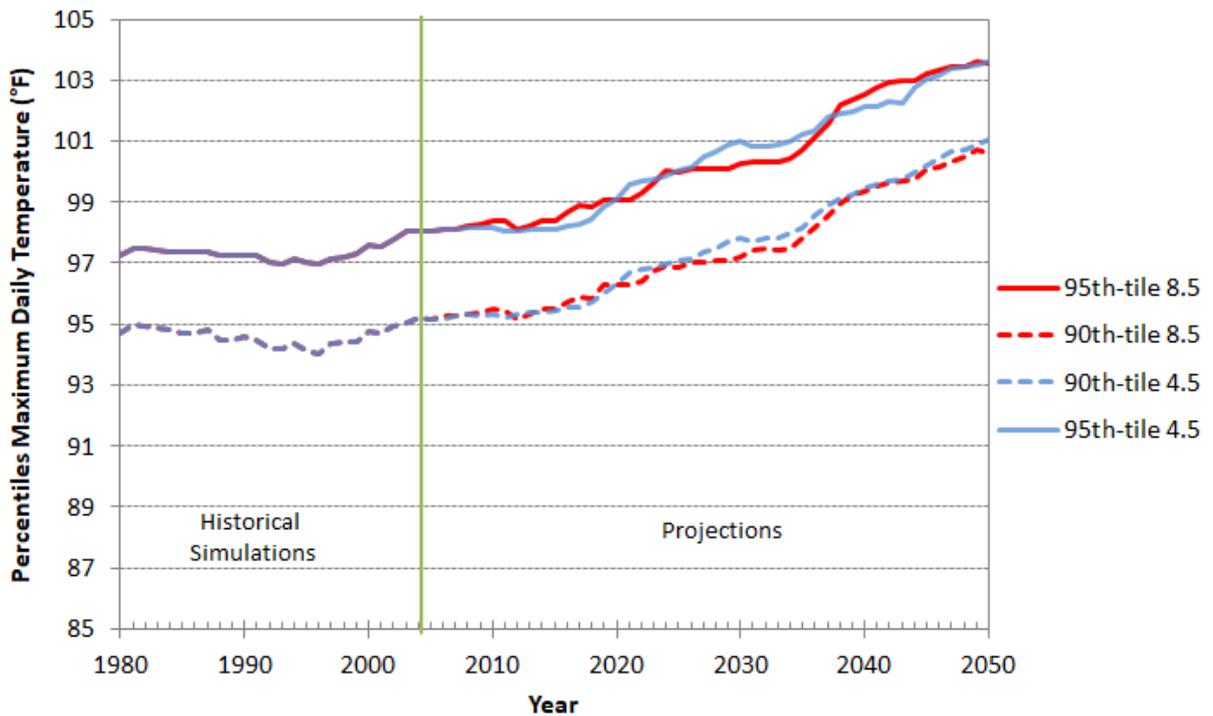
description would suffice – indicating that it lasted for several days; conditions at night were very humid and very hot; and the heat wave covered the entire state (thereby preventing the exchange of electricity between the utilities because they were all at peak demand). Using the historical record, this qualitative description can be translated in quantitative terms such as number of days, minimum (maximum) temperatures at specific times, levels of relative humidity, and spatial coverage.

The sections below present examples of climate-relevant parameters identified with assistance from the Energy Commission’s Demand Forecasting Office.

1-in-10 and 1-in-20 High Temperatures: Stockton

The Demand Forecasting Office estimates 1-in-10 (90th percentile) and 1-in-20 (95th percentile) events in about 16 meteorological stations distributed in California. One of these stations is in Stockton. In consultation with the Demand Forecasting Office, staff from the Energy Research and Development Division estimated how the two climate-relevant parameters would change up to 2050. Staff used maximum daily temperatures for May, June, July, and August for the prior 30 years. For example, in Figure 91 the 95th percentile for 1980 is calculated using data from 1950 to 1979 for about 3,600 days.

Figure 92: Thirty-Year 90th and 95th Percentiles of Maximum Daily Temperatures for Stockton



Source: California Energy Commission using data from Scripps Institution of Oceanography, July 25, 2017.

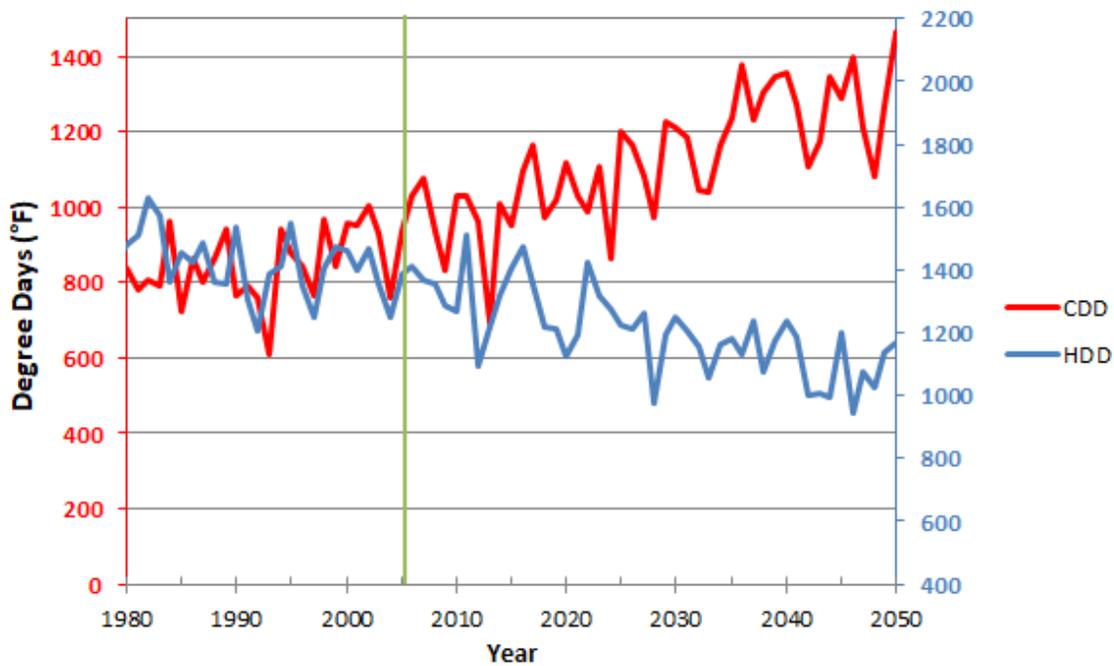
In Figure 91, values before 2005 are simulations of the historical period, and after 2006, the percentiles assume global GHG emissions that follow the RCP4.5 and RCP8.5 scenarios. The

percentiles depend on global GHG emissions, but the departures of these percentiles are relatively minor. It is clear from this figure that long-term planning, assuming stationary numbers for the percentiles, will underestimate the demand for electricity capacity in the rest of this half of this century.

Cooling and Heating Degree Days: Stockton

CDDs measure the departure of ambient temperature above a reference temperature, usually 65 degrees Fahrenheit. As indicated before, roughly speaking the demand for space cooling is proportional to CDD. *Heating degree days* (HDDs) measure departures for temperatures below the same reference temperature. Figure 92 shows a marked increase in CDDs in the rest of this half of this century and significant decreases but a less pronounced trend for HDDs. This agrees with the historical record provided by the National Oceanic Atmospheric Administration showing more dramatic changes for CDDs than HDDs in the last decades in California.

Figure 93: Potential Increases in CDDs and Decreases in HDDs in Stockton, California

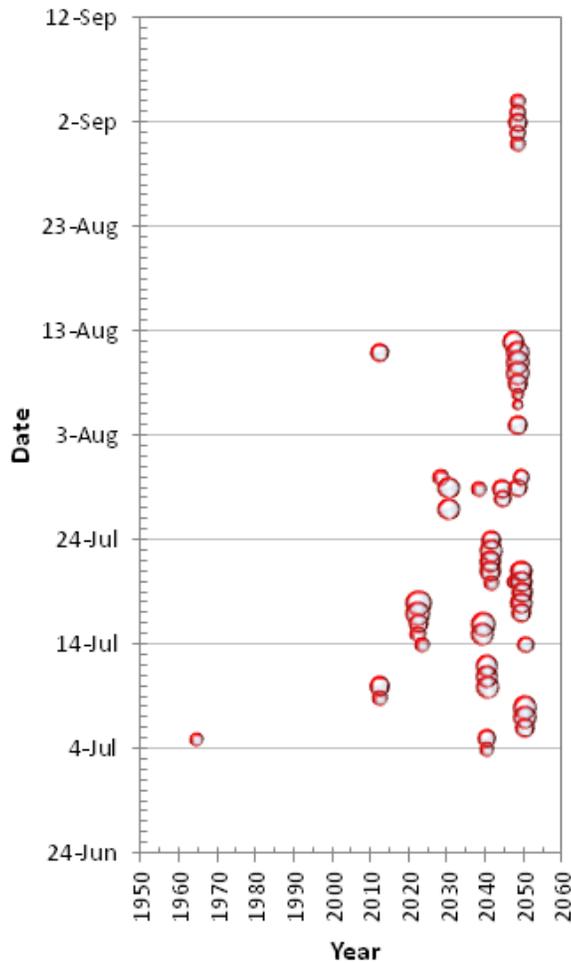


Source: California Energy Commission using data from Scripps Institution of Oceanography, July 25, 2017.

Regionwide Heat Waves

The electricity system experiences stresses during heat waves covering California and neighboring states. Using simulations from one global climate model from 1950 to 2000, it is found that these heat waves are rare in the historical period, as expected, but they become more common in the future, and the duration and intensity of these heat waves increase. Figure 93 shows these findings where regionwide heat waves are defined when 50-year historical heat waves occur simultaneously in major cities in California, Utah, Arizona, and Nevada. In this figure, the size (area) of the bubbles are proportional to the temperature departures from a given site-specific (50-year heat wave) threshold.

Figure 94: Potential Regionwide Heat Waves: Arizona, California, Utah, and Nevada



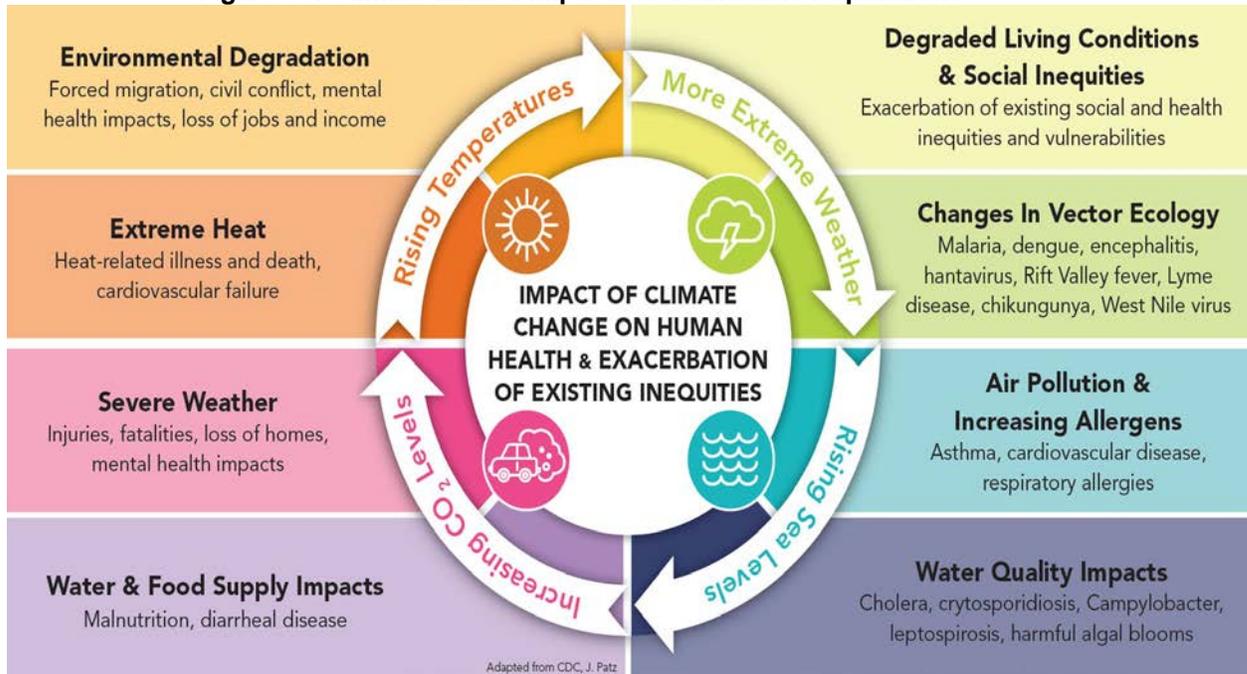
Source: California Energy Commission using LOCA data provided via LLNL. (http://gdo-dcp.uclnl.org/downscaled_cmip_projections/dcpInterface.html).

At the August 29, 2017, IEPR workshop, PG&E, SoCalGas, and SDG&E indicated that they are going to submit analyses of climate change related risks as part of their Risk Assessment and Risk Assessment and Mitigation Phase filings to the CPUC. The use of common or similar climate parameters may make it easier to analyze and communicate the risks.

Increasing Climate Resilience in Disadvantaged Communities

Uneven distribution of climate impacts can amplify the vulnerabilities of already disadvantaged and vulnerable populations. For example, Figure 94 below describes an array of climate-linked public health impacts to vulnerable populations.

Figure 95: Climate-Linked Impacts to Vulnerable Populations

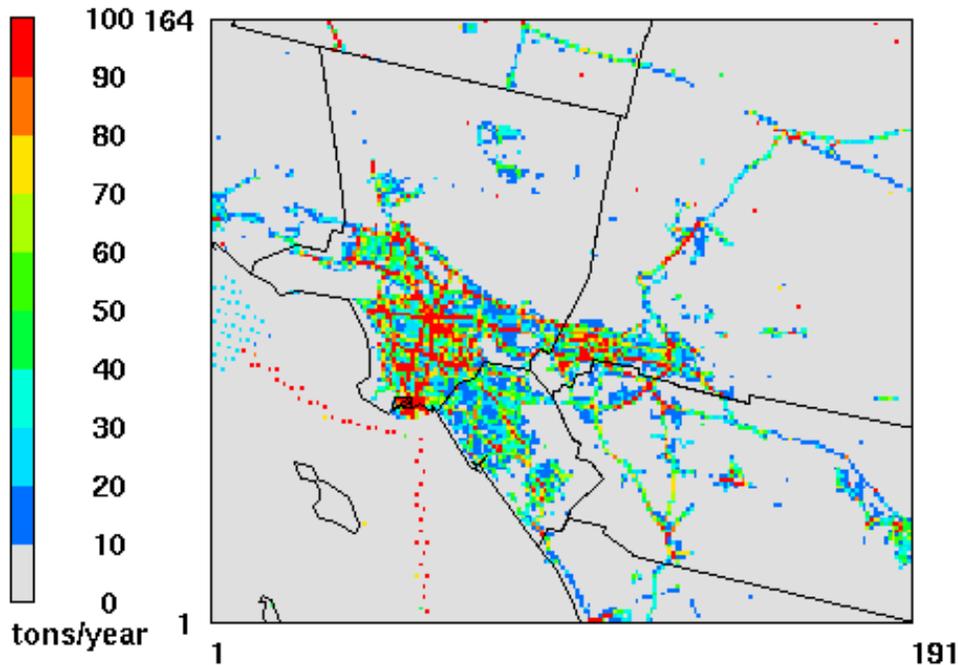


Source: California Department of Public Health, Climate Change and Health Equity Program

At the same time, local air quality may be disproportionately impacted by mobile sources. For example, the South Coast Air Quality Management District, estimated daily average NO_x emission in 2012 from electric utilities was 2.72 tons per day (less than 1 percent of the total emissions), while heavy-duty diesel trucks emitted 114.50 tons per day (about 20 percent of the total emissions). For PM_{2.5} emissions, the electric utility sector contributes only 2 percent of the total emissions, as the paved road dust contributes 11 percent of the total emissions. The following figure shows that NO_x emissions are high along transportation corridors near where many disadvantaged communities are located. A 2015 study supported by CARB indicates that associations of asthma-related hospital visits are enhanced among populations living in areas with high traffic-related air pollutants,⁷¹⁸ emphasizing the major contribution of mobile sources or local air pollution impacts.

718 Delfino, Ralph J., M.D., Ph.D., and Michael J. Kleeman, Ph.D., University of California, Irvine, University of California, Davis. April 7, 2015. *Risk of Pediatric Asthma Morbidity From Multipollutant Exposures*. Contract No. 10-319. California Air Resources Board. Final Report. <https://www.arb.ca.gov/research/apr/past/10-319.pdf>.

Figure 96: Geographical Distribution of NO_x Emissions in the South Coast Air Basin



Source: EPRI, June 2017

Presentations and peer-reviewed research from the Climate Justice Working Group, held on July 13, 2017, reported that climate impacts are not uniform across race, ethnicity, or income level. For example, the effects of urban heat island are felt more strongly in less expensive lower units in buildings, and heat-related mortality disproportionately impacts people of color.⁷¹⁹

The importance of environmental justice, social equity, tribal sovereignty, and participatory research methods for climate was also stressed at a Climate Science Symposium panel moderated by Matt Armsby with the Resources Legacy Fund; the Honorable Cynthia Gomez, tribal advisor to Governor Brown and executive secretary of the Native American Heritage Commission; Arsenio Mataka with the California Environmental Protection Agency; Colin Bailey, executive director for the Environmental Justice Coalition for Water; and Karen Andrade with the UC Davis Center for Regional Change.

The issue of environmental justice and disadvantaged communities has also been addressed by sister state agencies. On July 6, 2017, the CPUC hosted an en banc hearing on Environmental Justice and Disadvantaged Communities. CPUC staff and commissioners pointed to several initiatives that the agency is engaging in to strengthen the ability of disadvantaged communities to adjust to climate impacts. These include:

- A program to increase access to affordable energy alternatives for communities in the San Joaquin Valley that rely primarily on propane or wood to heat their homes.

⁷¹⁹ Presentation of Dr. Morello-Frosch. "The Climate Gap: Implications for Regulatory Decision-Making to Advance Environmental Justice and Sustainability." July 13, 2017. https://dornsife.usc.edu/assets/sites/242/docs/FacingTheClimateGap_web.pdf.

- Requirements that investments in electric vehicle infrastructure provide benefits to disadvantaged communities.
- Subsidies for efficiency through the Energy Savings Assistance Program.
- The use of the Renewable Auction Mechanism to direct clean energy investments to “locally constrained resource areas” – sections of the grid where congested transmission means that fossil-fuel fired plants must be available to maintain reliability, and which often coincide with disadvantaged communities.

Panelists discussed several procedural and distributional issues. Several panelists called for increased direct engagement with residents and members of grassroots organizations from disadvantaged communities to ensure that projects align with local priorities. Some of the distributional issues raised included the effects of climate change on low-income households, including health impacts and higher bills; the need to avoid siting additional gas-fired power plants in disadvantaged communities; and the need to direct research, subsidies, and rebates for efficiency to projects that benefit local residents and locally owned small business in disadvantaged communities. Commissioners emphasized the importance of incorporating inclusion and procedural justice into normal state agency processes.

At the August 29, 2017, IEPR workshop, a panel addressed the role of the energy sector on advancing climate resilience in disadvantaged communities. Panelists discussed a framework for consideration of climate impacts in disadvantaged communities, highlighting:

- Energy Commission actions to incorporate these considerations into research and development programs.
- SCE efforts to promote resilience in disadvantaged communities and reach out to disadvantaged communities to improve clean energy access.
- LADWP efforts to reduce impacts in disadvantaged communities and develop equity metrics to track progress.
- Perspectives from affected communities as voiced by the Asian Pacific Environmental Network, which organizes low-income immigrant and refugee communities on issues related to environmental justice.

Both utility panelists from Southern California acknowledged their membership in, and the role of, the Los Angeles Regional Collaborative as a means of coordinating comprehensive, regionally appropriate climate strategies. Adam Smith of SCE also discussed SCE’s partnership with the Greenlining Institute to promote dialogue with community-based organizations such as Liberty Hill Foundation, Moving Forward Network, and Coalition for Clean Air. This dialogue serves both to broadly engage communities on climate adaptation and to develop specific pilots and even explore potential regulatory or legislative initiatives or both focused on electric vehicles and community/rooftop solar.

Electricity Research Funding for Projects Addressing Local Priorities

Taking Community Feedback Into Account

The Energy Commission held workshops on Energy and Equity Research in Fresno and Los Angeles as part of a broader outreach to refine the Energy Commission's proposed Third EPIC Investment Plan. A key takeaway from these workshops was that communities would like to ensure funding opportunities reflect local priorities for investment. To help achieve this goal, stakeholders recommended greater local involvement, including reimbursement for community members' time and expertise.

Taking feedback from these workshops into consideration, the Energy Commission included proposed funding initiatives with heightened participation by disadvantaged communities in the EPIC Investment Plan for 2018–2020 approved by the CPUC on January 11, 2018. The Energy Commission also released a research funding opportunity to support studies of urban energy scenarios (GFO 16-311 – Advancing the Resilience and Environmental Performance of California's Electricity System). Community-based organizations will assist the researchers in prioritizing the environmental, public health, and other benefits to be considered by the research. This arrangement will help ensure electricity research projects funded through this competitive solicitation focus on locally defined priorities for environmental performance.

Recommendations

Prior *IEPRs* found that the energy system is vulnerable to climate impacts, but there are options to reduce the climate vulnerability of the system while drastically reducing greenhouse gas (GHG) emissions. Regional climate change science in California has made significant strides in the last few years, and more advances are expected as part of California's *Fourth Climate Assessment*. To make progress, California's climate researchers are working with climate science users to inform updates for climate-relevant parameters. This represents a new challenge requiring a closer collaboration with stakeholders, energy utilities, and research teams. In addition, at the August 29, 2017, workshop on Climate Adaptation and Resilience in the Energy Sector, California Public Utilities Commission (CPUC) Commissioner Clifford Rechtschaffen indicated that the CPUC will start requiring the IOUs to consider climate change in their filings for some CPUC proceedings.

According to PG&E, "...Specifically, as per CPUC Decision 14-12-025, the purpose of the Risk Assessment Mitigation Phase (RAMP) filing is to examine the utility's assessment of its key risks and its proposed programs for mitigating those risks. The RAMP filing precedes the 2020 General Rate Case application and provides quantitative views of top safety risks, identifies the costs associated with controlling these risks, and describes future mitigation plans based on an alternatives analysis and informed by the concept of "risk-spend efficiency," proposed by the Safety and Enforcement Division of the CPUC to be included in the risk mitigation decision-making process."⁷²⁰

⁷²⁰ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221734_20171113T143653_Pacific_Gas__Electric_Comments_PGE_Comments_on_2017_Draft_IEPR.pdf.

In addition, the Energy Commission fully supports SDG&E's statement in comments on the draft *2017 IEPR*: "In order for climate plans to be effective, every region of California must be considered and engaged. Specifically, SoCalGas wants to be involved in establishing a California Partnership for Energy Sector Climate Resilience and convening a joint-agency workshop on climate resilience metrics to help track California's action and successes."

For these reasons, the Energy Commission recommends the following:

- **To the extent that gas and electric utilities provide resiliency and vulnerability reports to the CPUC as part of the RAMP filings, the information should be disseminated to local governments.**
- **The Energy Commission should continue to support regional coordination to help local governments leverage resiliency actions. Also, state agencies may want to look at options for regional governance structures for such efforts.**
- **The Energy Commission should explore establishing a California Partnership for Energy Sector Climate Resilience.**
- **The clearinghouse being created by the Governor's Office of Planning and Research under the Integrated Climate Adaptation and Resiliency Program (PRC Sec. 71360) should be designed to increase access to data and efficiency of its use across all agencies and stakeholders, including as a resource to utilities and supporting access to utility-led studies and data that can support climate adaptation planning and action.**
- **The Energy Commission should convene a joint-agency workshop on climate resilience metrics to help track California's resilience action and successes.**
- **Given the impacts of climate change in California, and of wildfires in particular, there is a continued need to coordinate between state and federal agencies to encourage and advance utility relationships with federal, state, and local governments to ensure that infrastructure plans and improvements are consistent with climate adaptation goals. This work should include advancing policies that support utilities and governmental cooperation in sharing regional operations and maintenance plans and coordination to ensure that rights-of-way remain accessible to utilities and safely maintained.**
- **The Energy Commission should support consideration of research designed to equitably identify, reduce, and eliminate climate vulnerabilities in disadvantaged communities. This support must also entail explorations of how to directly benefit these communities with the adoption of clean energy technologies.**

CHAPTER 11:

Update on Energy Reliability Issues in Southern California

Southern California continues to be in the reliability spotlight following two large and unanticipated energy infrastructure failures in the past five years: the outage of the two San Onofre Nuclear Generating Station units (San Onofre) in January 2012, followed by the decision to retire San Onofre in June 2013; and the massive gas leak discovered on October 23, 2015, at the Aliso Canyon natural gas storage facility. These energy supply disruptions are coupled with a long-planned compliance schedule anticipating the closure of several Southern California coastal power plants that use ocean water for cooling as early as 2018. The Energy Commission, the California Public Utilities Commission (CPUC), and the California Independent System Operator (California ISO) worked together to address reliability issues first with the closure of San Onofre and again, with the additional partnership of the Los Angeles Department of Water and Power (LADWP), to respond to reliability issues related to Aliso Canyon. Ongoing work to address reliability issues related to San Onofre and Aliso Canyon are discussed below. The Energy Commission plans to hold another public workshop and continue to address these issues as part of the *2018 Integrated Energy Policy Report Update*.

2017 Aliso Canyon Natural Gas Storage Facility Energy Reliability Issues

The massive leak at the Aliso Canyon natural gas storage facility requires both near-term action to maintain reliability and long-term planning for the possible permanent closure of the facility. The Energy Commission, CPUC, California ISO, and LADWP (members of the “technical assessment group”) have jointly addressed the near-term reliability issues associated with Aliso Canyon through the Energy Commission’s *Integrated Energy Policy Report (IEPR)* proceeding, beginning with the *2016 IEPR Update*. (See Chapter 8, the sidebar titled “Background on the Aliso Canyon Natural Gas Storage Facility” in this chapter, and the *2016 IEPR Update*, Chapter 2, for more information.) The analysis presented here addresses short-term reliability issues for the summer of 2017 and winter 2017–2018.

Summer 2017 Analysis

Building on efforts in 2016, the joint agency technical assessment group developed the *Southern California Energy Reliability May 2017 Summary*⁷²¹ and an *Update of the Aliso Canyon Mitigation Measures*,⁷²² which focused on maintaining reliability in summer 2017. A companion document provided the technical assessment⁷²³ of both the natural gas and electricity systems. Since much of the needed natural gas system data and hydraulic modeling capacity were held by SoCalGas, the technical assessment group asked the gas company to perform the required reliability analysis and help explore mitigation

Background on the Aliso Canyon Natural Gas Storage Facility

The massive leak from the Aliso Canyon natural gas storage facility caused the displacement of thousands of local residents; emitted large amounts of natural gas, a potent greenhouse gas; took almost four months to seal; and disrupted the energy system in the greater Los Angeles area. Because of this event, use of the facility is severely constrained. Southern California Gas Company (SoCalGas) historically used Aliso Canyon to balance supply and demand for its system on a daily and hourly basis throughout the year. Aliso Canyon is one of the largest storage fields in the United States and is the largest of four storage fields operated by SoCalGas. The location and size of Aliso Canyon made it the natural fit for supporting substantial hourly operating changes in the Greater Los Angeles Area.

Beginning in December 2015, the Energy Commission, CPUC, the California ISO, and the LADWP worked together to assess the summer and winter reliability risks associated with the nearly shuttered facility and develop action plans for maintaining energy reliability in the Greater Los Angeles Area. The joint agencies developed and implemented the *2016 Summer Action Plan*¹ and the *2016-2017 Winter Action Plan*,¹ which included more than 30 mitigation measures that have improved the reliability outlook for the energy demands of thousands of residential and commercial customers. Some of these measures include improving operational coordination of the gas and electricity system, changing gas balancing rules to lessen reliance on storage, and reducing the amount of power and gas needed through efficiency and customer conservation. Aliso Canyon continues to be the subject of multiple proceedings – each addressing different aspects of the issue – ranging from a root cause analysis, whether to allow reinjection (and when), to the long-term future of the facility. Absent Aliso Canyon, the system continues to operate differently than it has historically, creating uncertainty that requires further analyses to maintain energy reliability in the area.

The action plans are available at
http://www.energy.ca.gov/2016_energypolicy/documents/index.html#04082016 and
http://www.energy.ca.gov/2016_energypolicy/documents/index.html#08262016.

⁷²¹ Prepared by the staff of the California Energy Commission, CPUC, California ISO, and LADWP, May 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217642_20170519T105740_Southern_California_Energy_Reliability_May_2017_Summary.pdf.

⁷²² Prepared by the staff of the Energy Commission, CPUC, California ISO, and LADWP, May 19, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217640_20170519T104801_Aliso_Canyon_Mitigation_Measures__May_19_2017.pdf.

⁷²³ Prepared by the staff of the California Energy Commission, CPUC, California ISO, and LADWP, and SoCalGas, *Aliso Canyon Risk Assessment Technical Report Summer 2017 Assessment, May 19, 2017*, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217639_20170519T104800_Aliso_Canyon_Risk_Assessment_Technical_Report_Summer_2017_Asses.pdf.

measures. The Los Alamos National Laboratory and Walker & Associates conducted an independent review of the hydraulic analysis.⁷²⁴

On May 22, 2017, the Energy Commission, CPUC, California ISO, and LADWP held a joint IEPR workshop in Diamond Bar to present the analysis and outlook for summer 2017. A summary of workshop comments and response to comments was published September 22, 2017.⁷²⁵

The 2017 Summer Assessment is based on a different type of analysis than the 2016 Summer Technical Assessment. The 2017 assessment calculated the ability of the SoCalGas/San Diego Gas & Electric (SDG&E) gas transmission system to support peak hour demand and determined the minimum amount of gas needed to maintain electric reliability during peak hours in a 1-in-10 year summer load day (hotter than average). The assessment includes two different analytical methods:

- Hydraulic modeling of summer peak day demand by SoCalGas, which was reviewed by two independent experts – Los Alamos National Laboratory and the consulting firm Walker & Associates.
- An electric impact analysis, including power flow, by the California ISO and LADWP using the deliverable gas demand estimates to determine whether electric generator gas demand could be served and whether electricity service interruptions could occur on a summer peak day.

The 2017 Summer Assessment finds that expected hourly electrical demand can be met if pipeline flowing supply is at 100 percent – 3.185 billion cubic feet per day (Bcfd) – and storage inventory at non-Aliso facilities is adequate to support withdrawal of 1.47 Bcfd during the peak hours. If pipeline supply is reduced or storage inventory at the other three storage facilities (Honor Rancho, La Goleta, and Playa del Rey) is inadequate, the system could face challenges. Other risk factors include prolonged hot weather affecting supply availability and electric capability into Southern California. If the electric system is not fully available or electric supplies outside California are limited, the electric system could still be at risk even with the higher storage supply rates. Any outage or change that reduces the maximum gas system capacity below 3.373 Bcfd (which reflects a 90 percent flowing supply and non-Aliso storage inventory) would result in insufficient gas being available to meet peak electric demand.⁷²⁶

⁷²⁴ Prepared by Los Alamos National Laboratory and Walker & Associates. *Independent Review Of Southern California Gas Hydraulic Modeling, May 2017*. http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217657_20170519T141559_Independent_Review_of_Southern_California_Gas_Hydraulic_Modeling.pdf.

⁷²⁵ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221298-2_20170922T102841_August_22_2017_DRAFT_Comments_Received_for_May_22_Workshop_on_S.pdf

⁷²⁶ 2017 Summer Assessment, pp. 5–6.

If gas supply is insufficient to meet peak demand and access to replacement electric supply is limited, emergency assistance from neighboring balancing authorities, electric load shed in Southern California, or withdrawal from the remaining Aliso inventory may be necessary. SoCalGas does have operational authority to curtail noncore customers to maintain gas system reliability if the combined demand from both core and noncore customers reaches or exceeds gas system capacity.

Natural Gas Hydraulic Analysis

The 2017 Summer Assessment includes a hydraulic analysis that simulates the physical operations of the SoCalGas transmission and storage system. (See the sidebar “Hydraulic Analysis” for more information.) In the hydraulic modeling, the maximum gas sendout⁷²⁷ from Aliso Canyon is 3.6 Bcfd. This amount assumes maximum storage withdrawal rate capability of 1.47 Bcfd without Aliso Canyon and 3.185 Bcfd⁷²⁸ flowing pipeline supply. Of the maximum sendout, 2.2 Bcfd (about 61 percent) is available to support electric generation. The results of the simulation show that during the peak hours, the storage withdrawal rate is at full capability (61.3 MMcf per hour), equivalent to 1.47 Bcfd, but that the withdrawal rate declines during the off-peak hours, resulting in 468 MMcf of storage withdrawal for the day. Achieving the maximum sendout requires 1) that no other transmission or storage facility outage occurs (beyond the current Line 3000 outage), 2) gas in the pipeline is flowing at 100 percent of capacity, and 3) needed withdrawal capacity is available at the other three fields (which assumes those fields hold sufficient storage inventory to support the withdrawal). Any reduction from 100 percent of pipeline flow will reduce the sendout capacity on a one-to-one basis. Also, any further unplanned or planned outages beyond Line 3000 would reduce the maximum gas sendout from 3.6 Bcfd on a one-to-one basis.⁷²⁹

Given the uncertainty about operations at Aliso Canyon and recognizing the January 2016 order from the CPUC to hold inventory at 15 Bcf to protect energy reliability,⁷³⁰ the hydraulic analysis

Hydraulic Analysis

Hydraulic modeling simulates withdrawing from or injecting gas into storage, opening or closing valve stations to the interstate pipeline supplies, and turning on or off compressor stations to meet the hourly demand. It examines a snapshot of a day and the intraday demand variations that determine the responsiveness of the system. Thus, hydraulic modeling has the unique capability to identify whether a gas system can respond to peak hourly demand. A successful simulation ensures that the gas system operates between the minimum and maximum operating pressures, operates within the capacities of the gas transmission facilities, and recovers system linepack at the end of each day.

⁷²⁷ *Sendout* is defined as total gas that is produced, purchased, or withdrawn from underground storage in a certain interval of time.

⁷²⁸ About 3.185 Bcfd is composed of 1.350 Bcfd on the northern system, 1.010 on the southern system, 0.765 Bcfd at Wheeler Ridge, and 0.060 Bcfd from the California producers.

⁷²⁹ SoCalGas conducted a second analysis using its hydraulic model, with reduced storage withdrawal capacity of 800 MMcf, in which the gas sendout falls to roughly 3.2 Bcfd. The joint agencies felt that the withdrawal capacity assumption of 800 MMcf was unreasonably low. The withdrawal capability as of April 1 was beyond that low level at about 1.2 Bcfd per SoCalGas’ electronic bulletin board Envoy. SoCalGas Vice President Rodger Schwecke presented the results of this second case at the Joint Agency Workshop on Energy Reliability in Southern California on May 22, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217673_20170522T082453_Joint_Agency_Workshop_on_Energy_Reliability_in_Southern_Califor.pdf.

⁷³⁰ Letter from CPUC Executive Director Timothy Sullivan to SoCalGas Senior Vice President Jimmy Cho: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/01-21-16%20Aliso%20Canyon%20Draw%20Down%20Levels.pdf%20-%20Adobe%20Acrobat%20Pro.pdf.

assumed no injection and no withdrawal from Aliso Canyon. Since gas at Aliso Canyon is preserved for conditions when it is most needed, it was held out of the analysis. The hydraulic analysis assumed full receipt at Wheeler Ridge Zone of 765 MMcfd, which means that full withdrawals at Honor Rancho are infeasible since the two compete for pipeline capacity. This finding was similar to the winter 2016–2017 assessment that receipts coming into Wheeler Ridge Zone plus full withdrawals at Honor Rancho are infeasible. Honor Rancho withdrawals are reduced to 840 MMcfd from 1.0 Bcfd, a loss of 160 MMcfd.

Electricity Impact Analysis

The California ISO and LADWP balancing authorities performed a complementary joint assessment of electric impacts based on 2.2 Bcfd of gas available needed to serve electric generation. The technical assessment group examined how variations in gas supply and electric import capability could affect the California ISO’s and the LADWP’s ability to meet summer 2017 peak load,⁷³¹ resulting in shortfalls in two scenarios.

The group modeled changes in the following three factors:

- The availability of withdrawal from storage facilities other than Aliso Canyon
- The amount of gas delivered to the area
- The amount of electric transmission import capacity

Table 29 presents six scenarios with varying assumptions for gas supply, storage withdrawal, and transmission capacity to identify what factors could result in an inability to fully meet electricity demand for an eight-hour peak demand period.

Table 29: Summary of Results for Six Scenarios of Gas Receipt Point and Transmission Use, Assuming a Hotter-Than-Average Summer in 2017 (1-in-10, 2017 Peak Summer Case)

	1	2	3	4	5	6
Original Demand Supportable by SoCalGas (MMcfd)	3,638	3,373	3,638	3,638	3,373	3,373
Flowing Gas Supply	100%	90%	100%	100%	90%	90%
Storage Withdrawal Excluding Aliso Canyon	100%	100%	100%	100%	100%	100%
Transmission Import Utilization	100%	100%	90%	85%	90%	85%
Gas Supply Surplus/Shortfall to Cover the Specified Scenario for 8-Hour Peak Period (MMcf)	240	95	102	35	-43	-110

Source: California Energy Commission

⁷³¹ The technical assessment group also examined two scenarios under a 3.6 Bcfd gas system capacity, based on historical 2016 peak day on June 20, 2016, and on the day of the Blue Cut fire on August 16, 2016. Sufficient gas was available in these two scenarios to maintain electric reliability.

Given storage constraints at Aliso Canyon, the analysis assessed and assumes the minimum amount of gas burn for electricity generation needed to maintain reliability (for all scenarios). Minimizing gas use and making other operational changes needed to manage the power system without the normal use of Aliso Canyon lead to higher power system operating costs. Thus, maintaining reliability without the use of Aliso Canyon increases energy costs.

The analysis found that expected demand can be met assuming pipeline supply is at 100 percent and adequate storage inventory remains available, excluding Aliso Canyon (Scenario 1). The analysis for Scenario 1 found that electric reliability can be satisfied for a 1-in-10 year summer peak electric load condition with a minimum gas burn (for electricity generation) of 1.87 Bcfd (976 MMcf during an eight-hour peak period) in response to a power system contingency⁷³² and with a gas burn as low as 1.75 Bcfd (858 MMcf during an eight-hour peak period, with somewhat higher risk) under normal precontingency conditions, along with the ability to import generation into the Greater Los Angeles Area. After accounting for the minimum generation and gas burn requirements over the eight-hour peak period under contingency conditions,⁷³³ the California ISO and LADWP joint 2017 power-flow study found that there was sufficient gas to meet the minimum electric reliability requirement, assuming SoCalGas delivered supply is 3.6 Bcfd, which would require 100 percent receipt point utilization and maximum storage withdrawal rate capability of 1.47 Bcfd during peak hours, excluding Aliso Canyon. If pipeline supply is reduced, system reliability depends on the availability of natural gas at the Honor Rancho, La Goleta, and Playa del Rey storage facilities.

The analysis also tested more limited operating conditions. Scenario 2 assumes a 90 percent⁷³⁴ flowing pipeline supply to account for further outages on the gas system beyond the Line 3000 outage. Under Scenario 2, servable gas demand is 3.37 Bcfd. Under these conditions, the electricity assessment finds that with the CPUC-directed storage supply rates of 1.47 Bcfd from Honor Rancho, La Goleta, and Playa del Rey storage facilities, electric reliability can be satisfied for a 1-in-10-year summer peak load. Scenario 2 results in a surplus of 95 MMcf over the eight-hour peak period. This assumes there is enough energy supply outside Southern California and sufficient electric transmission import capability into Southern California.

⁷³² A multiple transmission line contingency occurred during the Blue Cut Fire on August 16, 2016, giving real-time meaning to this scenario. Additional gas supplies were required to support electric reliability in the area. This is discussed later in this chapter.

⁷³³ 2017 Summer Assessment, table 2, rows 8 and 11, p. 20.

⁷³⁴ The percentage utilization calculation is based on the receipt point capacity of 3.185 Bcfd, not SoCalGas' full capacity rating of 3.875 Bcfd.

Electricity Sensitivity Analysis – Scenarios Assuming Reduced Availability of Electric System Transmission Imports

The analysis by the California ISO and LADWP considered the feasibility of procuring and delivering energy from outside the SoCalGas/SDG&E service territories into the Greater Los Angeles Area and Southern California more broadly. Scenarios 3 through 6 evaluated the ability to provide replacement energy at two additional, lower electric transmission capacity utilization levels (90 percent and 85 percent) using 100 percent and 90 percent flowing gas supply assumptions. In Scenarios 3 and 4, at the 100 percent flowing gas supply assumption, electric reliability can be satisfied for a 1-in-10-year summer peak load both at 90 percent and 85 percent transmission import utilization and no shortfalls occur. Further reducing assumptions to 90 percent flowing gas supply and reduced transmission import of 90 percent and 85 percent, gas need shortfalls do occur, ranging from 43 MMcf to 110 MMcf for the eight-hour peak period (Scenarios 5 and 6). Withdrawal from Aliso Canyon or electric load shed⁷³⁵ would be required to address the gas shortfall.

Given the range of assumptions, four of the six scenarios studied result in sufficient gas availability to maintain electric reliability. In the latter two scenarios, gas need shortfalls occur only under reduced assumptions for flowing gas supplies and electric transmission imports.

If there are multiple high electric load days, the same amount of gas would be needed for each day. The electric load could be at risk if the electric system is not fully available, electric supplies are limited, or other outages affect the amount of gas delivered to the gas system. In such circumstances, gas supplies from Aliso Canyon would be necessary to reduce the shortfall to avoid interruption of electric service. Gas storage levels are discussed below.

Heat Wave Summer 2017

California successfully weathered successive days of triple-digit heat that occurred in the interior of California (with warnings from the National Weather Service for “excessive heat” in not only California but the entire Southwest) from June 16, 2017, through June 23, 2017. During this time, the California ISO and LADWP coordinated closely with SoCalGas to assure continued reliable service to all customers. During this period, the CPUC and Energy Commission participated in and coordinated multiple briefings and remained in a state of heightened alert, standing by to facilitate or take additional action if needed.

Highlights of the facts and actions taken include the following:

- The excessive heat – including warmer-than-normal overnight temperatures – was limited to the Central Valley and desert areas; mild coastal temperatures meant that demand never reached peak levels.
- SoCalGas, the California ISO, and LADWP all issued restricted maintenance notices.
- SoCalGas withdrew from non-Aliso storage fields and took additional actions to remedy a key compressor outage.
- Electricity system Flex Alerts calling for voluntary conservation were issued for June 21, 2017, and June 22, 2017.

Demand levels and actions taken by SoCalGas and the two electricity balancing areas (the California ISO and LADWP) during the heat event are described here, along with impacts to natural gas prices during this period. A final section compares and contrasts the experience of this heat event to the summer 2015 SoCalGas high *sendout* event. (*Sendout* refers to the total gas that is produced, purchased, or withdrawn from underground storage in a given interval of time.)

⁷³⁵ *Load shedding* in electrical supply networks is a controlled process in which the utility company drops part of the load to balance the demand and the generated capacity. This is often done whenever there is excess load on the system.

Withdrawal Capability From Storage Facilities Other Than Aliso Canyon

The California ISO and LADWP's ability to meet the 1-in-10-year peak summer electric load depends partially on the amount of withdrawal capability from storage facilities other than Aliso Canyon.⁷³⁶ The electricity analysis assumed storage withdrawal capability of 1.47 Bcfd and storage withdrawal rate of 1.47 Bcfd are required. The amount of withdrawal capability depends partially on the amount of inventory in the field,⁷³⁷ as well as the number of wells available. Adequate natural gas inventory levels are necessary to maintain reliable delivery to customers during peak demand for both core and noncore customers.

Beginning March 2017, SoCalGas began implementing a Storage Safety Enhancement Plan to convert all of its storage fields to tubing only (to flow gas only through new steel inner tubing, enabling the outer casing to function as a secondary safety barrier). The storage plan has a significant impact on the injection and withdrawal capability of the fields in the near term.⁷³⁸ Recognizing the risk of low inventory and withdrawal capability at these storage fields, the CPUC directed SoCalGas to 1) increase storage injections into the Honor Rancho and La Goleta storage fields to adequate inventory levels to maintain reliable delivery to both core and noncore customers during peak summer and provide for sufficient winter inventory levels,⁷³⁹ and 2) revise its Storage Safety Enhancement Plan. In its response to the CPUC, SoCalGas indicated that it anticipated meeting the gas storage levels required by June 1, 2017, would be met.⁷⁴⁰ SoCalGas also took steps to revise its system operations practices to release injection capacity reserved for balancing, which became effective May 4, 2017. SoCalGas is working toward those inventory levels under close monitoring by the CPUC.

On April 1, 2016, after winter ended, the total storage inventory at Honor Rancho, La Goleta, and Playa del Rey storage facilities was 43.7 Bcf. One year later, on April 1, 2017, the storage level was 24.7 Bcf. Withdrawals to meet customer demand during winter 2016–2017 were made from these three storage fields since Aliso Canyon was operating under constrained conditions. To fill the void, SoCalGas planned significant injections during the transitional months of April through June 2017, as outlined in its response to the CPUC. However, injections for April were much less

⁷³⁶ Chapter 2 of the California Council on Science and Technology study on the long-term viability of underground gas storage in California (referenced previously in Chapter 8) contains a detailed discussion on why California has gas storage and how it is used to meet not only summer peak demand but high demand days in the winter and to remedy hourly gas system imbalances. It focuses not on use of Aliso Canyon *per se* but identifies the role of California's gas storage in general.

⁷³⁷ Gas is withdrawn from storage under natural pressure. The withdrawal capability from the gas field declines as inventory declines because lower volume in the field results in lower pressure.

⁷³⁸ February 15, 2017, letter from SoCalGas Vice President of Gas Transmission and Storage Rodger Schwecke to CPUC Energy Division director Edward Randolph, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/SoCalGasStorageSafetyEnhancementPlan.pdf.

⁷³⁹ March 16, 2017, letter from CPUC Executive Director Timothy Sullivan to Rodger Schwecke with SoCalGas, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/CPUCLettertoSoCalGasreStorageSafetyEnhancementPlan.pdf.

⁷⁴⁰ March 30, 2017, letter from Rodger Schwecke with SoCalGas to CPUC Executive Director, Timothy Sullivan, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/SoCalGasResponse.pdf.

than planned, amounting to 1.9 Bcf, putting at risk its ability to meet the June 1, 2017, requirement of 33.89 Bcf.

In April 2017, SoCalGas expressed concerns about its ability to serve its customers safely and reliably during the summer and upcoming winter, based upon the current operating status of its system.⁷⁴¹In response, the CPUC directed SoCalGas to maximize storage injections using the procurement capabilities of the SoCalGas Acquisition Department to support SoCalGas' storage requirement for system reliability.⁷⁴² In its response to the CPUC, SoCalGas filed Advice Letter Number 5139 with a proposed injection enhancement plan.⁷⁴³ As of November 1, 2017, SoCalGas storage fields held a systemwide inventory of 67 Bcf, and Aliso Canyon has a target of 24.6 Bcf, as reported in the CPUC's Public Utilities Code Section 715 report.⁷⁴⁴

Mitigation Measures

Mitigation measures developed during the 2016–2017 winter and 2016 summer improved the outlook for energy reliability for summer 2017.⁷⁴⁵ The measures included changing the gas balancing rules to encourage customers to buy natural gas to meet their demand on a daily basis rather than relying on gas storage, possibly using existing natural gas at Aliso Canyon, improving operational coordination, increasing customer conservation, and identifying steps to increase gas supply. Recognizing the risk of low inventories, the joint agencies added a new mitigation measure in the summer 2017 assessment – “increase gas inventories at the other SoCalGas storage facilities.” The joint agencies continued discussions and coordinated to eliminate any remaining barriers to achieving adequate injection rates.

