Exhibit II

Comment Letters and Attachments on the

Second Revised Environmental Impact Report (RDEIR2)

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BY ELECTRONIC MAIL AND US MAIL

August 6, 2012

Mono County Economic Development Dept.
ATTN: Dan Lyster
PO Box 2415
Mammoth Lakes, CA 93546
Email: dlyster@mono.ca.gov

RE: Mammoth Pacific I (ñMP-Iò) Replacement Project (State Clearinghouse No: 2011022020)

Dear Mr. Lyster:

I am writing on behalf of Laborers International Union of North America, Local 783, and its members living in Mono County (ñLIUNAò or ñCommentersò) regarding the Second Revised Draft Environmental Impact for the Mammoth Pacific I (MP-1) Replacement Project (ñProjectò or ñMammoth Projectò).

The proposed Mammoth Pacific Replacement Project proposes to replace the existing geothermal power plant (ñMPï I ñ) with a new binary power plant (ñMï 1ò) capable of generating, on average, approximately 18.8 MW (net) of electricity. The existing MP-I plant is a commercial geothermal development project operated by Mammoth Pacific L.P. (ñMPLPò) and located near Casa Diablo Hot Springs in Mono County, California. The existing MPï I plant consists of a binary power plant with a design capacity of about 14 megawatts (ñMWò), a geothermal wellfield, production and injection fluid pipelines, and ancillary facilities that have been operating since 1984. The new M-1 plant would maintain the existing geothermal wellfield, pipeline system and ancillary facilities of the existing MP-I plant. The existing MP-I geothermal power plant is located in unincorporated Mono County approximately 1,200 feet northeast of the intersection of U.S. Highway 395 and State Route 203 on 90 acres of private land owned by Ormat Nevada, Inc. (ñOrmatò), the parent company of MPLP. The project site is located on APN 037-050-002, with a Land Use Designation of Resource Extraction (ñREò), and is surrounded by lands under federal ownership and managed by the U.S. Forest Service as part of the Inyo National Forest and lands owned by the Los Angeles

Department of Water and Power. The project site is located within the existing Casa Diablo geothermal complex.

11-01 LIUNA hereby requests and urges Mono County, as lead agency ("County"), to fully comply with the California Environmental Quality Act, Public Resources Code § 21000 et seq. ("CEQA"), in all aspects of the Project, including but not limited to, County preparation and consideration of any and all further CEQA documents prepared for the Project, County consultation with all other relevant and responsible agencies, County responses to any and all comments submitted on the Project, and County consideration of any and all applications for licenses, permits, variances, or any other notices or approvals sought for the Project.

LIUNA expressly reserves the right to submit additional comments on the Project in conjunction with the Final Environmental Impact Report ("Final EIR") for the Project or any other future actions taken with regard to the Project.

Please place this office on the notice list for any and all CEQA or other land use actions, notices, or hearings related to the Mammoth Project, as well as notices of any actions taken in conjunction with federal agencies pursuant to the National Environmental Policy Act ("NEPA"). Please also inform us of any meetings, hearings, comment periods, or other actions taken with regard to the Draft and Final EIRs for the Project.

Please send notices by electronic mail and U.S. Mail to:

Richard Drury
Christina Caro
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Please call should you have any questions. Thank you for your attention to this matter.

Sincerely,

Richard T. Drury
Christina M. Caro
Counsel for LIUNA Local 783 and Mono County members

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August 6, 2012

BY EMAIL AND OVERNIGHT MAIL

Mono County Economic Development Department
ATTN: Dan Lyster
P.O. Box 2415
Mammoth Lakes, CA 93546
dlyster@mono.ca.gov

Re: **Comments on the Second Revised Draft Environmental Impact Report for the Mammoth Pacific I Replacement Project, California Clearinghouse Number 2011022020**

Dear Mr. Lyster:

We are writing on behalf of California Unions for Reliable Energy ("CURE") to provide comments on the Second Revised Draft Environmental Impact Report ("RDEIR2") prepared by Mono County ("County"), pursuant to the California Environmental Quality Act ("CEQA"),[1] for the Mammoth Pacific I Replacement ("M-1") unit, a geothermal power plant facility with a net generating capacity of approximately 18.8 megawatts ("MW"), proposed by Ormat Nevada, Inc ("Applicant"). The Applicant seeks a Conditional Use Permit from the County to build, route, and reroute geothermal pipelines; construct a substation and transmission line; develop and operate, and eventually decommission, the M-1 unit; and to eventually demolish and decommission the existing Mammoth Pacific Unit I ("MP-I") power plant and ancillary facilities. The MP-I unit and the M-1 unit will operate simultaneously for approximately two years. The RDEIR2, and these comments, refer to the proposed M-1 unit, substation, transmission line, and ancillary pipeline facilities together with the eventual decommissioning of the MP-I unit as the "Project" for the purpose of CEQA.