June 30, 2015, Gas Curtailments

The gas curtailments on June 30, 2015, and July 1, 2015, were shared by the California ISO and LADWP. The result was a split of roughly 75 percent of the June 30, 2017, gas curtailment going to generators within the California ISO balancing authority and 25 percent going to LADWP. LADWP curtailed about 500 MW of generation. On July 1, 2017, LADWP was asked to consume no more than what the hourly burn had been on June 30, 2017. LADWP was able to accommodate the second day without any customer interruptions only because temperatures were lower on the second day, reducing electricity demand slightly.

741 April 28, 2017, letter from SoCalGas Chief Operating Officer Brett Lane to Energy Commission Chair Robert Weisenmiller, California ISO President and CEO Stephen Berberich, and CPUC President Michael Picker, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/April28SCGIettertoPBW.pdf.

742 May 8, 2017, letter from CPUC Executive Director Timothy Sullivan to SoCalGas Chief Operating Officer Brett Lane, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/5-8-17_Ltr%20to%20SoCal%20Gas%20re%20SoCalGas%20Summer%20Reliability%20and%20Storage%20Instructions_A1507014.pdf.

743 SoCalGas Advice Letter Number 5139, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/AL5139.pdf.

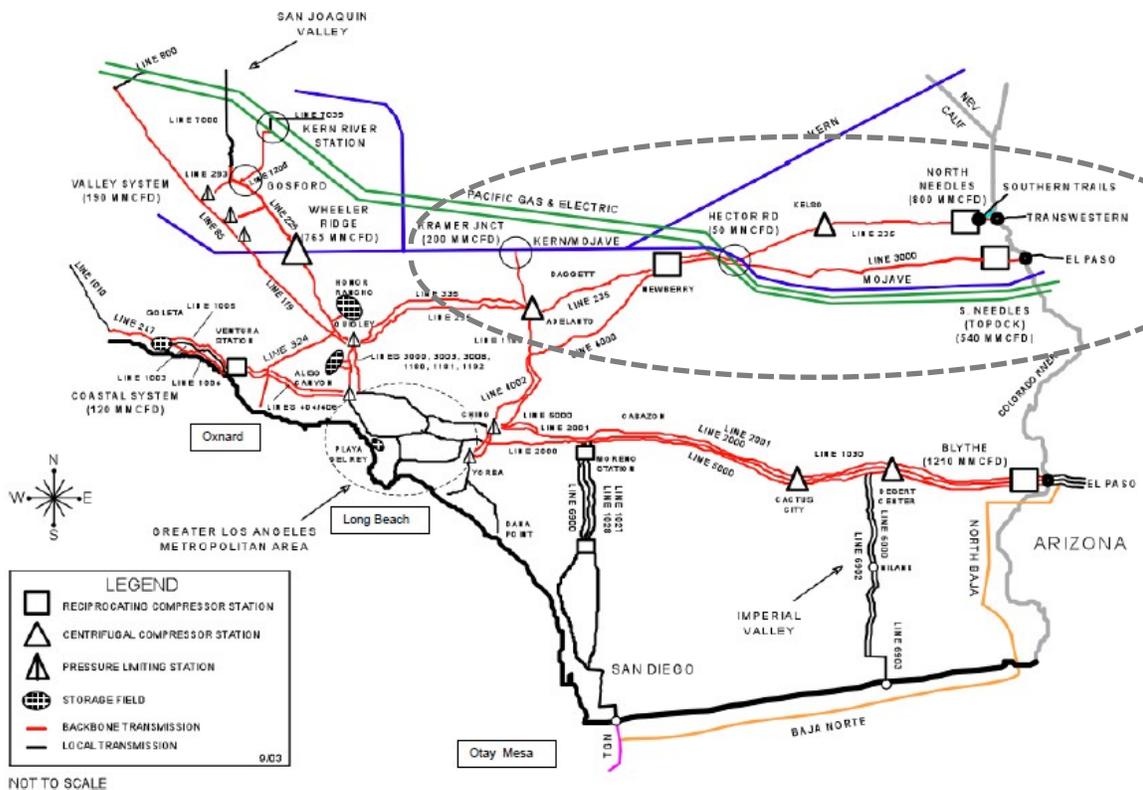
744 The CPUC *Aliso Canyon Working Gas Inventory, Production Capacity, Injection Capacity, and Well Availability for Reliability*, December 11, 2017 identifies a target of 24.6 Bcf to be held in Aliso Canyon to maintain reliability. The report is available at http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/715_Supplement_2017-12-11_FINAL.pdf.

745 Aliso Canyon Mitigation Measures, May 19, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217640_20170519T104801_Aliso_Canyon_Mitigation_Measures__May_19_2017.pdf.

Winter 2017–2018 Analysis

The winter 2017–2018 initial analysis showed upcoming winter impacts similar to last winter, but with a little more gas in Aliso Canyon⁷⁴⁶ and a major pipeline outage on Line 3000 (Topock receipt point). On October 1, 2017, SoCalGas suffered a rupture of Line 235-2 near the Newberry compressor station, which also damaged Line 4000 nearby. Figure 96 shows the SoCalGas system with Line 235 and Line 4000 continuing west from the Newberry station toward the greater Los Angeles area. As a result of the rupture of Line 235-2 and damage to Line 4000, an additional 800 MMcf⁷⁴⁷ was suddenly out of service, reducing deliveries to the North Needles receipt point to 0 on top of Topock receipt point being at 0 capacity.

Figure 97: SoCalGas System Map Highlighting Outages Affecting Northern Zone Receipts (Needles, Topock, and Newberry)



Source: February 24, 2004, Phase I Proposal by SoCalGas and SDG&E in R. 04-01-025

On October 17, 2017, Energy Commission Chair Robert B. Weisenmiller and CPUC President Michael Picker sent SoCalGas a letter expressing concern with SoCalGas' ability to meet its

⁷⁴⁶ SoCalGas was given the authority to begin injections in July 2017, Joint Division of Oil, Gas, and Geothermal Resources and California Public Utilities Commission letter to SoCalGas regarding Senate Bill 380 findings and concurrence of the safety of the Aliso Canyon Natural Gas Storage Facility. http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/OpenLettertoSoCalGasandPublic.pdf.

⁷⁴⁷ The winter analysis assumed 3,185 MMcf of flowing pipeline supplies before mitigation measures, so a loss of 800 MMcf is a reduction in flowing supplies of about 25% to 2,385 MMcf.

obligation to provide safe and reliable service this winter and requesting a mitigation plan.⁷⁴⁸ On October 30, 2017, SoCalGas submitted the *Southern California Gas Company Winter 2017–2018 Technical Assessment*,⁷⁴⁹ which indicated that noncore winter curtailments are likely. Accounting for the pipeline outages on Line 235, Line 3000, and Line 4000, SoCalGas stated it would not be able to meet 1-in-10-year winter peak day demand or have sufficient storage inventory to meet demand over the entire winter. The report also raised the possibility of curtailing noncore customers to preserve storage inventory and withdrawal capacity needed for core customers. SoCalGas further reiterated its top mitigation measure is to operate Aliso Canyon unrestricted in the same manner it did before the gas rupture and historic leak in 2015. Doing so, however, would be inconsistent with the long-term policy goals of reducing California’s reliance on methane and closing Aliso Canyon in 10 years.

Building on efforts last winter (2016–2017) and considering SoCalGas’ winter 2017–2018 technical assessment, the joint agency technical assessment group developed the *Aliso Canyon Winter Risk Assessment Technical Report 2017–2018 Supplement*,⁷⁵⁰ which focused on maintaining reliability in winter 2017–2018. While the joint agency analysis differs somewhat from SoCalGas on certain quantitative assumptions,⁷⁵¹ the assessment concludes that the region faces new challenges and greater uncertainty compared to last winter due to the unprecedented pipeline outages. The key findings are:

- Curtailments are more likely this winter than last due to the pipeline rupture.
- Conservation is needed to preserve storage inventory for core customers to meet gas demand later in the winter.
- Curtailments of noncore customers (besides electric generators) may be needed to preserve storage inventory for core customers.
- Weather is a key driver of the outcome this winter.

Revised SoCalGas System Capacity

The 2017–2018 winter supplement begins with the same hydraulic modeling inputs and results for the natural gas system as last winter’s assessment, which resulted in a maximum system

748 Letter from Energy Commission Chair Weisenmiller and CPUC President Picker to Brett Lane, President and Chief Operating Officer of SoCalGas, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221533_20171018T073903_101717_Letter_to_Mr_Bret_Lane_SoCalGas_reAliso_Canyon_Reliabili.pdf.

749 Letter from Brett Lane, President and Chief Operating Officer of SoCalGas to Energy Commission Chair Weisenmiller and CPUC President Picker, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221652_20171101T105131_103017_SoCalGas_Response_Letter_to_CPUC_CEC_with_Attachment_AE.pdf.

750 Prepared by the staff of the California Energy Commission, CPUC, California ISO, and LADWP, November 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221863_20171128T103411_Aliso_Canyon_Winter_Risk_Assesment_Technical_Report_201718_Supp.pdf.

751 SoCalGas assumptions included mitigation measures put in place to increase capacity at Kramer junction by 150 MMcf of interruptible supply and Wheeler Ridge receipt point by 35 MMcf and 200 MMcf supply at Otay Mesa. Of these mitigation measures, the joint agency gas balance analysis included only 75 MMcf of the 150 MMcf of interruptible supply to account for the uncertainty of the supplies being interruptible and not firm and included the 200 MMcf supply at Otay Mesa.

sendout of 4,567 million cubic feet per day (MMcfd).⁷⁵² This figure assumes withdrawals from SoCalGas' other three storage fields, but none from Aliso Canyon. Table 30 presents the adjustments to this figure based on the known outages, projected return to service dates, and additional mitigation measures implemented by SoCalGas. Three periods capture the outage end dates and timing of system mitigations.

The adjustments to the maximum system capacity include:

- -200 MMcfd lower operating pressures at Ehrenberg.⁷⁵³
- -800 MMcfd combined Line 235-2 and Line 4000 outage.
 - Line 4000 outage returns to service December 25, 2017, which restores 350 MMcfd.
- -260 MMcfd maintenance at Playa Del Rey until December 18, 2017.
- 200 MMcfd SoCalGas contracting for capacity to move 200 MMcfd south from Ehrenberg and west to Otay Mesa.
- 150 MMcfd temporary increase of capacity at Kramer Junction by 150 MMcfd on an interruptible basis until Line 4000 returns to service.⁷⁵⁴

As a result of the adjustments, maximum system capacity ranges from 3,657 MMcfd to 4,117 MMcfd. While Table 30 summarizes known outages, there is a risk that additional unplanned outages could further reduce SoCalGas' system capacity.⁷⁵⁵ Compared to last winter, system capacity is lower by 910 MMcfd at the beginning of December and lower by 450 MMcfd in January after Line 4000 is expected to return to service.

⁷⁵² See *Aliso Canyon Winter Risk Assessment Technical Report*, August 23, 2016. The 2016 report provides background information and an explanation of the hydraulic analysis referenced in this supplement. The 2016 report can be found at http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-02/TN212913_20160823T090035_Aliso_Canyon_Winter_Risk_Assessment_Technical_Report.pdf, page 19, Table 1: Supply and Demand for the 1 - in - 10 Scenarios and Curtailment Requirements.

⁷⁵³ SoCalGas Envoy reports the reduction as 202 MMcfd, which has been rounded to 200 MMcfd for this analysis.

⁷⁵⁴ Energy Commission staff contacted Kern River Gas Transmission (Kern) on November 3, 2017, to understand how often Kern can deliver the full 700 MMcfd instead of the normal 550 MMcfd. Kern indicated that it can do so daily "under current system operation conditions and gas nomination patterns."

⁷⁵⁵ The Independent Review Team recommended in the Aliso Canyon summer 2017 assessment that the probability of an additional unplanned outage be included.

Table 30: System Capacity and Maximum Supported Demand (MMcfd)

	Period 1: Present - 12/18/2017 Outage on Lines 3000, 4000, and 235-2; Maintenance at Playa del Rey	Period 2: 12/18/2017 - 12/30/2017 Outage on Lines 3000, 4000, and 235-2	Period 3: Post 12/31/2018 Outage on Lines 3000 and 235-2
Supported Gas Demand From Table 1 of the 2016 Winter Assessment (Includes Line 3000 Outage)	4,567	4,567	4,567
Reduced Operating Pressure at Ehrenberg	(200)	(200)	(200)
Combined Outage Lines 4000/235-2	(800)	(800)	(450)
Playa del Rey Maintenance	(260)	0	0
Total Supported Demand: No Mitigation	3,307	3,567	3,917
Mitigation 1: Otay Mesa	200	200	200
Mitigation 2: Kramer Junction (Interruptible)	150	150	0
Total Supported Demand With Mitigations	3,657	3,917	4,117

Source: *Aliso Canyon Winter Risk Assessment Technical Report 2017–2018 Supplement*, November 28, 2017

Electricity Impact Analysis

The California ISO and LADWP updated their joint winter seasonal assessment to analyze the natural gas requirements in the Greater Los Angeles area and Southern California regions during the winter of 2017–2018. This analysis determines how much natural gas the power plants must have to maintain transmission system reliability under normal and unexpected contingency conditions. LADWP had planned transmission upgrades to begin by December 1, 2017, but in response to the outages, LADWP postponed this work until February 1, 2018, after the risk of an abnormal peak day passes. The transmission upgrade is critical work that will allow LADWP to import more renewables. Prior to February 1, 2018, the minimum generation gas requirements are a little higher than last winter at 112.2 MMcfd postcontingency and increase to 293.3 MMcfd after February 1, 2018, when LADWP begins its transmission upgrade work. Table 31 presents the 1-in-10 winter peak day demand under normal dispatch and adjusted to account for minimum electric generation (MMcfd). Operating the electricity system at these minimum levels assumes importing electricity to avoid using local gas-fired electric generation, resulting in an increased cost to serve electric load. It also assumes there is sufficient energy available from external suppliers at the quantity and duration needed to meet energy import requirements.

Table 31: 1-in-10 Winter Peak Day Demand, Normal and Minimum Electric Generation (MMcfd)

Winter Demand (MMcfd)	1-in-10 Peak Day Normal Electric Generation ⁷⁵⁶	1-in-10 Peak Day Minimum Electric Generation, N-1 Contingency, November 1, 2017, to January 31, 2018	1-in-10 Peak Day Minimum Electric Generation, N-1 Contingency; LADWP Maintenance Work, Post Feb. 1, 2018
Core	3,250	3,250	3,250
Noncore, Non-Electric Generation	805	805	805
Noncore, Electric Generation	900	112	293
Total	4,955	4,167	4,348
Estimated Implied Electric Generation Curtailment ⁷⁵⁷	0	788	607

Source: Aliso Canyon Winter Risk Assessment Technical Report 2017–2018 Supplement, November 28, 2017

The system capacity and maximum supported demand from Table 31 are compared to the 1-in-10 winter peak demand in Table 32 and found that gas system shortfalls occur even with electric generation reduced to minimum generation. Table 32 presents the results through the winter reflecting the timing of the outages, return to service, and LADWP’s planned transmission upgrades.

Table 32: Shortfall on a 1-in-10 Peak Day With Minimum Electric Generation and an N-1 Contingency

(MMcfd)	Present-12/18/2017	12/18/2017-12/30/2017	12/30/2017-1/31/2018	Post-2/1/2018
1-in-10 Customer Demand With Generation Adjusted to Minimum Levels	4,167	4,167	4,167	4,348
Supported Demand Without Aliso Canyon	3,657	3,917	4,117	4,117
Shortfall Without Aliso Canyon	-510	-250	-50	-231

Source: Aliso Canyon Winter Risk Assessment Technical Report 2017–2018 Supplement, November 28, 2017

Winter Gas Balance Analysis

The Energy Commission updated the gas balances it prepared the 2016–2017 technical assessment. A gas balance assesses the gaps between capacity and demand that must be met with gas from storage and the impacts of storage drawdown over the winter. The gas balance reflects a 1-in-2 normal temperature condition winter, a 1-in-10 “cold and dry” winter, and an extreme

⁷⁵⁶ Default reference values estimated by SoCalGas to show readers the magnitude of the voluntary curtailment.

⁷⁵⁷ This represents the maximum voluntary reduction in gas use by electric generation.

winter peak day with 1-in-35 year demand for core customers. Compared to last year, it did not include a 10 percent reserve margin because given SoCalGas' current pipeline outages, the 10 percent reserve margin cannot be maintained. The gas balance instead shows storage withdrawals to achieve a 0 percent reserve margin.

The results of the analysis showed that under average normal temperatures, with mitigation measures in place and full deliveries at each receipt point, supplies appeared adequate to avoid curtailments of gas service to noncore customers. The cold winter demand case provided starker results and showed depleted storage inventory before the end of winter and inadequate storage inventory to provide the field pressure to withdraw sufficient gas to meet winter peak day demand.⁷⁵⁸ The results highlighted the need to preserve storage inventory for January 2018, which may require December curtailments.

<p style="text-align: center;">Gas Curtailment</p> <p>Core customers are homes, small commercial operations, and small industrial customers, whereas noncore customers are electric generators, refineries, large hospitals, and manufacturing. Core customers are to be the last customers curtailed in the event that there is insufficient supply in the system in part because restarting gas service for residential customers requires relighting pilot lights house by house.</p>

The Energy Commission updated the gas balance analysis in December 2017 and again in January 2018 to capture the impact of November and December data with the intent of providing updated situational outlooks for the remainder of the winter. The joint agencies released *Aliso Canyon Winter Risk Assessment Technical Report 2017–2018 Update: December Situational Update* and *Aliso Canyon Winter Risk Assessment Technical Report 2017–2018 Update: January Situational Update*.⁷⁵⁹ A warm November allowed SoCalGas to fully serve most demand using receipts of pipeline gas. As a result, it pulled no gas supply from inventory on a net basis. The December 1, 2017, reported inventory for all four fields was 68.9 Bcf – higher than the 67 Bcf inventory on November 1, 2017. Warm temperatures continued into December, which significantly contributed to SoCalGas avoiding the need to withdraw the quantities of gas it would during a normal (or cold) winter. The January 1, 2018, reported inventory for all four fields was 63.8 Bcf. As in the winter 2017–2018 technical assessment, the normal weather case still shows adequate supplies through the winter season. The cold temperature case in the January situational update estimates 45 Bcf at the end of January and 30 Bcf at the end of February. These compare to 15 Bcf and 3 Bcf, respectively, in the winter 2017–2018 technical assessment. The improved outlook for storage at the beginning of January means that the risk of gas service curtailments in January appears to be significantly reduced. Assuming no additional gas system or electric transmission system outages and that full

⁷⁵⁸ SoCalGas, in its October 30, 2017, Technical Assessment, cited inventory requirements of 43.3 Bcf as the level needed at the end of December to support the maximum withdrawals needed should an extreme peak day event occur in January. The technical assessment team knows of no publicly vetted analysis that verifies the 43.3 Bcf or the relationship between storage withdrawal capability and inventory.

⁷⁵⁹ *Aliso Canyon Winter Risk Assessment Technical Report 2017–2018 Update: December Situational Update*, December 14, 2017, is available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221988_20171215T161657_Aliso_Canyon_Winter_Risk_Assessment_Technical_Report_December_S.pdf. *Aliso Canyon Winter Risk Assessment Technical Report 2017–2018 Update: January Situational Update*, January 9, 2018, is available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN222118_20180109T094720_Aliso_Canyon_Winter_Risk_Assessment_Technical_Report_201718_Sup.pdf.

supplies arrive at the pipeline receipt points, the need for curtailments depends entirely on the weather and by how much consumers can decrease gas demand.

Mitigation Measures

All the existing mitigation measures will need to stay in place for winter 2017–2018. In addition, the joint agency technical assessment group suggests eight additional measures:

- Delay LADWP's transmission upgrade work until February 2018.
- Use more gas from Aliso Canyon than last winter.
- Perform more conservation, such as setting thermostats to lower temperatures and deploying more smart thermostats.
- Institute an emergency moratorium on new gas hookups in Los Angeles County.
 - Energy Commission Chair Weisenmiller and CPUC President Picker sent Los Angeles County Supervisor Barger a letter on December 4, 2017, recommending that Los Angeles County strongly consider and adopt an interim moratorium on new connections for gas service in areas of the Los Angeles County served by Aliso Canyon.⁷⁶⁰
 - The CPUC issued Draft Resolution G-3536, which was scheduled to be voted on January 11, 2018, but was held until February 8, 2018, pending further review. It orders SoCalGas to implement an emergency moratorium on new commercial and industrial natural gas service connections in both incorporated and unincorporated areas of Los Angeles County.⁷⁶¹
- Shift electric generation less (than down to minimum generation levels) but more frequently to preserve inventory (move gas demand outside the Greater Los Angeles Area).
- Update the CPUC's analysis in its Section 715 report to reflect the Aliso Canyon inventory target for new circumstances.
- Bring liquefied natural gas to Otay Mesa if SoCalGas cannot acquire pipeline capacity.
- Monitor inventory levels and gas system reliability outlook and communicate constantly, including to the public.

The outlook for winter 2017–2018 depends largely on the weather, even with the mitigation measures in place. Natural gas service is threatened to noncore customers, including electric generators this winter due to unprecedented pipeline outages on the SoCalGas system. This threat exists even though there is more gas in storage than at this time last year. Any actions consumers

⁷⁶⁰ Letter from Energy Commission Chair Weisenmiller and CPUC President Picker to Los Angeles County Supervisor Barger is available at: http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN221898_20171205T122310_12417_Letter_to_Kathryn_Barger_LA_County_re_Aliso.pdf

⁷⁶¹ CPUC Draft Resolution G-3536 is available at <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M201/K367/201367863.PDF>.

take to reduce natural gas use in December will help preserve gas in storage for January when the 1-in-35 year peak demand remains possible.

Other Aliso Canyon Activities

The CPUC has updated its Aliso Canyon Demand-Side Resource Impact Report.⁷⁶² The report examines steps taken to reduce the demand for natural gas. To get a more accurate assessment, the report updates metrics used to measure demand savings. It also refines the estimates of demand-side resources unrelated to the Aliso Canyon mitigation efforts that reduce the demand for natural gas in the region.

Planned Improvements

The California ISO has three transmission projects underway that will strengthen Southern California energy reliability. The planned addition of synchronous condensers at the Santiago, San Onofre, and San Luis Rey facilities will permit the electrical system to adjust more readily to changing conditions and will reduce the amount of in-basin generation needed to meet reliability.

The Energy Commission will continue to provide support and coordinate contingency planning efforts related to reliability with reduced access to Aliso Canyon, as well as help plan for its eventual closure. As noted in Chapter 8 (Natural Gas Trends and Outlook), various stakeholders have suggested ideas for measures to reduce reliance on Aliso Canyon, including Gill Ranch Gas Storage and Environmental Defense Fund. These ideas may or may not end up being workable and need to be more fully developed to make that determination.

Update on Southern California Electricity Reliability

Since 2013, the joint agencies, along with representatives from the investor-owned utilities and local air districts in the South Coast Air Basin, have conducted public workshops at least annually to discuss electrical reliability in Southern California. Much of the transmission system in Southern California was built around the assumption that San Onofre would continue to operate. The closure of San Onofre required a rapid response that was more complicated than replacing 2,200 MW of capacity. San Onofre provided voltage support and reactive power to maintain grid stability, as well as capacity to balance flows and keep transmission lines from overloading.

Building off an action plan developed in 2013 at the direction of Governor Brown, the energy agencies continue to put additional solutions in place. Circumstances and conditions continue to evolve – with schedule slippage on some critical resources and infrastructure – while new opportunities for solutions, such as storage, demand response, and energy efficiency, appear. One of two mitigation options designed for grid reliability is being triggered – a once-through cooling compliance deferral in response to the delay of the Carlsbad Energy Center has been requested by the joint agency Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) and granted by the State Water Resources Control Board (SWRCB).

⁷⁶² *Aliso Canyon Demand Side Management Impact Summary*, January 2017, http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/2017_AlisoDSMImpactSummary_01-31.pdf.

The workshop on May 22, 2017, provided an update from the previous year on overall reliability and the status of projects initiated to meet the 2014 suggested direction of the action plan that San Onofre's shuttered capacity be replaced with roughly 50 percent preferred resources, 50 percent conventional generation, and transmission infrastructure improvements that could provide voltage support. The status below updates the information provided in the *2016 IEPR Update*.

Local Reliability Assessment Framework

Reliability in Southern California is tied to the compliance schedule set by the SWRCB for closure of coastal power plants that use ocean water for once-through cooling. A SACCWIS representative provided a presentation on its annual review of power plant implementation plans with the SWRCB policy on OTC, potential impacts on grid reliability, and a request to the SWRCB for an Encina OTC compliance date deferral. Agency staff reported on progress milestones that each tracks. Preferred resources and conventional generation are tracked by the CPUC, transmission is tracked by the California ISO, and potential contingency options, including local capacity area assessment tool (LCAAT) scenarios and OTC deferral, are tracked by the Energy Commission.

The LCAAT provides an integrated assessment of whether resources in five regions of Southern California are expected to meet or exceed capacity requirements for each local area. Projected shortfalls indicate a looming reliability problem. If the assessment of the LCAAT is confirmed by in-depth power flow and stability studies by the California ISO, then contingency mitigation measures would be considered. In general, the request for the Encina OTC deferral (described in the next section) followed this method. In the *2016 IEPR Update*, the LCAAT showed projected capacity shortfalls in 2018 due to a delay in the construction of the Carlsbad power plant (replacement project for Encina). As a result of the delay of the Carlsbad plant, the California ISO conducted power flow and stability analyses. Energy Commission staff did not update the LCAAT analysis in this *IEPR* cycle because actions to deal with near-term reliability issues are already underway.

The Bay Area Municipal Transmission Group commented, "While the LCAAT tool's original objective of providing an early warning of the need to trigger short-term mitigation measures in implementing the 2020 plan will soon be met, this tool serves as a valuable visual tool in understanding the ability to maintain the local electric reliability in the face of planning uncertainties in the post-2020 period."⁷⁶³ Reliability issues in Southern California are further complicated by the evolving electricity market structure that is impacting utility procurement of preferred resources, as described in Chapter 1. Another complication relates to California's success in developing renewable energy, which has resulted in some areas in the California ISO footprint having a surplus of natural gas-fired generation capacity, while other areas face the risk of retirement of natural gas-fired power plants that are critical for reliability because they are strategically located and have the capability to provide the fast ramping and other ancillary

⁷⁶³ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217860_20170605T160951_Kathleen_Smiley_Hughes_Comments_BAMx_Comments_on_the_Joint_Agen.pdf.

services needed to integrate renewable resources. See Chapter 3 for more information. The LCAAT is expected to be useful on an ongoing basis to help manage these uncertainties.

Conventional Generation Projects

In 2017, progress on permitting generation continued with permits issued to Huntington Beach and Alamitos, and the Stanton application for certification underway. In addition, uncertainties introduced by interveners contesting CPUC-approved power purchase agreements between project developer and utility were resolved in early 2017. Table 33 lists the six conventional generation projects reported in the *2016 IEPR Update* that the joint agency team continues to track.

Table 33: Conventional Generation Projects in San Onofre Area

	Conventional Generation Projects	Capacity MW	Sponsor	Target In-Service Dates
1	Pio Pico	305	SDG&E	Operational 10/20/2016
2	Carlsbad Energy Center	500	SDG&E	4th Qtr. 2018
3	AES Alamitos	640	SCE	6/1/2020
4	AES Huntington Beach	644	SCE	5/1/2020
5	Stanton Energy Reliability Center	98	SCE	7/1/2020

Source: California Energy Commission

The joint agency team is tracking one SDG&E project (Carlsbad Energy Center) totaling 500 MW. The other SDG&E project the team was tracking, Pio Pico, became operational in October 2016. The Carlsbad Energy Center, which is replacing the OTC Encina facility, has been delayed by legal challenges that were resolved in January 2017. Although CPUC approval of the power purchase agreement for the Carlsbad project was appealed in 2015, delaying the on-line date until 2018, the First District Court of Appeals ruled on December 1, 2016, affirming the CPUC’s decision to grant the power purchase tolling agreement⁷⁶⁴ to SDG&E and NRG Energy for the 500 MW Carlsbad Energy Center project. The Sierra Club, Protect Our Communities Foundation, and the Center for Biological Diversity had until January 9, 2017, to seek Supreme Court review, which they did not. In a generator letter update to the SWRCB dated January 4, 2017, NRG Energy stated that it is optimistic that Carlsbad will be on-line in the fourth quarter of 2018. Accordingly, the energy agencies began to implement an OTC compliance date deferral for Encina with the SWRCB.

With confirmation that Carlsbad will not be available for summer 2018, the California ISO conducted an interim analysis of 2018, updating only key parameters from its *2017 Local Capacity Technical Analyses*⁷⁶⁵ (LCTA), to determine whether the OTC compliance schedule for Encina (December 31, 2017) and the revised on-line date for Carlsbad (fourth quarter of 2018) would adversely impact the reliability of California’s electricity supply. The California ISO

⁷⁶⁴ A *power purchase tolling agreement* is typically between a power buyer and a power generator, under which the buyer supplies the fuel and receives an amount of power generated based on an assumed heat rate at an agreed cost.

⁷⁶⁵ California ISO. April 29, 2016. *2017 Local Capacity Technical Analyses*. <http://www.caiso.com/Documents/Final2017LocalCapacityTechnicalReportApril292016.pdf>.

prepared the interim analysis to initiate the OTC deferral process, recognizing that the *2018 LCTA*,⁷⁶⁶ finalized in May 2017, would replace the interim analysis.

The California ISO studied the local capacity requirement consequences of a Carlsbad Energy Center delay beyond the second quarter of 2018 using updated assumptions to determine how much of Encina's capacity would be needed. Encina Unit 1 retired on April 18, 2017, to make way for the Carlsbad construction. The existing generation resources (regardless of technology) that were expected on-line with commercial operating dates on or before June 1, 2018, were modeled. In the interim analysis, the California ISO considered two scenarios assuming 1) Aliso Canyon was fully operational (unconstrained) and 2) Aliso Canyon was not available (constrained). The studies found the reliability need for Encina capacity ranged from 560 MW to 859 MW, depending on the assumed impact of the Aliso Canyon uncertainty.

Based on this analysis, SACCWIS considered the best course of action to recommend that SWRCB defer the OTC compliance dates for Encina Units 2–5 (840 MW) until December 31, 2018, to maintain grid reliability. SACCWIS documented the findings in the *Report of the Statewide Advisory Committee on Cooling Water Intake Structures Encina Power Station 2018 Reliability Study February 2017*⁷⁶⁷ and adopted it at a February 23, 2017, SACCWIS meeting. The report was then presented to the SWRCB as an information item at its March 21, 2017, board meeting. In May 2017, California ISO finalized the *2018 LCTA* and sent a letter to the executive director of the SWRCB informing him of the updated Encina analysis and confirming a base need for about 100 MW of the Encina plant, with other scenarios likely leading to a higher need.⁷⁶⁸ The SWRCB staff published an *Amendment to the Water Quality Control Policy On The Use Of Coastal And Estuarine Waters For Power Plant Cooling For Encina Power Station Draft Staff Report May 22, 2017*,⁷⁶⁹ which started a 60-day public comment period. The SWRCB approved the Encina OTC compliance date deferral at its August 15, 2017, board meeting. An amendment to the Encina OTC compliance date by the Office of Administrative Law was approved in December 2017.

The joint agency team is tracking three additional projects being pursued by SCE totaling 1,382 MW. The Energy Commission approved the Alamitos Energy Center application for certification and the Huntington Beach Energy Project license amendment on April 12, 2017. The Stanton Reliability Energy Center application for certification is in process. In D. 15- 11-041,⁷⁷⁰ the CPUC approved SCE's contracts for AES Alamitos (640 MW), AES Huntington Beach (644 MW), and Stanton Energy Reliability Center (98 MW), as well as 430 MW of preferred resources, including

766 Report located at <http://www.caiso.com/Documents/Final2018LocalCapacityTechnicalReport.pdf>.

767 Report is located at http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/saccwis_encina_2018rpt.pdf.

768 The *2018 LCTA* incorporated the latest Energy Commission demand forecast adopted in January 2017 and no longer included an Aliso Canyon sensitivity. The tighter noncore balancing rules adopted by the CPUC eliminated the gas storage constraint that the sensitivity was designed to resolve by balancing resources between the Greater Los Angeles and San Diego areas. The letter and the *2018 Local Capacity Technical Analysis* are located at http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/saccwis/docs/CAISO_170517_letter_and%20final_2018LCTR.pdf.

769 http://www.waterboards.ca.gov/water_issues/programs/ocean/cwa316/docs/otc_amend_appendix%20a.pdf.

770 CPUC D.15-11-041, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M156/K064/156064924.PDF>.

energy storage. Several parties submitted applications for rehearing the decision approving the power purchase agreements for conventional generation, which the CPUC denied in D.16-05-053.⁷⁷¹ Interveners then appealed the CPUC’s decision to the court of appeals, but the court rejected the petition on September 1, 2016. In D.16-05-053, CPUC modified the decision to require SCE to procure the minimum amounts of preferred resources. This modification effectively required SCE to procure an additional 169 MW of preferred resources or file a petition to change the underlying requirement if additional procurement is not necessary.

Preferred Resources

The joint agency team continues to track procurement of preferred resources identified in the CPUC’s Long-Term Procurement Plan (LTPP), which are designated in specific CPUC decisions, as well as procurement assumed to occur through ongoing programs. The procured preferred resources from competitive requests for offers began coming on-line as early as May 1, 2016, as shown in Table 34.

Table 34: Procurement of Preferred Resources in San Onofre Area

	Preferred Resource Projects	Capacity MW	PTO/Sponsor	Target In-Service Dates
1	SCE Energy Storage	165.7	SCE	2016–2023
2	SCE Energy Efficiency	113	SCE	2016–2020
3	SCE Demand Response	123	SCE	2016–2023
4	SCE Renewable Distributed Generation	51.75	SCE	2016–2023
5	SCE Preferred Resources Pilot Region includes EE, DR, Solar DG, Energy Storage, Hybrid PV + Energy Storage	205	SCE	2014–2020
6	SDG&E Wildan Energy Efficiency	18.5	SDG&E	Q4 2021
7	SDG&E Escondido/El Cajon Energy Storage	37.5	SDG&E	Jan. 2017
8	SDG&E Miramar/Fallbrook Energy Storage	70	SDG&E	Q1 2021/Q4 2019
9	SDG&E Powin/Enel/AMS	13.5	SDG&E	Q2 2021/Q4 2021/Q4 2019
10	SDG&E OhmConnect	4.5	SDG&E	Demand Response

Source: SCE and SDG&E presentations at the May 22, 2017, IEPR workshop

The CPUC approved preferred resource procurement for SCE through D.13-02-015⁷⁷² and D.14-03-004⁷⁷³ for 600–1,000 MW (as well as an additional 300–500 MW that could be from any resource). Subsequently, the CPUC approved SCE’s application for 500.6 MW of preferred resources in the Greater Los Angeles Area on November 19, 2015, with the exception of six demand response (DR) contracts totaling 70 MW, resulting in a net of 430.6 MW. These DR contracts were denied on the basis of not meeting the definition for “preferred resources” and

⁷⁷¹ CPUC D.16-05-053, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M162/K888/162888503.pdf>.

⁷⁷² CPUC D.13-02-015, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M050/K374/50374520.PDF>.

⁷⁷³ CPUC D.14-03-004, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M089/K008/89008104.PDF>.

excessive costs. Of the 656 MW of procured preferred resources from competitive requests for offers,⁷⁷⁴ most were procured from these two decisions authorizing resources for local capacity requirements, but preferred resources also were procured from SCE's Preferred Resource Pilot, Aliso Canyon Resolution to expedite resources, the Energy Storage Request for Offers, and the Renewables Portfolio Standard.

As mentioned, several parties submitted applications for rehearing the decision approving the power purchase agreements for conventional generation. Since the preferred resources were included in the same application for approval, the practical effect is a slowdown of the scheduled deployment of preferred resources relative to that shown in Table 35. Consequently, the ability to evaluate the performance of preferred resources is also delayed, and this puts evaluation of local capacity requirements (LCR) at risk. At the May 22, 2017, IEPR workshop, SCE confirmed that deployment of LCR preferred resources has lagged the original 2017 in-service dates, but the contracted LCR preferred resources are on track to deliver when they will be needed by 2020, the critical year when several OTC facilities are scheduled to retire.

SCE's Preferred Resources Pilot,⁷⁷⁵ a multiyear clean energy study, is investigating if, and how, preferred resources will allow SCE to meet local needs at the distribution level and manage or offset projected electricity demand growth from 2013–2022 in the Johanna and Santiago substation areas of Orange County. If successful, the pilot will allow SCE to meet demand growth with less conventional generation. The target in-service date for these resources is in the 2014–2020 time frame. The delay in LCR contract approval is affecting SCE's ability to meet the objective of the Preferred Resource Pilot to validate that distributed energy resources will perform as assumed and be able to meet planning needs. Due to the lagging deployment, SCE expects to provide validation on preferred resource performance after summer 2018. The joint agencies will continue to monitor progress and ensure that resources are on track to meet reliability needs. Any further delays should be addressed promptly before the scheduled retirement of the OTC facilities.

SCE's second Preferred Resources Pilot request for offers (RFO) resulted in contracts for 125 MW of preferred resources (55 MW of demand response, 60 MW of in-front-of-the-meter energy

774

[https://www.sce.com/wps/portal/home/procurement/solicitations!/ut/p/b1/rVRNc9owEP0rXJhpD0JrJLB8dPiOG2gToAm-MLKQwY0tObZJa359xcd02kMMTOOTLb99u-_trnCan3Gg-Fu84WWsFU8030F35Xt91xrRtgcLn4BL0E_7iwl8sTsGsDQAeOdx4RhvsZE79mbggX3vgHf37XHgzB3CbIKfcIADocqs3OJlIeRkaFVKVa6kasL5vQlSyXxTNbJci10u0-NZoZNYxOWx0uLAKol4jZc241xyK0QQdgm4FDEbLpGgtrrhARUNI9V11TVp3qIT3H1wBq4nuDTn38AXDBdf-SrSZB05_0JhtjCy-3KFaRxs8nG1Gxy7KkQilXfHM0888fvhMHO09dMRmcEQzG_lfwRvMHAh55gOnMNZVA9woya_ylGoMrVG4SHZoxfLrDwQvRQ_XzoMxVIWFGWS4jmcu8tdWfKZC3CslzsW1VfKt1S-gUL43N9rsZpm08u3FuLhBaNxP6V-xX_OP1NXDNIhy24Zdr-h9rUi9gSP4WQDih7bUIUSfsAKKWYMghEUEO73LqOCS02tYFwu9wM6F_xe59oCNNSLTgSUPwjJvDqpHL1118ghaNT4nIP9dr7C3-GSNJQ8YEI0hyWyAa2SFiIjKtt2wigBAH5PoSoXUzoX_FhfOhpvEkLrQxTVVaNc74otS5uVBwli5SRqo4RsESvTyO917JgHSyt_19NJ0iHrKK7OdRmq4mxW-0pbHS/dl4/d5/L2dBISEvZOFBIS9nQSEh/.](https://www.sce.com/wps/portal/home/procurement/solicitations!/ut/p/b1/rVRNc9owEP0rXJhpD0JrJLB8dPiOG2gToAm-MLKQwY0tObZJa359xcd02kMMTOOTLb99u-_trnCan3Gg-Fu84WWsFU8030F35Xt91xrRtgcLn4BL0E_7iwl8sTsGsDQAeOdx4RhvsZE79mbggX3vgHf37XHgzB3CbIKfcIADocqs3OJlIeRkaFVKVa6kasL5vQlSyXxTNbJci10u0-NZoZNYxOWx0uLAKol4jZc241xyK0QQdgm4FDEbLpGgtrrhARUNI9V11TVp3qIT3H1wBq4nuDTn38AXDBdf-SrSZB05_0JhtjCy-3KFaRxs8nG1Gxy7KkQilXfHM0888fvhMHO09dMRmcEQzG_lfwRvMHAh55gOnMNZVA9woya_ylGoMrVG4SHZoxfLrDwQvRQ_XzoMxVIWFGWS4jmcu8tdWfKZC3CslzsW1VfKt1S-gUL43N9rsZpm08u3FuLhBaNxP6V-xX_OP1NXDNIhy24Zdr-h9rUi9gSP4WQDih7bUIUSfsAKKWYMghEUEO73LqOCS02tYFwu9wM6F_xe59oCNNSLTgSUPwjJvDqpHL1118ghaNT4nIP9dr7C3-GSNJQ8YEI0hyWyAa2SFiIjKtt2wigBAH5PoSoXUzoX_FhfOhpvEkLrQxTVVaNc74otS5uVBwli5SRqo4RsESvTyO917JgHSyt_19NJ0iHrKK7OdRmq4mxW-0pbHS/dl4/d5/L2dBISEvZOFBIS9nQSEh/)

775 Information on SCE's preferred resource pilot is located at [https://www.sce.com/wps/portal/home/about-us/reliability/meeting-demand/our-preferred-resources-pilot!/ut/p/b1/hc-xDoLwGATgR-qVFijTyDlr4lKaiJ2MIME0UH4_MLhlW47ZLvhNBDCKM8ZNU8Z2eY7zPPRRXxw1JqzO23rSgXX7MqkbCQE7gMgH8CWFrxbhR6Sx1LEH25POwXVVKluzKn2-DhqHDaD1AiqLtnOHGfQKrHrsPZECigWsvHg9BiRO9AXFMTc8/dl4/d5/L2dBISEvZOFBIS9nQSEh/.](https://www.sce.com/wps/portal/home/about-us/reliability/meeting-demand/our-preferred-resources-pilot!/ut/p/b1/hc-xDoLwGATgR-qVFijTyDlr4lKaiJ2MIME0UH4_MLhlW47ZLvhNBDCKM8ZNU8Z2eY7zPPRRXxw1JqzO23rSgXX7MqkbCQE7gMgH8CWFrxbhR6Sx1LEH25POwXVVKluzKn2-DhqHDaD1AiqLtnOHGfQKrHrsPZECigWsvHg9BiRO9AXFMTc8/dl4/d5/L2dBISEvZOFBIS9nQSEh/)

storage, and 10 MW of hybrid behind-the-meter solar PV and energy storage), which are pending CPUC approval.

The CPUC authorized SDG&E to procure 300 MW of preferred resources (at least 25 MW of the 300 MW must be from energy storage) in D.15-05-051. SDG&E issued the 2014 All Source LCR RFO in September 2014 and accepted offers for 18.5 MW of energy efficiency and 20 MW of energy storage. The CPUC approved the contract for energy efficiency, but SDG&E exercised its rights and subsequently terminated the contract for energy storage.⁷⁷⁶ In response to an Aliso Canyon resolution seeking expedited resources to be on-line by the end of 2016, SDG&E filed an application (A.16-03-014) for 38.5 MW of energy efficiency and storage, of which 37.5 MW of energy storage⁷⁷⁷ was approved by the CPUC and came on-line in early 2017. SDG&E also launched a 2016 preferred resources LCR RFO and on April 19, 2017, filed an application seeking approval of 83.5 MW of energy storage and 4.5 MW of demand response resources, which is pending CPUC approval. (For more information on energy storage and demand response activities, see Chapter 3 and Chapter 4.) With approval of these projects, SDG&E will be on its way to meeting its minimum preferred resources procurement target.

Transmission Projects

The joint agency team continues to track the nine active transmission projects, including two critical transmission lines, and up to 1,800 MVars of reactive support identified in the *2016 IEPR Update*.⁷⁷⁸ Most of the transmission projects being tracked are on schedule to be in service in summer 2018 and summer 2021. Two large transmission line projects are encountering delays, however, with each possibly leading to reliability concerns unless mitigation measures are undertaken. The transmission projects being tracked, the sponsor, and expected in-service dates are shown in Table 35, with further discussion provided below.

⁷⁷⁶ The Hecate Energy Bancroft contract with San Diego Gas & Electric contained a provision that allowed San Diego Gas & Electric to terminate the contract “if it fails to continue to be attractive for SDG&E customers.”

⁷⁷⁷ SDG&E’s contracted with AES Energy Storage LLC for two lithium-ion battery storage facilities at the Escondido (30 MW/120 MWh) and El Cajon (7.5 MW/30 MWh) SDG&E substations farther south of Path 26, which help address Aliso Canyon-related reliability issues.

⁷⁷⁸ *Reactive power* is measured in volt ampere reactive (Var or VAr), and an over- or undersupply of reactive power causes voltages to climb or fall. The San Onofre Nuclear Generating Station provided crucial voltage support in the southern Orange County region, and California ISO approved several transmission projects to replace the voltage support lost with the retirement of San Onofre.

Table 35: Transmission Projects in San Onofre Area

	Transmission Projects	PTO/Sponsor	Target In-Service Dates
1	Talega Synchronous Condensers (2x225 MVAR)	SDG&E	In Service 8/7/2015
2	Extension of Huntington Beach Synchronous Condensers (280 MVAR)	SCE	Extended for 1/1/17– 12/31/17
3	Imperial Valley Phase Shifting Transformers (2x400 MVAR)	SDG&E	In Service 5/1/2017
4	Sycamore Canyon–Peñasquitos 230 kV Line	SDG&E	June-18
5	Miguel Synchronous Condensers (450/-242 MVAR)	SDG&E	In Service 4/28/2017
6	San Luis Rey Synchronous Condensers (2x225 MVAR)	SDG&E	Feb-18
7	San Onofre Synchronous Condensers (1x225 MVAR)	SDG&E	Aug-18
8	Santiago Synchronous Condensers (1x225 MVAR)	SCE	Dec-17
9	Mesa Loop-in Project and South of Mesa 230kV Line Upgrades	SCE	Mar-22

Source: California Energy Commission

The Talega synchronous condensers were completed and placed in service in August 2015. The California ISO Board of Governors extended the reliability-must-run contract for the Huntington Beach synchronous condensers through 2017, at which time they will be retired to make way for the new Huntington Beach Energy Center.

Two transmission projects began service in 2017. The California ISO Board of Governors approved the Imperial Valley phase-shifting transformer⁷⁷⁹ and the Miguel synchronous condenser projects March 20, 2014, as part of the California ISO’s 2013–2014 Transmission Planning Process (TPP). SDG&E is the project sponsor of both projects. The Imperial Valley phase-shifting transformer began service May 1, 2017, and the Miguel synchronous condensers began service April 28, 2017.

The California ISO board approved the San Luis Rey synchronous condenser project March 20, 2014, as part of the California ISO’s 2013–2014 TPP. The project sponsor is SDG&E. The project is within the existing facility boundary, which is already permitted for this purpose and voltage. SDG&E confirmed construction began in May 2015 with the removal of the 138 kV facilities at San Luis Rey. The project in-service date has been shifted from June 2017 to February 2018 due to the unexpected delay of grading permits from the City of Oceanside.

The California ISO board approved the San Onofre Synchronous Condenser project on March 20, 2014, as part of the California ISO’s 2013–2014 TPP. The project sponsor is SDG&E. This project is within the existing facility boundary, which is already permitted for this purpose and voltage.

⁷⁷⁹ The Imperial Valley phase shifter controls power flow between San Diego and CFE in Mexico to provide resources from the Imperial Valley to the SDG&E system to help address voltage instability under contingency conditions. The Miguel synchronous condensers provide reactive power support to address low voltage conditions at Miguel and ECO 500 kV buses under normal summer peak load conditions.

The facility was permitted August 13, 2015, and construction started on May 2, 2016. The target in-service date has been delayed to August 2018.

The California ISO board approved the Santiago synchronous condenser project March 20, 2014, as part of the California ISO's 2013–2014 TPP. The project sponsor is SCE. The project is within the existing facility boundary, which is already permitted for this voltage. This project was formerly collocated with the San Onofre synchronous condenser but became a separate project with a different sponsor and location due to the challenges in constructing two of these dynamic reactive support devices on limited real estate located within the U.S. Marines' Camp Pendleton facility. Onsite construction commenced May 2, 2016, with a targeted in-service date in December 2017.

The California ISO Board of Governors approved the Mesa Loop-in 500 kV project March 20, 2014, as part of the California ISO's 2013–2014 TPP and subsequently approved the South of Mesa 230 kV line upgrades in conjunction with the Mesa Loop-in project as part of the California ISO's 2014–2015 TPP. The Mesa Loop-in 500 kV project and South of Mesa 230 kV line upgrades were approved by the CPUC on February 9, 2017.

The CPUC's final decision approving the Mesa Loop-in project was largely consistent with SCE's proposed project and rejected alternative project configurations proposed by CPUC staff in the environmental impact report. Timing of the CPUC approval and preconstruction requirements for obtaining other permits and approvals have delayed the start of construction. As a result, SCE has revised the projected in-service date to 2022, which was reported in its Securities and Exchange Commission Form 10-Q filing March 31, 2017. At the May 22, 2017, workshop, SCE refined the projected operating date to March 2022. On June 26, 2017, the City of Montebello contested the CPUC decision, specifically its certification of the environmental impact report, and filed a petition for review with the California Supreme Court. The City of Montebello believes a "no project alternative" should have been considered. The appeal does not stay, or halt, construction. SCE originally planned to begin construction before bird nesting season, but due to the timing of the CPUC approval, construction cannot begin until after bird nesting season in September 2017. A biological opinion from the California Department of Fish and Wildlife must be issued before the CPUC issues the notice to proceed. The notice to proceed is expected by mid-September, at which time construction will begin. SCE estimates that construction will take 48 months once work begins.

The Mesa Loop-in project has been identified as critical for Southern California reliability before summer 2021, as scheduled retirements of OTC units proceed, according to sensitivity analysis conducted in the California ISO's 2015–2016 TPP. The results of California ISO sensitivity analysis showed that if the Mesa Loop-In project in-service date is delayed beyond the beginning of summer 2021 and resources are insufficient to satisfy resource adequacy requirements, then a temporary extension of the Redondo Beach or Alamitos facilities, if electrically feasible, beyond the December 31, 2020, OTC compliance date could be a potential mitigation option. The California ISO did not conduct a Mesa Loop-In sensitivity analysis in the 2016/2017 TPP, so further analysis would be needed to determine the impact of a delay. In light of the potential

delay, SCE has proposed other mitigation solutions to enable the scheduled retirement of the OTC units. These include:⁷⁸⁰

- Evaluating options to accelerate construction, such as double work shifts.
- Implementing a temporary operating procedure to manually change the system configuration (open Serrano corridor in Orange County) to redirect power to other transmission corridors after the loss of one bulk transmission element.
- Launching a temporary remedial action scheme to automatically change the system configuration (open Serrano corridor) after the loss of two bulk transmission elements consecutively.⁷⁸¹
- Upgrading the terminal equipment of 230 kV line(s) in the Serrano corridor to increased emergency rating.

The California ISO Board of Governors approved the Sycamore-Peñasquitos 230 kV transmission project March 20, 2013, as part of the California ISO 2012–2013 TPP. On March 14, 2014, the California ISO selected SDG&E, in conjunction with Citizens Energy Corporation, as project sponsor through a competitive solicitation. On October 13, 2016, the CPUC approved (in Decision D.16-10-005) the environmentally superior alternative with additional undergrounding identified in the final environmental impact report for this project with a cost cap of \$260 million. It is expected to be in-service June 25, 2018, with an accelerated schedule.

As the projected in-service date moved from June 1, 2018, to June 25, 2018, California ISO considered the project at risk of a potential delay beyond June 2018 and worked with SDG&E to develop a short-term solution. On April 25, 2017, California ISO conducted a workshop to discuss the Mission-Old Town Flow Control Upgrade. The project would provide a partial mitigation and minimize additional LCR for the summer 2018 in the San Diego local capacity subarea if the Sycamore-Peñasquitos project is delayed. SDG&E subsequently identified potential engineering and permitting challenges, questioning the ability to meet the June 1, 2018, target in-service date and avoid other schedule impacts on transmission projects in the area. Given these concerns, this short-term mitigation did not go forward.

The California ISO 2018 LCTA sensitivity analysis shows that a delay of the Sycamore-Peñasquitos transmission line beyond June 2018 causes overloading concerns of transmission lines in the Mission and Old Town areas in San Diego and increases the local capacity requirements in the San Diego-Imperial Valley local area. The transmission line overloads depend partially on the amount of Encina generation available. The power flow studies indicate, however, that even with all Encina generation available and with no other mitigations, overload conditions still exist. The CPUC did not adopt the higher local capacity requirements from this sensitivity in

⁷⁸⁰ At the May 22, 2017, IEPR workshop, SCE discussed the mitigation options under development in the event of a Mesa Loop-In delay, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-11/TN217645_20170519T114355_Energy_Reliability_in_Southern_California.pdf.

⁷⁸¹ This remedial action scheme requires installation of relays and telecommunication equipment to implement.

its resource adequacy proceeding. If this transmission project is delayed beyond June 2018, one of the mitigation solutions is load curtailment.

Contingency Mitigation Measures

At the 2016 workshop on Southern California electricity reliability, Energy Commission staff, with input from technical staff of the other Southern California reliability project (SCRIP) agencies, published a staff paper on *Mitigation Options for Contingencies Threatening Southern California Electric Reliability* that describes the two mitigation options – OTC compliance date deferral and new gas-fired generation.⁷⁸²

Once-Through Cooling Compliance Date Deferral

The OTC compliance date deferral measure relies on requesting the SWRCB to defer compliance dates for specific OTC facilities to maintain grid reliability. The OTC deferral process largely will follow five broad steps from conducting analyses, preparing reports, holding meetings and hearings, to obtaining Office of Administrative Law approval of an OTC amendment. The OTC deferral process can take up to one year or more, depending on the time to conduct additional analyses.

New Gas-Fired Generation

The new gas fired generation option relies on a pool of projects that are already permitted but do not have power purchase agreements. Three options exist: Carlsbad Energy Center, Huntington Beach Energy Project, and Alamitos Energy Center.

- Carlsbad is permitted for 600 MW (6 100 MW units), but it has a power purchase agreement for 500 MW. NRG, the developer of Carlsbad, plans to build 500 MW. The remaining 100 MW can be considered a contingent gas-fired generation option.
- The Energy Commission approved the application for certification for Alamitos on April 12, 2017, which includes Phase 1 (640 MW combined-cycle gas plant) and Phase 2 (400 MW simple-cycle gas plant). Alamitos has a power purchase agreement for Phase 1 only. Phase 2 can be considered a contingent gas-fired generation option.
- The Energy Commission approved the amendment to Huntington Beach on April 12, 2017, which includes Phase 1 (644 MW combined cycle gas plant) and Phase 2 (200 MW simple-cycle gas plant.) Huntington Beach has a power purchase agreement for Phase 1 only. Similar to Alamitos, Phase 2 can be considered a contingent gas-fired generation option.

These contingent generation options have a finite life because the air permits will expire over time. Reevaluation of best available control technology and lowest achievable emission rate⁷⁸³

⁷⁸² http://docketpublic.energy.ca.gov/PublicDocuments/16-IEPR-06/TN212836_20160818T131005_Staff_Report_Mitigation_Options_for_Contingencies_Threatening_S.pdf.

⁷⁸³ *Best available control technology* is required on major new or modified sources in clean areas (for example, attainment areas). An area is designated as in attainment if it meets federal emissions standards. *Lowest achievable emission rate* is required on major new or modified sources in nonattainment areas.

may be required on these contingent generator mitigation options, depending on the timing of construction and air district rules, and will be determined on a case-by-case basis.⁷⁸⁴

Triggering Mitigation Measures

The contingency process discussed among the SCRPs agencies seeks to assure reliability by anticipating any projected shortfall of energy resources needed to meet local capacity requirements. The nature and expected duration of a deficit would inform a choice between the two mitigation options developed to date. For example, a temporary deficit induced by a delay in the on-line date of a replacement power plant, such as the Carlsbad project, would lead to choosing the OTC deferral option.

Alternatively, if the expected deficit is shown to persist, then something more fundamental is creating the problem. For example, unexpected retirements due to more stringent air quality regulations than previously expected could cause a persistent deficit. The new gas-fired generation option should be considered a mitigation option of last resort to cure a systemic deficiency. If the energy agencies' leadership recommends triggering mitigation measures, then the applicable agencies overseeing the approval of a specific mitigation measure would implement proposed actions, according to established approval processes.

Over the past year, the joint agency SCRPs team triggered the OTC compliance date deferral contingency mitigation option in response to the delay of the Carlsbad Energy Center as described above. The joint agencies implemented the OTC deferral option according to the broad guidelines described at the *2016 IEPR Update* workshop on Southern California reliability. Since this was the first OTC deferral triggered to maintain grid reliability, the joint agencies worked through the details and completed the deferral by the end of 2017. Although the 2016 staff report identified contracting issues that pose a risk of further delay, the contracting issues were separated from the SWRCB's decision of whether to extend the compliance date. Procurement and contracting for the resource followed the regular CPUC resource adequacy process⁷⁸⁵ but the load serving entities were unable to procure sufficient capacity in the San Diego area. The California ISO issued a capacity procurement mechanism designation for 272 MW of Encina unit 4 and 273 MW of Encina unit 5, effective January 1, 2018. Construction of the Carlsbad Energy Center is underway and NRG expects to achieve full commercial operation by December 2018, at which time the Encina facility will be permanently retired.

After the SWRCB approval of the Encina OTC compliance date deferral, a contract for Encina should be executed for 2018. The 2018 CPUC resource adequacy decision raised contracting issues with an OTC facility beyond the associated OTC compliance date. To encourage IOUs to find non-OTC power generation sources, the CPUC adopted restrictions and benefits

⁷⁸⁴ The authority-to-construct permit for Carlsbad issued by the San Diego Air Pollution Control District cannot be valid for more than five years from the date the Energy Commission approved the amendments for the project. The Energy Commission approved the amendments to the project on July 30, 2015, which means the sixth 100 MW unit would need to be installed by July 30, 2020. Otherwise, that unit has to go through permitting all over again.

⁷⁸⁵ California ISO annually conducts its local capacity technical analyses, published May 1 of each year, as part of its annual resource requirements cycle in support of the CPUC's resource adequacy process. CPUC adopts the requirements after consideration of the local capacity technical analyses. The load-serving entities procure resources based on these requirements and must show to the California ISO that they have procured these resources by October each year.

demonstration requirements in D.12-04-046.⁷⁸⁶ One of the restrictions is that a utility cannot enter into a contract with an OTC facility beyond the OTC compliance date. SDG&E submitted comments during the resource adequacy proceeding, noting that “since there is no indication that Encina will either comply with the OTC Policy or obtain an extension from the SWRCB prior to the October year-ahead resource adequacy compliance filing, it is not reasonable to assume that Encina will be available for procurement for the 2018 compliance year.” The CPUC agreed in D. 17-06-027787. SDG&E is unable to contract with Encina without a petition to modify the decision, so it is not clear whether a bilateral contract is even a viable option. The California ISO can contract with Encina using its backstop procurement authority, which it may have to undertake due to the CPUC decisions.

Assessing Progress

As evident from workshops in previous *IEPR* cycles, and the most recent workshop held May 22, 2017, the Energy Commission and the collaborating agencies in the SCRCP are committed to assuring electrical reliability for the region. The agencies are reviewing progress of preferred resources, conventional generation, and transmission projects periodically to determine whether actions need to be taken to assure reliability of the electricity system in Southern California. One of the contingency mitigation measures developed over the last few years was implemented due to the delay of Carlsbad. The Encina OTC deferral request was completed by the end of 2017. The agencies will continue to monitor project milestones, and as uncertainties become clear, the agencies will seek mitigation solutions that maintain grid reliability and promote the state’s policy goals, such as the OTC policy.

Recommendations

Aliso Canyon

- **Continue coordinated efforts to address the energy reliability risks related to the limited use of the Aliso Canyon natural gas storage facility in the near term.** The Energy Commission, the California Public Utilities Commission (CPUC), the California Independent System Operator (California ISO), and the Los Angeles Department of Water and Power (LADWP) should continue to work together to assess the energy reliability impacts of limited operations at Aliso Canyon and take appropriate actions to address those risks.
- **Monitor, evaluate, refine, and extend as needed the existing mitigation measures, including tariff and market changes needed to reduce daily imbalances in gas scheduling, for the Greater Los Angeles Area.** The Energy Commission, the CPUC, the California ISO, and the LADWP should determine the effectiveness of mitigation measures and whether tighter gas balancing rules and the

786 CPUC. April 19, 2012. Order Instituting Rulemaking to Integrate and Refine Procurement Policies and Consider Long-Term Procurement Plans, http://docs.cpuc.ca.gov/PublishedDocs/WORD_PDF/FINAL_DECISION/164799.PDF.

787 CPUC D. 17-06-027, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M192/K027/192027253.PDF>.

California ISO market changes should be extended or made permanent, or whether any tariff changes are necessary.⁷⁸⁸

- **Assist in developing a long-term strategy that would lead to the eventual closure of the Aliso Canyon natural gas storage field.** The Energy Commission must continue to provide support to the CPUC as both agencies work to develop strategies for replacement resources that ensure electricity reliability in Southern California. These strategies will be led by advances in energy efficiency (see Chapter 2) and distributed energy resources such as demand response and storage of electricity or heat (see Chapter 4 for more information on accelerating distributed energy resources). Suggestions such as those mentioned in the California Council on Science and Technology’s underground gas storage study (including expanded electric transmission capacity), the Gas Imbalance Market suggested by Environmental Defense Fund, and Gill Ranch’s idea of better connecting the Pacific Gas and Electric and Southern California Gas Company systems need additional detail and further evaluation.

San Onofre Shutdown and Once-Through Cooling Compliance

- **Assure local reliability in the Greater Los Angeles Area and San Diego.** The California ISO should study the delay of the Mesa Loop-In project beyond summer 2021 to determine whether any mitigation measures are needed and, if so, whether a temporary extension of the Redondo Beach or Alamitos facilities, if electrically feasible, beyond the December 31, 2020, once-through cooling (OTC) compliance date still could be a potential mitigation option. The joint agencies should work with Southern California Edison to determine whether any of their mitigation options are viable solutions to accelerate construction or to mitigate reliability concerns.
- **Develop projections for local reliability resulting from generation, preferred resources, and transmission projects.** Reduce time lags in reporting evaluated preferred resource performance as these are the basis for expected future performance. Energy Commission staff should plan to update the local capacity area assessment tool in the *2018 Integrated Energy Policy Report Update* and continue working with agencies to vet and report results to the energy principals.
- **Continue focus on implementing the Southern California reliability action plan.** The preferred resources, transmission upgrades, and conventional generation identified in this 2013 report are crucial to continuing electric reliability.
- **Continue to refine the OTC deferral mitigation measure.** Use the experience gained from the Encina OTC deferral to refine and update the OTC deferral process.
- **Continue the Southern California Reliability Project agency team.** The multiagency team should continue the timely monitoring and information sharing now in place.

⁷⁸⁸ The California ISO requested a temporary extension of its Aliso Canyon-related tariff revisions, which FERC approved on November 28, 2017, http://www.caiso.com/Documents/Nov28_2017_Order_TariffRevisions-AlisoCanyonGas-ElectricCoordinationEnhancementsPhase3_ER17-2568.pdf.

- **Clarify contracting rules for a utility contracting with an OTC power plant that has a deferred compliance date.** In the event the State Water Resources Control Board approves an OTC compliance date deferral request, the CPUC should clarify its interpretation of D.12-04-046 to allow a contract between a utility and an OTC generator, subject to completion of the OTC compliance date deferral.

Acronyms

AAEE	—	additional achievable energy efficiency
AB	—	Assembly Bill
AC	—	alternating current
AFC	—	application for certification
APEN	—	Asian Pacific Environmental Network
AQIP	—	Air Quality Improvement Program
ARFVTP	—	Alternative and Renewable Fuel and Vehicle Technology Program
Bcf	—	billion cubic feet
Bcfd	—	billion cubic feet per day
BES	—	bulk electric system
BEV	—	Battery-electric vehicle
BioMAT	—	Bioenergy Market Adjusting Tariff
BLM	—	Bureau of Land Management
BOEM	—	Bureau of Ocean Energy Management
BPA	—	Bonneville Power Administration
CAES	—	compressed air energy storage
CAFE	—	Corporate Average Fuel Economy
California ISO	—	California Independent System Operator
CARB	—	California Air Resources Board
CBI	—	Conservation Biology Institute
CCA	—	community choice aggregator
CCST	—	California Council on Science and Technology
CDD	—	cooling degree days
CDFA	—	California Department of Food and Agriculture
CED 2015	—	<i>California Energy Demand 2016–2026, Revised Electricity Forecast</i>
CED 2017 Preliminary	—	<i>California Energy Demand 2018–2028, Preliminary Energy Forecast</i>
CF	—	cubic feet
CH₄	—	methane
CHEEF	—	California Hub for Energy Efficiency Financing
CLTP	—	Coolwater-Lugo Transmission Project
CMUA	—	California Municipal Utility Association
CNG	—	compressed natural gas
CNRA	—	California Natural Resources Agency
CO	—	carbon monoxide
CO₂	—	carbon dioxide
CO₂e	—	carbon dioxide equivalent

COPs	—	Conferences of the Parties
CPCN	—	Certificate of public convenience and necessity
CPUC	—	California Public Utilities Commission
CSD	—	Community Services and Development
CSI	—	California Solar Initiative
CSP	—	concentrating solar power
CUAC	—	California Utility Allowance Calculator
CVR	—	conservation voltage reduction
DAWG	—	Demand Analysis Working Group
DC	—	direct current
DER	—	distributed energy resources
DFA	—	development focus area
DG	—	distributed generation
DGE	—	diesel gallon equivalents
DGS	—	Department of General Services
Diablo Canyon	—	Diablo Canyon Power Plant
DME	—	dimethyl ether
DMV	—	Department of Motor Vehicles
DOE	—	Department of Energy
DOGGR	—	Department of Conservation's Division of Oil, Gas, and Geothermal Resources
DPV2	—	Devers-Palo Verde 2
DR	—	demand response
DRECP	—	<i>Desert Renewable Energy Conservation Plan</i>
DSO	—	distribution system operator
DSR	—	distributed series reactor
EBEE	—	existing buildings energy efficiency
ECC	—	enhanced curtailment calculator
EDF	—	Environmental Defense Fund
EE	—	energy efficiency
EIA	—	Energy Information Administration
EIM	—	energy imbalance market
EIR	—	environmental impact report
EIS	—	environmental impact statement
ELRAM	—	electricity resource assessment model
ELUTG	—	Environmental and Land Use Technical Group
EPA	—	Environmental Protection Agency
EPIC	—	Electric Program Investment Charge
EPS	—	Emission Portfolio Standards
ERCOT	—	Electric Reliability Council of Texas
EV	—	electric vehicle

FCEV	—	fuel cell electric vehicle
FERC	—	Federal Energy Regulatory Commission
GDP	—	gross domestic product
GGRF	—	Greenhouse Gas Reduction Fund
GHG	—	greenhouse gas
GIM	—	natural gas imbalance market
GIS	—	geographic information system
GO-Biz	—	Governor’s Office of Business and Economic Development
GREET	—	Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation
GtCO₂	—	gigatons of carbon dioxide
GW	—	gigawatts
GWh	—	gigawatt hours
GWP	—	global warming potential
HDD	—	heating degree days
HFC	—	hydrofluorocarbon
HVAC	—	heating, ventilation, and air conditioning
HVDC	—	high-voltage direct current
IEPR	—	<i>Integrated Energy Policy Report</i>
IID	—	Imperial Irrigation District
IOU	—	investor-owned utility
IRP	—	integrated resource plan
ISFSI	—	Independent Spent Fuel Storage Installations
ITC	—	International Trade Commission
JASC	—	Joint Agency Steering Committee
kV	—	kilovolt
kW	—	kilowatt
LADWP	—	Los Angeles Department of Water and Power
LA-NYMEX	—	Los Angeles-New York Mercantile Exchange
LBNL	—	Lawrence Berkeley National Laboratory
LCAAT	—	local capacity area accounting tool
LCFS	—	Low-Carbon Fuel Standard
LCOE	—	levelized cost of energy
LCR	—	local capacity requirements
LCTA	—	local capacity technical analyses
LDV	—	light-duty vehicle
LEA	—	local educational agency
LFG	—	landfill gas
LGIA	—	large generator interconnection agreement
LNG	—	liquefied natural gas
LOCA	—	localized constructed analogues

LSE	—	load-serving entity
LTPP	—	Long-Term Procurement Plan
MAPS	—	managing aging processes in storage
MCE	—	Marin Clean Energy
MCf	—	thousand cubic feet
MHDV	—	medium- and heavy-duty vehicles
MMcf	—	million cubic feet
MMcfd	—	million cubic feet per day
MMDth	—	million decatherms
MOU	—	memorandum of understanding
MPC	—	multipurpose canister
MPG	—	miles per gallon
MRF	—	material recovery facility
MT-CO₂e	—	metric ton of carbon dioxide equivalent
MTU	—	metric tons of uranium
MVAR	—	mega unit of reactive power
MW	—	megawatt
MWh	—	megawatt hour
NAMGas	—	North American Market Gas Trade model
NASA/JPL	—	National Aeronautics and Space Administration/Jet Propulsion Laboratory
NCPA	—	Northern California Power Agency
NDCTP	—	Nuclear Decommissioning Cost Triennial proceeding
NERC	—	North American Electric Reliability Corporation
NOI	—	notice of intent
NO_x	—	oxides of nitrogen
NO₂	—	nitrogen dioxide
NOW account	—	negotiable order of withdrawal account
NRC	—	Nuclear Regulatory Commission
NREL	—	National Renewable Energy Laboratory
NV Energy	—	Nevada Energy
NYMEX	—	New York Mercantile Exchange
OEM	—	Original equipment manufacturer
OFO	—	operational flow order
OIR	—	order instituting rulemaking
OPC	—	California Ocean Protection Council
OPEC	—	Organization of Petroleum Exporting Countries
OPR	—	Governor's Office of Planning and Research
OTC	—	once-through cooling
P2G	—	power-to-gas
PAC	—	program administrator cost

PACE	—	Property Assessed Clean Energy
PDCI	—	Pacific Direct Current Intertie
PEA	—	proponent’s environmental assessment
PEV	—	plug-in electric vehicle
PFM	—	petition for modification
PG&E	—	Pacific Gas and Electric
PHEV	—	plug-in hybrid electric vehicle
PHMSA	—	Pipeline and Hazardous Materials Safety Administration
PM	—	particulate matter
PMAC	—	Petroleum Market Advisory Committee
POU	—	publicly owned utility
PPA	—	power purchase agreement
PV	—	photovoltaic
R&D	—	research and development
RA	—	resource adequacy
RAC	—	refiner acquisition cost
RCA	—	regional conservation assessment
RCIS	—	Regional Conservation Investment Strategy
RCPs	—	Representative Concentration Pathways
REAT	—	Renewable Energy Action Team
REC	—	renewable energy credit
REN	—	regional energy network
RETI	—	Renewable Energy Transmission Initiative
RFO	—	request for offer
RFS	—	Renewable Fuel Standard
RIN	—	renewable identification number
RNG	—	renewable natural gas
RPS	—	Renewables Portfolio Standard
SACCWIS	—	Statewide Advisory Committee on Cooling Water Intake Structures
San Onofre	—	San Onofre Nuclear Generating Station
SAT	—	Science Advisory Team
SB	—	Senate Bill
SCC	—	social cost of carbon
SCE	—	Southern California Edison
SCPPA	—	Southern California Public Power Authority
SDG&E	—	San Diego Gas & Electric
SEIA	—	Solar Energy Industries Association
SGIP	—	Self-Generation Incentive Program
SLCP	—	short-lived climate pollutant
SMUD	—	Sacramento Municipal Utility District
SoCalGas	—	Southern California Gas Company

SOL	—	system operating limit
SPO	—	smart pricing options
SWIP	—	South West Intertie Project
SWRCB	—	State Water Resources Control Board
TAFAs	—	transmission assessment focus area
TEPPC	—	Transmission Electric Planning and Policy Committee
TOU	—	time-of-use
TPP	—	Transmission Planning Process
TRC	—	total resource cost
TRTP	—	Tehachapi Renewable Transmission Project
TTIG	—	Transmission Technical Input Group
UC	—	University of California
UCD ITS	—	University of California, Davis, Institute of Transportation Studies
U.S. BLM	—	United States Bureau of Land Management
U.S. DOE	—	United States Department of Energy
U.S. EPA	—	United States Environmental Protection Agency
USFS	—	United States Forest Service
V2G	—	vehicle-to-grid
VGI	—	vehicle-grid integration
WECC	—	Western Electricity Coordinating Council
WIEB	—	Western Interstate Energy Board
WIRAB	—	Western Interconnection Regional Advisory Body
WOPR	—	Western Outreach Project and Report
ZEV	—	zero-emission vehicle
ZNE	—	zero net energy

Glossary

Additional achievable energy efficiency

Additional achievable energy efficiency savings include incremental savings from the future market potential identified in utility potential studies not included in the baseline demand forecast, but reasonably expected to occur, including future updates of building codes, appliance regulations, and new or expanded investor-owned utility or publicly owned utility efficiency programs.

Balancing authority

A *balancing authority* is an entity responsible for integrating resource plans and maintaining the proper balance for load, transmission, and generation within an area defined by metered boundaries. California includes eight balancing authorities, of which the California ISO is by far the largest.

Climate adaptation

A growing body of new policies—referred to as *climate adaptation*—is intended to grapple with what is known from climate science and incorporate planning for climate change into the routine business of governance, infrastructure management, and administration.

Community choice aggregation

Community choice aggregation (or CCA) lets local jurisdictions aggregate their electricity load to purchase power on behalf of their residents. In California, CCAs are legally defined by state law as electric service providers and work together with the region's existing utility, which continues to provide customer services (for example, grid maintenance and power delivery). (For more information see <http://www.leanenergyus.org/what-is-cca/> and/or <http://newsroom.ucla.edu/releases/community-choice-is-transforming-the-california-energy-industry>.)

Community-scale bioenergy

Community-scale means that the project will support or use technologies and strategies sized to use the quantity of locally sourced biomass available for power generation. The feedstock must be adequate considering available biomass supply, cost, and distance from the generating facility. Environmental and/or community concerns, such as maintaining materials needed for soil fertility, habitat, and erosion control, providing jobs, as well as providing other benefits to local communities should also be considered.

Distributed energy resources

Distributed energy resources include:

- Demand response, which has been used traditionally to shed load in emergencies. It also has the potential to be used as a low-greenhouse gas, low-cost, price-responsive option to

help integrate renewable energy and provide grid-stabilizing services, especially when multiple distributed energy resources are used in combination and opportunities to earn income make the investment worthwhile.

- Distributed renewable energy generation, primarily rooftop photovoltaic energy systems.
- “Vehicle grid integration,” or all the ways plug-in electric vehicles can provide services to the grid, including coordinating the timing of vehicle charging with grid conditions
- Energy storage in the electric power sector to capture electricity or heat for use at a later time to help manage fluctuations in supply and demand

Energy storage

Energy storage can be used to capture electricity or heat for use later in the electric power sector and is a key tool for managing fluctuations in supply and demand. Examples include pumped hydropower, thermal energy (such as molten salt), batteries, flywheels, and compressed air and do not include the natural gas storage facilities.

Feed-forward charge controller

A *feed-forward charge controller* is a controller that uses future (forecast) information to schedule electric vehicles for charging.

Garamendi Principles

The *Garamendi Principles* declare that it is in the best interest of the state to:

- Encourage the use of existing rights-of-way by upgrading existing transmission facilities where technically and economically feasible.
- When construction of new transmission lines is required, encourage expansion of existing rights-of-way, when technically and economically feasible.
- Provide for the creation of new rights-of-way when justified by environmental, technical, or economic reasons, as determined by the appropriate licensing agency.

Where there is a need to construct additional transmission, seek agreement among all interested utilities on the efficient use of that capacity.

Hosting capacity

Hosting capacity is the upper bound for the size of PV installation that will pose no risk to the network; it will not trigger the need for an upgrade to the electricity system.

Impingement

Impingement is the entrapment and death of large marine organisms on cooling system intake screens, and “entrapment” is the death of small plants and animals that pass through the intake into the plant.

Integrated resource planning

Integrated resource planning is a strategy that balances the mix of demand and supply resources over a long-term planning horizon to meet specified policy goals.

Intertie

An *intertie* is an interconnection permitting passage of current between two or more electric utility systems.

Microgrid

A *microgrid* is a small, self-contained electricity system with the ability to “manage critical customer resources, provide services for the utility grid operator, disconnect from the grid when the need arises, and provide the customer and the utility different levels of critical support when the need exists.

Net energy demand

Net energy demand is energy demand minus wind and solar energy generation.

Once-through cooling

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.

Overgeneration

Overgeneration occurs when the total supply exceeds the total demand in a balancing authority area.

Resource shuffling

Resource shuffling is implementing pairwise changes in buyers and sellers of energy (for example, contract reassignment) to reduce GHG emissions allowance obligations without reducing actual emissions.

Short-lived climate pollutants

Short-lived climate pollutants cause more climate change in a shorter time frame than carbon dioxide, the primary greenhouse gas, such that emission reductions can produce faster benefits.

Time-of-use rates

Time-of-use rates refer to the cost of energy varying according to when it is consumed.

Volt-ampere reactive

Volt-ampere reactive, or *VAR*, is a measure of reactive power which exists when current and voltage are not in phase in the transmission or distribution system. Reactive power reduces system efficiency and its management is important to ensure voltage stability throughout the grid.

APPENDIX A: 2017 Lead Commissioner Request for Data Related to California’s Nuclear Power Plants

On May 31, 2017, as part of the California Energy Commission's *2017 Integrated Energy Policy Report (2017 IEPR)* proceeding, Lead Commissioner and Chair Robert B. Weisenmiller requested that Pacific Gas and Electric Company (PG&E) provide data related to the Diablo Canyon Power Plant (Diablo Canyon).⁷⁸⁹ PG&E announced plans in June 2016 to shut down Diablo Canyon at the end of its current licenses in 2024–2025, in accordance with an agreement (the joint proposal) among PG&E, labor, and environmental organizations.⁷⁹⁰ That announcement, and the California State Lands Commission’s approval of the land lease to coincide with the current Nuclear Regulatory Commission (NRC) operating license, caused the Energy Commission to shift focus to spent nuclear fuel management and facility decommissioning.⁷⁹¹ The Energy Commission submitted the data request to analyze issues related to the status of spent nuclear fuel storage and transfer into dry casks, as outlined in the *2017 IEPR* scoping order. This request was consistent with the shift in focus to spent nuclear fuel management and facility decommissioning outlined in the *2016 IEPR Update*.⁷⁹²

2017 Nuclear Power Plant Data Request and Company Response: Progress in Spent Nuclear Fuel Onsite Management

Spent Fuel Pool and Independent Spent Fuel Storage Installation – Diablo Canyon and San Onofre

As follow-up to the *2013 IEPR* recommendations, *2015 IEPR* recommendations, and the *2016 IEPR Update* data request, the Energy Commission requested information from PG&E regarding the status of onsite storage and disposal of low-level waste and spent nuclear fuel and its

⁷⁸⁹ 2017 Lead Commissioner Request for Data Related to California's Nuclear Power Plants. May 31, 2016. California Energy Commission. Retrieved from Docket 17-IEPR-01.

⁷⁹⁰ PG&E News Release. June 21, 2016. “In Step With California’s Evolving Energy Policy, PG&E, Labor and Environmental Groups Announce Proposal to Increase Energy Efficiency, Renewables and Storage While Phasing Out Nuclear Power Over the Next Decade.” Retrieved from http://www.pge.com/en/about/newsroom/newsdetails/index.page?title=20160621_in_step_with_californias_evolving_energy_policy_pge_labor_and_environmental_groups_announce_proposal_to_increase_energy_efficiency_renewables_and_storage_while_phasing_out_nuclear_power_over_the_next_decade.

⁷⁹¹ Notice of Modification: 2016 Lead Commissioner Request for Data Related to California's Nuclear Power Plants. June 30, 2016. California Energy Commission. Retrieved from <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=16-IEPR-07>.

⁷⁹² California Energy Commission Staff. 2016. *2016 Integrated Energy Policy Report Update*. California Energy Commission. Publication Number: CEC-100-2016-003-CMF.

management plans for the onsite Independent Spent Fuel Storage Installation (ISFSI).⁷⁹³ Furthermore, the Energy Commission asked PG&E to provide any relevant third-party plans or reports that touched upon spent nuclear fuel management or disposal.

The Energy Commission requested the following information from PG&E:

1. Please provide a progress report on the transfer of spent fuel from pools into dry casks (in compliance with NRC spent fuel cask and pool storage requirements). Please include details on the 2016 transfer campaign: UF06, moving 12 casks during the August 8, 2016, to November 6, 2016, operating window.
2. Please provide updated tables on the status of spent nuclear fuel and current onsite storage capacity and a table summarizing the current spent fuel conditions, including surface radiation levels and temperature. Tables on the current ISFSI should contain information on capacity, planned expansions and timetables, existing and planned loading configurations, and surface conditions of the current ISFSI multipurpose canisters.
3. Please provide an updated evaluation of the potential long-term impacts and projected costs of spent fuel storage in pools versus dry cask storage of higher burn-up fuels in densely packed pools, and the potential degradation of fuels and package integrity during long-term wet and dry storage and transportation offsite.
4. Please provide information on the developments of facility-specific aging cask management programs onsite and within the nuclear engineering community, and any related technological considerations. Also, please provide any Diablo Canyon Multi-Purpose Canister (MPC) inspection reports (EPRI 2016 Inspection Report).
5. Please provide a status update on currently mounted HI-STORM casks and the transport readiness of these casks under current NRC license requirements.
6. Alternative spent fuel management schemes to expeditiously transfer spent nuclear fuel assemblies from the wet spent fuel pool to dry casks in the ISFSI. PG&E alternate plans, if any, to isolate the spent fuel pool to eliminate the need for using Pacific Ocean seawater for cooling the spent fuel pool system.

Pacific Gas and Electric Company's Response to the 2017 IEPR Data Request on the Progress in Spent Nuclear Fuel On-site Management Concerning the Spent Fuel Pool and ISFSI

The following are excerpts from the submitted response with minor modifications to references, tables, and acronyms for consistency purposes.

1. There are a total of 1,712 used fuel assemblies stored in the spent fuel pools. There are 49 casks loaded in dry storage with a total of 1,568 assemblies. In compliance with NRC spent fuel cask and pool storage requirements, the current, budgeted plan is to load nine

⁷⁹³ Letter from PG&E to the NRC dated December 17, 2015, Docket No. 72-26, Materials License No. SNM-2511 Diablo Canyon Independent Spent Fuel Storage Installation Decommissioning Funding Plan, <https://www.nrc.gov/docs/ML1535/ML15351A502.pdf>.

additional casks (288 total fuel assemblies) in 2018 and eight casks (256 total fuel assemblies) in each of the years 2020 and 2022.

The last used fuel offload campaign—UFO6—was conducted August 8, 2016, to November 12, 2016, and successfully loaded 12 casks. The 12 casks contain 384 spent fuel assemblies; each cask used at Diablo Canyon holds 32 fuel assemblies.

2. Table 36 provides 2017 updates to Table 14 from the *AB 1632 Assessment of California's Operating Nuclear Plants: Final Consultant Report*.⁷⁹⁴

There are no planned changes to loading configurations at this time. All casks to be loaded will use the same vertically oriented, 32 assembly, multi-purpose canister in a seismically-anchored, steel and concrete shielding overpack known as the Holtec HI-STORM 100SA dry cask storage system.⁷⁹⁵

There is no table for spent fuel conditions including surface radiation levels and temperature as this data is not available.

As discussed in response to Question 4, PG&E voluntarily participated with the Electric Power Research Institute to perform a surface condition inspection in 2014 for two multipurpose canisters. The surface conditions for these two canisters are noted in the report.

Table 36: Onsite Spent Nuclear Fuel Capacity

Diablo Canyon		
	Assemblies	MTU
ISFSI Capacity	4,416	2,100 (lic.)
Planned Expansions	0	0
Total Planned ISFS Capacity	4,416	2,100
Spent Fuel Pool Current Capacity	2,648 (lic.)	N/A
Total Onsite Storage Capacity	7,064	N/A
Assemblies Generated During Current Licensing Period	4,382 est.	1,887 est.
Spent Fuel Pool Original Design Capacity (Before re-racking) (270/pool)	540	N/A

Source: Data provided by PG&E. Documents can be found at <https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=17-IEPR-01>. * Values are in metric tons of uranium (MTU). Abbreviations: est. = estimated, lic. = licensed, N/A = Not Applicable

⁷⁹⁴ California Energy Commission. 2008. *AB 1632 Assessment of California's Operating Nuclear Plants: Final Consultant Report*. CEC-100-2008-005-F. P. 217.

⁷⁹⁵ A description of the Holtec HI-STORM 100 system can be found at <https://holtecinternational.com/productsandservices/wasteandfuelmanagement/dry-cask-and-storage-transport/hi-storm/hi-storm-100/>.

3. The annual cost difference of wet spent fuel storage versus dry cask spent fuel storage is \$65.6 million (in 2014 dollars), as presented in PG&E's Prepared Testimony for the 2015 Nuclear Decommissioning Cost Triennial Proceeding (NDCTP), Table 2-8.⁷⁹⁶ This cost comparison is valid when spent fuel is located in both wet spent fuel storage and dry cask spent fuel storage. It should be noted that the annual dry cask storage costs in Table 2-8 would increase once all spent fuel is in dry cask storage due to other common site costs such as permitting, insurance, and property taxes being charged to dry storage.

The NRC has evaluated the potential degradation of fuel assemblies and fuel storage structures, systems, and components during long-term wet storage in NUREG-1801, "Generic Aging Lessons Learned Report," Revision 2, dated December 2010, Chapter VII, Sections A2 and A3.⁷⁹⁷ The potential degradation of fuel assemblies and package integrity during dry storage has been evaluated by the NRC in the draft report for comment "Managing Aging Processes in Storage Report," August 2016, Tables 4.3-1 through 4.3-5.⁷⁹⁸

The NRC has evaluated and identified the requirements for fuel assemblies and packaging during transportation offsite in NUREG-1617, "Standard Review Plan for Transportation Packages for Spent Nuclear Fuel," and 10 CFR Part 71. PG&E is not aware of any industry operating experience regarding potential degradation of fuel and the package integrity during transportation offsite.

4. The Diablo Canyon ISFSI Final Safety Analysis Report discusses maintenance of the cask systems during the licensed 20-year operating period. The following is a summary of maintenance activities that are performed to ensure the structures, systems, and components are adequately maintained. Only minimal maintenance is required over the lifetime of the cask system, and this maintenance results primarily from cask handling and weathering effects in storage. Typical of such maintenance is the reapplication of corrosion inhibiting materials on accessible external surfaces. Visual inspection of the overpack inlet and outlet air duct perforated plates (screens) is required by the Diablo Canyon ISFSI Technical Specifications to ensure that they are free from obstruction—including clearing of debris if necessary. The gamma and neutron shielding materials in the overpack, transfer cask, and MPC degrade negligibly over time or as a result of usage. Radiation monitoring of the ISFSI provides ongoing evidence and confirmation of shielding integrity and performance. If the monitoring program indicates increased

⁷⁹⁶ PG&E Response to the 2017 IEPR Nuclear Data Request, Attachment 1, available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN220129_20170712T150521_Valerie_Winn_Comments_PGE_Attachment_1_Nuclear_Data_Request.pdf.

⁷⁹⁷ PG&E Response to the 2017 IEPR Nuclear Data Request, Attachment 2, available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN220130_20170712T151613_Valerie_Winn_Comments_PGE_Att_2_Nuclear_Data_Request.pdf.

⁷⁹⁸ PG&E Response to the 2017 IEPR Nuclear Data Request, Attachment 3, available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN220131_20170712T152027_Valerie_Winn_Comments_PGE_Att_3_Nuclear_Data_Request.pdf.

radiation doses, additional surveys of the overpacks would be performed to determine the cause of the increased dose rates.

Consistent with the industry, to address potential aging of components after 20 years of storage, facility-specific aging management programs are required to be developed using the following NRC guidance documents:

- Draft Report for Comment “Managing Aging Processes in Storage (MAPS) Report,” August 2016. NUREG-TBD. NRC.⁷⁹⁹
- NUREG-1927, “Standard Review Plan for Renewal of Specific Licenses and Certificates of Compliance for Dry Storage of Spent Nuclear Fuel,” Revision 1, June 2016, NRC.⁸⁰⁰

In addition, PG&E participates with industry in the Electric Power Research Institute's Extended Storage Collaboration Program to study the long-term performance of participants' used fuel storage systems to develop the technical basis in support of extended storage through sharing of knowledge and research activities among Extended Storage Collaboration Program participants.

The requested Diablo Canyon MPC inspection report is publicly available as Electric Power Research Institute Technical Report 3002002822, *Diablo Canyon Stainless Steel Dry Storage Canister Inspection*, dated August 2016.

5. The currently mounted HI-STORM casks are licensed for storage only. In January 2016, Holtec International applied to the NRC to amend their HI-STAR 100 Transportation Certificate, 71-9261, to include the Diablo Canyon MPC-32 canister. There have been responses to two sets of requests for additional information submitted by Holtec in August 2016 and most recently in March 2017. The license amendment request is under review by NRC.
6. On August 11, 2016, PG&E filed Application (A.) 16-08-006 with the California Public Utilities Commission to obtain approval of a “joint proposal.” The joint proposal was prepared in concert with a broad coalition of community partners. In part, the joint proposal committed PG&E to developing a plan for “expedited post-shutdown transfer of spent fuel to dry casks storage as is technically feasible using the transfer schedules implemented at the San Onofre Nuclear Generating Station as a benchmark for comparison.” In addition, per the 2015 NDCTP Decision (D.) 17-05-020, dated May 25, 2017, “PG&E is directed to provide testimony concerning expedited dry cask loading both pre-and post-shut down for Diablo Canyon. PG&E is to provide any updated information concerning expediting the seven-year timeframe for transfer of spent nuclear fuel from wet to dry storage directed in this decision.” This expedited fuel study will be

799 Ibid.

800 PG&E Response to the 2017 IEPR Nuclear Data Request, Attachment 4, available at http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN220132_20170712T151828_Valerie_Winn_Comments_PGE_Att_4_Nuclear_Data_Request.pdf.

incorporated into the site-specific decommissioning study that will be submitted to the California Public Utilities Commission with the 2018 NDCTP.

PG&E is developing the 2018 NDCTP site-specific decommissioning cost estimate. The site-specific cost estimate may include alternate plans to isolate the spent fuel pool to eliminate the need for using Pacific Ocean seawater for cooling the spent fuel pool system.

Energy Commission Response to Information Provided by PG&E

PG&E's Diablo Canyon Power Plant joint proposal covers topics including facility decommissioning and spent nuclear fuel management—topics that have been identified as important and specifically addressed in previous *IEPRs*. Condition 5.4 Nuclear Decommissioning outlines plans to submit a site-specific decommissioning study to the CPUC no later than the 2018 NDCTP filing. PG&E will seek authorization from the CPUC application to disburse funds from the Diablo Canyon decommissioning trust to fund this site-specific decommissioning study (5.4.1). Under Condition 5.4.1 Part (iii), PG&E commits to "...a plan for expedited post-shut-down transfer of spent fuel to dry cask storage as promptly as is technically feasible using the transfer schedules implemented at the San Onofre Nuclear Generating Station as a benchmark for comparison, and PG&E will also provide the plan to the [Energy Commission], collaborate with the [Energy Commission], and evaluate the [Energy Commission's] comments and input." Moreover, under condition 6.4 NRC Dry Cask Fuel Storage, PG&E discussed expectations to file the Diablo Canyon ISFSI license renewal no later than five years before the 2024 expiration.

As these proceedings develop, the Energy Commission will need to consider to what extent the following topics are addressed in a future *IEPR*:

- PG&E's testimony concerning expedited dry cask loading both pre- and post-shutdown for Diablo Canyon.
- PG&E's plan for expedited post-shutdown transfer of spent fuel to dry cask storage.
- PG&E's Diablo Canyon and Humboldt Bay ISFSI license renewal applications.⁸⁰¹
- PG&E's ISFSI Aging Management Programs.

The Energy Commission's ability to review these topics as part of the *2018 IEPR Update* depends on PG&E's 2018 NDCTP filing schedule and the degree of early communication and collaboration between Energy Commission and PG&E staff regarding these items.

The Energy Commission continues to recommend actions focused on the safe, uneventful storage, management, and transport of spent nuclear fuel.⁸⁰² The Energy Commission supports efforts to develop an integrated system for the management, transport, and disposal of nuclear waste and

801 Humboldt Bay Power Plant ISFSI Materials License No. SNM-2514. Issuance Date November 17, 2005. Expiration Date November 17, 2025. Diablo Canyon Power Plant ISFSI Materials License No. SNM-2511. Issuance Date March 22, 2004. Expiration Date March 22, 2024

802 Specific language can be reviewed in previous *IEPR* recommendations for California's nuclear power plants and in various docketed correspondences from Chair Weisenmiller to federal agencies and representatives.

further recommends that federal agencies pursue the establishment of a consent-based approach for siting future nuclear waste management facilities. As recommended in multiple reports addressing nuclear issues from a broad range of reputable organizations, a defined method of public participation and the early, active involvement of stakeholders lead to a substantial improvement in safety, general acceptability, and, when conducted well, the process normally yields indisputable benefits.⁸⁰³

803 (A) Stakeholder Involvement in Nuclear Issues A Report by the International Nuclear Safety Group INSAG Series No. 20, IAEA 2006. (B) An Overview of Stakeholder Involvement in Decommissioning, IAEA Nuclear Energy Series No. NW-T-2.5, 2009. (C) *Blue Ribbon Commission on America's Nuclear Future, Report to the Secretary of Energy*, January 2012. Retrieved from <http://energy.gov/ne/downloads/blue-ribboncommission-americas-nuclear-future-reportsecretary-energy>. (D) Laura Price, Rob Rechar. *Progress in Siting Nuclear Waste Facilities: Fuel Cycle Research & Development*, Sandia National Laboratories, Sept. 2014, FCRD-NFST-2014-000628, SAND2014-18223R.

APPENDIX B:

Publicly Owned Utility Storage Goals Update

Assembly Bill 2514 (Skinner, Chapter 469, Statutes of 2010), amended by Assembly Bill 2227 (Bradford, Chapter 606, Statutes of 2012), requires California's publicly owned utilities (POUs) to develop energy storage procurement targets. (For more information on energy storage, see Chapter 4.) The legislation requires POUs to determine appropriate targets, if any, to procure viable and cost-effective energy storage systems to be achieved by 2016 and by 2020. The initial targets were required to be submitted to the Energy Commission by October 1, 2014, and were summarized in the *2015 Integrated Energy Policy Report (2015 IEPR)*, Appendix F.⁸⁰⁴ AB 2514 also requires the POUs to reevaluate their energy storage targets every three years and to submit reports demonstrating compliance with stated goals.

As reported in the *2015 IEPR*, the majority of California's POUs provided Energy Commission staff with reports outlining their targets. Energy Commission staff then developed a Web page to make the reports available to the public.⁸⁰⁵ At the time, most POUs opted not to adopt targets. Thirty-seven POUs submitted AB 2514 reports or resolutions to the Energy Commission. Four POUs did not submit reports or resolutions. Thirty POUs declined to adopt energy storage procurement targets or adopted targets of zero, and seven POUs adopted energy storage targets greater than zero. For the POUs that did not adopt targets, the primary reasons cited were the lack of viable or cost-effective energy storage options available or a lack of need for storage.

The legislation required the POUs to submit reports by January 1, 2017, demonstrating compliance with their initial energy storage targets. POUs were also required to re-evaluate their energy storage targets every three years. Since the original targets were required by October 1, 2014, all POUs should have completed the re-evaluation by October 1, 2017. The Energy Commission posted the compliance reports and re-evaluation reports received from POUs.⁸⁰⁶

The table below summarizes the targets adopted by the POUs and the compliance reports and reevaluation reports submitted by POUs that adopted energy storage targets greater than zero. In 2014, only seven POUs adopted targets. Although the majority of the state's POUs decided not to adopt targets again in 2017, several that had not adopted targets in 2014 did so in 2017, including Sacramento Municipal Utility District (SMUD) and Imperial Irrigation District (IID). On the other hand, some utilities decided to rescind the targets that they had previously adopted. POUs not listed in the table either did not set targets or set a target of zero energy storage.

804 California Energy Commission. 2015. *2015 Integrated Energy Policy Report*. Publication Number: CEC-100-2015-001-CMF.http://doCKETpublic.energy.ca.gov/PublicDocuments/15-IEPR-01/TN212018_20160629T154356_2015_Integrated_Energy_Policy_Report_Full_File_Size.pdf.

805 http://www.energy.ca.gov/assessments/ab2514_energy_storage.html.

806 http://www.energy.ca.gov/assessments/ab2514_energy_storage.html.

Table 37: POU Energy Storage Targets

POU	Initial 2016 Target	Initial 2020 Target	Storage Achieved	October 2017 Reevaluated 2020 Target
Anaheim Public Utilities	Zero	Zero	3.15 MW of thermal storage existed prior to adoption of AB 2514	1 MW battery storage target, in addition to existing 3.15 MW
Cerritos, City of	1 percent of 2015 peak load (2014 peak load was 19.6 MW).	1 percent of 2020 peak load.	Zero (2016 target was rescinded)	2016 target was rescinded; 2020 target remains 1 percent of peak load.
Corona Department of Water and Power	1 percent of 2015 peak load (2010 peak load was 27 MW).	1 percent of 2020 peak load.	Zero (2016 target was rescinded)	2016 target was rescinded; 2020 target remains 1 percent of peak load.
Glendale Water and Power (GWP)	1.5 MW	1.5 MW	1.53 M	2 MW battery storage target, in addition to existing 1.53 MW
Imperial Irrigation District	Zero	Zero	30 MW battery storage project was operational in 2016	5 MW, in addition to existing 30 MW
Los Angeles Department of Water and Power (LADWP)	24.08 MW	154 MW	22.57 MW	155 MW, in addition to 1,284 MW of storage installed prior to 2010
Redding Electric Utility (REU)	3.6 MW	4.4 MW	3.46 MW	3.6 MW; 2020 target was decreased due to flat load forecast
Riverside Public Utilities (REU)	Zero	Zero	1.5 MW	6 MW (5 MW thermal storage and 1 MW battery storage)
Silicon Valley Power (SVP)	30 kW (SVP did not adopt separate targets for 2016 and 2020.)	30 kW	30 KW	Report adoption delayed; expected January 2018.
Sacramento Municipal Utility District	Zero	Zero	Numerous research and development projects	9 MW of primarily behind the meter storage
Victorville Municipal Utility Services	1 percent of 2015 peak load (2010 peak load was 12 MW).	1 percent of 2020 peak load.	Zero (2016 target was rescinded.)	2016 target was rescinded; 2020 target remains 1 percent of peak load

Source: California Energy Commission staff

Highlights of Reevaluation Reports Submitted by POU's

- **Anaheim Public Utilities.** In its reevaluation report, Anaheim Public Utilities established an energy storage target of 1 MW. Previously, Anaheim had not adopted energy storage targets. Anaheim has 3.15 MW of previously existing thermal energy storage.
- **City of Cerritos.** The City of Cerritos initially adopted a target of 1 percent of peak load for 2016 and for 2020. Cerritos rescinded its 2016 target in June 2016 but has kept its 2020 target of 1 percent of peak load.
- **Glendale Water and Power.** Glendale Power and Water adopted a target of 1.5 MW of energy storage. Glendale Power and Water has met its energy storage target through the installation of 1.6 MW of Ice Bear thermal energy storage units. The city completed installation of 166 Ice Bear units in June 2011. Since that time, 5 of the Ice Bear units have been decommissioned, but 161 remain in operation. The city experienced a demand reduction of 1.53 MW for June 2016 due to operation of the Ice Bear units. The Ice Bear units were installed as part of a U.S. Department of Energy modernization grant project. Glendale investigated the potential for additional investments in energy storage, including battery energy storage and additional Ice Bear storage, but found that the economics do not meet the “least cost-best-fit” criteria for resource selection. However, Glendale has entered into an agreement for installation of a 2 MW battery storage pilot project scheduled to be completed in 2017.
- **Imperial Irrigation District.** IID installed a 30 MW battery energy storage system in 2016, but did not include this as part of its AB 2514 targets. In its re-evaluation of targets, IID has increased its target to 5 MW of energy storage, in addition to its existing 30 MW battery storage project.
- **Los Angeles Dept. of Water and Power.** LADWP’s energy storage target for 2016 was 24.08 MW, in addition to the 1,284.08 MW of energy storage that had been procured before 2010, of which the primary component is the 1,275 MW of pumped storage at the Castaic Pumped Hydro Power Plant. As of January 2017, LADWP installed 22.57 MW of energy storage, about 1.5 MW short of its goal of 24.08 MW. Of the 22.57 MW installed, 21 MW was an upgrade of the Castaic Pumped Hydro Power Plant, 1.25 MW was through the LAX Thermal Energy Storage project, and 324.4 kW was through a variety of smaller battery and thermal energy storage projects. LADWP’s revised energy storage target for 2020 is 155 MW, comprising 128 MW of transmission connected, 25 MW distribution connected, and 2 MW of behind-the-meter energy storage.
- **Redding Electric Utility.** REU’s energy storage target for 2016 was 3.6 MW. As of December 2016, REU had installed 3.46 MW of energy storage. REU’s energy storage portfolio consists of nearly 90 Ice Bear thermal energy systems and 3 CALMAC thermal energy systems. Redding decreased its 2020 target from 4.4 MW to 3.6 MW of energy storage due to lower-than-expected load growth.

- **Riverside Public Utilities.** In its reevaluation report, Riverside increased its 2020 target to 6 MW, from an initial target of zero. This target will be achieved through an ongoing program to install 5 MW of Ice Bear thermal energy storage units and 1 MW of battery storage to provide ancillary services, including frequency regulation, in the California ISO market.
- **Silicon Valley Power.** SVP's energy storage target for 2016 was 30 kW. This target was achieved through the installation of a 30 kW lithium-ion battery system paired with electric vehicle charging stations at Levi's® Stadium. The project was installed by Green Charge in 2014. As of 2017, Silicon Valley Power is evaluating several possible future energy storage projects.
- **Sacramento Municipal Utility District.** In its initial 2014 report, SMUD elected not to adopt an energy storage target. SMUD looked extensively at energy storage through implementation of numerous energy storage research and development projects. In its 2017 reevaluation report, SMUD reported that it has revised its 2020 energy storage target upward to 9 MW of energy storage. This target would be achieved primarily through adopting behind-the-meter energy storage.
- **City of Victorville.** In 2014, Victorville established an energy storage target for 2016 of 1 percent of peak load. In 2016, Victorville City Council passed a resolution rescinding its energy storage target for 2016, but the city council kept its energy storage target for 2020 of 1 percent of peak load.

Although the table above reflects the energy storage targets reported by POUs in response to AB 2514, it is not a complete reflection of all energy storage installed by the California POUs. Some POUs not listed in the table have energy storage installed on their systems but did not include those systems in their AB 2514 targets because the projects were not installed in direct response to AB 2514. For example, LADWP's board-approved plan to accelerate the procurement of 178 MW of battery storage to address reliability impacts resulting from constrained operations at the Aliso Canyon natural gas storage facility (see Chapter 11 for more information) is not reflected in the table.

Although many California POUs have found that energy storage is not cost-effective for their systems, they continue to maintain an interest in energy storage in the event that future conditions make energy storage more attractive. During the June 29, 2017, *IEPR* Workshop on distributed energy resources, POU representatives indicated that they were collaborating on studies to assess the value of energy storage. Several of the larger POUs, particularly SMUD and LADWP, have invested significantly in energy storage research and development projects. In the past decade, SMUD has researched a wide variety of energy storage technologies. LADWP was an early adopter of thermal energy storage and has investigated an array of energy storage technologies and applications. Many of the smaller POUs participate in energy storage research through programs with their public power authorities, Northern California Power Agency and Southern California Public Power Authority. If conditions change in the future, California's POUs

are well-positioned to take advantage of the potential benefits of more widespread use of energy storage.

Going forward, AB 2514 requires that each POU submit a compliance report by January 1, 2021, to demonstrate compliance with the adopted 2020 energy storage targets.

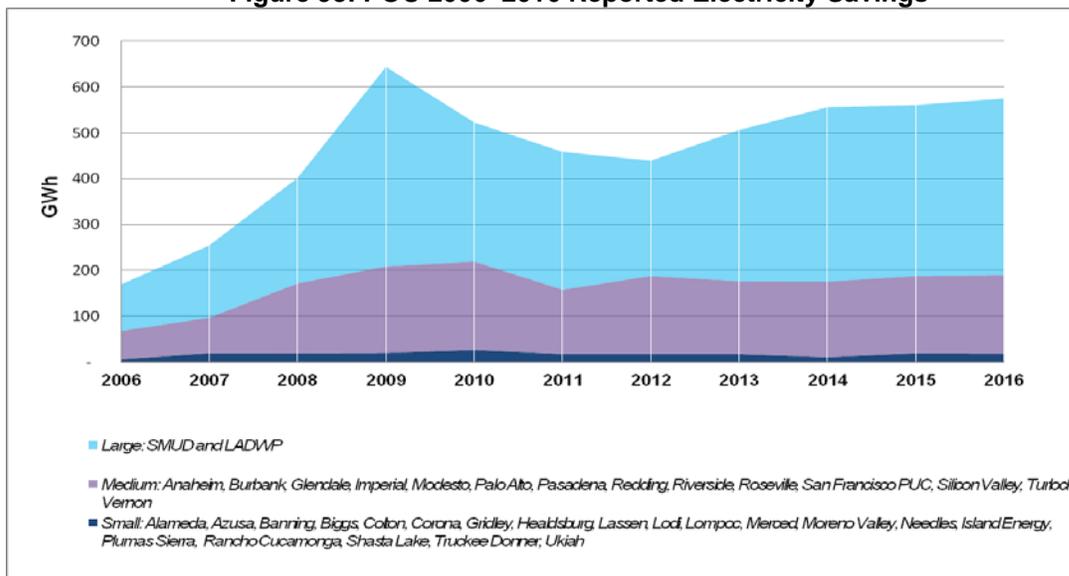
APPENDIX C: Publicly Owned Utility Energy Efficiency Savings

This appendix summarizes historical and projected energy efficiency savings for publicly owned utilities (POUs) in California. The California Energy Commission conducts this assessment based on information reported by POUs in compliance with Public Utilities Code Sections 9505 and 9620(d).⁸⁰⁷

Historical Electricity Savings in POU Service Territories

California's POUs account for roughly one-quarter of statewide retail electricity sales. The largest two POUs – Sacramento Municipal Utility District (SMUD) and Los Angeles Department of Water and Power (LADWP) – jointly represent more than half of total POU retail electricity sales. POU implemented energy efficiency and demand reduction programs are essential in managing California's electricity demand and reducing greenhouse gas (GHG) emissions.

Figure 98: POU 2006–2016 Reported Electricity Savings



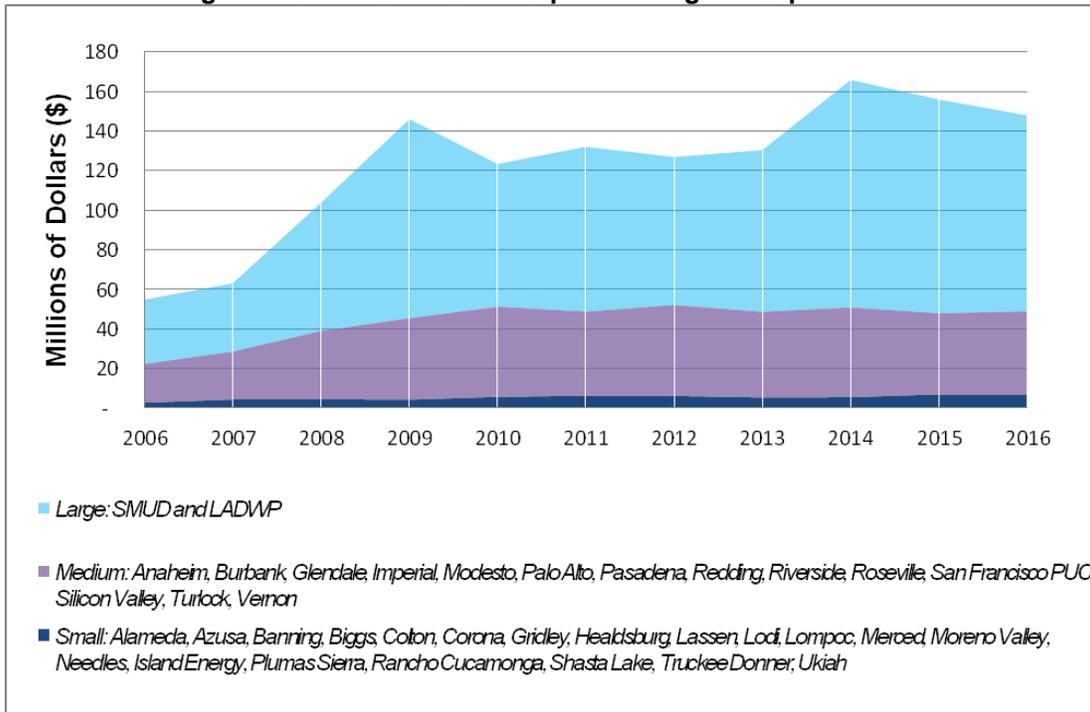
	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Large	102	158	230	436	304	301	252	330	381	373	385	3,250
Medium	62	78	153	189	193	141	170	159	165	169	172	1,650
Small	6	19	19	20	26	17	17	17	11	19	18	189
Total	169	254	402	644	523	459	440	506	556	561	575	5,090

Source: California Energy Commission, Demand Analysis Office, July 2017, based on Energy Efficiency in California's Public Power Sector Status Reports, <http://www.ncpa.com/policy/reports/energy-efficiency/>.

⁸⁰⁷ Public Utilities Code Section 9505 requires each POU to provide to its customers and the Energy Commission information on its investments in energy efficiency and demand reduction programs; program descriptions, funding sources, expenditures, cost-effectiveness, and expected and actual savings. Provisions of Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) and Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006).

Figure 97 summarizes the POU-reported progress in efficiency savings from 2006 through 2016 grouped by POU size: large, medium, and small. In 2016, POUs reported 575 gigawatt-hours (GWh) in net electricity savings from first-year efficiency measure installations; this is a slight increase of 2 percent over 2015. Cumulatively, for the past 10 years, POUs reported more than 5,000 GWh in net electricity savings. POUs' electricity savings have been increasing steadily since 2012 but are below the high point in 2009.

Figure 99: POU 2006–2016 Reported Program Expenditures



	2006	2007	2008	2009	2010	2011	2012	2013	2014	2015	2016	Total
Large	33	34	65	101	72	83	75	82	115	108	99	867
Medium	20	24	34	41	46	43	46	43	45	41	42	425
Small	3	4	5	4	6	6	6	5	6	7	7	59
Total	55	63	104	146	123	132	127	130	166	156	148	1,351

Source: California Energy Commission, Demand Analysis Office, July 2017, based on Energy Efficiency in California's Public Power Sector Status Reports, <http://www.ncpa.com/policy/reports/energy-efficiency/>

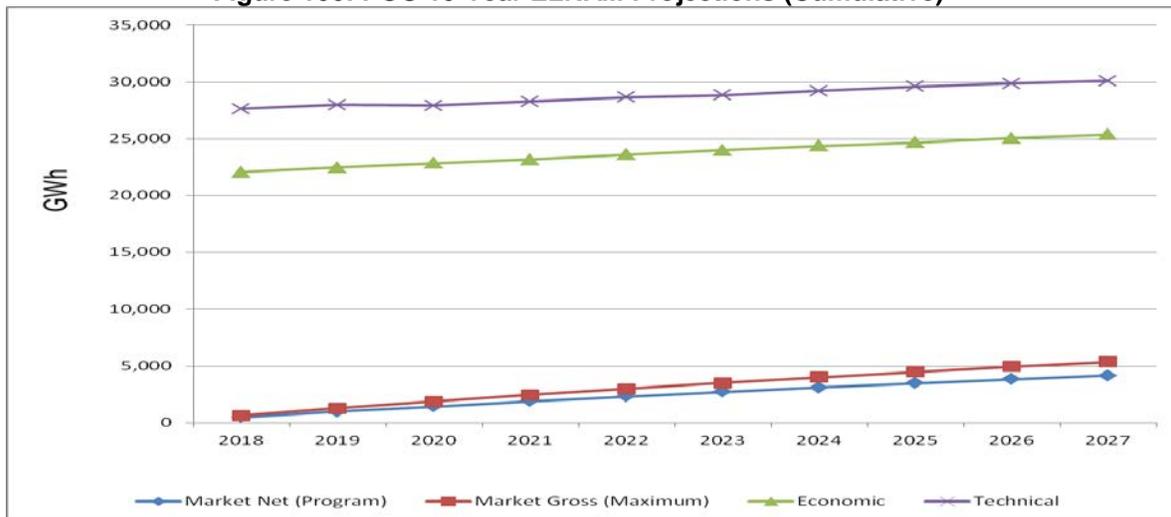
The POU-reported program expenditures are shown in Figure 98. POUs spent a total of \$148 million in 2016 on electricity savings programs and more than \$6 million on codes and standards programs.⁸⁰⁸ After a few years of relatively flat spending between 2010 and 2013, POU expenditures have since been higher than the previous peak in 2009. Cumulatively, over the past 10 years, POUs have spent more than \$1.3 billion on energy efficiency programs. The reasons for the year-to-year changes in program costs and claimed electricity savings are due to each utility's unique characteristics – such as customer base, geographic location, and size.

⁸⁰⁸ Public Utilities Code Section 385, also known as the POU Public Benefit Fund, was established in 1996. POUs have been voluntarily providing information about their energy efficiency and overall public benefit budgets. Although information is scattered and uneven, it appears that collectively in 2016, POUs acquired more than \$268 million to spend on public benefit programs, including efficiency programs.

POU Efficiency Potential

Public Utilities Code Section 9505(b) requires each POU to identify achievable cost-effective energy efficiency savings and establish energy efficiency savings and demand reduction targets for the next 10-year period on a four-year cycle.⁸⁰⁹ Similar to the approach taken in reporting POU annual electricity savings accomplishments, the California Municipal Utility Association (CMUA), in partnership with the Northern California Public Agency (NCPA) and the Southern California Public Power Authority (SCPPA), collaborated on developing the POU efficiency targets for a 10-year period starting in 2018. This information was published as part of the annual POU energy efficiency report released in March 2017.⁸¹⁰ The technical, economic, and market savings projections for establishing POU targets were completed using the Electricity Resource Assessment Model (ELRAM). ELRAM estimates electricity savings and demand reduction as a function of projected electricity sales based on the total baseline-system-electricity sales projections, and the energy efficiency programs implementation assumptions provided by each POU. Adjustments to the model to accommodate each POU's unique set of inputs are common.⁸¹¹

Figure 100: POU 10-Year ELRAM Projections (Cumulative)



Source: California Energy Commission, Demand Analysis Office, July 2017, based on Energy Efficiency in California's Public Power Sector Status Reports, Appendix B <http://www.ncpa.com/policy/reports/energy-efficiency/>.

Figure 99 provides results of the ELRAM projections for the composite of all POU's. Technical and economic potential are relatively constant through time, reflecting the definition of these concepts described below. Market gross and net potential⁸¹² grow through time as year-by-year savings

⁸⁰⁹ Assembly Bill 2227 (Bradford, Chapter 606, Statutes of 2012) amended the POU target cycle to align more closely with the *IEPR* timeline. It also consolidated reporting requirements into a section of the Public Utilities Code, making compliance easier for POU's.

⁸¹⁰ *Energy Efficiency in California's Public Power Sector Status Reports*, Appendix B <http://www.ncpa.com/policy/reports/energy-efficiency/>.

⁸¹¹ Senate Bill 350 (De León, Chapter 547, Statutes of 2015) requires the California Energy Commission to set annual targets for increasing energy efficiency savings and demand reduction to achieve a cumulative doubling goal. The 2016 POU study did not consider the doubling goal.

⁸¹² The energy efficiency evaluation community uses the concept of net and gross savings to address program participation. Generally, gross savings include savings from consumers who would have implemented measures even if

accumulate. However, by the end of the 10-year period, only limited amounts of economic potential have been achieved.

Technical Potential

POU technical potential provides a starting point for determining achievable levels of cost-effective market potential. It is calculated as a product of the electricity savings per unit of a measure, the quantity of applicable efficiency units in each facility, and the number of facilities in a utility service territory. The quantity of applicable units per year is determined by measuring effective useful life. The cumulative estimate of technical energy savings potential for all 39 POUs combined is 30,117 GWh in 2027. This estimate is 44 percent higher than the 2013 estimate.

Economic Potential

POU economic potential represents a portion of the technical potential if a utility installs measures selected by the results of the cost-effectiveness screening. Cost-effective measures are those that have a total resource cost (TRC) and the program administrator cost (PAC) of 1 or greater. POUs provide TRC and PAC test results, using a benefit/cost ratio, derived from the E3 Reporting Tool. Historically, economic potential has been around 80 percent of the technical potential. The economic potential estimated for the POUs in the 2018–2027 study is 60 percent higher than the 2013 estimate.

Market Potential

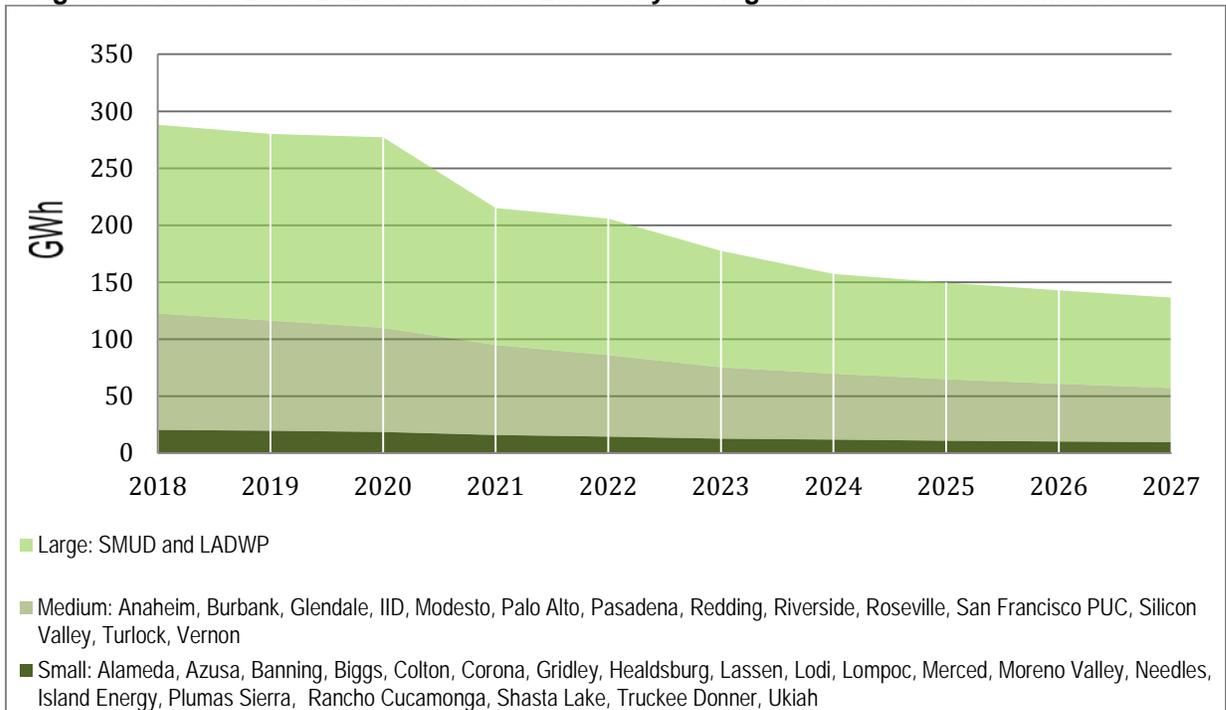
POU market potential is estimated in response to specific levels of incentives, program design, the magnitude of utility rebates, and assumptions about policies, market influences, and market barriers. CMUA, in its annual report, formulated a foundational principle for POU energy efficiency efforts – that the end users are central to realizing energy savings. POU market potential varies significantly based on local policy and program assumptions. Some of the POU-specific methods differ in whether the estimates are considered net of naturally occurring efficiency or free riders. In addition to gross and net estimates, market potential is estimated incrementally and cumulatively. The gross market potential estimated for the POUs in the 2018–2027 study is 60 percent lower than the 2013 estimate.

Codes and Standards

The CMUA report does not provide details on how its preferred method determines the incremental impact on building and appliance codes and standards requirements that can be attributed to utility efforts.

they were not participants in a program (free riders) and savings that extend beyond the time period assumed for specific measures promoted as incentives in a program (spillover). Net savings adjust for these two components of savings.

Figure 101: POU 2018–2027 Incremental Electricity Savings From Codes and Standards

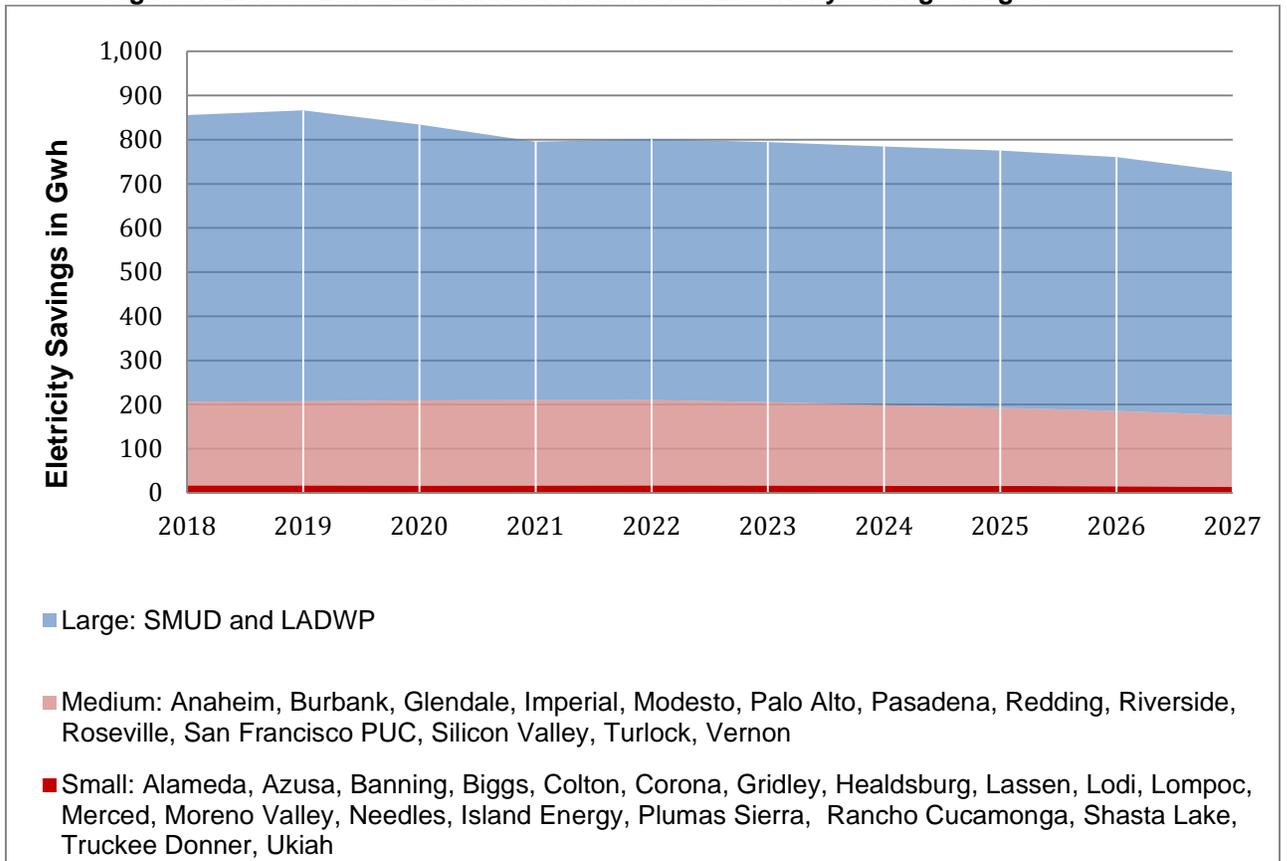


	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Large	166	164	167	120	120	102	87	85	82	79	1,172
Medium	102	97	91	79	72	63	58	54	51	48	714
Small	20	20	19	16	15	13	12	11	10	10	145
Total	288	280	277	215	206	178	157	150	143	137	2,030

Source: California Energy Commission, Demand Analysis Office, July 2017, based on Energy Efficiency in California’s Public Power Sector Status Reports, Appendix C <http://www.ncpa.com/policy/reports/energy-efficiency/>

Figure 100 shows annual incremental 10-year codes and standards savings grouped by POU size. LADWP and SMUD together account for more than half of total cumulative savings from codes and standards. The medium-sized and small POU collectively account for less than half of composite POU savings.

Figure 102: POU 2018–2027 Annual Incremental Electricity Savings Targets



	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
Large	649	659	625	585	591	589	585	583	575	551	5,993
Medium	190	190	193	193	193	189	183	177	171	162	1,840
Small	17	17	17	17	17	17	16	16	15	14	162
Total	856	866	834	795	802	794	784	775	760	727	7,995

Source: California Energy Commission, Demand Analysis Office, July 2017, based on Energy Efficiency in California's Public Power Sector Status Reports, Appendix C <http://www.ncpa.com/policy/reports/energy-efficiency/>.

Figure 101 shows the annual incremental 10-year savings targets by POU. LADWP, SMUD, and Anaheim chose to base their targets on gross market potential, including savings projections from codes and standards. Imperial, Turlock, Glendale, and Vernon chose to base their targets on net market potential, including savings projections from codes and standards. Riverside, Pasadena, Burbank, Roseville, and Redding based their targets on gross market potential only. The 14 medium-sized POUs account for about a quarter of the cumulative savings. The majority of the remaining 20 smaller POUs based their targets on net market potential only and collectively account for a very small share of the overall POU savings.

The Energy Commission has assessed the POU electricity savings projections provided by CMUA in March 2017 report. Additional information was obtained from CMUA and some POUs through data requests and two webinars. Staff understands that the flexibility of the energy efficiency potential study administered by CMUA for POUs has resulted in a set of projections for the POUs that does not use a uniform set of assumptions or accounting rules. Detailed implementation

targets for each POU are provided in Table 38. Table 39 summarizes the results of demand reduction targets.

Table 38: POU Energy Efficiency Targets (GWh)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
LADWP	499	504	461	410	408	402	404	414	417	406	4,324
SMUD	150	155	164	175	184	187	181	169	158	146	1,669
Imperial	33	34	34	32	31	29	28	27	25	22	295
Anaheim	28	28	27	26	26	25	24	23	22	20	249
Riverside	23	23	23	23	23	23	23	23	23	24	233
Pasadena	14	14	14	14	14	14	14	14	14	14	137
Turlock	16	15	15	15	14	14	13	12	11	10	134
Santa Clara	13	13	14	15	15	15	13	12	12	11	132
Glendale	15	15	15	14	14	14	12	12	11	10	131
Burbank	11	11	11	12	13	13	14	14	13	13	124
Modesto	9	10	11	12	13	13	14	14	13	12	121
Roseville	8	9	9	10	10	10	9	9	8	8	89
Palo Alto	7	7	8	8	8	8	9	9	9	9	82
Vernon	5	5	6	6	6	5	5	4	4	4	48
Redding	4	4	4	4	4	4	4	4	4	3	40
San Francisco	4	4	4	4	4	4	4	3	3	3	38
Small POUs*	17	17	17	17	17	17	16	16	15	14	162
All Combined	855	866	834	795	801	794	784	775	760	727	7,995

Source: Energy Efficiency in California's Public Power Sector Status Reports, Appendix B. Individual POU electricity savings targets are rounded to the nearest GWh. * Small POUs group include Colton, Lodi, Merced, Moreno Valley, Alameda, Truckee Donner, Shasta Lake, Banning, Healdsburg, Rancho Cucamonga, Lassen, Lompoc, Corona, Pittsburg, Ukiah, Victorville, Plumas-Sierra, Gridley, Needles, Biggs, Trinity, and Azusa.

Table 39: POU Demand Reduction Goals (MW)

	2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	Total
LADWP	108	112	104	89	88	88	89	91	91	91	951
SMUD	30	32	35	38	39	41	41	39	38	38	371
Imperial	10	10	10	10	9	9	9	8	8	7	89
Riverside	8	8	8	8	8	8	7	7	6	5	72
Anaheim	7	7	7	7	7	7	7	7	7	6	69
Burbank	3	4	4	4	4	4	4	4	4	4	39
Santa Clara	3	3	3	3	3	3	3	2	2	2	25
Glendale	3	3	3	3	3	3	2	2	2	2	25
Pasadena	3	2	2	2	2	2	2	2	2	2	23
Turlock	3	3	3	3	2	2	2	2	2	2	23
Modesto	2	2	2	2	2	2	2	2	2	2	21
Redding	1	1	1	1	1	1	1	1	1	1	11
Palo Alto	1	1	1	1	1	1	1	1	1	1	10
Vernon	1	1	1	1	1	1	1	1	1	-	9
Roseville	1	1	1	1	1	1	1	-	-	-	7
San Francisco	-	-	-	-	-	1	1	1	1	1	5
Small POU's	3	3	3	3	3	3	3	3	3	3	30
All Combined	186	191	187	175	175	176	176	174	172	168	1,781

Source: Energy Efficiency in California's Public Power Sector Status Reports, Appendix B. Individual POU demand reduction targets are rounded to the nearest MW.

APPENDIX D: Benefits Report for the Alternative and Renewable Fuel and Vehicle Technology Program

The transportation sector policy drivers identified in Chapter 1 highlight some of the aggressive goals for cleaning and diversifying California’s fuels and vehicles. In particular, the reduction of greenhouse gases to 40 percent below 1990 levels by 2030 established by Senate Bill 32 (Pavley, Chapter 249, Statutes of 2016) will require a rapid transformation from gasoline and diesel toward zero- and near-zero-emission vehicles, as well as a dedicated shift toward lower carbon alternative fuels for the conventional vehicles that will still be on the road.

In 2007, the Legislature established the Alternative and Renewable Fuel and Vehicle Technology Program (ARFVTP) within the Energy Commission.⁸¹³ With about \$100 million per year from vehicle registration fees, the ARFVTP provides funding to “*develop and deploy innovative technologies that transform California’s fuel and vehicle types to help attain the state’s climate change policies.*”⁸¹⁴ The statutes also require the Energy Commission to include an evaluation of ARFVTP efforts as part of each biennial *Integrated Energy Policy Report (IEPR)*. Similar evaluations were included in the *2011, 2013, and 2015 IEPRs*, as well as the *2014 IEPR Update*.

Funding Summary

The ARFVTP is funded by a surcharge on vehicle registrations, totaling roughly \$100 million per fiscal year. Each year, the Energy Commission develops an investment plan update to guide funding allocations for the coming fiscal year. The allocations reflect the Energy Commission’s perspective on where both barriers and opportunities lie for each fuel or technology, acknowledgment of the ARFVTP’s role as one part of a broader suite of policies and programs, and a portfolio approach that avoids adopting any one preferred fuel or technology. The *2017-2018 Investment Plan Update*, adopted at the Energy Commission business meeting in April 2017, was the ninth and most recent edition of this report.⁸¹⁵

Based on the funding allocations within previous investment plan updates, the Energy Commission usually develops and releases competitive solicitations for each project type. Each solicitation includes unique scoring or selection criteria that are applicable to the type of projects under consideration. For instance, a solicitation focused on commercially mature technologies may emphasize cost-related scoring criteria, or rely on a first-come, first-served system for

813 Assembly Bill 118 (Nuñez, Statutes of 2007, Chapter 750. Subsequently modified by Assembly Bill 109 (Nuñez, Statutes of 2008, Chapter 313).

814 Health and Safety Code Section 44272 (a).

815 California Energy Commission, *2017-2018 Investment Plan Update for the Alternative and Renewable Fuel and Vehicle Technology Program, Commission Report*, 2017. Available at <http://www.energy.ca.gov/altfuels/2016-ALT-02/documents/>.

projects that meet minimum requirements. Solicitations also typically assign preference to projects that benefit disadvantaged communities, whether in the form of additional scored points or higher funding levels.

For specialized project types, the Energy Commission may also develop funding agreements directly with partner agencies. Examples include the California Employment Training Panel, the University of California campuses, or the Division of Measurement Standards.

Since its first ARFVTP grant in 2009, the Energy Commission has provided \$745.0 million in funding. These project awards are summarized in Table 40.

Table 40: ARFVTP Awards as of September 1, 2017

Category	Funded Activity	Cumulative Awards to Date (in millions)*	# of Projects or Units
Alternative Fuel Production	Biomethane Production	\$60.9	20 Projects
	Gasoline Substitutes Production	\$32.1	15 Projects
	Diesel Substitutes Production	\$75.1	25 Projects
Alternative Fuel Infrastructure	Electric Vehicle Charging Infrastructure**	\$79.9	7,698 Charging Stations
	Hydrogen Refueling Infrastructure	\$122.3	60 Fueling Stations
	E85 Fueling Infrastructure	\$13.7	158 Fueling Stations
	Upstream Biodiesel Infrastructure	\$4.0	4 Infrastructure Sites
	Natural Gas Fueling Infrastructure	\$21.9	64 Fueling Stations
Alternative Fuel and Advanced Technology Vehicles	Natural Gas Vehicle Deployment***	\$65.8	3,148 Vehicles
	Propane Vehicle Deployment	\$6.0	514 Trucks
	Light-Duty Electric Vehicle Deployment	\$25.1	10,700 Cars
	Medium- and Heavy-Duty Electric Vehicle Deployment	\$4.0	150 Trucks
	Medium- and Heavy-Duty Vehicle Technology Demonstration and Scale-Up	\$130.1	49 Demonstrations
Related Needs and Opportunities	Manufacturing	\$46.5	21 Manufacturing Projects
	Emerging Opportunities	†	†
	Workforce Training and Development	\$30.7	96 Recipients
	Fuel Standards and Equipment Certification	\$3.9	1 Project
	Sustainability Studies	\$2.1	2 Projects
	Regional Alternative Fuel Readiness and Planning	\$9.6	43 Regional Plans and Implementation Projects
	Centers for Alternative Fuels	\$5.8	5 Centers
	Technical Assistance and Program Evaluation	\$5.5	n/a
Total		\$745.0	

Source: California Energy Commission. Sum of cumulative awards may not equal total because of rounding. *Includes all agreements that have been approved at an Energy Commission business meeting or are expected for business meeting approval following a notice of proposed award. For canceled and completed projects, includes only funding received from ARFVTP, which may be smaller than initial award. **Includes \$15.3 million for an agreement to provide EV incentives throughout California, which will fund a yet-to-be-determined number of EV chargers. ***Funding includes both completed and pending vehicle incentives, as well as encumbered funds for future incentives.

Quantifying Benefits From ARFVTP Projects

Section 44273 of the Health and Safety Code requires the Energy Commission to evaluate the following types of benefits:

- Petroleum Use Reduction
- Air Quality
- Greenhouse Gas (GHG) Emissions Reduction
- Benefit-Cost Assessment
- Technology Advancement

The Energy Commission partnered with the National Renewable Energy Laboratory (NREL) to develop quantifiable estimates of petroleum use reduction, air quality benefits, and GHG emissions reductions associated with ARFVTP projects. NREL had similarly helped develop ARFVTP benefits analysis in the *2013 IEPR*, *2014 IEPR Update*, and *2015 IEPR*.

For the *2017 IEPR*, NREL used the same approach toward quantifying ARFVTP project benefits as it did in previous years, beginning with the *2014 IEPR Update*. This includes analyzing two categories of benefits: Expected Benefits and Market Transformation Benefits. These categories are discussed further in the respective sections.

Inputs and Assumptions

Energy Commission staff provided NREL a list of pending, active, and completed ARFVTP projects through June 2017, along with relevant information about each.⁸¹⁶ The list included projects totaling about \$622.4 million, or roughly 84 percent of all ARFVTP project funding. Other projects were not included in this analysis, such as projects without direct petroleum displacement or emissions reduction benefits (including regional readiness planning grants, workforce training, or fueling standards and certification), projects that were canceled or otherwise not expected to be completed, and projects that had only recently been proposed for awards. Table 41 shows the amount and percentage of funding included in the NREL analysis by project type.

⁸¹⁶ Projects that were canceled by the Energy Commission, or pending cancellation, were not included.

Table 41: Funding Analyzed by NREL by Project Type Through June 2017

Category	Project Type	Funding Analyzed by NREL (in millions)	% of Funding Analyzed by NREL
Alternative Fuel Production	Biomethane	\$56.4	93%
	Gasoline Substitutes	\$29.3	91%
	Diesel Substitutes	\$75.1	100%
Alternative Fuel Infrastructure	Electric Vehicle Charging	\$53.4	67%*
	Hydrogen Refueling	\$115.1	94%**
	E85 Fueling	\$13.7	100%
	Upstream Biodiesel Infrastructure	\$4.0	100%
	Natural Gas Fueling	\$21.9	100%
Alternative Fuel and Advanced Technology Vehicles	NG Commercial Trucks	\$64.5	98%
	Light-Duty BEVs and PHEVs	\$25.1	100%
	Electric Commercial Trucks	\$4.0	100%
	MD-HD Truck Demonstration	\$117.7	90%
	Manufacturing	\$42.2	91%
Other Project Types		\$0	0%
Total		\$622.4	84%

Source: California Energy Commission staff. *Did not include funding recently reserved for a charging equipment block grant project (ARV-16-017).

The Energy Commission staff also provided NREL with project information from a variety of sources, including initial funding proposals, surveys of funding recipients, and (when available) final project reports. Where necessary, Energy Commission staff judgment was also applied to rein in some of the more optimistic recipient assumptions.

The most critical information included:

- The amount of alternative fuel produced at ARFVTP-funded production facilities, dispensed at ARFVTP-funded fueling stations, or consumed by ARFVTP-funded vehicles. This amount is used to estimate petroleum displacement.
- The life-cycle carbon intensity of the alternative fuel of the project (if distinct from statewide averages). This information is used to estimate GHG emissions reduction.
- The type of conventional vehicle replaced by the ARFVTP-funded vehicle or alternative fuel (if applicable). This information is used to estimate petroleum displacement, air quality pollutant reduction, and GHG emissions reduction.

In addition to project data from the Energy Commission, NREL also relied on other established models. NREL incorporated carbon intensity values from the California Low Carbon Fuel Standard and the California-adjusted Greenhouse Gases, Regulated Emissions, and Energy Use in Transportation (GREET) model, when possible. For certain unique biofuel production projects, ARFVTP-supplied carbon intensity numbers were used. NREL also used the VISION and GREET

models to estimate reductions of oxides of nitrogen (NO_x), as well as particulate matter of less than 2.5 micrometers (PM_{2.5}).

Results from this analysis are reported primarily on a per-year basis (for example, GHG emissions reduced in 2030) rather than a cumulative basis (such as GHG emissions reduced through 2030). NREL assumed lifespans for each project class, with fuel production and fueling infrastructure projects having a longer lifespan than vehicle projects. Only vehicle projects with an estimated lifespan of 16 years had a shorter lifespan than the duration of the analysis. Projects were assumed to begin accruing benefits at the time of completion of the ARFVTP agreement. For vehicle projects, NREL applied a “vehicle miles traveled depreciation rate” to account for the fact that older vehicles typically drive fewer miles per year as they age. Conversely, fuel production projects were assigned a three-year “ramp up” period to reach anticipated capacity.

For this analysis, the benefits of a project are assumed to include all alternative fuel produced, dispensed, or consumed by an ARFVTP-funded project. This is the most straightforward approach to quantifying benefits but necessarily risks overstating the direct impacts of the ARFVTP’s investment. In almost all cases, ARFVTP funding for a project must be matched by private funding. To date, the ARFVTP’s total investment of \$745 million has been contractually matched with more than \$700 million in outside funding.⁸¹⁷ Furthermore, other public funding and regulatory programs help ensure the success of ARFVTP projects, including the Low Carbon Fuel Standard, the Renewable Fuel Standard, the zero-emission vehicle (ZEV) mandate, the Air Quality Improvement Program, and the Greenhouse Gas Reduction Fund. For similar reasons, benefits from this analysis may not be independent of (or in addition to) the estimated benefits of related programs.

Expected Benefits

Expected benefits represent the outcomes directly supported by ARFVTP funding. These benefits assume a one-to-one substitution of conventional petroleum-derived fuels with an alternative fuel and/or improved vehicle efficiency. The amount of gasoline or diesel displaced, multiplied by the carbon intensity ratio of the new alternative fuel against gasoline or diesel, results in an estimate of GHG reductions.

Table 42 highlights the expected benefits from ARFVTP-funded projects in terms of annual petroleum fuel reductions and GHG reductions. By 2030, projects supported by the ARFVTP are expected to directly reduce petroleum fuel consumption by 314 million gallons each year and to reduce GHG emissions by nearly 2.8 million metric tons carbon dioxide-equivalent (CO_{2e}) each year.

The ratio between petroleum fuel reductions and GHG reductions in Table 42 also illustrates the relative carbon reduction benefits of various alternative fuels. For example, in 2025, the biomethane fuel production projects reduce GHG emissions by about 17,500 tonnes of CO_{2e} per million gallons of displaced petroleum (193.5/11.0), while the natural gas commercial trucks reduce GHG emissions by just 2,700 tonnes per million gallons (12.5/4.6). This reflects the

⁸¹⁷ Not including the match funding associated with as-yet-unsigned grant agreements.

significantly lower carbon intensity of biomethane compared to natural gas and highlights the GHG reduction value of incorporating biomethane into natural gas vehicles (as discussed in Chapter 9).

Table 42: Annual Petroleum Fuel and GHG Reductions (Expected Benefits)

Project Type	Petroleum Fuel Reductions (in million gallons)			GHG Reductions (in thousands tonnes CO ₂ e)		
	2020	2025	2030	2020	2025	2030
Fuel Production	92.2	137.9	137.9	1,734.7	1,582.9	1,582.9
Biomethane	6.3	11.0	11.0	103.1	193.5	193.5
Diesel Substitutes	81.5	111.3	111.3	894.1	1,228.3	1228.3
Gasoline Substitutes*	4.4	15.6	15.6	737.5	161.1	161.1
Fueling Infrastructure	71.3	71.9	73.4	323.2	329.2	338.6
Biodiesel	8.5	8.5	8.5	73.8	73.8	73.8
E85	11.1	11.2	11.2	33.7	33.8	33.8
Electric Charging	2.8	2.6	2.6	20.9	20.0	20.0
Hydrogen	13.6	14.3	15.5	107.7	113.8	123.2
Natural/Renewable Gas	35.3	35.3	35.6	87.1	87.8	87.8
Vehicles	73.3	116.0	102.8	580	951.2	863.5
Electric Commercial Trucks	0.4	0.3	-	3.1	2.1	-
Light-Duty BEVs and PHEVs**	1.5	1.1	0.9	11.3	8.4	6.5
Manufacturing	65.1	108.8	97.8	543.8	919.7	841.6
MD-HD Truck Demonstration	0.9	1.2	1.0	7.1	8.5	6.9
Natural Gas Commercial Trucks	5.4	4.6	3.1	14.7	12.5	8.5
Total	236.8	325.8	314.1	2,637.9	2,863.3	2,785.0

Source: NREL. Note: subtotals and totals may not match due to rounding. *Does not include pre-2020 benefits from projects funded under the California Ethanol Producers Incentive Program. **BEV= battery electric vehicle, PHEV= plug-in hybrid electric vehicle

In its expected benefits analysis, NREL also included tailpipe reductions of certain key criteria pollutants: NO_x and PM_{2.5}. However, for this analysis, NREL focused specifically on fuel and vehicle types with emission reductions recognized under the VISION and GREET models. This narrows the analysis to projects using electricity and hydrogen as the alternative fuel.⁸¹⁸ Table 43 summarizes the annual NO_x and PM_{2.5} reductions anticipated from the expected benefits approach.

⁸¹⁸ Discussions are underway with Energy Commission staff and NREL as to how natural gas can be included as well.

Table 43: Annual Air Pollutant Reductions (Expected Benefits)

Project Type		NOx Reductions (Tonnes / year)			PM2.5 Reductions (Tonnes / year)		
		2020	2025	2030	2020	2025	2030
Fuel Infrastructure	Electric Chargers	0.49	1.16	1.57	1.07	1.46	1.46
	Hydrogen	0.12	2.58	5.03	2.39	4.66	4.65
	Natural Gas	N/A	N/A	N/A	N/A	N/A	N/A
Vehicles	CVRP/HVIP Support	2.89	1.75	1.17	0.59	0.42	0.23
	NG Commercial Trucks	N/A	N/A	N/A	N/A	N/A	N/A
	MD-HD Demonstration	3.03	4.02	3.07	0.30	0.37	0.27
	Manufacturing	3.03	0.75	0.50	0.30	0.06	0.04
Total		9.56	10.26	11.34	4.65	6.97	6.65

Source: NREL

Market Transformation Benefits

Unlike expected benefits, market transformation benefits represent estimates of how ARFVTP funding might indirectly influence the expansion of alternative fuel production and use in the future. A simple example might be the impact of seeing additional charging stations in the vicinity makes a prospective vehicle buyer more willing to consider buying a PEV or the effect of a successful demonstration of an advanced technology truck increases the likelihood of that technology achieving future commercial success. The latter example is one way of evaluating ARFVTP-funded “technological advancement” as required by the statutes of the program.

NREL has identified four potential ways ARFVTP projects can influence market transformation. These potential influences are described in Table 44. There may be other ways that ARFVTP projects influence the future market growth of clean fuels and vehicles; however, these are the examples NREL found to be the most readily quantifiable. The methods used to quantify these influences were established in the 2014 *Program Benefits Guidance: Analysis of Benefits Associated With Projects and Technologies Supported by the ARFVTP*, produced by NREL for that year’s *IEPR Update*.⁸¹⁹

⁸¹⁹ NREL. 2014. *Program Benefits Guidance: Analysis of Benefits Associated with Projects and Technologies Supported by the ARFVTP*, draft project report. Available at <http://www.energy.ca.gov/2014publications/CEC-600-2014-005/CEC-600-2014-005-D.pdf>.

Table 44: Market Transformation Benefits Description

Market Transformation Influence	Applicable ARVTP Project Types	Description of Influence Outcomes
Perceived Vehicle Price Reduction	<ul style="list-style-type: none"> • Electric charging • Hydrogen stations • Light-duty BEVs and PHEV incentives 	<ul style="list-style-type: none"> • Increased consumer awareness • Removal of consumer choice barriers via increased refueling access
Vehicle Cost Reduction	<ul style="list-style-type: none"> • Manufacturing 	<ul style="list-style-type: none"> • Reduced cost to produce or supply a technology • “Learn by doing” • Economies of scale
Next-Generation Trucks	<ul style="list-style-type: none"> • MD/HD truck demonstration • Medium-duty BEV incentives 	<ul style="list-style-type: none"> • Additional trucks deployed as a result of successful demonstration projects
Next-Generation Fuels	<ul style="list-style-type: none"> • Biofuel production (all fuel types) 	<ul style="list-style-type: none"> • Additional or expanded biofuel production facilities in response to successful projects

Source: NREL

Because the market transformation benefits analysis relies on future market conditions and decisions in a way that the expected benefits analysis does not, NREL includes two sets of assumptions to generate a “low case” and “high case.”⁸²⁰ In general, the low case reflects more conservative assumptions about demand elasticity for ZEVs, savings from economies of scale, and the ability of successful demonstration projects to leverage private interest for larger commercial-scale projects, while the high case reflects the opposite.

Table 45 summarizes the total market transformation benefits under consideration with regard to petroleum displacement, GHG emission reduction, and air pollutant reduction. Since market transformation benefits lag behind the initial expected benefits of a project, this table focuses on benefits in 2030. As with the expected benefits, NREL did not attempt to quantify air pollutant reductions associated with the market transformation benefits of biofuel production projects (under “Next-Generation Fuels”). Moreover, air quality improvements for “Next-Generation Trucks” could not be reliably calculated due to significant uncertainties about what varieties of baseline vehicles would be displaced and their respective emissions profiles.

⁸²⁰ These are unrelated to the demand cases used in the *IEPR* energy demand forecasts.

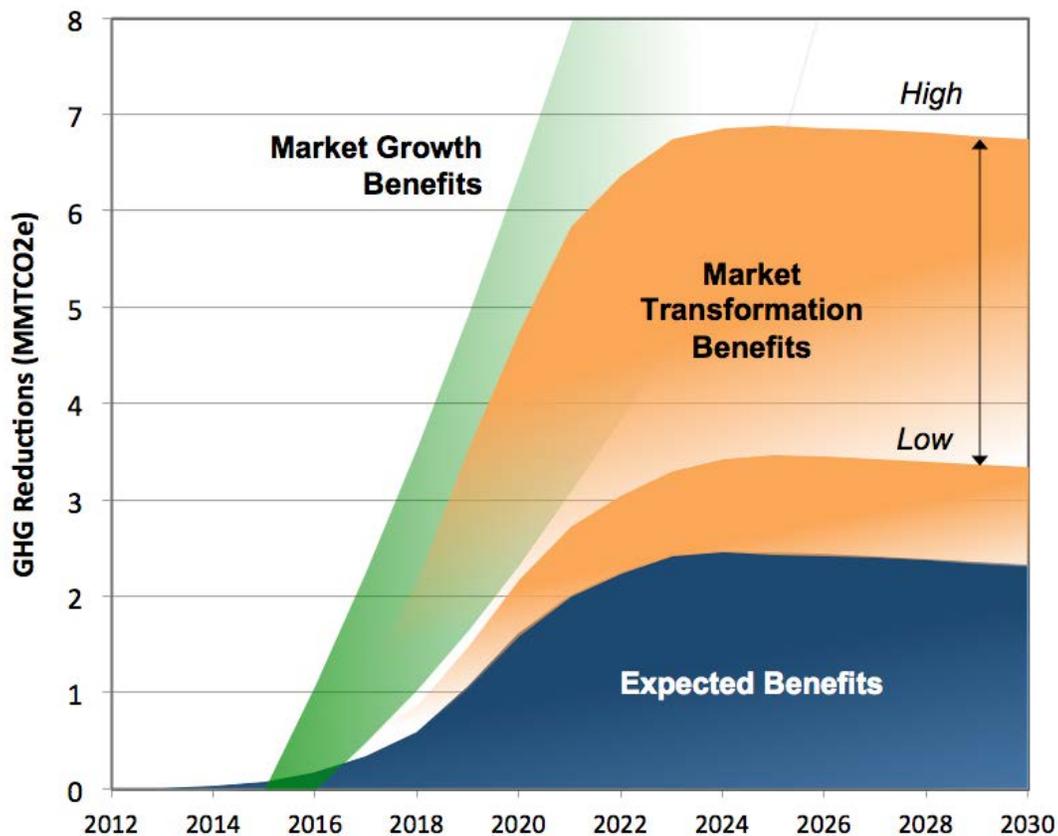
Table 45: Annual Market Transformation Benefits in 2025

Market Transformation Influence	Case	Petroleum Displacement (M gal)	GHG Reduction (thousand tonnes CO2e)	NOx Reduction (tonnes)	PM 2.5 Reduction (tonnes)
		2030	2030	2030	2030
Perceived Vehicle Price Reductions	High	104.4	865.5	68.5	61.9
	Low	45.0	371.2	29.4	26.4
Vehicle Cost Reduction	High	10.9	83.4	6.1	4.8
	Low	9.6	71.1	5.9	4.6
Next-Generation Trucks	High	257.8	1513.0	?	?
	Low	10.2	70.7	?	?
Next-Generation Fuels	High	286.6	2032.5	N/A	N/A
	Low	71.7	508.1		
Total	High	659.7	4,494.4	74.6	66.7
	Low	136.5	1,021.1	35.3	31.0

Source: NREL

Expected benefits and market transformation benefits can be combined to show the overall quantified benefits anticipated by ARFVTP-funded projects. For example, Figure 102 shows the expected GHG reductions per year from both benefit categories. The lower section of the graph, in blue, reflects the expected benefits of all ARFVTP project types over time. Above that, the low case and high case for GHG reductions from market transformation benefits are shown in orange. The low case for market transformation includes just the lower orange wedge, and the high case includes the entire orange section. The green segment roughly depicts the necessary trajectory for the transportation sector to be “on track” toward meeting its share of long-term GHG reduction goals.

Figure 103: Annual GHG Reduction From ARFVTP-Funded Projects



Source: NREL

Benefit-Cost Assessment

As noted, ARFVTP statutes require the 2017 IEPR to include a “benefit-cost assessment” for ARFVTP-funded projects. While such an assessment is not further defined, a reasonable assumption is that “benefit-cost” has a meaning similar to that used elsewhere in the ARFVTP statutes. Specifically, the “benefit-cost” represents the “...expected or potential GHG emissions reduction per dollar awarded by the commission...”⁸²¹

Unlike the previous estimates of benefits, this requires assessing GHG emission reductions on a cumulative basis, not an annual basis. A simple yet conservative assumption is to include the cumulative GHG emission reductions of ARFVTP-funded projects through 2025, since all projects are assumed to continue accruing benefits by that time. Based on this approach, the cumulative GHG emission reductions of expected benefits and market transformation benefits by 2025 range from roughly 23.6 million metric tons (using the low case for market transformation benefits) to 47.4 million metric tons (using the high case).

The Energy Commission has awarded \$622.4 million toward ARFVTP projects (not including canceled and defunded projects) with GHG emission reductions measurable using NREL’s method. When including projects that do not readily lend themselves to measurable GHG

⁸²¹ Health and Safety Code Section 44270.3.

emissions (such as regional fuel readiness grants, workforce training agreements, and fuel standards and certification agreements), this amount increases to nearly \$745 million. Table 46 shows the resulting benefit-cost ratios, depending on (1) which funding amount is used as the cost, and (2) whether the low case or the high case for market transformation benefits is applied. The values in Table 46 represent the approximate amount of carbon dioxide-equivalent metric tons reduced for every \$1 invested by the ARFVTP.

Table 46: Kilograms CO₂e Reduced Through 2025 per ARFVTP Dollar

	Cost Basis: Analyzed Projects Only	Cost Basis: All ARFVTP Projects
Expected Benefits + Market Transformation (Low Case)	37.9 kg per ARFVTP \$	31.7 kg per ARFVTP \$
Expected Benefits + Market Transformation (High Case)	76.2 kg per ARFVTP \$	63.7 kg per ARFVTP \$

Source: California Energy Commission

As an alternative to the benefit-cost ratios in Table 46, the results can also be presented as cost-benefit ratio, in terms of dollars per metric ton. This metric is more commonly used when discussing carbon prices and is presented in Table 47. However, as indicated, GHG emission reductions from ARFVTP projects cannot be attributed solely to ARFVTP investment, as there is a wide array of complementary policies and programs that contribute to the success of ARFVTP projects.

Table 47: ARFVTP Funding per Metric Ton CO₂e Reduced Through 2025

	Cost Basis: Analyzed Projects Only	Cost Basis: All ARFVTP Projects
Expected Benefits + Market Transformation (Low Case)	\$26 per metric ton	\$32 per metric ton
Expected Benefits + Market Transformation (High Case)	\$13 per metric ton	\$16 per metric ton

Source: California Energy Commission

Promoting Investment in California(ns)

The Energy Commission’s first years in implementing the ARFVTP coincided with the state and nation’s plunge into an economic recession. Although the main emphasis of the program was still in cleaning and diversifying transportation fuels, job creation and economic impacts were quickly recognized as additional priorities for the program.

Expanding In-State Manufacturing

Within the ARFVTP funding portfolio, the manufacturing investments of the program offer a unique opportunity to simultaneously accelerate the state’s deployment of advanced technology vehicles and expand the creation of green jobs within the state. For example, after successfully competing in an ARFVTP solicitation, Proterra was awarded a \$3 million grant in April 2015 to design, develop, and manufacture zero-emission buses in the San Gabriel Valley. Proterra proposed match funding for the grant equal to the ARFVTP’s investment; since the start of 2017,

however, Proterra has attracted nearly \$195 million in private investments. As of January 2017, the company had 36 customers and 377 orders.

ARFVTP Jobs Estimates

In response to ARFVTP funding, funding recipients made numerous investments into short- and long-term jobs within the state. In 2015, the Energy Commission surveyed ARFVTP funding recipients, including questions about job creation associated with the project. These 2015 results indicated the creation of around 4,144 short-term jobs and 3,712 long-term jobs spread across a then-total of \$606 million in ARFVTP investment. Of these, roughly 57 percent were in construction or engineering positions; 15 percent were in manufacturing positions; 9 percent were in operations and maintenance positions; and 19 percent were administrative or “other” positions.

Extrapolating these 2015 numbers to the current 2017 total of \$745 million invested by ARFVTP suggests revised totals around 5,100 short-term jobs and 4,600 long-term jobs, likely with a similar ratio of position categories. These numbers do not include any estimates of multipliers, such as the “upstream” jobs generated by equipment manufacturers or the “downstream” jobs generated by employees’ incomes.

Workforce Training and Development

To grow and maintain a broad market for alternative fuels and advanced technology vehicles, California must have a workforce that is properly trained to supply, refuel, operate, and maintain the related facilities and vehicles. To date, the Energy Commission has invested nearly \$30 million in workforce training and development agreements. These agreements are managed by partnering state agencies, on behalf of the Energy Commission, with a specific focus on identifying training needs that are specific to alternative fuels and advanced technology vehicles.

Table 48 summarizes the ARFVTP investments into workforce training and development with partner agencies. More than 17,000 individuals have received training funded by the ARFVTP, including assistance to more than 277 businesses and 16 local municipalities. The largest funding partner, the Employment Training Panel, focuses on training for incumbent employees. Recipient employers must commit to provide matching funds and must demonstrate the retention of trained employees 91 days after training completion. Investments with the California Community Colleges Chancellor’s Office has supported curriculum development, “train-the-trainers” programs, and specialized equipment needs at campuses. The office is also preparing a focus on apprenticeship training programs.

Table 48: ARFVTP Investments in Workforce Training and Development

Partner Agency	Funded Training (Millions)	Match Contributions (Millions)	Trainees	Businesses Assisted	Municipalities Assisted
Employment Training Panel	\$13.5	\$11.3	16,441	173+	18+
Employment Development Department	\$8.2	\$7.5	999	36+	-
California Community Colleges Chancellor's Office	\$5.75	\$0.5	N/A*	68+*	-
California Workforce Development Board	\$0.25	\$0.5	N/A*	N/A*	-
Advanced Transportation Technology and Energy Center	\$4.0	N/A	N/A*	N/A*	-
Total	\$29.70	\$19.3	16,943	255+	18+

Source: California Energy Commission. The number of trainees includes completed, partially completed, and anticipated participants from approved contracts. *Participant data are incomplete because these are new agreements.

APPENDIX E:

Western Reliability and Planning Coordination

Western regional coordination is built on the strong foundation of collaboration among the electricity industry and state governments in the West over many decades. The relationships forming this foundation have been built through the activities of many critical western organizations and initiatives including the Western Electricity Coordinating Council (WECC), Western Interconnection Regional Advisory Body (WIRAB), Western Interstate Energy Board (WIEB), and Peak Reliability, among others.

Western Electricity Coordinating Council

The Western Electricity Coordinating Council (WECC) is the regional entity for the Western Interconnection. As the only regional entity that is also a multistate and international interconnection, WECC is unique among the U.S. regions. As regional entity, WECC has a delegation agreement with the electricity reliability organization for the United States, the North American Electric Reliability Corporation (NERC). Under this agreement, WECC is responsible for conducting planning analyses and ensuring compliance with mandatory reliability standards promulgated by NERC, as approved by the Federal Energy Regulatory Commission (FERC).

In June 2017, WECC adopted its budget, totaling about \$27 million for calendar year 2018. Much of this budget covers WECC's statutorily mandated activities, including enforcing federal standards. Enforcement is a multitiered process, ranging from participation in standards development (to ensure they are clear and applicable to the Western Interconnection) to reviewing compliance documentation. Onsite audits are routinely conducted to better understand how each regulated entity is complying with the standards and to identify potential violations. If violations occur, these are reviewed through a complex enforcement process. More innovative analytic and institutional initiatives are housed in its Reliability Assessment and Performance Analysis Program. Examples of important Western initiatives now underway at WECC include:

- **Integration with Mexico:** Over the past two years, the government of Mexico has implemented a major restructuring of its electric industry, such that it resembles the deregulated industry model applied in U.S. regions with independent system operators overseen by federal regulators. This is relevant to the WECC, because Northern Mexico is an integral part of the Western Interconnection. Significant progress is being made on a memorandum of understanding (MOU)⁸²² that specifies how Mexico will meet U.S. reliability standards and what other planning services WECC could provide to Mexico. This agreement is expected to be signed in 2018.

⁸²² The Mexican Secretary General of Energy Pedro J. Coldwell and California Governor Edmund G. Brown Jr. signed the MOU in July 2014.

As the Western EIM continues to yield proven benefits, the California ISO and El Centro Nacional de Control de Energía (CENACE) announced in October 2016 that the Mexican electric system operator has agreed to explore participation of its Baja California Norte grid in the real-time market. CENACE and the California ISO have begun a benefits assessment as well as entered into a cooperation agreement to support CENACE's market implementation, as directed by the clean energy MOU between the Ministry of Energy of the United Mexican States and the State of California.⁸²³

- **Assessment of Interdependence of Natural Gas and Electric Infrastructure:** WECC has initiated a two-year, \$1.5 million study of the gas electric interface, relying on consultants including the firms McKenzie and E3. The purposes of this study are threefold: (1) Identify key natural gas contingencies that should be included in utility planning; (2) highlight risks associated with increasing dependence on gas and communicate these to policy makers; and, (3) identify risk mitigation for policy maker and utility consideration. Key concerns the study is designed to address include:
 - Supply restrictions due to weather.
 - Effects of firm vs. interruptible contracts.⁸²⁴
 - Use of storage as a shock absorber to balance increasing ramping needs.
 - Use of natural gas storage and pipeline pack⁸²⁵ to meet deliverability requirements.
 - Challenges in permitting and siting new infrastructure.
 - Midstream⁸²⁶ risks that should be factored into electric reliability plans.

Deliverables of the study will map the bulk electric system (BES) assets to gas infrastructure and identify key points of vulnerability; assess infrastructure adequacy to meet future needs based on the 2026 Common Case 10-year future; assess the firmness of Western Interconnection gas supply and transportation contracts; and identify key planning contingencies for utility planners.

- **Development of the "State of the Interconnection" Interactive Platform and Data:** in June 2017, WECC staff rolled out a major new online tool for reporting its data and analytics regarding electric generation and transmission system. This approach replaces written documents traditionally prepared assessing resource adequacy, loads, resources, and

⁸²³ The benefits study will be made available at <https://www.westerneim.com/pages/default.aspx>.

⁸²⁴ Contracts for natural gas supply vary by price and deliverability terms. Firm contracts are required for core customers (residential/commercial), but suppliers may negotiate lower prices for industrial or electric utility customers that can tolerate periods of pipeline supply interruptions due to scarcity or redirection of supply to higher paying customers.

⁸²⁵ Natural gas occupies all pressurized sections of the pipeline network. Introduction of new gas at a receipt point "packs" or adds pressure to the line. Removal of gas at a delivery point lowers the pressure (unpacks the line). *Line-packing* is a form of short-term storage on the pipeline system.

⁸²⁶ Midstream activities connect upstream production to downstream end markets. Midstream activities include the gathering, processing/blending, transportation, and storage of oil, natural gas, and related products.

transmission transfer capability. Work is underway to report these data by state boundaries, as well as subregions of the Western Interconnection.⁸²⁷

- **Integration of WECC Power Flow and Production Cost Data, Models and Committees:** A major internal focus of WECC staff and stakeholders in 2017–18 has been the overhaul of longstanding institutions, data, and stakeholder engagement in preparing datasets, running models, and preparing studies of reliability and dispatch of the western generation and transmission system. These functions, beginning in September 2018, will be conducted by one integrated staff and one committee, the Reliability Assessment Committee. This entails phasing out two major WECC committees, including the Transmission Expansion Planning Policy Committee, which had done all production cost and transmission expansion studies for more than 10 years.

Western Interconnection Regional Advisory Body

The WIRAB⁸²⁸ was established in the Western Interconnection to advise NERC, WECC, and FERC on whether proposed reliability standards within the region, as well as the governance and budgets of NERC and WECC, are just, reasonable, not unduly discriminatory or preferential, and in the public interest. Because WIRAB is a multistate body organized on an "interconnectionwide basis," it is unique in the United States and is granted deference to its advice on BES by FERC under the Energy Policy Act of 2005. Funded under Section 215 of the act, WIRAB proposes a budget of slightly more than \$1 million. This is funded in part (\$700,000) by an assessment on all Western Interconnection load-serving entities (a wires charge). The five-plus full-time staff members supported by the budget will focus on the six major 2018 initiatives described below.

1. Advise WECC on the implications of high levels of photovoltaic (PV) on the reliable operation of the bulk electric system.
2. Advise WECC on interdependencies between the natural gas and electric industries in the West and implications for the reliable operation of the bulk electric system.
3. Encourage WECC to systematically assess the availability of essential reliability services under a wide range of future resource scenarios.
4. Encourage the WECC and Peak member committees to increase focus on reliability and improve processes.
5. WIRAB and its partner group WIEB are also implementing a United States Department of Energy (U.S. DOE) SunShot grant through a cooperative agreement with national labs and technical advisory teams; funds support completion of research concerning barriers to distributed solar PV in the West.

⁸²⁷ Users can access the interactive analytic tool online at <http://www.wecc.biz>.

⁸²⁸ WIRAB was created by Western Governors under Section 215(j) of the Federal Power Act (FPA). Section 215 of the FPA provides establishment of a federal regulatory system of mandatory and enforceable electric reliability standards for the nation's bulk power system. More information on the structure of WIRAB is available at <http://westernenergyboard.org/wirab/organizational-structure/>. Commissioner Janea Scott is currently the chair of WIRAB (see <http://westernenergyboard.org/wirab/members/>).

6. WIRAB has initiated the Western Electricity Market Forum to provide a venue for western stakeholders to better understand past, present, and future market design and to formulate potential paths forward for achieving potential benefits of increased western market integration.

Western Interstate Energy Board

The Western Interstate Energy Board (WIEB) is an organization of 11 western states and three western Canadian Provinces formed via the Western Interstate Nuclear Compact. The governor of each state and the premier of each province appoint a member to the board.⁸²⁹ The WIEB provides the instruments and framework for cooperative state efforts to enhance the economy of the West and contribute to the well-being of the region's people by promoting energy policy that is developed cooperatively among member states, provinces, and the federal government.

As part of the RETI 2.0 process, the California RETI 2.0 agencies requested assistance from the WIEB staff to help estimate western regional renewable resource potential, costs, and locations; the capability of the existing transmission system to deliver these resources to California load centers (and allow for export of California renewable energy); and the potential for new transmission proposals to expand this capacity. WIEB initiated the Western Outreach Project and Report (WOPR) with technical support from Energy Strategies LLC. As part of the effort, WIEB developed a series of outreach questions to explore these topics and held two workshops in Portland, Oregon, and Las Vegas, Nevada. WIEB published a summary report on October 28, 2016, that included several recommendations regarding the need for further collaboration. The three types of collaboration discussed during the Western Outreach project include western resource planning coordination, new market products, and study of coal unit retirement implications.⁸³⁰

Peak Reliability

Peak Reliability (Peak) was formed as a result of the bifurcation of the WECC into a regional entity (the role served by WECC) and a reliability coordinator (the role served by Peak). The bifurcation of WECC received final approval from the FERC on February 12, 2014. As a reliability coordinator (RC), Peak provides reliability services for the Western Interconnection, with the exception of Alberta (which chooses to provide its own RC services). Peak supports the reliable operation of the Western Interconnection through the development and deployment of real-time tools and assessments, including the Enhanced Curtailment Calculator (ECC) tool, which evaluates the Western Interconnection system in real time to determine possible system reliability issues and system operating limit (SOL) exceedances, as well as related causes. The ECC leverages a full interconnection real-time system state from the Peak State Estimator every five minutes.

⁸²⁹ For more information, see <http://westernenergyboard.org/wirab/organizational-structure/>.

⁸³⁰ Western Interstate Energy Board. *RETI 2.0 Western Outreach Project Report*. Prepared by Energy Strategies, LLC. October 28, 2016 (revised version). http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf.

While Peak pursues the vision of being the single RC in the West, as mentioned above, the Alberta Electric System Operator also supplies RC services for its small geographic and remote portion of the Western Interconnection. Thus, there are presently two RC service providers in the Western Interconnection. In contrast, the Eastern Interconnection operates under a multiple RC regime, often with ISO and regional transmission organization market operators also providing RC services. Recognizing that both arrangements exist, WIRAB sought consulting services to help analyze the possible developments surrounding RC service provision.

The WIRAB consultant report⁸³¹ introduces a framework for the objective review and assessment of the reliability and cost implications of a transition from a single, interconnectionwide RC to multiple RCs. The framework attempts to identify the tools and capabilities an additional provider of RC services would need to provide service comparable to a single RC structure. The report identifies those tools and technologies that must be provided to deliver minimum reliability per NERC reliability standards and highlights tools developed over time in the Western Interconnection to improve reliability above the minimum standards.

As noted in Chapter 3, some developments under consideration in the West have the potential to challenge traditional concepts of the bulk electric system. On September 22, 2017, the Mountain West Transmission Group participants announced they were beginning final negotiations with the Southwest Power Pool for regional transmission organization membership.⁸³² If these negotiations and the resultant implementation efforts are successful, the Southwest Power Pool would become the first regional transmission organization to operate in separate synchronous interconnections. This development represents one of several fronts in a many-faceted competition to deliver competitive market solutions to participants in the Western bulk electric system.

Another development announced on December 7, 2017, has Peak Reliability, the reliability coordinator for the majority of the Western Interconnection, engaging with PJM Connex, a subsidiary of the PJM Interconnection (PJM), to explore alternative market solutions in the Western region.⁸³³ The announcement has proven to be somewhat controversial, as market participants in the Western region have expressed concern that PJM lacks experience in the West.⁸³⁴

On January 2, 2018, the California ISO announced it plans to become its own Reliability Coordinator^{835, 836} and offer reliability services to other balancing authorities and transmission

831 Western Interconnection Regional Advisory Board. June 27, 2017. *A Framework for Considering Multiple Reliability Coordinators in the Western Interconnection*. <http://westernenergyboard.org/wp-content/uploads/2017/06/06-24-17-WIRAB-reliability-coordinator-review-framework.pdf>.

832 <https://www.wapa.gov/newsroom/NewsReleases/2017/Pages/Mountain-West-SPP-negotiations.aspx>.

833 Peak Reliability and PJM Connex, Press Release titled *Peak Reliability and PJM Connex Agree to Jointly Explore Reliability Services and Markets in the West*, December 7, 2017, https://www.peakrc.com/aboutus/Newsletters/2017_12_07%20Final%20Release.pdf.

834 RTO Insider, PJM Unit to Help Develop Western Markets, December 8, 2017, <https://www.rtoinsider.com/pjm-connex-peak-reliability-western-electric-markets-81332/>.

835 California ISO, News Release titled *California ISO Announces Plans to Become Reliability Coordinator*, January 2, 2018, <http://www.caiso.com/Documents/CaliforniaISOAnnouncesPlanstoBecomeReliabilityCoordinator.pdf>.

operators in the Western United States. The California ISO also notified Peak Reliability of its intent to withdraw from the Reliability Coordinator Funding Agreement it has with Peak, effective September 2019. The California ISO plans for its new Reliability Coordinator unit to be certified and operational by spring 2019.

836 A reliability coordinator is responsible for complying with NERC and regional standards, including providing oversight, monitoring operational and security risks, acting or directing action to preserve system reliability, and providing leadership in system restoration following a major reliability event. As noted in the January 2, 2018 press release, the RC services the California ISO is contemplating will include outage coordination and day-ahead planning, in addition to real-time monitoring for reliability. For more information see California ISO, News Release titled California ISO Announces Plans to Become Reliability Coordinator, January 2, 2018, <http://www.caiso.com/Documents/CaliforniaISOAnnouncesPlanstoBecomeReliabilityCoordinator.pdf>.

APPENDIX F:

Status of Major California and Western Transmission Projects

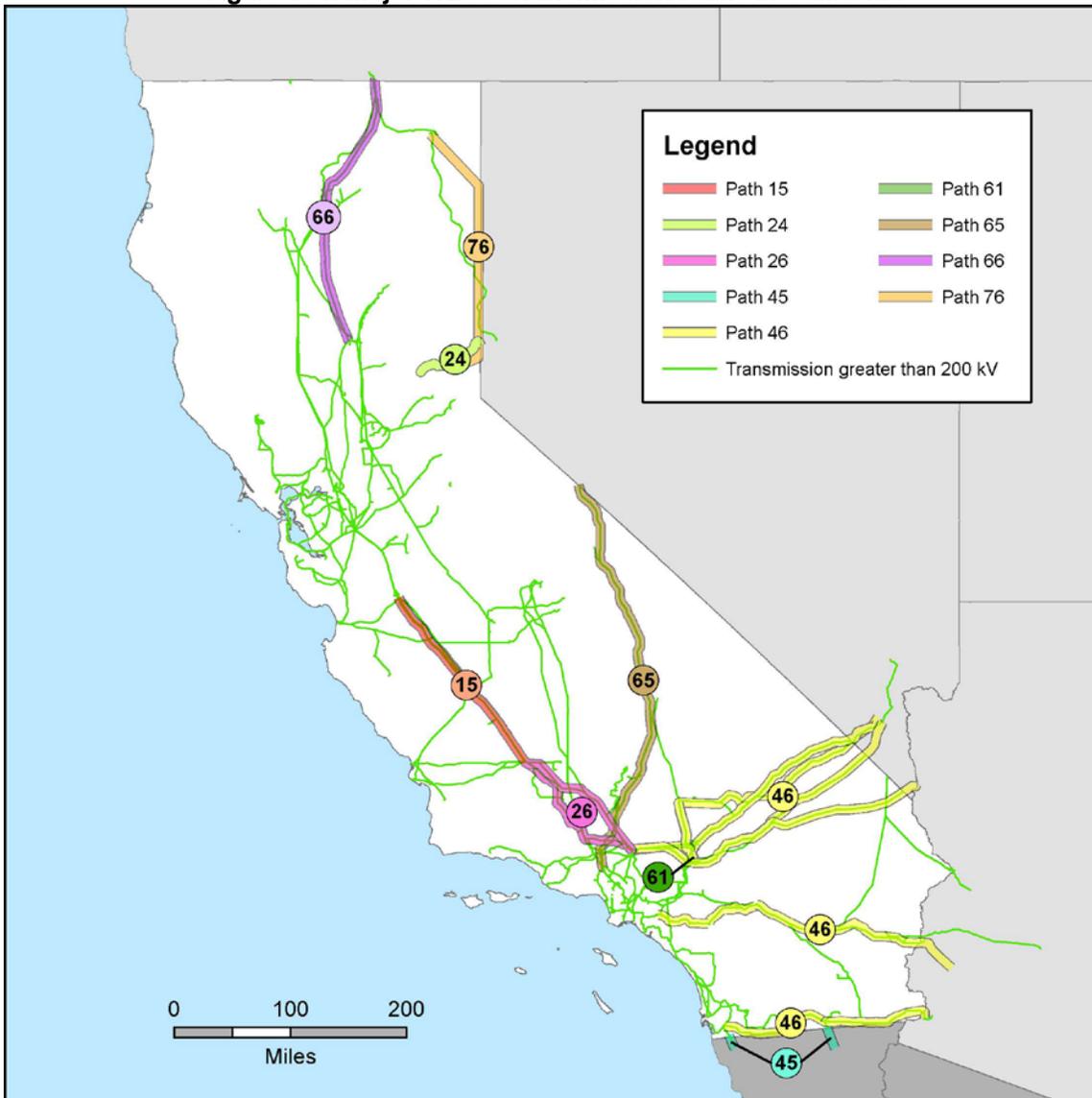
Most of California's electric transmission system was originally built to connect generating facilities to major load centers in the Los Angeles, San Francisco, and Sacramento areas. Thermal generating facilities, such as large gas-fired and nuclear plants, had been built near the coast or in nearby valleys generally close to the load centers, thereby requiring relatively short transmission lines. Hydroelectric facilities in the Sierra Nevada have typically been some of the most remote sources of generation in the state. Each of the state's investor-owned utilities (PG&E, SCE, and SDG&E) designed, built, and operated its own system to meet the needs of its customers.

Until the mid-1960s, the three IOUs operated their transmission systems as islands, with only a few small ties between utilities. As California's dependence on oil and gas generation increased, the IOUs began planning and building higher-voltage, long lines to neighboring states. The 500 kV transmission lines were built primarily for importing hydroelectric power from the Pacific Northwest and thermal generation from the Southwest. While these transmission lines provided access to less costly out-of-state power, they also provided the additional benefit of emergency interconnection support among the state's utilities to avoid potential wide-scale power disruptions.

California's major bulk intrastate and interstate transmission system is shown in Figure 103. The map highlights the paths as defined by the Western Electricity Coordinating Council. Key transmission lines in the Western Interconnection are grouped into numbered paths for planning and operational purposes.⁸³⁷

⁸³⁷ For more information, see the WECC State of the Interconnection page at <https://www.wecc.biz/epubs/StateOfTheInterconnection/Pages/Transmission/WECC-Paths.aspx>.

Figure 104: Major WECC Transmission Paths in California

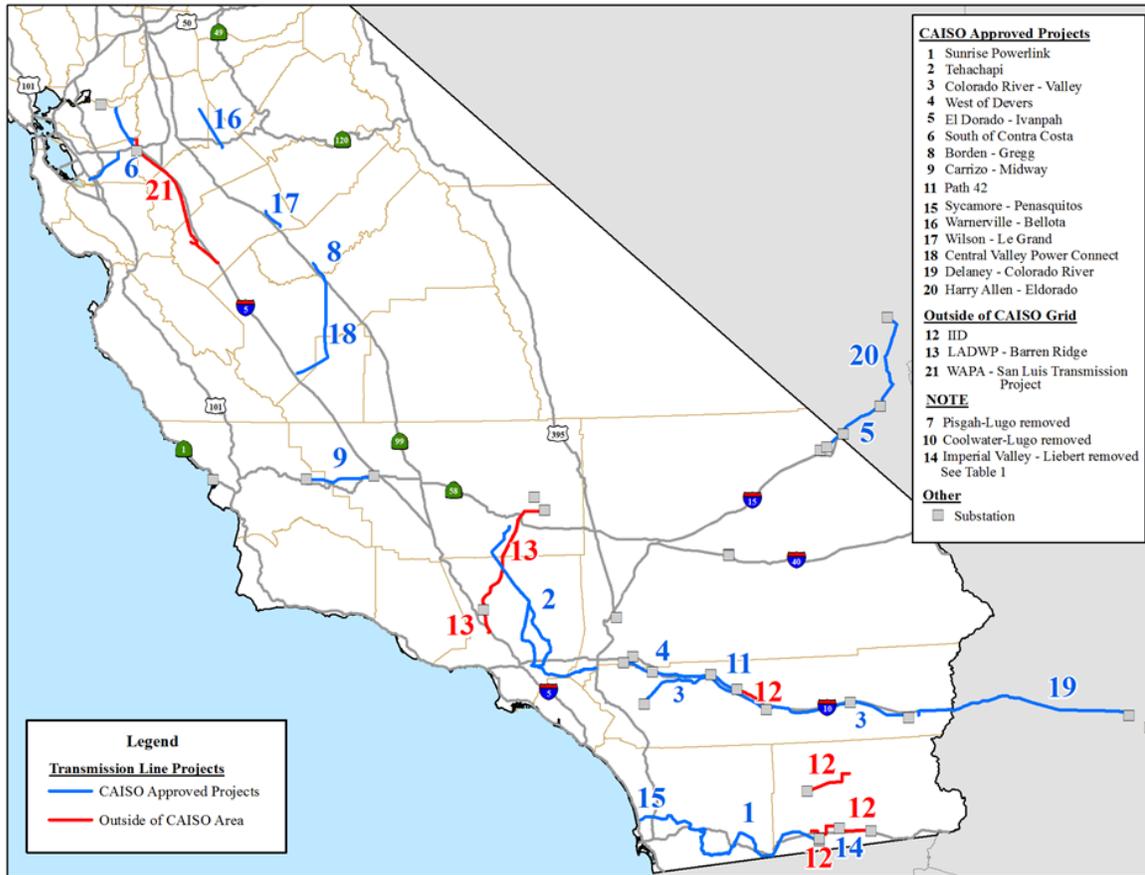


Source: California Energy Commission

Major California Transmission Projects

As noted in Chapter 5, the California Independent System Operator (California ISO) and other entities have identified and approved many transmission projects to meet reliability requirements, provide economic benefits, and support recent policy goals, including delivering renewable generation to meet the 33 percent Renewables Portfolio Standard (RPS) by 2020 mandate. The *California ISO 2016-2017 Transmission Plan* lists 177 previously approved transmission lines, new substations, reconductoring projects, and other upgrades. The map in Figure 104 below shows the approximate locations of 21 recently approved transmission projects supporting RPS policy goals and other critical infrastructure upgrades.

Figure 105: Map of California ISO and Outside California ISO Grid-Approved Transmission Projects



Source: California Energy Commission

#1 - Sunrise Powerlink

Description

On June 17, 2012, San Diego Gas and Electric (SDG&E) completed construction and energized the 117-mile, 230/500 kV Sunrise Powerlink transmission line that increases the import capability into San Diego from the renewable energy-rich Imperial Valley. Sunrise Powerlink, combined with the Imperial Valley (IV) Collector Station and IV-Collector transmission line and Sycamore-Peñasquitos projects (discussed below), will increase the import capability by an additional 1,000 MW for a total of 1,700 MW. More than 7,000 MW of renewable generation projects in Imperial County have withdrawn from the California ISO's queue. The Imperial Irrigation District's (IID) interconnection queue consists of 17 projects with proposed generation of 1,099 MW that could also use the Sunrise Powerlink.⁸³⁸

⁸³⁸ Asbury, Jamie, Imperial Irrigation District, comments on *2013 IEPR – Transmission Planning and Permitting Issues*, Docket No. 13-IEP-1E, May 21, 2013, p. 1, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Imperial_Irrigation_District_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70922.pdf.

Key Dates

August 3, 2006: California ISO Board of Governors approved project.

August 4, 2006: SDG&E filed application with California Public Utilities Commission (CPUC) for a certificate of public convenience and necessity (CPCN).

December 18, 2008: CPUC issued Decision 08-12-058⁸³⁹ approving project.

January 20, 2009: U.S. Bureau of Land Management (BLM) issued record of decision⁸⁴⁰ (ROD) approving project.

July 13, 2010: U.S. Forest Service (USFS) issued record of decision⁸⁴¹ approving project.

December 9, 2010: SDG&E started construction.

June 17, 2012: In service.

#2 - Tehachapi Renewable Transmission Project

Description

Southern California Edison's (SCE's) Tehachapi Renewable Transmission Project (TRTP) provides the electrical facilities necessary to integrate 4,500 MW of wind generation in eastern Kern County to the Los Angeles Basin and accommodate planned or future solar and geothermal projects. TRTP addresses reliability needs of the California ISO-controlled grid due to projected load growth in the Antelope Valley and the South of Lugo transmission constraints in Hesperia (San Bernardino County). TRTP was built in 11 segments and includes more than 300 miles of new and upgraded 220 kV and 500 kV transmission lines and substations. All segments are operational. The final segment was completed in December 2016.

Key Dates

Segments 1-3

December 9, 2004: SCE filed application with CPUC for a CPCN.

January 11, 2005: SCE filed special use application with U.S. Forest Service.

March 1, 2007: CPUC issued Decision 07-03-012⁸⁴² approving the project.

August 23, 2007: USFS issued a record of decision⁸⁴³ approving project.

⁸³⁹ CPUC Decision 08-12-058 approving the Sunrise Powerlink,
<http://www.cpuc.ca.gov/environment/info/aspen/sunrise/D08-12-058.pdf>.

⁸⁴⁰ BLM Record of Decision approving Sunrise Powerlink,
<http://www.cpuc.ca.gov/environment/info/aspen/sunrise/rod.pdf>.

⁸⁴¹ USFS Record of Decision approving Sunrise Powerlink,
http://www.fs.usda.gov/Internet/FSE_DOCUMENTS/stelprdb5320675.pdf.

⁸⁴² CPUC Decision 07-03-012. http://docs.cpuc.ca.gov/published/FINAL_DECISION/65273.htm.

⁸⁴³ USFS Record of Decision.
http://www.cpuc.ca.gov/environment/info/aspen/antelopepardee/record_of_decision.pdf.

2008: SCE started construction.

December 2009: Segments 1, 2, and 3A in-service.

Spring 2012: Construction started on 3B.

Fall 2012: Segment 3B in-service.

Segments 4-11

January 24, 2007: California ISO Board of Governors approved project.

June 29, 2007: SCE filed application with CPUC for a CPCN and special use application with U.S. Forest Service.

December 17, 2009: CPUC issued Decision 09-12-044 approving the project.

April 2010: SCE started construction.

October 4, 2010: USFS issued a record of decision approving project.

October 17, 2011: SCE filed a petition for modification of Decision 09-12-044 to address the FAA's recommendations near Chino airport for Segment 8, Phase 3.

November 10, 2011: CPUC issued Decision 11-11-020 granting a construction stay for Segment 8A within Chino Hills.

July 12, 2012: CPUC issued a Decision 12-03-050 modifying Decision 11-11-020.

January 19, 2013: Segments 4, 5, and 10 in-service.

June 11, 2013: CPUC Administrative Law Judge (ALJ) Jean Vieth's proposed decision denied Chino Hills' petition for modification of Decision 09-12-044.

June 11, 2013: CPUC President Michael Peevey alternate proposed decision granted Chino Hills' petition for modification of Decision 09-12-044.

July 11, 2013: CPUC Decision favors President Peevey's alternate proposed decision for Chino Hills.

Spring 2014: Segment 6 in service.

October 31, 2014: City of Ontario filed a petition to stay construction and underground Segment 8B.

Winter 2014: Segment 7 in-service.

January 20, 2015: Segment 9 (Whirlwind Substation and Vincent Substation expansion) in service.

March 6, 2015: CPUC Assigned ALJ issued a proposed decision denying the City of Ontario's petition.

Spring 2015: Overhead portion of Segment 8 in-service.

April 9, 2015: Proposed decision presented for CPUC Commissioners' approval but held for further review.

May 7, 2015: CPUC Commissioners, without the concurrence of President Michael Picker, approved the ALJ's proposed decision. President Picker's concurrence was mailed separately.

May 31, 2015: Segment 11 in-service.

December 2016: In-service.

#3 - Colorado River-Valley (and Red Bluff Substation)

Description

SCE's Colorado River-Valley 500 kV transmission project includes the Colorado River to Devers project, also referred to as the California side of the Devers-Palo Verde 2 (DPV2) project, consisting of the following main components:

- New 500/220 kV Colorado River Substation near Blythe.
- New Red Bluff Substation west of the Colorado River Substation.
- 111-mile Devers-Colorado River 500 kV transmission line between SCE Devers Substation and Colorado River Substation paralleling the existing Devers-Palo Verde transmission line.
- 42-mile Devers-Valley No. 2 500 kV transmission line between Devers Substation and Valley Substation in Menifee paralleling the existing Devers-Valley transmission line.

On May 22, 2013, SCE completed construction on the Red Bluff Substation, ahead of SCE's target in-service date of July 2013.⁸⁴⁴ On September 29, 2013, SCE completed and energized the Colorado River-Valley project.

The project allows generators in eastern Riverside County to connect with the Devers Substation in Southern California. This project, along with the West of Devers upgrade (discussed below), allows delivery of about 4,000 MW from Riverside County.

Key Dates

February 24, 2005: California ISO Board of Governors approved the original Devers-Palo Verde 2 (DPV2) project. No further board approval required for the Colorado River-Valley project.

April 11, 2005: SCE filed an application with CPUC for a CPCN.

January 25, 2007: CPUC issued Decision 07-01-040⁸⁴⁵ approving DPV2.

⁸⁴⁴ Alvarez, Manuel, Southern California Edison, comments on *California Energy Commission Docket No. 13-IEP-1E Transmission Planning and Permitting Issues*, May 21, 2013, p. 5, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Southern_California_Edison_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70920.pdf.

⁸⁴⁵ CPUC Decision 07-01-040, http://docs.cpuc.ca.gov/published//FINAL_DECISION/64017.htm.

July 14, 2011: CPUC issued Decision 11-07-011⁸⁴⁶ approving construction of the expanded Colorado River Substation.

May 14, 2008: SCE filed a petition for modification (PFM) of Decision 07-01-040 requesting the CPUC authorize SCE to construct only the California portion of the DPV2 facilities.

November 20, 2009: CPUC issued Decision 09-11-007⁸⁴⁷ approving the PFM.

July 19, 2011: BLM issued record of decision⁸⁴⁸ approving the project.

September 2011: SCE started construction on Colorado River and Red Bluff Substations.

January 2012: SCE started transmission line construction.

May 22, 2013: Red Bluff Substation completed.

September 29, 2013: In-service.

#4 - West of Devers

Description

The California ISO's Generator Interconnection Procedures identified SCE's West of Devers transmission lines as delivery network upgrades for the Blythe, Genesis, and Palen solar generating projects in Riverside County. The West of Devers project consists of removing and replacing nearly 48 miles of existing 220 kV transmission lines with new double-circuit 220 kV transmission lines between the existing SCE Devers Substation (near Palm Springs), Vista Substation (in Grand Terrace), and San Bernardino Substation. SCE received approval from the Federal Energy Regulatory Commission (FERC) and the California ISO through acceptance of the nonconforming Large Generator Interconnection Agreement (LGIA) for the Blythe, Genesis, and Palen solar generating projects.

Without the West of Devers upgrades, most of the renewable generation proposed in eastern Riverside County would be unable to meet the deliverability requirements in the power purchase agreements. On October 25, 2013, SCE filed an application for a CPCN and PEA with the CPUC.⁸⁴⁹ The CPUC issued Decision 16-08-017 approving West of Devers CPCN on August 18, 2016. The BLM issued its record of decision approving the project on December 27, 2016. West of Devers construction is scheduled to begin in the third quarter of 2017 and SCE's expected in-service date is 2021.

⁸⁴⁶ CPUC Decision 11-07-011, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/139770.htm.

⁸⁴⁷ CPUC Decision 09-11-007, http://docs.cpuc.ca.gov/published/FINAL_DECISION/110360.htm.

⁸⁴⁸ BLM Record of Decision (on the CPUC website), http://www.cpuc.ca.gov/Environment/info/aspn/dpv2/record_of_decision_071911.pdf.

⁸⁴⁹ SCE's West of Devers application for a CPCN and PEA, <http://www.cpuc.ca.gov/environment/info/aspn/westofdevers/westofdevers.htm>.

Key Dates

February 4, 2011: FERC Order⁸⁵⁰ accepting Blythe LGIA.

February 17, 2011: FERC Order⁸⁵¹ accepting Palen LGIA.

October 20, 2011: FERC Order⁸⁵² accepting Genesis LGIA.

October 25, 2013: SCE filed an application for a CPCN and PEA with the CPUC.

August 18, 2016: CPUC issued Decision 16-08-017 approving West of Devers CPCN.⁸⁵³

December 27, 2016: BLM issued record of decision approving the project.⁸⁵⁴

Q3 2017: Expected start of construction.

2021: Expected in-service date.⁸⁵⁵

#5 - Eldorado-Ivanpah

Description

The California ISO's Generator Interconnection Procedures identified SCE's Eldorado-Ivanpah transmission project as delivery network upgrades for the Ivanpah Solar Electric Generating System. The Eldorado-Ivanpah project provides the electrical facilities necessary to integrate 1,400 MW of new solar energy generation in the Ivanpah Dry Lake area. The major components of the project include:

- New Ivanpah Substation in San Bernardino County.
- Replacement of a portion of an existing 115 kV transmission line with a 35-mile double-circuit 220 kV transmission line between the new Ivanpah Substation and the existing Eldorado Substation near Boulder City, Nevada.
- Installation of associated telecommunication infrastructure.

On July 1, 2013, SCE completed and energized the Eldorado-Ivanpah project.

850 FERC Order accepting Blythe LGIA, http://www.caiso.com/Documents/Feb4_2011Orderconditionallyacceptingnon-conformingLGIAsanddenyingmotions-consolidate_docketER11-2329_etal_.pdf.

851 FERC Order accepting Palen LGIA, http://www.caiso.com/Documents/February17_2011Orderconditionallyacceptingnon-conformingLGIAs_denyingmots_consolidateindocketno_ER11-2451.pdf.

852 FERC Order accepting Genesis LGIA, http://www.caiso.com/Documents/2011-10-20_ER11-4512_GenMcCoyLGIOrder.pdf.

853 CPUC West of Devers Decision 16-08-017, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M166/K441/166441910.PDF>.

854 BLM Record of Decision approving West of Devers, https://eplanning.blm.gov/epl-front-office/projects/nepa/64793/94672/114332/ROD_West_of_Devers_12-27-2016.pdf.

855 SCE West of Devers project webpage, <https://www.sce.com/wps/portal/home/about-us/reliability/upgrading-transmission/west-of-devers/>.

Key Dates

May 28, 2009: SCE filed an application with CPUC for a CPCN.

September 22, 2010: Energy Commission Decision⁸⁵⁶ on Ivanpah AFC.

March 15, 2011: FERC Order⁸⁵⁷ accepting amendments to original 2010 Ivanpah LGIAs.

December 16, 2010: CPUC issued Decision 10-12-052⁸⁵⁸ approving the project.

May 25, 2011: BLM issued record of decision⁸⁵⁹ approving the project.

March 2012: SCE started construction.

July 1, 2013: In-service.

#6 - South of Contra Costa

Description

The California ISO's Generator Interconnection Procedures identified PG&E's South of Contra Costa project as needed to deliver 300 MW of new wind generation in Solano County. The South of Contra Costa project includes replacing existing transmission lines with larger capacity conductor of the following transmission lines:

- 8 miles of the Kelso-Tesla 230 kV transmission line
- 18.3 miles of the Contra Costa Power Plant-Delta Pumps 230 kV transmission line
- 21 miles of the Las Positas-Newark 230 kV transmission line

Without replacing these lines, none of the renewable generation proposed in Solano County will be considered deliverable. The Kelso-Tesla 230 kV project was completed in November 2012. PG&E is in the engineering phase for the Contra Costa Power Plant-Delta Pumps and Las Positas-Newark 230 kV transmission lines. The project is on hold until generators make further progress, at which time PG&E will submit an application to the CPUC requesting approval. PG&E states the remaining projects could be in-service in 2018.⁸⁶⁰

Key Dates

July 6, 2012: PG&E submitted Advice Letter 4083-E⁸⁶¹ to CPUC for Kelso-Tesla line.

856 Energy Commission Decision on Ivanpah AFC, <http://www.energy.ca.gov/2010publications/CEC-800-2010-004/CEC-800-2010-004-CMF.PDF>.

857 FERC Order accepting amendments to original Ivanpah LGIA, http://www.caiso.com/Documents/March15_2011LetterorderacceptingLGIAsbetweenISO_SCE__SolarPartnersindocketnos_ER11-2885_ER11-2899.pdf.

858 CPUC Decision 10-12-052, http://docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/128873.htm.

859 BLM Record of Decision, https://eplanning.blm.gov/epl-front-office/projects/nepa/66577/81414/95587/EITP_ROD.pdf.

860 PG&E April 2017 progress report to WECC, <https://www.wecc.biz/Reliability/2017%20APR%20PGandE.docx>.

861 PG&E Advice Letter 4083-E, http://www.pge.com/notes/rates/tariffs/tm2/pdf/ELEC_4083-E.pdf.

August 5, 2012: CPUC approved Advice Letter 4083-E.

November 2012: In-service date for Kelso-Tesla transmission line.

2018: Possible in-service date for remaining projects on hold.

#7 - Pisgah-Lugo

Description

SCE's Pisgah-Lugo project was identified by the California ISO as being needed for the interconnection of the proposed 850 MW K Road Calico Solar Project. On June 20, 2013, K Road, LLC, filed a request with the Energy Commission to terminate the Calico Solar Project.⁸⁶² The California ISO noted that the project is not reflected in any other interconnection agreements. As a result, the Pisgah-Lugo project was removed from the CPUC portfolios and the California ISO 2012–2013 Transmission Planning Process. With the termination of Calico, the California ISO made the determination that the Pisgah-Lugo transmission project was no longer needed.

#8 - Borden-Gregg

Description

The California ISO's Generator Interconnection Procedures identified PG&E's Borden-Gregg 230 kV transmission line project as a delivery network upgrade as needed for the delivery of 800 MW of new solar generation proposed in the Fresno area, specifically the Westlands area. PG&E will replace the existing Borden-Gregg 230 kV transmission line with larger capacity conductor. The project is on hold until generators make further progress, at which time PG&E will submit an application to the CPUC requesting approval. If the project goes forward, PG&E expects the project could be in-service date in 2018.

#9 - Carrizo-Midway

Description

The California ISO's Generator Interconnection Procedures identified PG&E's Carrizo-Midway transmission project as a delivery network upgrade identified as needed for the delivery of 900 MW of solar generation in the Carrizo Plain area in San Luis Obispo County. On May 5, 2011, PG&E submitted a notice of exempt construction, Advice Letter 3842-E,⁸⁶³ to the CPUC for transmission facilities that would interconnect renewable generators in the Carrizo Plain. San Luis Obispo County issued permits for the switching stations as part of the conditional use permits granted for two PV projects: the California Valley Solar Ranch Project (250 MW) and the Topaz Solar Farm Project (550 MW). The project consists of the Caliente Switching Station in San Luis Obispo County and the Solar Switching Station in San Luis Obispo County, associated with the two solar PV projects and replacing roughly 35 miles of the existing Morro Bay-Midway

⁸⁶² June 20, 2013. K Road, LLC request filed with the Energy Commission to terminate the Energy Commission license for the Calico Solar Project, http://www.energy.ca.gov/sitingcases/calicosolar/compliance_2012/notices/2013-06-24_Notice_of_Receipt_of_Request_to_Terminate_License_TN-71374.pdf.

⁸⁶³ PG&E Advice Letter 3842-E, http://www.pge.com/notes/rates/tariffs/tm2/pdf/ELEC_3842-E.pdf.

double-circuit 230 kV transmission line with larger capacity conductor. On September 14, 2011, the CPUC issued Resolution E-4434, approving PG&E's Advice Letter 3842-E. On March 20, 2013, PG&E completed and energized the Morro Bay-Midway transmission line.

Key Dates

May 5, 2011: PG&E submitted Advice Letter 3842-E to the CPUC.

September 14, 2011: CPUC issued Resolution E-4434 approving Advice Letter 3842-E.

March 20, 2013: In-service.

#10 - Coolwater-Lugo

Description

The California ISO's Generator Interconnection Procedures identified SCE's Coolwater-Lugo Transmission Project (CLTP) as a delivery network upgrade needed for the Abengoa Mojave Solar Project, renamed Mojave Solar, with full capacity deliverability status. The project included:

- 34 miles of a 220 kV double-circuit transmission line from SCE Coolwater 220 kV Switchyard south to the existing Pisgah-Lugo transmission corridor located near the intersection of Haynes Road and State Route (SR)-247.
- 16.6 miles of a 500 kV single-circuit transmission line, initially operated at 220 kV, from Lugo Substation to the proposed Desert View Substation.
- 13.6 miles of 220 kV double-circuit transmission line in existing ROW from proposed Desert View Substation near the intersection of Haynes Road and SR-247.
- Removal of 29.1 miles of the existing Pisgah-Lugo No. 1 220 kV transmission line from Lugo Substation northeast to the intersection of Haynes Road and SR-247.
- Removal of 16 miles of the existing Pisgah-Lugo No. 2 220 kV transmission line from Lugo Substation northeast to the proposed Desert View Substation and terminate the remaining portion of the line into the proposed Desert View Substation.
- Site for future Desert View 500 kV/220 kV/115 kV/12 kV Substation east of Apple Valley.

On August 28, 2103, SCE filed an application for a CPCN and PEA with the CPUC and BLM. On April 25, 2014, SCE submitted an amended application with the CPUC. On October 24, 2014, NRG notified the CPUC of its intent to shut down the Coolwater Generating Station (Coolwater) on January 1, 2015. On December 3, 2014, a joint CPUC Assigned Commissioner and ALJ ruling directed SCE, the California ISO and parties to the proceeding to provide input on the shutdown of Coolwater and the need for the CLTP. On March 17, 2015, the California ISO submitted supplemental comments with the CPUC stating that the CLTP was no longer needed to interconnect Mojave Solar with full capacity deliverability status. The change in deliverability status for the Mojave Solar project was primarily due to the election by several generating facilities in the area (other than Coolwater) to permanently retire and forego repowering. As a result, the retiring generating facilities have relinquished deliverability status, and the capacity

associated with those projects was released to interconnection customers in the form of full capacity deliverability status, including Mojave Solar.

On March 19, 2015, the CPUC Assigned ALJ directed parties to file comments on the dismissal without prejudice of SCE's CPCN application in light of the California ISO's supplemental comments.⁸⁶⁴ On April 20, 2015, the CPUC assigned ALJ issued a proposed decision to dismiss SCE's CPCN application (A.13-08-023) without prejudice or without any loss of rights or privileges.⁸⁶⁵ The significant material changes in grid conditions on SCE's application for a CPCN for the CLTP necessitated this action. On May 21, 2015, the CPUC Commissioners approved the ALJ proposed decision.⁸⁶⁶ SCE's application was closed.

Key Dates

September 8, 2010: Energy Commission decision⁸⁶⁷ on Abengoa AFC.

January 28, 2011: FERC Order⁸⁶⁸ accepting Abengoa LGIA.

November 10, 2011: CPUC approves power purchase agreement between PG&E and Abengoa.

August 28, 2013: SCE filed an application for a CPCN and PEA with the CPUC and BLM.

April 25, 2014: SCE submitted an amended application with the CPUC.

October 24, 2014: NRG notified the CPUC of its intent to shutdown Coolwater on January 1, 2015.

December 3, 2014: CPUC ruling directing parties to provide input on shutdown of Coolwater and the need for the CLTP.

April 20, 2015: CPUC ALJ proposed decision to dismiss SCE's CPCN application without prejudice.

May 21, 2015: CPUC Commissioners approved the ALJ proposed decision.

#11 and #12 - SCE/IID Joint Path 42

Description

The SCE/IID Joint Path 42 project is a successful collaboration among the California ISO, SCE, and IID. The SCE/IID Joint Path 42 project would increase the transfer capacity from 600 MW to 1,500 MW of renewable energy from IID to SCE's portion of the California ISO's controlled

⁸⁶⁴ CPUC ALJ Moosen's Proposed Decision, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M148/K824/148824915.PDF>.

⁸⁶⁵ CPUC ALJ Moosen's Proposed Decision, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M151/K169/151169662.PDF>.

⁸⁶⁶ CPUC Commission Decision 15-05-040, <http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M152/K058/152058507.PDF>.

⁸⁶⁷ Energy Commission Decision on Ivanpah AFC, <http://www.energy.ca.gov/2010publications/CEC-800-2010-008/CEC-800-2010-008-CMF.PDF>.

⁸⁶⁸ FERC Order accepting amendments to original Abengoa LGIA, http://www.caiso.com/Documents/January28_2011Orderconditionallyacceptingnon-conformingLGIAAs_denyingmots_-consolidateindocketno_ER11-2368.pdf.

grid.⁸⁶⁹ Upgrading Path 42 requires improvements to facilities under the control of SCE and the California ISO, as well as facilities under IID's control. On May 18, 2011, SCE's portion of the upgrade received California ISO Board of Governors approval as a policy upgrade upon adoption of the *2010-2011 Transmission Plan*.⁸⁷⁰ SCE's upgrade includes a 15-mile, double-circuit 230 kV transmission lines between SCE's Devers and Mirage Substations.

On August 16, 2011, the IID Board of Directors approved its portion of the Path 42 upgrade.⁸⁷¹ The upgrade consists of replacing 20 miles of a double-circuit 230 kV transmission line (one conductor per phase) with a bundle of two conductors per phase conductors between SCE Mirage Substation and IIDs Coachella Valley and Ramon Substations. On August 20, 2013, IID and SCE filed with BLM a draft mitigated negative declaration and environmental assessment/initial study for public review and comment. IID is the California Environmental Quality Act lead for the project. On October 28, 2013, IID, SCE and BLM released the final mitigated negative declaration. On November 5, 2013, IID Board of Directors adopted the final mitigated negative declaration. SCE completed its portion of the Path 42 upgrade in October 2016.⁸⁷²

Key Dates

May 18, 2011: California ISO Board of Governor approved the *2010-2011 Transmission Plan*.

August 16, 2011: IID Board of Directors initial approval of Path 42 upgrade.

August 21, 2012: IID Board of Directors reaffirmed approval of Path 42 upgrade.⁸⁷³

August 20, 2013: IID and SCE filed with BLM a draft mitigated negative declaration and environmental assessment/initial study.

October 28, 2013: IID and SCE filed with BLM a final mitigated negative declaration.

November 5, 2013: IID Board of Directors adopted the final mitigated negative declaration.

October 2016: In-service.

#12 - IID: Additional Upgrades

IID identified three additional upgrades for interconnecting generating resources in its transitional cluster. The upgrades would include the El Centro-Highline, El Centro-Imperial Valley (S line), and Midway-Bannister projects listed below. IID notified the California ISO of its intent to suspend its portion of the Path 42 upgrades during the California ISO 2015-2016

869 Asbury, Jamie, Imperial Irrigation District, comments on *2013 IEPR – Transmission Planning and Permitting Issues*, Docket No. 13-IEP-1E, May 21, 2013, p. 2, http://www.energy.ca.gov/2013_energypolicy/documents/2013-05-07_transmission_workshop/comments/Imperial_Irrigation_District_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70922.pdf.

870 California ISO Board approved *2010-2011 Transmission Plan*, p. 524 (no longer posted online).

871 IID Board of Directors Regular Meeting, August 16, 2011, p. 2 (no longer posted online).

872 See SCE October 2016 Quarterly Compliance Report, [http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/7E7D821620D7225C88258041005DD6CB/\\$FILE/SCE%20Quarterly%20AB%20970%20Rpt%202016%20Q4%20Memo.pdf](http://www3.sce.com/sscc/law/dis/dbattach5e.nsf/0/7E7D821620D7225C88258041005DD6CB/$FILE/SCE%20Quarterly%20AB%20970%20Rpt%202016%20Q4%20Memo.pdf).

873 IID Regular Meeting of August 21, 2012 minutes, p. 10, <http://www.iid.com/index.aspx?page=30&recordid=236&returnURL=%2Findex.aspx>.

Transmission Planning Process. IID has stopped all work on Path 42 and did not complete substation, transmission, and RAS work on Path 42.

- The El Centro-to-Highline project replaces existing 161 kV and 92 kV lines with a double-circuit 230 kV transmission line. The expected in-service date is 2018.
- The El Centro-Imperial Valley project, S line, replaces an existing 230 kV line with a double-circuit 230 kV transmission line between jointly owned IID/SDG&E Imperial Valley Substation to IID El Centro Switching Station. This upgrade is required for completion of the Imperial Valley-Liebert project approved by the California ISO. The expected in-service date is 2015.
- The Midway-Bannister project consists of 8.7 miles of a new 230 kV transmission line between IID Midway Substation and Bannister Substation that was completed on March 15, 2011.

#13 - LADWP: Barren Ridge

Description

LADWP's Barren Ridge Renewable Transmission Project consists of:

- About 75 miles of two new 230 kV transmission lines from the Barren Ridge Switching Station to the proposed Haskell Canyon Switching Station located north of Santa Clarita.
- A 12-mile, 230 kV transmission line on existing structures from Haskell Canyon to the Castaic Power Plant, a pumped-storage generating facility, where renewable energy can be stored until needed to meet utility customer power needs.

The project will provide additional transmission capacity to access 1,400 MW of wind, solar, and other renewable resources. LADWP completed the Barren Ridge project in September 2016.⁸⁷⁴

Key Dates

September 18, 2012: LADWP Board of Water and Power Commissioners approved final environmental impact statement (EIS)/environmental impact report (EIR).⁸⁷⁵

September 24, 2012: BLM issued record of decision⁸⁷⁶ approving the project.

June 14, 2013: U.S. Forest Service issued record of decision⁸⁷⁷ approving the project.

September 2016: In-service.

⁸⁷⁴ September 29, 2016, LADWP news release, <http://www.ladwpnews.com/corrected-barren-ridge-project-brings-renewable-energy-home/>.

⁸⁷⁵ LADWP September 18, 2012, Regular Meeting of Commissioners minutes, http://ladwp.granicus.com/DocumentViewer.php?file=ladwp_69b5304d708cda93b1241529efe7ffef.pdf&view=1.

⁸⁷⁶ BLM Record of Decision, https://eplanning.blm.gov/epl-front-office/projects/nepa/66559/81400/95361/BRRTTP_ROD_Final.pdf.

⁸⁷⁷ USFS Record of Decision, http://a123.g.akamai.net/7/123/11558/abc123/forestservic.download.akamai.com/11558/www/nepa/46681_FSPLT3_1424746.pdf.

#14 - Imperial Valley (IV)-Liebert

Description

In coordination with IID, the California ISO identified a policy project with capital costs under \$50 million for the Imperial Valley Area in the board-approved *2012–2013 Transmission Plan*.⁸⁷⁸ The project was identified to help resolve transmission development and permitting issues, as well as commercial concerns of generators who desire to interconnect directly to the California ISO grid.⁸⁷⁹ The elements of the project include the 230 kilovolt (kV) Liebert Substation and a one-mile 230 kV transmission line from the Liebert Substation to the existing Imperial Valley Substation. The Liebert Substation and transmission line will provide an efficient means by which generation in the California ISO queue in the Imperial Valley can move forward to commercial operation. The project is contingent upon IID upgrading the IV-El Centro line (S line) and looping it into the new Liebert Substation. The IID upgrade will enhance its ownership rights at the IV Substation. The Liebert Substation and transmission line qualify for the competitive solicitation process.

Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process for reliability, policy, and economic transmission projects. The bid window for interested project sponsors to submit applications to finance, construct, and own the IV-Liebert 230 kV line was opened December 19, 2012, and closed February 19, 2013. On February 25, 2013, the California ISO posted the list of validated project sponsor applications for the project. On July 11, 2013, the California ISO selected the IID as the approved project sponsor and accepted IID's offer of a cost cap of \$14.3 million to construct the project.⁸⁸⁰ Since the project resides within IID's service area, IID is the lead agency for CEQA. On June 30, 2014, IID completed the final mitigated negative declaration. On July 8, 2014, IID Board of Directors adopted the final mitigated negative declaration.⁸⁸¹ The California ISO received notice from IID on November 24, 2015, exercising its right to terminate the approved project sponsor agreement. As the project depended on IID's participation, the project has been canceled.

Key Dates

December 14, 2012: California ISO management approved the project following a briefing to the California ISO Board of Governors.⁸⁸²

⁸⁷⁸ California ISO Board approved *2012-2013 Transmission Plan*, p. 12, <http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf>.

⁸⁷⁹ Asbury, Jamie, Imperial Irrigation District, comments on *2013 IEPR – Transmission Planning and Permitting Issues*, Docket No. 13-IEP-1E, May 21, 2013, p. 2, http://www.energy.ca.gov/2013_energy_policy/documents/2013-05-07_transmission_workshop/comments/Imperial_Irrigation_District_Comments_re_Transmission_Planning_and_Permitting_Issues_2013-05-21_TN-70922.pdf.

⁸⁸⁰ California ISO's *Imperial Valley Policy Element Project Sponsor Selection Report*, http://www.caiso.com/Documents/ImperialValleyPolicyElement-ProjectSponsorSelectionReport_Jul11_2013.pdf.

⁸⁸¹ Final Mitigated Negative Declaration for the IV-Liebert transmission line and the IID Board of Directors Resolution No. 25-2014 adopting the Final Mitigated Negative Declaration, <http://www.iid.com/home/showdocument?id=9013>.

⁸⁸² California ISO management briefing to the Board of Governors on the Imperial Valley Area policy transmission elements, <http://www.caiso.com/Documents/BriefingImperialValleyAreaPolicy-DrivenTransmissionElementsUnder50Million-Presentation-Dec2012.pdf>.

December 19, 2012, through February 19, 2013: Competitive solicitation bid window open.

February 25, 2013: California ISO posted the list of validated project sponsor applications.

July 11, 2013: California ISO selected IID as the project sponsor.

June 30, 2014: IID completed the final mitigated negative declaration.

July 8, 2014: IID Board of Directors adopted the final mitigated negative declaration.

November 24, 2015: Project canceled by IID.

#15 - Sycamore-Peñasquitos

Description

The California ISO identified a policy need for an 11-mile 230 kV transmission line between SDG&E Sycamore and Peñasquitos Substations in its board-approved *2012–2013 Transmission Plan*.⁸⁸³ The policy line will ensure delivery of generation needed to meet the 33 percent RPS, as well as reliability benefits to the San Diego area. As part of the 2012–2013 Transmission Planning Process, the California ISO examined the reliability impact without the Diablo Canyon Power Plant (Diablo Canyon) and San Onofre Nuclear Generating Station (San Onofre). This study identified several transmission system upgrades that, in addition to generation replacement and mitigation measures already underway, would help manage future unplanned extended outages to the San Onofre plant. The upgrades included the installation of 650 MVAR of dynamic reactive support near the San Onofre and the Sycamore-Peñasquitos project. Construction of this project becomes more important in light of SCE's June 7, 2013, announcement of its decision to permanently retire San Onofre Units 2 and 3. The project is eligible for competitive solicitation.

Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process for reliability, policy, and economic transmission projects. The bid window for interested project sponsors to submit applications to finance, construct, and own the Sycamore-Peñasquitos 230 kV line opened April 1, 2013, and closed June 3, 2013. On June 6, 2013, the California ISO posted the list of validated project sponsor applications for the project. On March 4, 2014, the California ISO selected SDG&E and Citizens Energy Corporation as approved project sponsors.⁸⁸⁴

On April 7, 2014, SDG&E filed with the CPUC an application for a CPCN and proponent's environmental assessment (PEA).⁸⁸⁵ On July 24, 2014, the CPUC deemed the application complete. The CPUC issued the draft EIR on September 17, 2015, and the final EIR on March 7,

⁸⁸³ California ISO Board approved *2012-2013 Transmission Plan*, pp. 296 and 374, <http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf>.

⁸⁸⁴ The California ISO's *Sycamore-Peñasquitos Project Sponsor Selection Report* can be found on the California ISO website at <http://www.caiso.com/Documents/Sycamore-PenasquitosProjectSponsorSelectionReport.pdf>.

⁸⁸⁵ SDG&E's application for a CPCN and PEA with the CPUC can be found on the CPUC website at: http://www.cpuc.ca.gov/Environment/info/panoramaenv/Sycamore_Penasquitos/index.html#PEA.

2016. On October 13, 2016, the CPUC issued Decision 16-10-005 approving the Sycamore-Peñasquitos project.⁸⁸⁶

Key Dates

March 20, 2013: California ISO Board of Governor approved the *2012–2013 Transmission Plan*.

April 1, 2013, through June 3, 2013: Competitive solicitation bid window open.

June 6, 2013: California ISO posted the list of validated project sponsor applications.

March 4, 2014: California ISO selected SDG&E and Citizens Energy Corporation as project sponsors.

April 7, 2014: SDG&E filed with the CPUC an application for a CPCN and PEA.

July 24, 2014: CPUC deemed SDG&E application complete.

September 17, 2015: CPUC issued the draft EIR.

March 7, 2016: CPUC issued the final EIR.

October 13, 2016: CPUC issued Decision 16-10-005 approving the project.

January 2017: Start of construction.

June 2018: Expected in-service date.⁸⁸⁷

#16 - Warnerville-Bellota

Description

The California ISO identified a policy need for replacing the 230 kV transmission line between PG&E Warnerville and Bellota Substations with larger capacity conductor in its board-approved *2012-2013 Transmission Plan*.⁸⁸⁸ The policy upgrade will allow the delivery of renewable generation in the Greater Fresno, Central Valley North, Merced and Westlands zones needed to meet the 33 percent RPS. The Warnerville-Bellota, Wilson-Le Grand, and Gates-Gregg projects will allow for delivery of roughly 700 MW of renewable generation. PG&E's expected in-service date is 2022.⁸⁸⁹

Key Dates

March 20, 2013: California ISO Board of Governor approved the *2012–2013 Transmission Plan*.

August 2022: Expected in-service date.

⁸⁸⁶ CPUC Decision 16-10-005, http://www.cpuc.ca.gov/Environment/info/panoramaenv/Sycamore_Penasquitos/PDF/Decision.PDF.

⁸⁸⁷ SDG&E's Sycamore-Peñasquitos project website for information on project status, <https://www.sdge.com/key-initiatives/sycamore-penasquitos-230kv-transmission-line-project>.

⁸⁸⁸ California ISO Board approved *2012-2013 Transmission Plan*, pp. 263 and 374, <http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf>.

⁸⁸⁹ PG&E's *2017 Annual Progress Report to WECC*, <https://www.wecc.biz/Reliability/2017%20APR%20PGandE.docx>.

#17 - Wilson-Le Grand

Description

The California ISO identified a policy need for replacing the 115 kV transmission line between the PG&E Wilson and Le Grand Substations with larger capacity conductor in its board-approved *2012-2013 Transmission Plan*.⁸⁹⁰ The policy upgrade will allow the delivery of renewable generation in the Greater Fresno, Merced, and Westlands zones needed to meet the 33 percent RPS. The Wilson-Le Grand, Warnerville-Bellota, and Gates-Gregg transmission projects will allow for the delivery of roughly 700 MW of renewable generation. The project has an approved notice of exempt construction and is in the planning phase. PG&E's expected in-service date is 2020.

Key Dates

March 20, 2013: California ISO Board of Governor approved the *2012-2013 Transmission Plan*.

2020: Expected in-service date.

#18 - Central Valley Power Connect (Gates-Gregg)

Description

The California ISO identified the need for a 230 kV transmission line between PG&E Gates and Gregg Substations as a reliability project with policy benefits in its board-approved *2012-2013 Transmission Plan*.⁸⁹¹ The transmission line will be constructed as a double-circuit, 230 kV line with one side strung, facilitating future development requirements to supply load or integrate renewable generation while minimizing future right-of-way requirements. The Central Valley Power Connect, Wilson-Le Grand, and Warnerville-Bellota projects will allow the delivery of nearly 700 MW of renewable generation. The project qualified for the California ISO's competitive solicitation process.

Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process for reliability, policy, economic transmission projects. The bid window for interested project sponsors to submit applications to finance, construct, and own the Gates-Gregg 230 kV line opened on April 1, 2013, and closed June 3, 2013. On June 6, 2013, the California ISO posted the list of validated project sponsor applications for the Gates-Gregg project.⁸⁹² On November 6, 2013, the California ISO selected the consortium of PG&E, MidAmerican Transmission, and Citizens Energy Corporation as the approved project sponsor to finance, own, construct, operate, and maintain the Central Valley Power Connect project.

⁸⁹⁰ California ISO Board approved 2012-2013 Transmission Plan, pp. 263 and 374, <http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf>.

⁸⁹¹ California ISO Board approved *2012-2013 Transmission Plan*, pp. 149 and 376, <http://www.caiso.com/Documents/BoardApproved2012-2013TransmissionPlan.pdf>.

⁸⁹² Central Valley Power Connect project sponsors list, http://www.caiso.com/Documents/List-ProjectSponsorProposalsReceived-Gates_Gregg230kVLineProposedPolicyDrivenElement.pdf.

The California ISO *2016–2017 Transmission Plan*, released in March 2017, states the project requires further evaluation in future planning cycles to reassess the need scope of the project and recommends putting the project on hold until a review is completed. PG&E states the timeline, including filing an application for a CPCN at the CPUC, is delayed until the project is reassessed in the California ISO transmission planning process.⁸⁹³

Key Dates

March 20, 2013: California ISO Board of Governors approved the *2012–2013 Transmission Plan*.

April 1, 2013, through June 3, 2013: Competitive solicitation bid window open.

June 6, 2013: California ISO posted the list of validated project sponsor applications.

November 6, 2013: California ISO selected the consortium of PG&E, MidAmerican Transmission, and Citizens Energy Corporation as project sponsor.

March 15, 2017: Project on hold for future evaluation in the California ISO transmission planning process.

#19 - Ten West Link (Delaney-Colorado River)

Description

The California ISO identified the need for a 500 kV transmission line between the existing SCE Colorado River Substation and the new APS Delaney Substation as an economic project with reliability and policy benefits in its board-approved *2013–2014 Transmission Plan*. The approximate length of the single-circuit 500 kV transmission line is 115–140 miles depending on the approved route. The project is eligible for competitive solicitation.

Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process for reliability, policy, economic transmission projects. The bid window for interested project sponsors to submit applications to finance, construct, and own the Ten West Link 500 kV line opened on August 19, 2014, and closed November 19, 2014. On January 13, 2015, the California ISO posted the list of validated project sponsor applications for the Ten West Link⁸⁹⁴ Following a collaboration period, on March 19, 2015, the California ISO posted a revised list of validated project sponsor applications. On April 15, 2015 the California ISO posted the list of qualified project sponsors and proposals. On July 10, 2015, the California ISO selected DCR Transmission, LLC, a joint venture company owned by Abengoa Transmission & Infrastructure, LLC and an affiliate of Starwood Energy Group Global, Inc., as the approved project sponsor to finance, construct, own, operate, and maintain the Ten West Link project.

⁸⁹³ PG&E Central Valley Connect project Web page, https://www.pge.com/en_US/safety/electrical-safety/safety-initiatives/central-california/details.page.

⁸⁹⁴ Ten West Link project sponsors list, http://www.caiso.com/Documents/List-ValidatedProjectSponsorApplications-Delaney_ColoradoRiverProject.pdf.

On March 23, 2016 BLM issued a notice of intent (NOI) to prepare an EIS for the project.⁸⁹⁵ On October 12, 2016 DCR Transmission, LLC filed with the CPUC an application for a CPCN.⁸⁹⁶ The expected in-service date is 2020.⁸⁹⁷

Key Dates

March 20, 2014: California ISO Board of Governors approved *2013–2014 Transmission Plan*.

August 19, 2014, through November 19, 2014: Competitive solicitation bid window open.

January 13, 2015: California ISO posted the list of validated project sponsor applications.

March 19, 2015: California ISO posted a revised list of validated project sponsor applications following a collaboration period.

April 15, 2015: California ISO posted the list of qualified project sponsors and proposals.

July 10, 2015: California ISO selected DCR Transmission, LLC as project sponsor.

March 23, 2016: BLM issued NOI to prepare EIS.

October 12, 2016: DCR Transmission, LLC filed with the CPUC application for CPCN.

2020: Expected in-service date.

#20 - Harry Allen-Eldorado

Description

The California ISO identified the need for a 500 kV transmission line between SCE majority-owned Eldorado Substation and NV Energy Harry Allen Substation as an economic project with reliability and policy benefits in its board approved *2013-2014 Transmission Plan*. The approximate length of the single-circuit 500 kV transmission line is 60 miles. The project is eligible for competitive solicitation.

Phase 3 of the California ISO's transmission planning process includes a competitive solicitation process for reliability, policy, and economic transmission projects. The bid window for interested project sponsors to submit applications to finance, construct, and own the Harry Allen-Eldorado 500 kV line opened January 30, 2015, and closed April 30, 2015. On June 19, 2015, the California ISO posted the list of validated project sponsor applications for the Harry Allen-Eldorado transmission line. On January 11, 2016, the California ISO selected DesertLink, LLC, a wholly owned subsidiary of LS Power Associates, L.P., as the approved project sponsor.⁸⁹⁸

⁸⁹⁵ BLM NOI for Ten West Link project, http://www.cpuc.ca.gov/environment/info/dudek/tenwest/03232016_FedReg_NOI_EIS.pdf.

⁸⁹⁶ CPUC Ten West Link project page, <http://www.cpuc.ca.gov/environment/info/dudek/tenwest/>.

⁸⁹⁷ DRC Transmission, LLC Ten West Link project Web page, <http://www.tenwestlink.com/news.html>.

⁸⁹⁸ California ISO Harry Allen-Eldorado sponsor selection report, <http://www.caiso.com/Documents/HarryAllentoEldoradoTransmissionLine-ProjectSponsorSelectionReport.pdf>.

Key Dates

March 20, 2014: California ISO Board of Governors approved *2013-2014 Transmission Plan*.

January 30, 2015, through April 30, 2015: Competitive solicitation bid window open.

June 19, 2015: California ISO posted the list of validated project sponsor applications.

November 11, 2016: California ISO selected DesertLink, LLC as project sponsor.

May 1, 2020: Expected in-service date.

#21 - San Luis Transmission Project

Description

The purpose of the San Luis Transmission Project is to minimize ongoing power delivery costs for operating the U.S. Bureau of Reclamation's San Luis Unit, a key component in delivering water to Central Valley agricultural companies and farmers. The Western Area Power Administration (Western) proposes to construct, own, operate, and maintain 95 miles of new transmission lines within Alameda, San Joaquin, Stanislaus, and Merced Counties along the foothills of the Diablo Range in the western San Joaquin Valley. Western would also upgrade or expand its existing substations, make the necessary arrangements to upgrade or expand existing PG&E substations, or construct new substations to accommodate the interconnections of these new transmission lines. Much of the project would be located near existing high-voltage transmission line easements along the foothills west of Interstate 5.⁸⁹⁹

The project consists of:

- A 500 kV transmission line – A single-circuit 500 kV transmission line, about 65 miles long, terminating at the existing, expanded, or new substations in the Tracy and Los Banos areas.
- 230 kV transmission lines – A single-circuit 230 kV transmission line, about 3 miles long, connecting the San Luis Substation and the existing Los Banos Substation or new Los Banos West Substation; and a single-circuit 230 kV transmission line, about 20 miles long, connecting the San Luis and Dos Amigos Substations or a single-circuit 230 kV transmission line, about 18 miles long, connecting the new Los Banos West and existing Dos Amigos Substations.
- A 70 kV transmission line – A single-circuit 70 kV transmission line, about 7 miles long connecting the San Luis and O'Neill Substations.

Western proposes to construct two new 500 kV substations, the Tracy East Substation and the Los Banos West Substation. The Tracy East Substation would be adjacent to and east of the existing Tracy Substation with a footprint of up to 50 acres. The Los Banos West Substation would be adjacent to and west of the existing Los Banos Substation with a footprint of up to 50

⁸⁹⁹ Western San Luis Transmission Project Final EIR Chapter 2 project description, <https://www.wapa.gov/regions/SN/environment/Pages/san-Luis-transmission-project.aspx>.

acres. Western may also interconnect the existing Western 500 kV Los Banos-Gates No. 3 transmission line just south of PG&E's existing Los Banos Substation into this new Los Banos West Substation. The existing Tracy, Los Banos, San Luis, and/or Dos Amigos Substations may be expanded to add new or modify existing 230 kV terminal bays. Western would also construct a 230/70 kV transformer bank and associated facilities at the San Luis Substation.

Key Dates

March 2016: Western and the San Luis & Delta-Mendota Water Authority released the final EIS/EIR for the project.

April 7, 2016: San Luis & Delta-Mendota Water Authority signed notice of decision (CEQA) approving the project.

April 26, 2016: Western signed the record of decision approving the project.

2017: Western Sierra Nevada region staff continues design and engineering work.⁹⁰⁰

2018: Expected to commence construction.

2022: Expected in-service date.⁹⁰¹

Major Western Transmission Projects

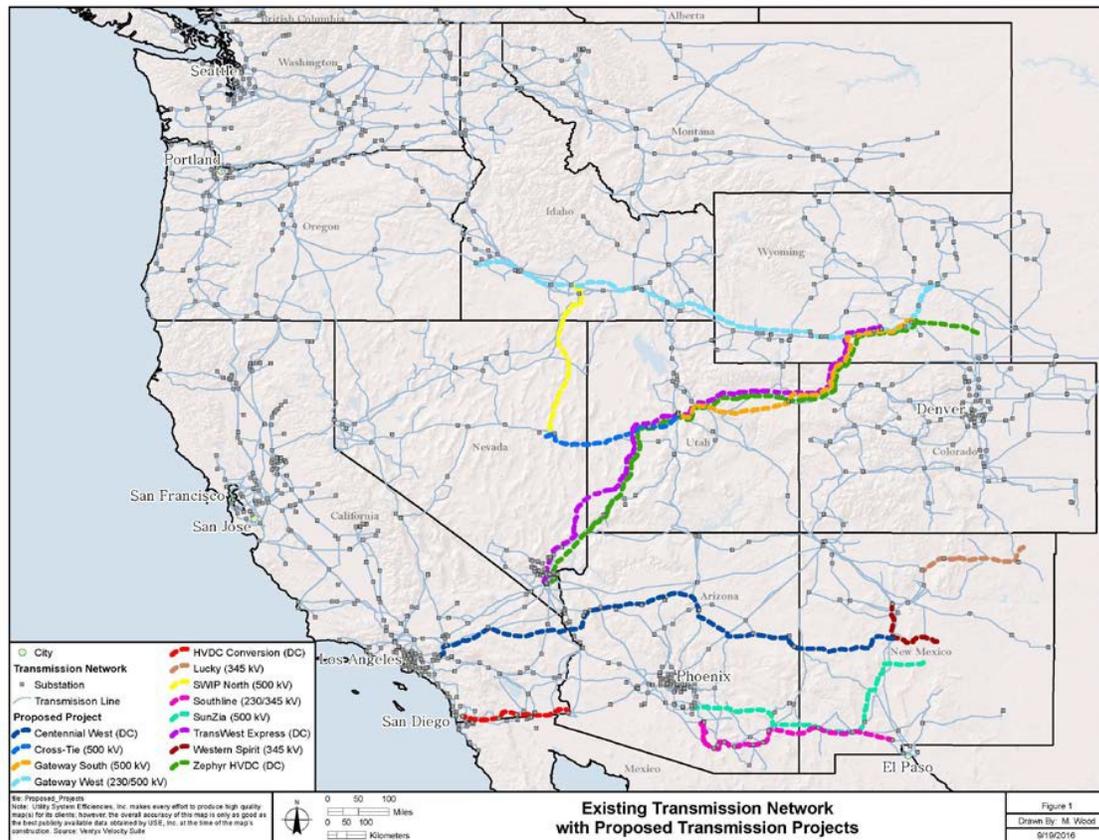
The Renewable Energy Transmission Initiative 2 (RETI 2.0) Western Outreach⁹⁰² identified 12 western transmission projects having some portion of the overall benefit of these projects tied to overcoming the transmission constraints associated with delivering high-quality renewable resources to California. As of summer 2017, five of the projects are in advanced development; nearly 3,300 line miles of transmission have both received federal final EIS and are in the WECC path rating process. The five projects combined could deliver 10,000 MW of renewable resources to California. Project proponents propose to deliver resources from across the West, although Wyoming and New Mexico are the most likely sources, given the prevalence of high-quality, low-cost, and complementary wind profiles in those areas. In addition to resource delivery benefits, other benefits such as congestion relief, reliability enhancements, and future market efficiencies are expected to result from the projects' completion. A map of the proposed transmission projects is shown in Figure 105.

900 Western March 2017 status report on the state of its assets, p.9, <https://www.wapa.gov/newsroom/Publications/Documents/customer-circuit/WAPA-state-of-assets-Winter2017.pdf>.

901 Western April 2017 San Luis Transmission Project Newsletter, <https://www.wapa.gov/regions/SN/environment/Documents/STLP-newsletter4.pdf>.

902 RETI 2.0 *Western Outreach Project Report*, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf.

Figure 106: Western Transmission Projects Accessing Out-of-State Resources



Source: Western Interstate Energy Board, *RETI 2.0 Western Outreach Project Report*, November 2016, http://docketpublic.energy.ca.gov/PublicDocuments/15-RETI-02/TN214339_20161102T083330_RETI_20_Western_Outreach_Project_Report.pdf

Centennial West

A proposed 600 kV HVDC project, spanning 900 miles, with terminals in eastern New Mexico, western Arizona, and Southern California would directly deliver renewables to the California grid. The project would interconnect with the California ISO balancing authority and operate with 3,500 MW of transfer capability by 2030. Depending on project design, HVDC lines and converters allow for bi-directional flow, which could ease significant exports and reduce potential California ISO over-generation. The developer has filed the BLM SF-299 Application for Transportation and Utility Systems and Facilities on Federal Lands (SF-299) for the project.

Cross-Tie

A proposed 500 kV AC line, spanning 213 miles, in combination with Gateway South would enable up to 600 MW of Wyoming wind and 900 MW of Central Utah resources delivered to Robinson Summit. This configuration assumes that 1,500 MW of transmission capacity rights on the One Nevada Line are available for transferring resources to California. Varied project configurations could yield operating transfer capabilities ranging from 700 MW to 1,600 MW by 2024. The developer has filed the BLM SF-299 for the project.

Gateway Full

The full AC build-out of Gateway could allow for up to 3,000 MW of renewable resources delivered to Robinson Summit by South West Intertie Project (SWIP) North and Cross-Tie. However, anticipated capacity limitations between Robinson Summit and Harry Allen would limit delivery to the California system to 1,500 MW. The full project would construct 1,400 miles of high-voltage line in the 2019 to 2024 time frame. Project combinations involving SWIP North and Cross-Tie would improve transfer capability between NV Energy and PacifiCorp. Both projects could allow for enhanced California ISO exports by increasing capacity between Harry Allen and Robinson Summit. The project was identified as one of five projects that met RETI 2.0 advanced development criteria.

Gateway South

This 500 kV AC portion of the Gateway project, spanning 400 miles, would create 600 MW of transfer capability. In combination with the Cross-Tie project, the facilities would enable 600 MW of Wyoming wind and 900 MW of Central Utah resources delivered to Robinson Summit. This configuration assumes that 1,500 MW of transmission capacity rights on NV Energy's One Nevada Line is used for transferring resources to California. The final BLM EIS has been published for this project.

Gateway West

This 230/500 kV AC portion of the Gateway project, with a length of 1,000 miles, would enable 600 MW of transfer capability. In combination with the SWIP North project, the facilities would enable 600 MW of Wyoming wind and 900 MW of Northern Nevada and/or Central Idaho resources to be delivered to Robinson Summit, at which point it is assumed that the One Nevada Line (SWIP South segment), which links Robinson Summit to Harry Allen, would deliver the resources to the California grid. The project has received a partial BLM ROD.

Lucky Corridor

A proposed 345 kV AC project, 62 miles in length, would deliver New Mexico wind resources to the Ojo, New Mexico, area, at which point the power would be delivered to Four Corners and then California via the existing transmission system. The project would add 850 MW of transfer capability, contingent on transmission capacity from Four Corners to the California grid by 2020.

Southline

A proposed 230/345 kV AC project, spanning 370 miles, would enable 1,000 MW of transfer capability. Project designs combining both new-build lines and upgrades to existing facilities would deliver New Mexico wind and southwest solar to Saguaro/Tortolita in Arizona, at which point the existing system, or other new build transmission, would be relied upon to deliver resources to the California grid. The project has received a ROD from BLM and Western. Construction is planned to start in 2018 with the facilities in service by 2020. The project was identified as one of five projects that met RETI 2.0 advanced development criteria.

Southwest Powerlink HVDC Conversion

A proposed 450 kV HVDC conversion of the 165 miles of existing Southwest Powerlink facilities would seek a final rating of 3,000 MW, which would provide approximately 500-1,000 MW of additional import capability between Arizona and California on Path 46 (West of River) and Path 49 (East of River). Upgraded facilities would continue to be operated by the California ISO. This project has been submitted to the WECC Regional Planning Entities for early study with a planned in-service date in the 2021 to 2025 time frame.

SunZia

A phased 500 kV AC project, spanning 515 miles, would allow New Mexico wind to be delivered to Pinal Central and wheeled to the Palo Verde area. The project phases would enable 1,500 MW to 3,000 MW of transfer capability by 2020, contingent on transmission capacity from Pinal Central to the Palo Verde area. The project has received a BLM ROD. The project was identified as one of five projects that met RETI 2.0 advanced development criteria.

SWIP North

A proposed 500 kV AC project, 275 miles in length, would add up to 1,700 MW of transfer capability. The project, in combination with Gateway West would enable 600 MW of Wyoming wind and 900 MW of Northern Nevada and/or Central Idaho resources to be delivered to Robinson Summit and wheeled to the California grid by 2021. The project has a secured right-of-way and has received both a notice to proceed and a BLM ROD. The project was identified as one of five projects that met RETI 2.0 advanced development criteria.

TransWest Express

A proposed 600 kV HVDC configuration, spanning 730 miles, that would directly deliver 1,500 MW to 3,000 MW of Wyoming wind to the California ISO transmission system at Eldorado/Mead through a phased build-out. The project would interconnect with the California ISO controlled grid by 2021. Depending on project design, HVDC lines and converters allow for bidirectional flow, which could facilitate significant exports and mitigate potential California ISO over-generation. The project has received ROD from BLM, Western and USFS. The project was identified as one of five projects that met RETI 2.0 advanced development criteria.

Western Spirit

A proposed 345 kV AC project, 140 miles in length, would deliver New Mexico wind to the Rio Puerco area New Mexico and wheeled to the California grid. The project would enable 1,000 MW of transfer capability by 2019. The developer has filed the BLM SF-299 for the project.

Zephyr

A proposed 500 kV HVDC project, spanning up to 850 miles, would directly deliver 2,100 MW to 3,000 MW of Wyoming wind to the California ISO controlled grid. An alternative project configuration terminates near Delta, Utah, and would seek capacity on the Intermountain Power Plant DC line, assuming retirement of the Intermountain Power Plant, to directly deliver 1,900 MW to California. Depending on project design, HVDC lines and converters allow for bi-

directional flow, which could promote significant exports and reduce potential California ISO over-generation. The developer has filed the BLM SF-299 for the project.

APPENDIX G:

June 2017 Heat Event in Southern California

Southern California Gas Company

Southern California Gas Company's (SoCalGas') highest sendout for the June 2017 heat event (June 16–June 23, 2017) reached about 3.2 million decatherms (MMDth)⁹⁰³ on June 21, 2017, and June 22, 2017. This level of demand is lower than the maximum demand found to be servable in the *Summer 2017 Technical Assessment*, which is achievable only as long as the assumptions described in the assessment about pipeline capacity, receipts, and storage supply hold true. To encourage customers to schedule sufficient supply, SoCalGas issued a critical notice on June 16, 2017, warning of the upcoming hot weather. Over the weekend, temperatures were higher than had been forecast, but lower sendout to customers, as typical over a weekend, resulted in too much gas supply being delivered. As the system operator, SoCalGas injected this excess supply into storage.

As the work week began, demand increased, and the oversupply shifted to undersupply. SoCalGas issued low operational flow orders (OFOs), reaching Stage 2 penalties, but still experienced a large enough imbalance that it withdrew more than 200,000 decatherms from non-Aliso storage on June 20, 2017, and again on June 21, 2017. (See Table 49.) During the peak hours, however, the total hourly sendouts were much greater than the daily totals and the maximum withdrawal rate from SoCalGas' Honor Rancho storage field was required to maintain service to customers.

Table 49: SoCalGas Daily Operations Summary

Total Daily Dth	June 16, 2017	June 17, 2017	June 18, 2017	June 19, 2017	June 20, 2017	June 21, 2017	June 22, 2017	June 23, 2017	June 24, 2017	June 25, 2017
Receipts	2,583,000	2,638,000	2,496,000	2,547,000	2,906,000	2,915,000	3,023,000	3,040,000	2,795,000	2,474,000
Sendout	2,310,000	2,442,000	2,304,000	2,523,000	3,117,000	3,162,000	3,180,000	2,988,000	2,573,000	2,379,000
Net Injections	272,000	196,000	194,000	25,000	(212,000)	(246,000)	(156,000)	53,000	222,000	94,000
Composite Wtg Avg	77	78	78	80	80	80	77	77	79	80
OFO	Weather Warning	High C2	High C1	Low C1	Low C2	Low C3	none	High C3	High OR C1	none
									High C2	

Source: Envoy™

SoCalGas' weighted average system composite temperature is reported in Table 50. These are the temperatures that SoCalGas made available to shippers on its Envoy system. Table 51 presents daily high and nighttime low temperatures at select locations, including Phoenix, showing hot temperatures extending to the Southwest. On some days, actual temperatures were higher than forecast, especially on June 19, 20, and 21, 2017—days SoCalGas experienced under deliveries

903 SoCalGas electronic bulletin board Envoy reports data in therms or decatherms (10 therms).

(customers delivered less gas than they used). Even on days that actual temperatures were higher than had been forecast on a day-ahead basis, shippers had been warned to expect temperatures even higher two or three days prior and to be sure to deliver supplies needed to meet anticipated demand.

Table 50: SoCalGas Forecast and Actual Composite Weighted Average Temperatures

Forecast Composite Weighted Average System Temperature Each Set of Four Days											
	16	17	18	19	20	21	22	23	24	25	26
16	77	78	81	83							
17		77	78	81	83						
18			79	80	81	79					
19				81	81	79	77				
20					81	79	78	78			
21	Key:					78	77	78	80		
22	Match Forecast						76	78	81	80	
23	< Forecast							78	80	79	76
24	> Forecast								80	78	74
25										78	74

Source: Envoy™

Table 51: Reported Daily High and Nighttime Low Temperatures at Select Locations

Date	Sacramento	Downtown LA	Oxnard	Ontario	Riverside	Blythe	Bakersfield	Barstow	Palm Springs	Phoenix
June 16	100 / 64	88 / 64	81 / 58	99 / 65	100 / 62	111 / 74	96 / 68	107 / 68	113 / 77	109 / 73
June 17	101 / 68	86 / 64	77 / 56	97 / 64	99 / 63	112 / 75	100 / 74	110 / 72	115 / 78	108 / 76
June 18	106 / 72	86 / 62	76 / 59	97 / 65	98 / 64	115 / 78	105 / 81	111 / 74	117 / 79	110 / 78
June 19	105 / 75	84 / 63	79 / 60	97 / 67	98 / 65	118 / 80	109 / 80	115 / 79	119 / 82	112 / 80
June 20	104 / 70	84 / 63	74 / 60	103 / 69	104 / 68	122 / 83	110 / 83	115 / 80	122 / 84	118 / 84
June 21	106 / 63	82 / 64	77 / 60	101 / 71	104 / 69	119 / 84	110 / 81	114 / 78	118 / 84	119 / 86
June 22	107 / 71	81 / 65	74 / 59	91 / 63	91 / 62	112 / 87	110 / 81	113 / 75	113 / 83	117 / 90
June 23	98 / 65	78 / 63	70 / 60	91 / 62	91 / 65	114 / 81	106 / 80	114 / 77	114 / 81	113 / 91
June 24	94 / 60	77 / 62	74 / 58	92 / 64	92 / 64	120 / 86	106 / 79	113 / 80	122 / 86	112 / 87

Source: National Weather Service

SoCalGas experienced several system issues during the June heat wave. Because the outages were of short duration, it was nonetheless able to serve its entire load, with no curtailments. For example, the Blythe compressor station experienced the loss of a compressor, but SoCalGas was able to restore the unit within a short time. Had the outage continued, it could have caused curtailment of noncore customers on the southern system. As indicated elsewhere above, SoCalGas used injections to and withdrawals from underground storage to remedy the customer imbalances that occurred despite warnings and OFO notices.

California Independent System Operator

The California Independent System Operator (California ISO) forecasted daily demand for the week beginning Monday June 19, 2017, that would exceed 47,000 MW. California ISO Operations took the following steps to prepare for and help manage the heat event:

- Conducted a market participant call on June 15, 2017, in anticipation of high loads for the following week indicating that gas fired generation was anticipated to be on-line to serve the load.
- Issued restricted maintenance notices for June 19–22, 2017.

- Issued a state-wide flex alert for June 20, 2017, and June 21, 2017, to reduce peak load through voluntary conservation. The California ISO has observed up to 500 MW in peak load reduction during past Flex Alerts.
- Conducted daily coordination with SoCalGas and LADWP.
- Conducted peak day calls with market participants throughout the week.
- Ensured resource availability to meet forecasted load.

Actual peak loads for the week turned out to be lower than forecasted, reaching only 45,000 MW. This was mainly due to lower temperatures in Southern California coastal areas than originally anticipated. In addition, the load serving entities within the California ISO balancing area used their demand response programs, which lowered actual electricity load by an estimated 500 MW.

Los Angeles Department of Water and Power

The Los Angeles Department of Water and Power's (LADWP's) demand peaked at 5,208 MW, well below its recorded high of 6,396 MW. As shown in Table 51, coastal temperatures remained moderate and kept demand from reaching the record levels that occur when air conditioners kick on in coastal communities. No generation or major transmission facility outages occurred during the heat storm. LADWP participated in daily coordination calls with the California ISO and SoCalGas, as well as the "peak day" calls hosted by the California ISO. Based in part on these calls, LADWP declared restricted maintenance days for the four days from June 19, 2017, to June 22, 2017, for extra-high-voltage transmission facilities in its balancing area.

Prices

Natural gas prices spiked during the heat event, relative to those prevailing before the heat storm, by close to \$1.00 per million British thermal units (MMBtu). SoCal Border jumped 22 cents to \$3.54, a 64-cent increase from Monday to Wednesday. SoCal Citygate increased by even more, gaining 33 cents to close at \$4.15, a 90-cent gain over those same two days. Prices fell 55 cents to \$2.85 at SoCal Border and 62 cents to \$3.37 at SoCal Citygate by Friday, June 23, 2017, with moderating temperatures in sight.

Key Differences From High Sendout Event Summer 2015

By way of comparison, the June 2017 heat storm produced less demand than SoCalGas experienced on its most recent summer curtailment days of June 30, 2015, and July 1, 2015. Table 52 indicates sendouts of 3.3 MDth and 3.4 MDth, with composite weighted average system temperatures similar to those seen July 20, 2017, through July 22, 2017. The major differences between the two events is that in 2015, SoCalGas' 36-inch Line 4000 was out of service for repairs, and Aliso Canyon was available, such that shippers were not required to balance loads and receipts so closely as recommended by the *Summer 2016 Reliability Action Plan* and now required under CPUC D. 16-06-021. Another key difference would be the closer gas-electric coordination now in place to help manage gas burn requirements.

Table 52: SoCalGas Operations Summary June/July 2015 Curtailment Event

Total Daily Dth	28-Jun	29-Jun	30-Jun	1-Jul	2-Jul					
Receipts	2,614,000	2,665,000	2,638,000	2,620,000	2,637,000					
Sendout	3,239,000	3,349,000	3,424,000	3,429,000	3,105,000					
Net Injections	(661,000)	(586,000)	(812,000)	(839,000)	(462,000)					
Composite Wtg Avg T	81	81	79	79	77					
OFO	n/a	n/a	n/a	n/a	n/a					

Source: Envoy™

Wildfires

Fires occurring during heat events are a major concern of the energy agencies, the Office of Emergency Services, and the electricity balancing areas (California ISO and LADWP), given the possibility of damage to transmission lines during high loads. A fire that damages a transmission line is an unplanned outage and is the kind of event that can increase requirements for natural gas-fired generation potentially beyond that assumed in the risk assessment delivered by agency staff, the California ISO, and LADWP on May 19, 2017, at the joint en banc hearing and discussed at the May 22, 2017, joint agency IEPR workshop on Southern California Electricity Reliability. At least four fires occurred during the June 2017 heat wave that could have caused major interruptions to electricity service and that, in turn, could have led to higher gas requirements. Only one of those fires damaged a transmission line and fortunately its impact was limited.

The Lake Fire broke out on Saturday June 17, 2017, on the north side of Castaic Lake and spread from 5 to 500 acres in a little more than two hours.⁹⁰⁴ That fire was out by June 21, 2017, and had no impact on electric facilities.

The Holcomb Fire began on Monday June 19, 2017, near the Pacific Crest Trail and Holcomb Valley Road in the San Bernardino National Forest.⁹⁰⁵ By Wednesday June 21, 2017, one local transmission line running from the Lucerne Valley into Big Bear and local load-serving entity Bear Valley Electric was damaged; another was threatened for a time. Bear Valley Electric asked for conservation while the line was repaired and warned residents insufficient conservation would result in rolling blackouts.⁹⁰⁶

⁹⁰⁴ See <http://www.scp.org/news/2017/06/18/73025/castaic-lake-fire-burns-up-1-000-acres-amid-heat-w/>, (Accessed June 28, 2017).

⁹⁰⁵ See <https://inciweb.nwcg.gov/incident/article/5256/35769/>, (Accessed June 28, 2017).

⁹⁰⁶ See <http://www.sbsun.com/general-news/20170621/holcomb-fire-prompts-more-rolling-blackouts-in-san-bernardino-mountains>, (Accessed June 28, 2017).

Table 53: Fires With Potential Impact on Electric Facilities During Heat Wave

Date	Fire Name	Area Affected	Impact	General Information
June 17	Lake	Castaic Lake	None	Started prior to "heat wave"
June 19	Holcomb	Big Bear	Lucerne Valley to Big Bear line damaged	Conservation requested to avoid local rolling blackouts until repaired
June 25	Placerita	Santa Clarita	Line relay	500-kV Adelanto-Rinaldi Line 1
June 27	Mart	San Bernardino	None	

Source: Aspen Environmental Group

The Placerita fire started June 25, 2017; at this point, the San Fernando Valley had experienced five days with temperatures more than 100 degrees, the other four days were more than 90 degrees.⁹⁰⁷ The Placerita Fire was the only fire to affect the LADWP system, causing the 500-kV Adelanto-Rinaldi Line 1 to relay. The line failed on test, but was restored 24 minutes later. Two 500-kV circuits also required washing due to fire retardant dropped on them during the fire. The loss of this line reduced LADWP's import capability by 1,550 MW. The Mart Fire in San Bernardino was clear of all facilities and posed no impact.

⁹⁰⁷ As shown in Table 51, the weather service reports downtown L.A. area never exceeding 90 degrees, but LADWP has a different measurement showing greater than 90 on the peak load day for this period, which was June 26, 2017.

APPENDIX H:

Vehicle-Grid Integration Roadmap

Successful vehicle-grid integration (VGI) will enable PEVs to help integrate renewable energy, reduce charging infrastructure and vehicle operating costs, and reduce the utilities' distribution maintenance requirements. (See sidebar for definition of VGI and definitions for greater levels of vehicle-grid integration.) Two related documents have led California's policy development in VGI. The first is the CPUC Energy Division's white paper, published in the order instituting the Alternative Fuel Vehicles rulemaking (R.13.11-007).⁹⁰⁸ The second, the *California Vehicle-Grid Integration Roadmap*⁹⁰⁹ was developed collaboratively by the Energy Commission, CPUC, California ISO, and stakeholders through public workshops beginning in late 2012.

2014 Vehicle-Grid Integration Roadmap

The *2014 California Vehicle-Grid Integration Roadmap* identified three tracks to direct the state's efforts:

- 1) Determine VGI value and potential.
- 2) Develop enabling policies, regulations, and business practices.
- 3) Support enabling technology development.

Vehicle-Grid Integration Defined

Vehicle grid integration (VGI) encompasses the ways EVs can provide grid services.

Unidirectional power flow into the battery (also known as "V1G") can start, stop, and vary the charging level up and down but doesn't discharge the battery to the grid. Meeting recharging needs in coordination with TOU pricing or to the constraints of the system, can be referred to as "smart-," "managed-," or "controlled-" charging.

Bidirectional power flow in and out of the battery, also known as "vehicle-to-grid" or "V2G," can similarly fluctuate charging but also decrease the state of charge by discharging energy to the grid.

VGI is enabled through technology tools and products that provide reliable and dependable vehicle charging services to EV owners, and potentially additional revenue opportunities, while reducing risks and creating cost savings opportunities for grid operators. Such tools might include technologies such as inverters, controls or chargers, or programs and products, such as time-of-use tariffs or bundled charging packages.

Source:

<http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M080/K775/80775679.pdf> and

<http://www.caiso.com/documents/vehicle-gridintegrationroadmap.pdf>

908 Langton, A., N. Crisostomo, 2014. *Vehicle-Grid Integration A Vision For Zero Emissions Transportation Interconnected Throughout California's Electricity System*. Energy Division staff paper. California Public Utilities Commission.

http://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/Utilities_and_Industries/Energy/Energy_Programs/Demand_Side_Management/EE_and_Energy_Savings_Assist/CPUCEnergyDivisionVehicleGridIntegrationZEVSummit.pdf

909 California Independent System Operator, *Vehicle- Grid Integration Roadmap*, March 3, 2014. <https://www.caiso.com/informed/Pages/CleanGrid/Vehicle-GridIntegrationRoadmap.aspx>.

These tracks are discussed below. As previously noted, updates to the roadmap are discussed in Chapter 4.

Track 1: Determine VGI Value

The lack of a quantified value for VGI is an ongoing issue that, among other barriers, inhibits the widespread use of PEVs as grid resources. Valuing VGI is challenging due to the need to examine it from multiple perspectives and interests. However, clarifying the value of PEV charging to provide customer or grid services will provide manufacturers with the greater clarity they need to develop technologies at scaled production volumes at lower costs, compared to first-of-a-kind pilot projects. Transparent value also enables developers to integrate communications and control systems more efficiently into products and field operations, while allowing resource planners to model charging flexibility for procurement planning. UC Irvine analyzed the operational requirements of an 80 percent RPS in California by 2050 and determined that replacing immediate charging (charging that is conducted as soon as a vehicle is parked) with “smart charging” (charging with internal controls that adjusts to customer and grid needs) would reduce the amount of energy storage that would otherwise be needed to achieve the same level of load management. For instance, the study found that using smart charging in 80 percent of California’s entire light-duty vehicle fleet (assuming a fleet of BEVs with the capability to drive 200-mile between charges and that use 10 kW chargers at work and home) could reduce the overall need for aggregate energy storage from roughly 60 percent of the state’s renewable electricity generation capacity to just 16 percent. Or, on an energy basis, the amount of electric generation used to charge the fleet would drop from about 2.3 percent of renewable electricity generation to 0.6 percent. The difference in magnitude in the results for storage capacity and energy (16 percent and 0.6 percent, respectively) reflects the potentially large impact of concentrating a relatively small amount of load at specific times.

Lawrence Berkeley National Laboratory (LBNL) quantified 105 MWh per year of shiftable residential PEV demand response to be cost-competitive with other resources at \$30/kWh-year in 2025 and consistent with the grid value for shift demand response of \$20–\$50/kWh. Further, LBNL expects additional charging technology development and dynamic pricing (real-time pricing) to introduce even lower cost options. Meanwhile, LADWP found that doubling the rate of EV adoption would increase energy consumption when there is excess generation and would reduce rates by an average of 0.6 cents/kWh for the 2016-2036 planning horizon. To realize these benefits, LADWP is considering the use of EV-specific rates that vary by time and system conditions to accommodate new load without grid upgrades.

Overall, these studies highlight the benefits that could be realized if California achieves massive deployment of plug-in EVs and encourages charging profiles that integrate well with the grid. By identifying these benefits, the state can clarify how investment in and the deployment of highly functional charging technologies that can benefit the grid and interoperate seamlessly with it, while simultaneously simplifying the driver’s experience.

Track 2: Develop Enabling Policies, Regulations, and Business Practices

Before customers' PEVs can more seamlessly serve grid integration needs, communication and control systems need to be in place to connect a variety of actors (for example, a vehicle, charging station, facility, and DR aggregator) that are involved in creating and receiving grid operator messages and responding to those messages. A given PEV will likely roam across utility service territories and balancing authority control areas, and among a heterogeneous charging market, where multiple actors could attempt to control charging. If charging controls are misaligned (whether in terms of prices, charging or discharging, charge sequencing, or recipient of the grid service), there is the potential for lost or negative value to one or more of the entities involved (for example, stranding a driver without sufficient energy, increased monthly demand fees, and penalties from grid operators if the resource fails to deliver services). This “fragmented actors” case, as described in the CPUC white paper, may hinder realization of VGI benefits in the evolving and increasingly diverse charging infrastructure market.

In September 2016, the CPUC's assigned commissioner's ruling in R.13-11-007 stated an intention to overcome barriers that prevent expeditious actions toward effective VGI, particularly as the utilities were ordered to prepare applications for widespread transportation electrification under SB 350.⁹¹⁰ The CPUC Energy Division considered options for adopting a VGI communications standard to achieve the technology development and system reliability objectives enumerated in the VGI white paper and recommended the use of the International Organization for Standardization and International Electrotechnical Commission's (ISO/IEC) 15118 Vehicle-to-Grid Communications Protocol. While there was not consensus on the use of ISO/IEC 15118 in the IOUs' programs, the protocol is supported by many global stakeholders, including automakers,⁹¹¹ charging providers,⁹¹² and industry.⁹¹³

Ratepayer advocates also support standardized communications to foster electrification by providing consistent metering, telemetry, and billing across vehicles, charging stations, and service territories, and improving security by reducing points of integration, failure, and cyberattacks.⁹¹⁴

910 CPUC, Assigned Commissioner's Ruling Regarding the Filing of the Transportation Electrification Applications Pursuant to Senate Bill 350, September 14, 2016, <http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M167/K099/167099725.PDF>.

911 Reinsdorf, S. "OEM Consolidated Comment to CEC VGI Communications Standard workshop," Audi, BMW, Daimler, Ford Lucid, Porsche, Volvo, VW, Vehicle-Grid Integration Communications Standards Workshop, http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN215671_20170130T164622_Anne_Smart_Comments_ChargePoint_Comments_on_VGI_Standard__Dec_7.pdf.

912 Rodine, C., "ChargePoint's Perspective on ISO/IEC 15118" ChargePoint, December 7, 2016, Vehicle-Grid Integration Communications Standards Workshop, http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN215671_20170130T164622_Anne_Smart_Comments_ChargePoint_Comments_on_VGI_Standard__Dec_7.pdf.

913 CharIn Press Release, "California Public Utilities Commission Supports Vehicle to Grid Communications Through ISO/IEC 15118 in Latest Ruling," September 28, 2016. Retrieved from http://www.combined-charging-system.org/fileadmin/user_upload/CPUC_supports_Vehicle_to_Grid_communications_RevA.pdf.

914 Office of Ratepayer Advocates, "The Office of Ratepayer Advocates' Comments of the California Energy Commission's Public Workshop on Vehicle-Grid Integration Communication Standards." December 22, 2016, http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN215098_20161222T135853_ORA_Comments.pdf.

Subsequently, in April 2017, the CPUC, Energy Commission, CARB, California ISO, and Governor's Office of Business and Economic Development began an interagency-led working group of stakeholders to understand whether standards within charging equipment are needed to help enable vehicle-grid integration economically and at scale.⁹¹⁵ Through the effort, VGI Communications Protocol Working Group participants recognized the complexity of VGI technology and that quantifying value could be addressed with demonstrations.⁹¹⁶ Parties also suggest that those complexities must be overcome quickly to deploy charging infrastructure and to commensurately achieve the goals of PEV adoption at the scale needed to improve grid reliability and emissions reductions.⁹¹⁷ As of December 2017, the VGI Communications Protocol Working Group has not determined a unanimous specification for the communications standards within charging equipment, and has instead identified hardware performance requirements to enable PEV charging equipment to support the multiple communications standards that are viable to enable VGI. In the first quarter of 2018, CPUC staff will release a final report summarizing the Working Group's efforts and making a recommendation on how the CPUC should consider the Working Group's recommendations in evaluating IOU proposals to support PEVs.

Specific attention may also be warranted regarding the VGI needs and opportunities of direct current (DC) fast charging. This may become particularly apparent as the charging capacity of DC fast chargers increases, from 50 kW systems in previous years to upward of 350 kW in coming years. Some station developers, for instance, are researching how to predict the power curves of vehicles and examining how to schedule aggregated DC fast charging energy consumption into energy markets for grid service revenues. This can include integrating stationary storage systems to shave their peak loads and reduce demand charges. Scheduling and savings alone, however, may not be sufficient to fully recover the costs of storage.⁹¹⁸ As a result, redesigning utility cost recovery mechanisms may be essential to enable the broader installation and use of the next generation of DC fast charging infrastructure.

Track 3: Support Enabling Technology Development

The *2016 ZEV Action Plan*⁹¹⁹ update includes direction to continue to integrate charging to optimize the use of the state's electricity infrastructure, including:

915 California Public Utilities Commission Vehicle-Grid Integration Communications Protocol Working Group, updated December 18, 2017, <http://www.cpuc.ca.gov/vgi/>.

916 Joint Utility-Automaker Parties, Comments on the *Draft 2017 Integrated Energy Policy Report*, November 13, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-01/TN221781_20171115T100743_Hannah_Goldsmith_Comments_Final_Updated_Joint_UTILITY_Automaker.pdf.

917 Oxygen Initiative, 2017 IEPR Comments, November 13, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN221741_20171113T155256_Stephen_Davis_Comments_Oxygen_Initiative_2017_IEPR_Comments.pdf.

918 Ashley, T. "Improving Commercial Viability of Fast Charging by Providing Renewable Integration and Grid Services with Integrated Multiple DC Fast Chargers (DCFC)," Greenlots, April 18, 2017, http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-07/TN217139_20170417T164547_Improving_Commercial_Viability_of_Fast_Charging.pptx.

919 Governor's Interagency Working Group on Zero-Emission Vehicles, *2016 ZEV Action Plan*. October 2016, https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf.

- Expanding the scope of the VGI interagency task force to ensure technology research is coordinated with the development of standards, procurement policies, and tariffs.
- Supporting state- and federally funded VGI pilots that help commercialize applications that aggregate vehicles as distributed energy resources, enhance communication, and control functionality between vehicle and grid infrastructure, and derive value for vehicles (PEV or FCEV) as flexible load and storage in grid support applications.
- Recognizing and leveraging research to assess the grid impacts of an integrated transportation and electricity system by exploring partnerships with laboratories, industry, and academia.

These goals frame and complement multiple Energy Commission research initiatives. Within the proposed *EPIC 2018-2020 Triennial Investment Plan*, for instance, the Grid-Friendly PEV Mobility funding initiative would seek charging interoperability for broad availability and acceptance, integrate charge scheduling with traffic flows and automated vehicles to improve the value of VGI, seek to reduce the component costs of PEVs capable of vehicle-to-grid discharge, quantify battery degradation in first and second use applications, and develop diagnostic tools to monitor the state of health and predict degradation to reduce the cost of second-use applications.⁹²⁰

Future projects should build upon lessons from the Los Angeles Air Force Base V2G project, which will conclude in September 2017 after nearly two years of operations providing regulation services to the California ISO.⁹²¹ Key lessons include the need to:

- Closely monitor vehicles and chargers, particularly first-generation equipment, to ensure reliable interoperation in field conditions.
- Ensure fleet management systems are honed to actual user inputs and meet fleet requirements based on constant feedback.⁹²²

A recent project involving the electrification of nontactical vehicles at Naval Base San Diego, as part of a larger southwest regionwide Navy Electric Vehicle Initiative, programs 50 light-duty vehicles to limit recharging to off-peak hours.⁹²³ Also, the Energy Commission continues to monitor and advise the EV Smart Grid Working Group, composed of six U.S. Department of Energy (DOE) National Laboratories that are conducting VGI research under the Grid Modernization Lab Consortium.

⁹²⁰ Gutierrez, A., V. Lew, A. Ng, F. Piña, L. Spiegel, and E. Stokes. 2017. *EPIC Proposed 2018-2020 Triennial Investment Plan*. California Energy Commission, CEC-500-2017-023-CMF. http://docketpublic.energy.ca.gov/PublicDocuments/17-EPIC-01/TN217366_20170501T115606_Application_of_the_California_Energy_Commission_for_Approval_of.pdf.

⁹²¹ Southern California Edison, Advice Letter 3479-E, October 23, 2016, <https://www.sce.com/NR/sc3/tm2/pdf/3479-E.pdf>.

⁹²² Southern California Edison, Vehicle-to-Grid Pilot Overview, Third Annual Multi-Agency Update on Vehicle-Grid Integration Research, December 12, 2016, http://www.energy.ca.gov/research/notices/2016-12-12_workshop/presentations/08_SCE_Los_Angeles_Air_Force_Base.pptx

⁹²³ Icar, M. "NAVFAC Southwest Leads Department of Navy's Transition to Electric Vehicles," May 24, 2017, http://www.navy.mil/submit/display.asp?story_id=100639.

In April 2017, the U.S. Environmental Protection Agency and DOE published the first version of the ENERGY STAR certification program for electric vehicle supply equipment (EVSE). Key criteria for Level 1 and 2 EVSE include power requirements for no-vehicle, partial-on, and idle modes and an optional “connected functionality” for demand response enabled via open standards to connect to an external application, device, or system⁹²⁴ that can be overridden by the customer.⁹²⁵

Finally, supporting VGI technology research and development is critical for validating the functionality of charging control equipment, approaches, and algorithms; quantifying development and operational costs; and supporting the widespread use of VGI. Projects, however, are often developed in isolation, change scope, are subject to resource changes or time delays, or are limited in the broader application in mass-market programs. More comprehensive assessments of the portfolio of projects are needed to improve policy development and technology incentives. To increase understanding, improve collaboration, and advance the state of the art, the CPUC and Energy Commission partnered to gather information on VGI projects funded through the Alternative and Renewable Fuel Vehicle and Technology Program, EPIC, and other projects.⁹²⁶ For more information on the state’s work to advance charging infrastructure, see Chapters 2, 3, and 4.

⁹²⁴ *Open standards* include those that are listed within the Smart Grid Interoperability Panel Catalogue of Standards, National Institute of Standards and Technology Smart Grid framework, or those that are adopted by the American National Standards Institute or other international standards organization including the International Organization for Standardization (ISO), International Electrotechnical Commission (IEC), International Telecommunication Union (ITU), Institute of Electrical and Electronics Engineers, or Internet Engineering Task Force (IETF).

⁹²⁵ Energy Star, Energy Star Program Requirements for Electric Vehicle Supply Equipment Version 1.0, April 7, 2017, https://www.energystar.gov/sites/default/files/Version%201.0%20EVSE%20Program%20Requirements%20%28Rev.%20Apr-2017%29_0.pdf.

⁹²⁶ California Public Utilities Commission’s EV and VGI Research Reports Database, updated May 16, 2016, tiny.cc/evreports.

APPENDIX I:

Energy Commission Senate Bill 350 Implementation Progress

This appendix summarizes the status of implementation activities related to Senate Bill 350, the Clean Energy and Pollution Reduction Act of 2015 (De León, Chapter 547, Statutes of 2015). For each major goal outlined in SB 350 and described in Chapter 2, this appendix includes a list of the specific requirements specified in SB 350, the key publicly noticed activities and events that have occurred to move forward with implementation of the requirements and the products that have been generated and posted to demonstrate evidence of progress. In addition to the events, activities, and products listed, several informal activities, meetings, and interim deliverables were developed throughout the process. The information presented is organized as follows:

- Integrated resource planning for publicly owned utilities
- Transportation electrification for publicly owned utilities
- 50 percent Renewables Portfolio Standard
- Doubling end-use energy efficiency savings (Although an important part of achieving the SB 350 energy efficiency savings goal, the listing below does not include activities related to building or appliance energy efficiency standards updates as they are implemented separately.)
- Low-Income Barriers Study
- Energy data collection regulations
- Regional grid operator and governance
- Miscellaneous SB 350 goals

Integrated Resource Planning for Publicly Owned Utilities

SB 350 Requirements:

Public Utilities Code Section 9621

(a) This section shall apply to a local publicly owned electric utility with an annual electrical demand exceeding 700 gigawatthours, as determined on a three-year average commencing January 1, 2013.

(b) On or before January 1, 2019, the governing board of a local publicly owned electric utility shall adopt an integrated resource plan and a process for updating the plan at least once every five years to ensure the utility achieves all of the following:

(1) Meets the greenhouse gas emissions reduction targets established by the State Air Resources Board, in coordination with the commission and the Energy Commission, for the electricity sector and each local publicly-owned electric utility that reflect the electricity sector's percentage in achieving the economywide greenhouse gas emissions reductions of 40 percent from 1990 levels by 2030.

(2) Ensures procurement of at least 50 percent eligible renewable energy resources by 2030 consistent with Article 16 (commencing with Section 399.11) of Chapter 2.3.

(3) Meets the goals specified in subparagraphs (C) to (H), inclusive, of paragraph (1) of subdivision (a) of Section 454.52.

(c) (1) The integrated resource plan shall address procurement for the following:

(A) Energy efficiency and demand response resources pursuant to Section 9615.

(B) Energy storage requirements pursuant to Chapter 7.7 (commencing with Section 2835) of Part 2 of Division 1.

(C) Transportation electrification.

(D) A diversified procurement portfolio consisting of both short-term and long-term electricity, electricity-related, and demand response products.

(E) The resource adequacy requirements established pursuant to Section 9620.

(2) (A) The governing board of the local publicly owned electric utility may authorize all source procurement that includes various resource types, including demand-side resources, supply side resources, and resources that may be either demand-side resources or supply side resources, to ensure that the local publicly owned electric utility procures the optimum resource mix that meets the objectives of subdivision (b).

(B) The governing board may authorize procurement of resource types that will reduce overall greenhouse gas emissions from the electricity sector and meet the other goals specified in subdivision (b), but due to the nature of the technology or fuel source may not compete favorably in price against other resources over the time period of the integrated resource plan.

(d) A local publicly owned electric utility shall satisfy the notice and public disclosure requirements of subdivision (f) of Section 399.30 with respect to any integrated resource plan or plan update it considers.

Public Utilities Code Section 9622

(a) Integrated resource plans and plan updates adopted pursuant to Section 9621 shall be submitted to the Energy Commission.

(b) The Energy Commission shall review the integrated resource plans and plan updates. If the Energy Commission determines an integrated resource plan or plan update is inconsistent with the requirements of Section 9621, the Energy Commission shall provide recommendations to correct the deficiencies.

(c) The Energy Commission may adopt guidelines to govern the submission of information and data and reports needed to support the Energy Commission's review of the utility's integrated resource plan pursuant to this section at a publicly noticed meeting offering all interested parties an opportunity to comment. The Energy Commission shall provide written public notice of not less than 30 days for the initial adoption of guidelines and not less than 10 days for the subsequent adoption of substantive changes. Notwithstanding any other law, any guidelines adopted pursuant to this section shall be exempt from the requirements of Chapter 3.5 (commencing with Section 11340) of Part 1 of Division 3 of Title 2 of the Government Code.

Link: <http://www.energy.ca.gov/sb350/IRPs/>

Title: SB 350-Required Publicly Owned Utility (POU) Integrated Resource Plans (IRP) Workshop

Date: 4/18/16	Subject: Guidelines	Docket: 16-OIR-04
----------------------	----------------------------	--------------------------

Description: IEPR Lead Commissioner workshop with publicly owned utility representatives to discuss preexisting integrated resource planning processes and the new requirements of SB 350.

Title: SB 350 Publicly Owned Utility (POU) Integrated Resource Plans (IRP) Renewable Energy Workshop

Date: 12/13/16	Subject: Resources	Docket: 16-OIR-04
-----------------------	---------------------------	--------------------------

Description: Workshop to discuss considerations for renewable energy and the 50 percent renewable energy requirement by 2030 included in SB 350 as it relates to integrated resource planning.		
Title: Joint Agency Workshop on 2030 Greenhouse Gas Emission Reduction Targets for Integrated Resource Planning		
Date: 2/23/17	Subject: GHG Targets	Docket: 17-IEPR-07
Description: Joint agency workshop with the California Public Utilities Commission (CPUC) and California Air Resources Board (CARB) participation to discuss potential methods for establishing the 2030 greenhouse gas emission reduction planning targets called for by SB 350.		
Title: IEPR Commissioner Workshop on Publicly Owned Utilities Integrated Resource Plans		
Date: 2/23/17	Subject: Guidelines	Docket: 17-IEPR-07
Description: Lead Commissioner workshop to discuss proposed integrated resource plan guidelines topics with publicly owned utility representatives.		
Title: IEPR Staff Webinar on Publicly Owned Utilities Integrated Resource Plans		
Date: 3/13/17	Subject: Guidelines	Docket: 17-IEPR-07
Description: Staff webinar to follow up the integrated resource planning guidelines topics lead commissioner workshop held on February 23, 2017, to answer outstanding questions from publicly owned utility representatives.		
Title: Joint Agency Workshop on Potential Methodologies to Establish Publicly Owned Utility Greenhouse Gas Reduction Targets for Integrated Resource Planning		
Date: 4/17/17	Subject: GHG Targets	Docket: 17-IEPR-07
Description: Joint agency workshop with the CARB to discuss potential methods for establishing individual greenhouse gas emission reduction targets for publicly owned utilities meeting the reporting threshold described in SB 350. This workshop builds off the discussion at the February 23, 2017, joint agency workshop on greenhouse gas methodologies.		
Title: IEPR Staff Webinar on Inputs, Assumptions, and Administrative Review for Publicly Owned Utility Integrated Resource Plans		
Date: 4/20/17	Subject: Guidelines	Docket: 17-IEPR-07
Description: Staff webinar to review proposed inputs, assumptions, and the administrative review process for publicly owned utility integrated resource plans, to inform the development of Energy Commission guidelines.		
Title: IEPR Commissioner Workshop on Draft Guidelines for Publicly Owned Utility Integrated Resource Plans		
Date: 5/25/17	Subject: Guidelines	Docket: 17-IEPR-07
Description: Lead Commissioner workshop to review the contents of draft integrated resource guidelines with representatives of publicly owned utilities and the public.		
Title: Webinar on Light-Duty Plug-In Electric Vehicle Calculator Tool for Publicly Owned Utility Integrated Resource Plans		
Date: 5/31/17	Subject: Resources	Docket: 17-IEPR-07

Description: Staff webinar to provide a tutorial to utility technical staff on a proposed tool for calculating emissions of light-duty electric vehicles for use in publicly owned utility integrated resource planning. The tool will be revised to reflect the final 2018–2030 California Energy Demand Forecast.		
Title: Webinar on Standardized Tables and Instructions for Publicly Owned Utility Integrated Resource Plans		
Date: 5/31/17	Subject: Guidelines	Docket: 17-IEPR-07
Description: Staff webinar with utility technical staff to review proposed tables and instructions requested to be submitted in support of publicly owned utility integrated resource plans.		
Title: Business Meeting to Consider Adoption of Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines		
Date: 8/9/17	Subject: Guidelines	Docket: 17-IEPR-07
Description: Business meeting adoption of final <i>Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines</i> . The commission final guidelines were posted more than 30 calendar days prior to the business meeting, and the Energy Commission voted unanimously to adopt the guidelines.		
Product(s):		
<ul style="list-style-type: none"> • <u>Options for Setting GHG Planning Targets for Integrated Resource Planning & Apportioning Targets</u> – Posted February 10, 2017 • <u>Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines</u>– Adopted August 9, 2017 • <u>Standardized Reporting Tables for Publicly Owned Utility IRP Filings</u>– Posted August 9, 2017 		

Transportation Electrification for Publicly Owned Utilities

SB 350 Requirements:

Public Utilities Code Section 237.5

“Transportation electrification” means the use of electricity from external sources of electrical power, including the electrical grid, for all or part of vehicles, vessels, trains, boats, or other equipment that are mobile sources of air pollution and greenhouse gases and the related programs and charging and propulsion infrastructure investments to enable and encourage this use of electricity.

Public Utilities Code Section 740.12

(a) (1) The Legislature finds and declares all of the following:

- (A) Advanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse gas emissions reduction goals.
- (B) Widespread transportation electrification is needed to achieve the goals of the Charge Ahead California Initiative (Chapter 8.5 (commencing with Section 44258) of Part 5 of Division 26 of the Health and Safety Code).
- (C) Widespread transportation electrification requires increased access for disadvantaged communities, low- and moderate-income communities, and other consumers of zero-emission and near-zero-emission vehicles, and increased use of those vehicles in those communities and by other consumers to enhance air quality, lower greenhouse gases emissions, and promote overall benefits to those communities and other consumers.
- (D) Reducing emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050 will require widespread transportation electrification.
- (E) Widespread transportation electrification requires electrical corporations to increase access to the use of electricity as a transportation fuel.
- (F) Widespread transportation electrification should stimulate innovation and competition, enable consumer options in charging equipment and services, attract private capital investments, and create high-quality jobs for Californians, where technologically feasible.
- (G) Deploying electric vehicles should assist in grid management, integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions.
- (H) Deploying electric vehicle charging infrastructure should facilitate increased sales of electric vehicles by making charging easily accessible and should provide the opportunity to access electricity as a fuel that is cleaner and less costly than gasoline or other fossil fuels in public and private locations.
- (I) According to the State Alternative Fuels Plan analysis by the Energy Commission and the State Air Resources Board, light-, medium-, and heavy-duty vehicle electrification results in approximately 70 percent fewer greenhouse gases emitted, over 85 percent fewer ozone-forming air pollutants emitted, and 100 percent fewer petroleum used. These reductions will become larger as renewable generation increases.

(2) It is the policy of the state and the intent of the Legislature to encourage transportation electrification as a means to achieve ambient air quality standards and the state’s climate goals. Agencies designing and implementing regulations, guidelines, plans, and funding programs to reduce greenhouse gas emissions shall take the findings described in paragraph (1) into account.

(b) The commission, in consultation with the State Air Resources Board and the Energy Commission, shall direct electrical corporations to file applications for programs and investments to accelerate widespread transportation electrification to reduce dependence on petroleum, meet air quality standards, achieve the goals set forth in the Charge Ahead California Initiative (Chapter 8.5 (commencing with Section 44258) of Part 5 of Division 26 of the Health and Safety Code), and reduce emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050. Programs proposed by electrical corporations shall

seek to minimize overall costs and maximize overall benefits. The commission shall approve, or modify and approve, programs and investments in transportation electrification, including those that deploy charging infrastructure, via a reasonable cost recovery mechanism, if they are consistent with this section, do not unfairly compete with nonutility enterprises as required under Section 740.3, include performance accountability measures, and are in the interests of ratepayers as defined in Section 740.8.

Link: <http://www.energy.ca.gov/altfuels/2016-TRAN-01/>

Title: Lead Commissioner Workshop on Transportation Electrification in Publicly Owned Utility Integrated Resource Planning

Date: 10/5/16	Subject: POU IRP Guidelines	Docket: 16-TRAN-01
----------------------	------------------------------------	---------------------------

Description: Workshop to discuss the transportation electrification plans and resource needs of publicly owned utilities in the context of SB 350 integrated resource planning. Discussion also included presentations from relevant industry experts and other key experts.

Title: IEPR Commissioner Workshop on Integrated Resource Plans – Light-Duty Vehicle Sector

Date: 4/18/17	Subject: Light-Duty	Docket: 17-IEPR-07
----------------------	----------------------------	---------------------------

Description: Lead Commissioner workshop to review plans for publicly owned utilities to accelerate deployment and integration of light-duty electric vehicle charging infrastructure across their territories, and resources and guidance needed to do so.

Title: IEPR Commissioner Workshop on Integrated Resource Plans – Medium- and Heavy-Duty Vehicle Sector

Date: 4/27/17	Subject: Medium-Heavy Duty	Docket: 17-IEPR-07
----------------------	-----------------------------------	---------------------------

Description: Lead Commissioner workshop with publicly owned utilities and key industry experts to plan for accelerated deployment of medium and heavy-duty electric vehicles across their territories, including discussion of any resources and guidance needed to do so. This workshop builds off the discussion at the April 18, 2017, workshop on light-duty vehicle electrification.

Product(s):

- [Transportation Electrification Guidance for Publicly Owned Utility Integrated Resource Plans](#)– Posted April 14, 2017
- [Publicly Owned Utility Integrated Resource Plan Submission and Review Guidelines \(Transportation Section\)](#)– Adopted August 9, 2017

50 Percent Renewables Portfolio Standard

SB 350 Requirements:

Public Utilities Code Section 399.11

(a) In order to attain a target of generating 20 percent of total retail sales of electricity in California from eligible renewable energy resources by December 31, 2013, 33 percent by December 31, 2020, and 50 percent by December 31, 2030, it is the intent of the Legislature that the commission and the Energy Commission implement the California Renewables Portfolio Standard Program described in this article.

Public Utilities Code Section 399.13

(b) A retail seller may enter into a combination of long- and short-term contracts for electricity and associated renewable energy credits. Beginning January 1, 2021, at least 65 percent of the procurement a retail seller counts toward the renewables portfolio standard requirement of each compliance period shall be from its contracts of 10 years or more in duration or in its ownership or ownership agreements for eligible renewable energy resources.

Public Utilities Code Section 399.15

(c) The commission shall establish a limitation for each electrical corporation on the procurement expenditures for all eligible renewable energy resources used to comply with the renewables portfolio standard. This limitation shall be set at a level that prevents disproportionate rate impacts.

Public Utilities Code Section 399.30

(c) (2) The quantities of eligible renewable energy resources to be procured for all other compliance periods reflect reasonable progress in each of the intervening years sufficient to ensure that the procurement of electricity products from eligible renewable energy resources achieves 25 percent of retail sales by December 31, 2016, 33 percent by December 31, 2020, 40 percent by December 31, 2024, 45 percent by December 31, 2027, and 50 percent by December 31, 2030. The Energy Commission shall establish appropriate multiyear compliance periods for all subsequent years that require the local publicly owned electric utility to procure not less than 50 percent of retail sales of electricity products from eligible renewable energy resources.

(c) (4) Beginning January 1, 2014, in calculating the procurement requirements under this article, a local publicly owned electric utility may exclude from its total retail sales the kilowatthours generated by an eligible renewable energy resource that is credited to a participating customer pursuant to a voluntary green pricing or shared renewable generation program. Any exclusion shall be limited to electricity products that do not meet the portfolio content criteria set forth in paragraph (2) or (3) of subdivision (b) of Section 399.16. Any renewable energy credits associated with electricity credited to a participating customer shall not be used for compliance with procurement requirements under this article, shall be retired on behalf of the participating customer, and shall not be further sold, transferred, or otherwise monetized for any purpose. To the extent possible for generation that is excluded from retail sales under this subdivision, a local publicly owned electric utility shall seek to procure those eligible renewable energy resources that are located in reasonable proximity to program participants.

(l) (1) (A) For purposes of this subdivision, "large hydroelectric generation" means electricity generated from a hydroelectric facility that is not an eligible renewable energy resource and provides electricity to a local publicly owned electric utility from facilities owned by the federal government as a part of the federal Central Valley Project or a joint powers agency formed and created pursuant to Chapter 5 (commencing with Section 6500) of Division 7 of Title 1 of the Government Code.

(B) Large hydroelectric generation does not include any resource that meets the definition of

hydroelectric generation set forth in subdivision (k).

(2) If, during a year within a compliance period set forth in subdivision (b), a local publicly owned electric utility receives greater than 50 percent of its retail sales from large hydroelectric generation, it is not required to procure eligible renewable energy resources that exceed the lesser of the following for that year:

(A) The portion of the local publicly owned electric utility retail sales unsatisfied by the local publicly owned electric utility's large hydroelectric generation.

(B) The soft target adopted by the Energy Commission for the intervening year of the relevant compliance period.

(3) Except for an existing agreement effective as of January 1, 2015, or extension or renewal of that agreement, any new procurement commitment shall not be eligible to count towards the determination that the local publicly owned electric utility receives more than 50 percent of its retail sales from large hydroelectric generation in any year.

(4) The Energy Commission shall adjust the total quantities of eligible renewable energy resources to be procured by a local publicly owned electric utility for a compliance period to reflect any reductions required pursuant to paragraph (2).

(5) This subdivision does not modify the compliance obligation of a local publicly owned electric utility to satisfy the requirements of subdivision (c) of Section 399.16.

(m) (1) (A) For purposes of this subdivision, "unavoidable long-term contracts and ownership agreements" means commitments for electricity from a coal-fired power plant, located outside the state, originally entered into by a local publicly owned electric utility before June 1, 2010, that is not subsequently modified to result in an extension of the duration of the agreement or result in an increase in total quantities of energy delivered during any compliance period set forth in subdivision (b).

(B) The governing board of a local publicly owned electric utility shall demonstrate in its renewable energy resources procurement plan required pursuant to subdivision (f) that any cancellation or divestment of the commitment would result in significant economic harm to its retail customers that cannot be substantially mitigated through resale, transfer to another entity, early closure of the facility, or other feasible measures.

(2) For the compliance period set forth in paragraph (4) of subdivision (b), a local publicly owned electric utility meeting the requirement of subparagraph (B) of paragraph (1) may adjust its renewable energy procurement targets to ensure that the procurement of additional electricity from eligible renewable energy resources, in combination with the procurement of electricity from unavoidable long-term contracts and ownership agreements, does not exceed the total retail sales of the local publicly owned electric utility during that compliance period. The local publicly owned electric utility may limit its procurement of eligible renewable energy resources for that compliance period to no less than an average of 33 percent of its retail sales.

(3) The Energy Commission shall approve any reductions in procurement targets proposed by a local publicly owned electric utility if it determines that the requirements of this subdivision are satisfied.

Link: <http://www.energy.ca.gov/portfolio/>

Title: Business Meeting to Consider Proposed Change to Renewables Portfolio Standard Guidelines

Date: 3/9/16

Subject: RPS Eligibility

Docket: 16-RPS-01

Description: Business meeting to consider proposed modifications for select elements of the Renewables Portfolio Standard Eligibility Guidebook, including a process for publicly owned utilities to retire renewable energy credits and an updated appeal process.

Title: Scoping Workshop for the Renewables Portfolio Standard Eligibility Guidebook

Date: 3/17/16

Subject: RPS Eligibility

Docket: 16-RPS-01

Description: Workshop to discuss with stakeholders and the public proposed revisions to the Renewables Portfolio Standard Eligibility Guidebook to support implementation of SB 350.		
Title: Request for Comments on Draft Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition		
Date: 7/11/16	Subject: RPS Eligibility	Docket: 16-RPS-01
Description: Request for public comments on draft changes to the Renewables Portfolio Guidebook to implement the 50 percent requirement of SB 350 and other changes.		
Title: Staff Workshop on Renewables Portfolio Standard Online System		
Date: 8/18/16	Subject: RPS Eligibility	Docket: 16-RPS-01
Description: Staff workshop to provide stakeholders an opportunity to view the new RPS Online System, participate in a demonstration, and provide feedback to staff.		
Title: Staff Workshop on Implementing SB 350: Amendments to the RPS Regulations for Publicly Owned Utilities		
Date: 8/18/16	Subject: POU RPS Enforcement	Docket: 16-RPS-03
Description: Staff workshop to discuss needed changes for the Renewables Portfolio Standard enforcement regulations for publicly owned utilities to support implementation of SB 350.		
Title: Staff Workshop on Renewables Portfolio Standard Online System		
Date: 10/6/16	Subject: POU RPS Enforcement	Docket: 16-RPS-01
Description: Staff workshop to provide stakeholders an opportunity to view the new RPS Online System, participate in a demonstration, and provide feedback to staff.		
Title: Request for Public Comment on the Draft Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition		
Date: 12/7/16	Subject: RPS Eligibility	Docket: 16-RPS-01
Description: Request for public comments on the revised draft final Renewables Portfolio Standard Eligibility Guidebook implementing the requirements of SB 350. These revisions incorporated feedback received as a result of the scoping workshop on March 17, 2016.		
Title: Business Meeting Adoption of the Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition		
Date: 1/25/17	Subject: RPS Eligibility	Docket: 6-RPS-01
Description: Business meeting adoption of the revised Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition, which implements new RPS requirements from SB 350.		
Title: Renewables Portfolio Standard Online System Staff Training Webinar		
Date: 3/22/17	Subject: RPS Eligibility	Docket: 16-RPS-01
Description: Staff webinar to provide interested parties with guidance and technical support for using the RPS Online System, including account administration and user access, submitting certification applications, and an overview of verification reporting.		
Title: Business Meeting to Consider Adoption of Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition (Revised)		

Date: 4/27/17	Subject: RPS Eligibility	Docket: 16-RPS-01
Description: Business meeting adoption of the revised Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition, which implements new RPS requirements from SB 350. This revision incorporates non-substantive changes to the version adopted at the January 25, 2017 business meeting.		
Title: Renewables Portfolio Standard Online System Annual Verification Reporting Staff Training Webinar		
Date: 5/3/17	Subject: RPS Eligibility	Docket: 16-RPS-01
Description: Staff training webinar to provide guidance and technical support to load-serving entities on using the RPS Online System for RPS annual verification reporting.		
Title: Business Meeting to Consider Adoption of the Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition (Revised) Changes for Aggregated Facility Certification		
Date: 7/12/17	Subject: RPS Eligibility	Docket: 16-RPS-01
Description: Business meeting adoption of revisions to the Renewables Portfolio Standard Eligibility Guidebook, Ninth Edition, to add clarification for facilities comprising aggregated units.		
Product(s):		
<ul style="list-style-type: none"> • <u>9th Edition Renewables Portfolio Standard Eligibility Guidebook Draft</u>– Posted July 11, 2016 • <u>RPS Pre-Rulemaking Amendments to the Enforcement Procedures for Local POU's</u>– Posted August 4, 2016 • <u>Renewables Portfolio Standard Eligibility Draft Guidebook, Ninth Edition</u>– Posted December 7, 2016 • <u>Renewables Portfolio Standard Guidebook, Ninth Edition</u>– Adopted January 25, 2017 • <u>RPS Eligibility Guidebook, Ninth Edition (Revised)</u>– Adopted April 27, 2017 		

Doubling End Use Energy Efficiency Savings

SB 350 Requirements:

Public Utilities Code 25302.2.

As part of the 2019 edition of the integrated energy policy report, the commission shall evaluate the actual energy efficiency savings, as defined in Section 25310, from negative therm interactive effects generated as a result of electricity efficiency improvements.

Public Resources Code Section 25310 -

- (c) (1) On or before November 1, 2017, the commission, in collaboration with the Public Utilities Commission and local publicly owned electric utilities, in a public process that allows input from other stakeholders, shall establish annual targets for statewide energy efficiency savings and demand reduction that will achieve a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030. The commission shall base the targets on a doubling of the mid case estimate of additional achievable energy efficiency savings, as contained in the California Energy Demand Updated Forecast, 2015-2025, adopted by the commission, extended to 2030 using an average annual growth rate, and the targets adopted by local publicly owned electric utilities pursuant to Section 9505 of the Public Utilities Code, extended to 2030 using an average annual growth rate, to the extent doing so is cost effective, feasible, and will not adversely impact public health and safety.
- (2) The commission may establish targets for the purposes of paragraph (1) that aggregate energy efficiency savings from both electricity and natural gas final end uses. Before establishing aggregate targets, the commission shall, in a public process that allows input from other stakeholders, adopt a methodology for aggregating electricity and natural gas final end-use energy efficiency savings in a consistent manner based on source of energy reduction and other relevant factors.
- (3) In establishing the targets pursuant to paragraph (1), the commission shall assess the hourly and seasonal impact on statewide and local electricity demand.
- (4) In assessing the feasibility and cost-effectiveness of energy efficiency savings for the purposes of paragraph (1), the commission and the Public Utilities Commission shall consider the results of energy efficiency potential studies that are not restricted by previous levels of utility energy efficiency savings.
- (5) The energy efficiency savings and demand reduction reported for the purposes of achieving the targets established pursuant to paragraph (1) shall be measured taking into consideration the overall reduction in normalized metered electricity and natural gas consumption where these measurement techniques are feasible and cost effective.
- (d) The targets established in subdivision (c) may be achieved through energy efficiency savings and demand reduction resulting from a variety of programs that include, but are not limited to, the following:
- (1) Appliance and building energy efficiency standards developed and adopted pursuant to Section 25402.
 - (2) A comprehensive program to achieve greater energy efficiency savings in California's existing residential and nonresidential building stock pursuant to Section 25943.
 - (3) Programs funded and authorized pursuant to the California Clean Energy Job Creation Act (Division 16.3 (commencing with Section 26200)).
 - (4) Programs funded by the Greenhouse Gas Reduction Fund established pursuant to Section 16428.8 of the Government Code.
 - (5) Programs funded and authorized pursuant to this division.
 - (6) Programs of electrical or gas corporations, or community choice aggregators, that provide financial incentives, rebates, technical assistance, and support to their customers to increase energy efficiency, authorized by the Public Utilities Commission.
 - (7) Programs of local publicly owned electric utilities that provide financial incentives, rebates, technical assistance, and support to their customers to increase energy efficiency pursuant to

Section 385 of the Public Utilities Code.

(8) Programs of electrical or gas corporations, local publicly owned electric utilities, or community choice aggregators that achieve energy efficiency savings through operational, behavioral, and retrocommissioning activities.

(9) Programs that save energy in final end uses by reducing distribution feeder service voltage, known as conservation voltage reduction.

(10) Programs that save energy in final end uses by using cleaner fuels to reduce greenhouse gas emissions as measured on a lifecycle basis from the provision of energy services.

(11) Property Assessed Clean Energy (PACE) programs.

(e) Beginning with the 2019 edition of the integrated energy policy report and every two years thereafter, the commission shall provide recommendations and an update on progress toward achieving a doubling of energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030, pursuant to paragraph (1) of subdivision (c). The commission shall also include with the recommendations and update both of the following:

(1) An assessment of the effect of energy efficiency savings on electricity demand statewide, in local service territories, and on an hourly and seasonal basis.

(2) Specific strategies for, and an update on, progress toward maximizing the contribution of energy efficiency savings in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

Public Resources Code Section 25943

(a) (2) On or before January 1, 2017, and at least once every three years thereafter, the commission shall adopt an update to the [existing building energy efficiency] program in furtherance of achieving a cumulative doubling of statewide energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030.

Public Utilities Code Section 454.55

(a) The commission, in consultation with the Energy Commission, shall identify all potentially achievable cost-effective electricity efficiency savings and establish efficiency targets for an electrical corporation to achieve, pursuant to Section 454.5, consistent with the targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code.

Public Utilities Code Section 454.56

(a) The commission, in consultation with the Energy Commission, shall identify all potentially achievable cost-effective natural gas efficiency savings and establish efficiency targets for the gas corporation to achieve, consistent with the targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code.

(d) By July 1, 2019, and every four years thereafter, the commission shall, pursuant to Section 9795 of the Government Code, report to the Legislature on the progress toward achieving the targets established pursuant to subdivision (a). The commission shall include specific strategies for, and an update on, progress toward maximizing the contribution of energy efficiency savings in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

Public Utilities Code Section 9505

(a) By March 15, 2013, and by March 15 of each year thereafter, each local publicly owned electric utility shall report to the Energy Commission and to its customers all of the following:

(1) Its investments in energy efficiency and demand reduction programs.

(2) A description of each energy efficiency and demand reduction program, program expenditures, the cost-effectiveness of each program, and expected and actual energy efficiency savings and demand reduction results that reflect the intent of the Legislature to encourage energy savings and reductions in emissions of greenhouse gases resulting from providing service to existing residential and nonresidential buildings, while taking into consideration the effect of the program on rates, reliability, and financial resources.

(3) The sources for funding of its energy efficiency and demand reduction programs.

(4) The methodologies and input assumptions used to determine the cost-effectiveness of its energy efficiency and demand reduction programs.

(5) A comparison of the local publicly owned electric utility's annual targets established pursuant to subdivision (b) and the local publicly owned electric utility's reported electricity efficiency savings and demand reductions.

(b) By March 15, 2013, and by March 15 of every fourth year thereafter, each local publicly owned electric utility shall identify all potentially achievable cost-effective electricity efficiency savings and shall establish annual targets for energy efficiency savings and demand reduction for the next 10-year period, consistent with the annual targets established by the Energy Commission pursuant to subdivision (c) of Section 25310 of the Public Resources Code. A local publicly owned electric utility's determination of potentially achievable cost-effective electricity efficiency savings shall be made without regard to previous minimum investments undertaken pursuant to Section 385. A local publicly owned electric utility shall treat investments made to achieve energy efficiency savings and demand reduction targets as procurement investments.

(c) Within 60 days of establishing annual targets pursuant to subdivision (b), each local publicly owned electric utility shall report those targets to the Energy Commission, and the basis for establishing those targets.

(d) Each local publicly owned electric utility shall make available to its customers and to the Energy Commission the results of any independent evaluation that measures and verifies the energy efficiency savings and the reduction in energy demand achieved by its energy efficiency and demand reduction programs.

Public Utilities Code Section 9620

(d) A local publicly owned electric utility serving end-use customers shall, upon request, provide the Energy Commission with any information the Energy Commission determines is necessary to evaluate the progress made by the local publicly owned electric utility in meeting the requirements of this section, consistent with the annual targets established pursuant to subdivision (c) of Section 25310 of the Public Resources Code.

(e) The Energy Commission shall report to the Legislature, to be included in each integrated energy policy report prepared pursuant to Section 25302 of the Public Resources Code, regarding the progress made by each local publicly owned electric utility serving end-use customers in meeting the requirements of this section.

Links: http://www.energy.ca.gov/sb350/doubling_efficiency_savings/
<http://www.energy.ca.gov/ab758/documents/>

Title: Joint Agency Workshop on Energy Demand Forecast and Doubling of Energy Efficiency - Data and Analytical Needs

Date: 7/11/16	Subject: EE Doubling	Docket: 16-IEPR-05
----------------------	-----------------------------	---------------------------

Description: Preliminary joint agency workshop with the CPUC to discuss coordinated data and analysis needs to support improvements to the statewide energy demand forecast and establishing the 2030 energy efficiency savings doubling goals required by SB 350.

Title: Staff Workshop on 2016 Existing Building Energy Efficiency Action Plan Update

Date: 10/17/16	Subject: Existing Building Action Plan	Docket: 16-EBP-01
-----------------------	---	--------------------------

Description: Preliminary workshop to describe additional strategies and changes proposed for the 2016 Existing Building Energy Efficiency Action Plan Update, required to be completed by SB 350.

Title: Staff Workshop on 2016 Existing Building Energy Efficiency Action Plan Update

Date: 12/14/16	Subject: Existing Building Action Plan	Docket: 16-EBP-01
-----------------------	---	--------------------------

Description: Business meeting adoption of the <i>2016 Existing Building Energy Efficiency Action Plan Update</i> , required to be completed by SB 350.		
Title: Joint Agency Workshop on 2030 Energy Efficiency Targets		
Date: 1/23/17	Subject: EE Doubling	Docket: 17-IEPR-06
Description: Joint agency workshop with the CPUC to discuss the proposed framework for establishing the 2030 energy efficiency savings doubling goal and associated subtargets. This workshop built upon the discussion at the July 11, 2016, joint agency workshop.		
Title: Staff Workshop on Methodologies for 2030 Energy Efficiency Target Setting		
Date: 6/19/17	Subject: EE Doubling	Docket: 17-IEPR-06
Description: Staff workshop to discuss the method to be used for establishing the 2030 energy efficiency savings doubling goals required by SB 350.		
Title: Request for Comments on 2 Draft Staff Papers on SB 350 Energy Efficiency Savings Doubling Targets		
Date: 7/21/17	Subject: EE Doubling	Docket: 17-IEPR-06
Description: Request for comments on two staff draft papers documenting plans for establishing targets for utility-funded and nonutility programs to support the 2030 energy efficiency savings doubling goal called for in SB 350.		
Title: Joint Agency Workshop on Senate Bill 350 2030 Energy Efficiency Savings Doubling Targets		
Date: 9/7/17	Subject: EE Doubling	Docket: 17-IEPR-06
Description: Joint agency workshop with the CPUC and key stakeholders to discuss the Energy Commission's draft report on establishing the SB 350 2030 energy efficiency savings doubling targets. This workshop and associated commission draft report built upon the previous workshop discussions and the two draft staff papers published in July 2017 for comment.		
Title: Business Meeting to Consider Adoption of 2030 Energy Efficiency Savings Doubling Targets		
Date: 11/9/17	Subject: EE Doubling Targets	Docket: 17-IEPR-06
Description: Business meeting to consider adoption of final commission report establishing the 2030 energy efficiency savings doubling targets called for in SB 350.		
Product(s):		
<ul style="list-style-type: none"> • <u>2016 Existing Buildings Energy Efficiency Action Plan Update Draft</u> – Posted October 12, 2016 • <u>2016 Existing Buildings Energy Efficiency Action Plan Update Final</u> – Adopted December 14, 2016 • <u>Framework for Establishing the Senate Bill 350 Energy Efficiency Savings Doubling Targets Staff Paper</u> – Published January 18, 2017 • <u>Senate Bill 250 Energy Efficiency Targets for Programs Not Funded through Utility Rates Draft Staff Paper</u> – Published July 21, 2017 • <u>Senate Bill 350 Energy Efficiency Target Setting for Utility Programs Draft Staff Paper</u> – Published July 21, 2017 • <u>Attachment A SB 350 Energy savings Potential Development Plan</u> – Posted September 14, 2017 • <u>Senate Bill 350 Doubling Energy Efficiency Savings by 2030 Commission Draft Report</u> – Published August 28, 2017 		

- Senate Bill 350 Doubling Energy Efficiency Savings by 2030 Commission Final Report – Adopted on November 8, 2017

Low-Income Barriers Study

SB 350 Requirements:

Public Resources Code Section 25327 -

(b) On or before January 1, 2017, the commission, with input from relevant state agencies and the public, shall conduct and complete a study on both of the following:

(1) Barriers to, and opportunities for, solar photovoltaic energy generation as well as barriers to, and opportunities for, access to other renewable energy by low-income customers.

(2) Barriers to contracting opportunities for local small businesses in disadvantaged communities.

(c) On or before January 1, 2017, the commission, with input from relevant state agencies and the public, shall develop and publish a study on barriers for low-income customers to energy efficiency and weatherization investments, including those in disadvantaged communities, as well as recommendations on how to increase access to energy efficiency and weatherization investments to low-income customers.

(d) On or before January 1, 2017, the State Air Resources Board, in consultation with the commission and with input from relevant state agencies and the public, shall develop and publish a study on barriers for low-income customers to zero-emission and near-zero-emission transportation options, including those in disadvantaged communities, as well as recommendations on how to increase access to zero-emission and near-zero-emission transportation options to low-income customers, including those in disadvantaged communities.

Link: http://www.energy.ca.gov/sb350/barriers_report/

Title: Public Workshop on Senate Bill 350 Barriers Study

Date: 6/3/16

Subject: Barriers Study

Docket: 16-OIR-02

Description: Initial workshop to solicit public input on the proposed scope and schedule of the SB 350-required Low-Income Barriers Study. Including a stakeholder panel discussion on strategies to engage with other state agencies and key representatives to coordinate development of the Barriers Study.

Title: Workshop Regarding Barriers of Low-Income and Disadvantaged Communities to Energy Efficiency and Renewable Energy

Date: 8/12/16

Subject: Barriers Study

Docket: 16-OIR-02

Description: Technical workshop to discuss input on the barriers faced by low-income customers in accessing energy efficiency, weatherization, photovoltaics, and other renewable energy technologies, as well as the contracting barriers faced by small businesses located in disadvantaged communities. To inform the development of the draft Barriers Study.

Title: Energy Commission Workshop Regarding Barriers of Low-Income and Disadvantaged Communities to energy Efficiency and Renewable Energy

Date: 9/13/16

Subject: Barriers Study

Docket: 16-OIR-02

Description: Workshop to discuss staff draft report on the barriers and solutions to energy efficiency, renewables, and contracting opportunities among low-income customers and disadvantaged communities.

Title: Request for Comments on the Energy Commission's SB 350 Low-Income Barriers Study Draft Recommendations

Date: 10/21/16

Subject: Recommendations

Docket: 16-OIR-02

Description: Request for public comments and feedback on the proposed draft recommendations to address barriers identified in the staff draft Low-Income Barriers Study. Building off the staff draft report and discussion held at the September 13, 2016, workshop.		
Title: Business Meeting to Consider Adoption of the Energy Commission's SB 350 Low-Income Barriers Study		
Date: 12/14/16	Subject: Barriers Study	Docket: 16-OIR-02
Description: Energy Commission adoption of the Low-Income Barriers Study, Part A at the business meeting, including a staff presentation of the barriers and potential solutions identified and an overview of the 12 recommendations included in the study.		
Title: Joint Agency Workshop on Senate Bill 350 Low-Income Barriers Study Implementation		
Date: 5/16/17	Subject: Barriers Implementation	Docket: 17-IEPR-08
Description: Joint agency workshop with the CPUC and including CARB participation to discuss initial plans for implementation of the recommendations identified in the Barriers Study. Discussion topics included multifamily buildings, regional one-stop shop pilots, labor and workforce development, financing pilots, and the development of energy equity indicators to track progress over time.		
Title: Joint Agency Workshop on Senate Bill 350 Low-Income Barriers Study Implementation		
Date: 8/1/17	Subject: Barriers Implementation	Docket: 17-IEPR-08
Description: Second joint agency workshop with the CPUC and CARB participation to discuss the development of plans for implementation of the recommendations identified in the Barriers Study. Discussion topics focused on existing utility efforts, small business contracting opportunities, consumer protection, and low-income plug load efficiency opportunities.		
Product(s):		
<ul style="list-style-type: none"> • SB 350 Barriers Study Draft Report – Published September 9, 2016 • SB 350 Low-Income Barriers Study Draft Recommendations – Published October 21, 2016 • Senate Bill 350 Low-Income Barriers Study, Part A: Overcoming Barriers to Energy Efficiency and Renewables for Low-Income Customers and Small Business Contracting Opportunities in Disadvantaged Communities – Adopted December 14, 2016 • California Clean Energy Equity Framework and Indicators Draft Staff Report– Published May 15, 2017 		

Energy Data Collection Regulations

SB 350 Requirements:

Public Resources Code Section 25310

(e) Beginning with the 2019 edition of the integrated energy policy report and every two years thereafter, the commission shall provide recommendations and an update on progress toward achieving a doubling of energy efficiency savings in electricity and natural gas final end uses of retail customers by January 1, 2030, pursuant to paragraph (1) of subdivision (c). The commission shall also include with the recommendations and update both of the following:

(1) An assessment of the effect of energy efficiency savings on electricity demand statewide, in local service territories, and on an hourly and seasonal basis.

(2) Specific strategies for, and an update on, progress toward maximizing the contribution of energy efficiency savings in disadvantaged communities identified pursuant to Section 39711 of the Health and Safety Code.

Link: <http://www.energy.ca.gov/sb350/energydata/>

Title: Staff Workshop on Title 20 Data Collection Regulations to Support New Analytical Needs

Date: 9/26/16

Subject: Data Collection

Docket: 16-OIR-03

Description: Staff workshop to discuss proposed data collection regulation updates to support SB 350 implementation with representatives of California utilities and other key stakeholders.

Title: Commissioner Workshop on Title 20 Data Collection Regulations to Support New Analytical Needs

Date: 11/16/16

Subject: Data Collection

Docket: 16-OIR-03

Description: Commissioner pre-rulemaking workshop to review preliminary proposed Title 20 data collection regulatory language changes in line with implementation of SB 350.

Title: Vehicle-Grid Integration Communications Standards Workshop

Date: 12/7/16

Subject: Data Collection

Docket: 16-OIR-03

Description: Workshop to discuss the development of vehicle-grid integration standards for California utilities, with some focus on potential data collection needs to support the development of public electric vehicle charging infrastructure and while supporting electricity grid operations.

Title: Publication of Initial Title 20 Data Collection Rulemaking Package

Date: 4/27/17

Subject: Rulemaking

Docket: 16-OIR-03

Description: Publication of initial title 20 data collection regulations rulemaking documents to begin the official rulemaking process and implement changes required by SB 350.

Title: Postponement of Rulemaking Adoption to Evaluate Stakeholder Comments to Proposed Express Terms

Date: 10/4/17

Subject: Rulemaking

Docket: 16-OIR-03

Description: Staff evaluation of stakeholder comments on the initial Title 20 Data Collection, the development of appropriate express term revisions, and the identification of new adoption date to meet SB 350 requirements. The October 11, 2017 adoption date has been postponed to allow for consideration and evaluation of comments.

Product(s):

- Proposed Language for Discussion at the November 16, 2016 Commissioner Workshop– Posted November 14, 2016
- Data Collection Rulemaking Notice of Proposed Action– Posted August 4, 2017
- Data Collection Rulemaking Express Terms– Posted August 4, 2017
- Data Collection Initial Statement of Reasons (ISOR) – Posted August 4, 2017
- Data Collection Standard Form 399– Posted August 4, 2017
- Data Collection Standard Form 400– Posted August 4, 2017
- Notice of Postponement – Posted September 29, 2017

Regional Grid Operator and Governance

SB 350 Requirements:

Public Utilities Code Article 5.5 Section 359.5-

(a) It is the intent of the Legislature to provide for the transformation of the Independent System Operator into a regional organization to promote the development of regional electricity transmission markets in the western states and to improve the access of consumers served by the Independent System Operator to those markets, and that the transformation should only occur where it is in the best interests of California and its ratepayers.

(b) The transformation of the Independent System Operator into a regional organization shall not alter its obligations to the state or to electricity consumers within the state or its obligations to comply with state laws. The Independent System Operator shall retain its obligations set forth in Section 345.5, shall maintain the standards for open meetings and public access to corporate records as set forth in Section 345.5, and shall facilitate effective tracking and reporting mechanisms in support of state enforcement of Division 25.5 (commencing with Section 38500) of the Health and Safety Code.

(c) The voluntary transformation described in subdivision (a) shall occur through additional transmission owners joining the Independent System Operator with approval from their own state or local regulatory authorities, as applicable.

(d) Modifications to the Independent System Operator governance structure, through changes to its bylaws or other corporate governance documents, would be needed to allow this transformation.

(e) The Independent System Operator shall prepare the governance modifications needed as described in subdivision (d), but they shall not become effective until all of the following occur:

(1) The Independent System Operator conducts one or more studies of the impacts of a regional market enabled by the proposed governance modifications, including overall benefits to ratepayers, including the creation or retention of jobs and other benefits to the California economy, environmental impacts in California and elsewhere, impacts in disadvantaged communities, emissions of greenhouse gases and other air pollutants, and reliability and integration of renewable energy resources. The modeling, including all assumptions underlying the modeling, shall be made available for public review.

(2) The commission, Energy Commission, and State Air Resources Board jointly hold at least one public workshop where the Independent System Operator presents the proposed governance modifications and the results of the studies described in paragraph (1). The related Independent System Operator documents shall be made public before the workshop.

(3) The Independent System Operator submits to the Governor the studies described in paragraph (1) and revised bylaws or other corporate governance documents setting forth the proposed modifications to its governance structure.

(4) The Governor transmits to the Legislature the studies described in paragraph (1) and revised

bylaws or other corporate governance documents setting forth the proposed modifications to its governance structure, no later than December 31, 2017.

(5) The Legislature enacts a statute implementing the revised governance changes.

(f) The Independent System Operator shall expeditiously adopt the modifications to its governance structure enacted by the Legislature pursuant to paragraph (5) of subdivision (e) so that the modifications become effective before new transmission owners from outside California complete the process of joining the Independent System Operator.

(g) The revised governance structure shall not alter or abridge the contractual rights of a transmission owner to withdraw from participation in the Independent System Operator.

(h) One year after the seating of the new, revised governing board of the Independent System Operator pursuant to the modifications of its governance structure, and every two years thereafter, the Independent System Operator shall prepare a report to the states within the areas it serves documenting its furtherance of applicable state and federal laws and regulations affecting the electric industry.

(i) This article is repealed on January 1, 2019, if a statute implementing the governance modifications has not become effective on or before January 1, 2019.

Link: http://www.energy.ca.gov/sb350/regional_grid/

Title: Regional Grid Operator and Governance Workshop

Date: 5/6/16	Subject: Regional Grid	Docket: 16-RGO-01
---------------------	-------------------------------	--------------------------

Description: Commissioner-led workshop with participation from the Governor's Office, CPUC, and the California Independent System Operator (California ISO) to discuss the potential governance structure and framework for a regional grid operator as described in SB 350. The workshop included presentations on recent papers and a roundtable discussion on governance principles and concepts. Presenters and workshop attendees included representatives from other western states' system operators and public utilities commissions, utilities, as well as industry, environmental, and other key stakeholder groups.

Title: Regional Grid Operator and Governance Workshop - Sacramento

Date: 6/16/16	Subject: Regional Grid	Docket: 16-RGO-01
----------------------	-------------------------------	--------------------------

Description: Commissioner-led workshop with participation from the Governor's Office, CPUC, and the California ISO to present and discuss the California ISO's *Proposed Principles for Governance of a Regional ISO*. The workshop also included representatives from other western states' system operators and public utilities commissions, utilities, as well as industry, environmental, and other key stakeholder groups.

Title: Regional Grid Operator and Governance Workshop - Denver

Date: 6/20/16	Subject: Regional Grid	Docket: 16-RGO-01
----------------------	-------------------------------	--------------------------

Description: Commissioner-led workshop with participation from the Governor's Office, CPUC, and the California ISO to present and discuss the California ISO's *Proposed Principles for Governance of a Regional ISO*. The workshop also included representatives from other western states' system operators and public utilities commissions, utilities, as well as industry, environmental, and other key stakeholder groups.

Title: Joint State Agency Workshop on the Proposed Regionalization of the Independent System Operator

Date: 7/26/16	Subject: Regional Grid	Docket: 16-RGO-01
----------------------	-------------------------------	--------------------------

<p>Description: Joint agency workshop of the Energy Commission, CPUC, and CARB to present the California ISO's revised proposal: <i>Principles for Governance of a Regional ISO</i>, and the results of regional market expansion studies (<i>SB 350 Study Report: The Impacts of a Regional ISO-Operated Power Market in California</i>). The California ISO and its consultants provided presentations on the potential impacts to California ratepayers, air emissions, economy, disadvantaged communities, environment, and reliability and integration of renewables. Representatives from agencies, utilities, as well as industry, environmental, and other key stakeholder groups were also in attendance.</p>		
<p>Title: Regional Grid Operator and Governance Workshop</p>		
<p>Date: 10/17/16</p>	<p>Subject: Regional Grid</p>	<p>Docket: 16-RGO-01</p>
<p>Description: Lead Commissioner workshop with participation from the Governor's Office and the California ISO to discuss the second revised proposal from the California Independent System Operator: <i>Proposed Principles for Governance of a Regional ISO</i> and a discussion paper on <i>Potential Topics within the Primary Authority of the Western States Committee</i>. The workshop also included a regional ISO briefing from chief legislative consultants, an update on regional stakeholder initiatives, and an expert roundtable discussion on the two documents.</p>		
<p>Product(s):</p> <ul style="list-style-type: none"> • <u>California ISO Proposal: Proposed Principles for Governance of a Regional ISO</u>– Posted June 9, 2016 • <u>SB 350 Study Report: The Impacts of a Regional ISO-Operated Power Market in California</u>– Posted July 13, 2016 • <u>California ISO Revised Proposal: Principles of Governance of a Regional ISO</u>– Posted July 15, 2016 • <u>Potential Topics within the Primary Authority of the Western States Committee</u>–October 7, 2016 • <u>California ISO Second Revised Proposal: Principles of Governance of a Regional ISO</u>– Posted October 7, 2016 • <u>Summary of Stakeholder Comments to Revised Proposal Principles for Governance of a Regional ISO dated July 15, 2016</u>– Docketed October 17, 2016 • <u>Summary of Stakeholder Comments to Second Revised Proposal Principles for Governance of a Regional ISO dated October 7, 2016</u>– Docketed December 1, 2016 		

Miscellaneous SB 350 Goals

SB 350 Requirements:

Public Utilities Section 400.

The commission and the Energy Commission shall do all of the following in furtherance of meeting the state's clean energy and pollution reduction objectives:

- (a) Take into account the use of distributed generation to the extent that it provides economic and environmental benefits in disadvantaged communities as identified pursuant to Section 39711 of the Health and Safety Code.
- (b) Take into account the opportunities to decrease costs and increase benefits, including pollution reduction and grid integration, using renewable and nonrenewable technologies with zero or lowest feasible emissions of greenhouse gases, criteria pollutants, and toxic air contaminants onsite in proceedings associated with meeting the objectives.
- (c) Where feasible, authorize procurement of resources to provide grid reliability services that minimize reliance on system power and fossil fuel resources and, where feasible, cost effective, and consistent with other state policy objectives, increase the use of large- and small-scale energy storage with a variety of technologies, targeted energy efficiency, demand response, including, but not limited to, automated demand response, eligible renewable energy resources, or other renewable and nonrenewable technologies with zero or lowest feasible emissions of greenhouse gases, criteria pollutants, and toxic air contaminants onsite to protect system reliability.
- (d) Review technology incentive, research, development, deployment, and market facilitation programs overseen by the commission and the Energy Commission and make recommendations to advance state clean energy and pollution reduction objectives and provide benefits to disadvantaged communities as identified pursuant to Section 39711 of the Health and Safety Code.
- (e) To the extent feasible, give first priority to the manufacture and deployment of clean energy and pollution reduction technologies that create employment opportunities, including high wage, highly skilled employment opportunities, and increased investment in the state.
- (f) Establish a publicly available tracking system to provide up-to-date information on progress toward meeting the clean energy and pollution reduction goals of the Clean Energy and Pollution Reduction Act of 2015.
- (g) Establish an advisory group consisting of representatives from disadvantaged communities identified in Section 39711 of the Health and Safety Code. The advisory group shall review and provide advice on programs proposed to achieve clean energy and pollution reduction and determine whether those proposed programs will be effective and useful in disadvantaged communities.

Public Resources Code Section 25943

- (a) (3) The commission shall adopt, implement, and enforce a responsible contractor policy for use across all ratepayer-funded energy efficiency programs that involve installation or maintenance, or both installation and maintenance, by building contractors to ensure that retrofits meet high-quality performance standards and reduce energy savings lost or foregone due to poor-quality workmanship.
- (4) The commission, in consultation with the Public Utilities Commission, shall establish consumer protection guidelines for energy efficiency products and services.

Link(s):

Disadvantaged Communities Advisory Group - <http://www.energy.ca.gov/sb350/DCAG/>

Title: Business Meeting to Consider Adoption of Charter Establishing SB 350 Disadvantaged Communities Advisory Group

Date: 12/13/17	Subject: Advisory Group	Docket: 16-OIR-06
<p>Description: Energy Commission Business Meeting to consider adoption of the charter establishing the joint CPUC and Energy Commission Disadvantaged Communities Advisory Group required by SB 350.</p>		
<p>Product(s):</p> <ul style="list-style-type: none"> • <u>Joint Staff Draft Proposal SB 350 Disadvantaged Communities Advisory Group Structure and Framework</u>– Posted August 1, 2017 • <u>Request for Applications for Appointment to the Senate Bill 350 Disadvantaged Communities Advisory Group</u>– Posted November 1, 2017 • <u>Charter Establishing the Senate Bill 350 Disadvantaged Communities Advisory Group</u>– Adopted December 13, 2017 • <u>Energy Commission Tracking Progress Reports</u>– Updated Periodically 		

APPENDIX J:

Energy Storage and Demand Response Roadmap Accomplishments

These accomplishments were presented at the June 13, 2017, joint agency staff workshop on the Review of the Actions and Status of State-Level Energy Roadmaps.

Table 54: Energy Storage Roadmap (ESR)⁹²⁷

ESR: PLANNING		
Action	Forum	Status
Describe distribution grid operational needs and required resource characteristics	Distribution Resources Plan (DRP) (California Public Utilities Commission [CPUC])	Commenced in 2014
Complete investor-owned utilities (IOUs) implementation integration capacity analysis to guide distribution planning and siting of DERs on the grid in locations that do not require distribution upgrades to accommodate interconnection on the distribution system	CPUC DRP Developing Integration Capacity Analysis (ICA); new interconnection OIR	ICA will inform Rule 21 streamlining of interconnection process
Examine and clarify opportunities for storage to defer or displace distribution upgrades	DRP, IDER & 2016 Storage request for offer (RFO) (CPUC, IOUs)	DRP Track 2 Demonstration Projects & Track 3 Distribution Investment Deferral Framework
Describe California Independent System Operator (California ISO) grid operational needs and required resource characteristics	ESDER 1, 2 & 3 (California ISO)	Ongoing
Develop coordination process for transmission and distribution system planning	Joint Agency Steering Committee (JASC)	Ongoing
Clarify assessment of energy storage resources classified as transmission assets to defer or displace transmission upgrades	California ISO	Federal Energy Regulatory Commission (FERC) Order 792; Transmission planning process (TPP)

⁹²⁷ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN217998_20170608T151645_Advancing_And_Maximizing_The_Value_Of_Energy_Storage_Technology.pdf.

ESR: PROCUREMENT		
Action	Forum	Status
Evaluation of the existing energy storage framework to support CPUC decisions on storage procurement	R.15-03-011 (CPUC)	Consultant request for proposal (RFP) pending release
Clarify rules for energy storage qualification and counting in an evolving Resource Adequacy framework	R.14-10-010 (CPUC)	D.14-06-050
Consider “unbundling” flexible capacity RA counting	R.14-10-010 (CPUC)	D.16-06-045
Prepare summary of efforts underway focused on developing models for energy storage valuation and plans public distribution	Energy Commission	Storage VET

ESR: RATE TREATMENT		
Action	Forum	Status
Clarify wholesale rate treatment and ensure that the California ISO tariff and applicable business practices manuals and other documentation provide sufficient information	California ISO Storage Interconnection Stakeholder Initiative and ESDER 3; CPUC R.15-03-011	Station power: ESDER 2, CPUC Decision 17-04-039 & IOU Advice Letters approved in 2017
Clarify and potentially modify net energy metering tariffs applicable to cases where energy storage is paired with renewable generators	R.12-11-005 and R.14-07-002 (CPUC)	D.16-04-020
Develop rules for multiple use applications for energy storage resources, across grid domains	R.15-03-011, Phase 2 (CPUC) California ISO ESDER 3	Multiple Use Applications – CPUC D. 18-01-003, adopted January 11, 2018
Evaluate the need and potential to define distribution level grid services and products	R.14-10-003 (CPUC)	IDER Competitive Solicitation Framework Pilot – October 2017
Consider a new proceeding to develop distribution grid services provided by distributed energy resources to the utility or other entities	R.14-10-003 (CPUC)	IDER Competitive Solicitation Framework Pilot – October 2017
Clarify assessment of energy storage resources classified as transmission assets to defer or displace transmission upgrades	California ISO, R.14-08-013 (CPUC)	FERC Order 792; TPP process; Reflecting location-specific avoided transmission value in

ESR: RATE TREATMENT		
Action	Forum	Status
		Locational Net Benefits Analysis in Distribution Resource Plan Proceeding (R.14-08-013)

ESR: INTERCONNECTION		
Action	Forum	Status
Clarify existing transmission and distribution interconnection processes, including developing integrated process flow charts and check lists	R.11-09-011 (CPUC)	Rule 21 flow charts approved in March 2017
Evaluate opportunities to coordinate between Rule 21 and Wholesale Distribution Access tariff (WDAT) to streamline interconnection processes and ability to efficiently move between processes	No state agency or California ISO jurisdiction over WDAT. New interconnection OIR (r.17-07-007) will examine Rule 21 – WDAT transfer streamlining	
Evaluate the potential for a streamlined or "fast track" distribution interconnection process for storage resources that meet certain use-case criteria	R.11-09-011 (CPUC); R.17-07-007 (CPUC)	D.16-06-052 – Expedited process for non-exporting storage <500 kW live July 2017; R.17-07-007 will develop streamlined interconnection for systems proposed within hosting capacity limits calculated in the Distribution Resource Plan Proceeding (R.14-08-013)
Evaluate defining and establishing a fee structure to interconnect non-exporting resources	R.11-09-011 (CPUC)	Fee approved in March 2017; may be reexamined in July 2018
Define and support entities collecting telemetry data from multiple facilities, to allow bulk submission of this data	Expanded Metering & Advanced Telemetry (California ISO)	Virtual aggregated resources can provide a single telemetry point
Clarify assessment of energy storage resources classified as transmission assets to defer or displace transmission upgrades	California ISO; R.14-08-013 (CPUC)	FERC Order 792; TPP process; reflecting location-specific avoided transmission value in Locational Net Benefits Analysis in Distribution Resource Plan Proceeding (R.14-

ESR: INTERCONNECTION		
Action	Forum	Status
		08-013)
Review and potentially modify utility WDAT to incorporate applicable modifications consistent with the ISO interconnection tariff including adjustments that streamline requirements	State agencies do not have jurisdiction for WDAT	
Review California ISO's procedure for testing and certifying resources for ancillary services	California ISO	AS testing methodology includes storage
Evaluate expanding technology options for providing resource telemetry	Expanded Metering & Advanced Telemetry (California ISO)	Dispersive technology may be used
Initiate and administer a working group to evaluate common telemetry framework and recommend actions to standardize resource telemetry requirements	Energy Commission	
Evaluate and consider refinements to California ISO or IOU telemetry requirements	Proposals can be submitted for Electric Program Investment Charge (EPIC) funds or to California ISO; R.17-07-007 (CPUC) is considering changes to Rule 21 telemetry requirements to improve visibility while minimizing cost.	
Research and evaluate refinements to IOU telemetry requirements		
Initiate and administer a working group to research and recommend a certification process for integrated device metering that can be used in place of the California ISO or utility meter	Energy Commission	
Evaluate the rules for certifying sub metering and third-party meter data collection and consider a process to validate, estimate and edit meter data to expand options for sourcing revenue quality meter data	Energy Commission and CPUC	Not yet commenced
Establish the value and develop a framework under which the ISO and utility can share metering and meter data	California ISO, CPUC and Energy Commission	California ISO allows resource owners to share data
Initiate and administer a working group to review existing fire protection codes and materials handling guidelines for various energy storage technologies and applications and identify best practices	CPUC	2015 SED convened two working groups
Initiate and administer a working group to review and determine applicability, scope, and consistency of UL and other certification requirements for energy storage systems	Energy Commission	
Evaluate establishing rules for utility	Metering Rules Enhancement	allows SCs to submit

ESR: INTERCONNECTION		
Action	Forum	Status
subtractive metering for behind-the-meter wholesale resources to improve resource granularity, visibility, and clarity in retail billing	(California ISO) and CPUC	meter SQMD meter data to the California ISO derived from an approved metering plan

ESR: MARKET PARTICIPATION		
Action	Forum	Status
Clarify existing & identify gaps in California ISO requirements, rules and market products for energy storage to participate in the California ISO market	ESDER (California ISO)	Ongoing
Where appropriate, expand options to current California ISO requirements and rules for aggregations of distributed storage resources	ESDER (California ISO)	Ongoing
Define and develop models and rules for multiple-use applications of storage. Clarify rules for participation.	R.15-03-011 (CPUC) and ESDER (California ISO)	R.15-03-011 consideration.18-01-003; ESDER 3
Identify and develop models of hybrid storage configurations for wholesale market participation	Technical Bulletin (California ISO)	Issued October 19, 2016
For configurations of greatest interest or likelihood of near-term development, clarify the requirements and rules for participation	R.15-03-011 (CPUC) and ESDER (California ISO)	R.15-03-011–D.18-01-003 under consideration; ESDER 3

Source: California Energy Commission

Table 55: Goals and Key Activities outlined in the Demand Response and Energy Efficiency Roadmap (DR&EE)⁹²⁸

DR&EE Goal 1: Ensure consistent assumptions in California ISO, Energy Commission, and CPUC planning and procurement processes			
Key Activities	CPUC	California ISO	Energy Commission
Identify process interaction and dependencies	Coordination via the Joint Agency Steering Committee (JASC) and the Executive Oversight Committee (members from Energy Commission, California ISO, CPUC, and California Air Resources Board [CARB])		
Identify and implement adjustments to processes			

DR&EE Goal 2: Modify load shape to reduce resource procurement requirements, mitigate over-generation, and moderate ramp			
Key Activities	CPUC	California ISO	Energy Commission
Create targeted EE	All three electric utilities		

⁹²⁸ http://docketpublic.energy.ca.gov/PublicDocuments/17-IEPR-12/TN217999_20170608T151647_Demand_Response_And_Energy_Efficiency_Roadmap.pdf.

DR&EE Goal 2: Modify load shape to reduce resource procurement requirements, mitigate over-generation, and moderate ramp			
Key Activities	CPUC	California ISO	Energy Commission
programs and incentives to locations and time periods	have implemented targeted DSM efforts in response to a CPUC decision directing them to do so (D.14-10-046 Ordering Paragraphs 12 and 13). Results from these efforts are being used to inform locational targeting efforts in the DRP/IDER proceedings and in the EE Business Plans currently under consideration by the Commission		
Investigate and define retail rate options	Late-shift time-of-use (TOU) and demand charge reforms under review in GRC Phase 2s. IOUs complex optional residential TOU rates in 2018 RDWs. Pacific Gas and Electric (PG&E) and Southern California Edison (SCE) "matinee pricing" pilot proposals withdrawn in lieu of broader rate changes		GFO-15-311: awardees will compare DR capabilities under existing with experimental tariff structures
Develop approach to align retail rates with grid conditions	D.17-01-006 Adopted guidelines for TOU periods and rate design (TOU order instituting rulemaking [OIR])	Developed TOU periods & submitted into CPUC OIR	GFO-15-311 Group 3: developing a transactive signal that reflects grid conditions
Execute pilots and measure load shape impacts of above measures	Residential opt-in TOU pilots now underway. Default TOU pilots begin March 2018. By summer 2018, data will be available		Published a staff report on Translating Aggregate Energy Efficiency Savings Projections into Hourly System Impacts, CEC-200-2016-007; GFO-15-311: 7 pilot projects ~ \$29M split between supply and load-following DR

DR&EE Goal 2: Modify load shape to reduce resource procurement requirements, mitigate over-generation, and moderate ramp			
Key Activities	CPUC	California ISO	Energy Commission
Implement effective load reshaping measures	TOU changes underway. BTM storage (Self-Generation Incentive Program [SGIP], LCR and Storage RFOs) being deployed		
Evaluate Flex Alert program effectiveness and transfer administration and funding	Approved transfer of the program to California ISO	Completed – in 2016 helped reduce peak by max 540 MW	
Develop centralized electrical location mapping tool			Energy Maps of California at http://www.energy.ca.gov/maps/ .

DR&EE Goal 3: Clarify California ISO needs for DR and EE to be most effective in planning and operations			
Key Activities	CPUC	California ISO	Energy Commission
Capture DR resource types and operational attributes in base catalog to support California ISO transmission planning process		Published in 2013 and part of planning process	
Include DR and EE resources in selected ISO transmission planning studies		Via joint agency steering committee (JASC)	
Perform study of local areas impacted by San Onofre		Completed	
Develop flexible resource adequacy (RA) requirements for DR and ISO must offer obligation for flexible resources	Adopted flexible Requirements in 2013.	FRACMOO was Implemented in 2014	
Develop California ISO must offer		RSI (RAAIM) and CCE3	

DR&EE Goal 3: Clarify California ISO needs for DR and EE to be most effective in planning and operations			
Key Activities	CPUC	California ISO	Energy Commission
obligation for use-limited local and system RA and standard capacity product for DR			

DR&EE Goal 4: Ensure resources are procured and developing to meet capability, timing, and location needs			
Key Activities	CPUC	California ISO	Energy Commission
Develop more granular forecasts for EE	Removed from 2018+ P&G scope due to Assembly Bill 802 and Senate Bill 350 Implementation needs		Via JASC, Demand Analysis Working Group (DAWG) and Integrated Energy Policy Report (IEPR) proceedings; Title-20 data collection regulations will provide data to inform more granular forecasts
Develop criteria for classification of demand side programs	Adopted bifurcation policy for DR resources in 2014. Refined in 2015		GFO-15-311 pilots can provide useful input for this task
Include load-modifying DR programs in demand forecast	Implemented in 2014		Long-term hourly forecasting model over 10 year period, including additional achievable EE and DR programs will be included in the 2017 and future IEPR Energy Demand Forecasts
Revise RA counting for DR programs classified as supply resources	Under development		
Develop policy guidance for DR and EE programs targeted	IDER pilot authorized to test competitive solicitation and		Via Energy Action Plan and IEPR Proceedings

DR&EE Goal 4: Ensure resources are procured and developing to meet capability, timing, and location needs			
Key Activities	CPUC	California ISO	Energy Commission
to meet needs	shareholder incentive framework to defer / avoid traditional transmission and distribution investment with DER alternatives (including EE and DR)		
Develop approach to monitor progress of DR and EE program development and implementation	EE evaluation, monitoring, and verification and DR LI studies inform best available information and potential studies		Via IEPR Proceedings; Updates to Title-20 data collection regulations, data to be collected starting in 2018; Senate Bill 350 EE savings targets – In 2017–2018, establishing methods to track and report progress on the Senate Bill 350 savings targets
Develop multi-year forward RA requirements and procurement mechanism	Have been considered, but not adopted		
Develop market-based replacement for California ISO backstop capacity (CPM replacement)		Competitive Solicitation Process developed	
Develop DR auction pilot	Approved demand response auction mechanism pilots for deliveries in 2016-2019	Deferred to demand response auction mechanism	GFO-15-311 awardees participating in demand response auction mechanism
Evaluate and measure DR and EE program Effectiveness	DR and EE programs are regularly evaluated for savings and effectiveness		Via Energy Savings DAWG Subgroup, Demand Response DAWG Subgroup and Demand Response Measurement and Evaluation Committee (DRMEC), (the Energy Commission is a member), results to be incorporated into Senate Bill 350 EE tracking and reporting

DR&EE Goal 5: Increase DR program and pilot participation in California ISO market developing operations experience and providing feedback for policy refinement			
Key Activities	CPUC	California ISO	Energy Commission
Complete CPUC Rule 24	Approved in 2013		
Implement ISO RDRR		Implemented in 2014. SCE integrated in 2016; PG&E began in 2017	
Bid DR resources into California ISO markets	IOUs are required to bid DR by 2018. (SCE started in 2015). Demand response auction mechanism resources are bid	Implemented proxy demand response in 2010	
Expand California ISO metering and telemetry options		Completed in 2014	
Refine and automate wholesale DR registration process	Authorized funding for infrastructure to support IOU/3P DR registration (2015- present)	Completed in 2016	
Execute PG&E intermittent resource pilot in California ISO market	Approved PG&E's IRM2 pilot in 2012 and Excess Supply pilot in 2014	Conducted in 2015	
Modify and implement California ISO NGR – PDR model		Continues to be discussed	
Define and execute pilot programs and assess resource flexibility capabilities		Refined pilot process	GFO-15-311 pilots will provide data on customer capabilities

Source: California Energy Commission