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[1] Pub. Resources Code, §§ 21000 et seq.

The Project requires a conditional use permit from Mono County; variances from County land use regulations authorizing construction of an overhead transmission line and construction within 100 feet of the exterior property line; and an Authority to Construct and Permit to Operate from the Great Basin Unified Air Pollution Control District. The Project also requires the County to amend the Mono County General Plan to authorize the Applicant to develop geothermal facilities within 500 feet of a watercourse within the Hot Creek Buffer Area. The County for the first time addressed the required General Plan amendment in the RDEIR2. Our comments focus on this revision to the County's analysis.

12-01 We thoroughly reviewed the RDEIR2 and conclude that the County's analysis of the proposed General Plan Amendment fails to comply with the requirements of CEQA. In particular, the County failed to include the proposed General Plan Amendment in the Project description, evaluate alternatives to the proposed Plan Amendment, and identify the environmental impacts of the General Plan Amendment in the RDEIR2. In addition, the County has not complied with the applicable procedural requirements for amending a General Plan by failing to provide the public and other agencies with at least 45 days in which to review and comment on the proposed Plan Amendment. For these reasons, set forth fully in the following paragraphs, we urge the County to withdraw the RDEIR2 and recirculate a revised analysis consistent with these comments.

I. STATEMENT OF INTEREST

CURE has an interest in enforcing environmental laws that encourage sustainable development and ensure a safe working environment for its members. Environmentally detrimental projects can jeopardize future jobs by making it more difficult and more expensive for industry to expand in Mono County, and by making it less desirable for businesses to locate and people to live in the County, including the Project vicinity. Continued degradation can, and has, caused construction moratoriums and other restrictions on growth that, in turn, reduce future employment opportunities. CURE's members live, work, recreate and raise their families in Mono County, including in and around Mammoth Lakes. Accordingly, CURE's members would be directly affected by the Project's adverse environmental impacts. The members of CURE's member unions may also work on the Project itself. They will, therefore, be first in line to be exposed to any hazardous materials, air contaminants, and other health and safety hazards that exist onsite.

II. THE PROJECT DESCRIPTION IS INCOMPLETE AND INACCURATE

The RDEIR does not meet CEQA's requirements because it fails to include a complete and accurate Project description, rendering the entire analysis inadequate. Without a complete project description, the environmental analysis under CEQA is impermissibly narrow, thus minimizing the project's impacts and undercutting public review.[2] A complete project description, under CEQA, is one that includes a list of all project-related environmental review and consultation requirements mandated by federal, state, or local laws, regulations, or policies.[3] The project description must also be accurate and consistent throughout an EIR.[4]

12-02

The RDEIR2 does not comply with CEQA's requirements because it does not include the proposed General Plan Amendment in the description of the Project. For the first time in the RDEIR2, the County proposes to amend the General Plan to authorize development of geothermal facilities within 500 feet of a watercourse within the Hot Creek Buffer Zone.[5] However, the County did not include the proposed amendment in the Project description. Instead, the County buried the newly proposed General Plan Amendment in the Environmental Assessment section of the RDEIR2. Merely including this land use change in section 4.10 of the RDEIR2 violates CEQA's requirement to describe all aspects of the Project which may result in potentially significant environmental impacts.

III. THE RDEIR FAILS TO INCLUDE AN ADEQUATE PROJECT ALTERNATIVES ANALYSIS

12-03

An EIR "must produce information sufficient to permit a reasonable choice of alternatives so far as environmental impacts are concerned."[6] "An EIR for any project subject to CEQA review must consider a reasonable range of alternatives to the project, or to the location of the project which (1) offer substantial environmental advantages over the project proposal . . . ; and (2) may be feasibly accomplished in a successful manner considering the economic, environmental,

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[2] *See, e.g., Laurel Heights Improvement Association v. Regents of the University of California* (1988) 47 Cal.3d 376.
[3] Cal. Code Regs., tit. 14, § 15124 subd. (d)(1)(c) ("CEQA Guidelines").
[4] *See County of Inyo v. City of Los Angeles* (1977) 71 Cal.App.3d 185, 193.
[5] *See, e.g.*, RDEIR2, p. 19.
[6] *San Bernardino Valley Audubon Society v. County of San Bernardino* (1984) 155 Cal. App. 3d 738, 750-51.

12-03 Cont.

social, and technological factors involved."[7] This requirement for an EIR is intended to foster informed decisionmaking and public participation.[8] The burden is on the lead agency to select a range of project alternatives for examination, and the agency's reasoning for selecting what the agency deems to be a reasonable range of alternatives must be publicly disclosed.[9]

The RDEIR2 provides that the Project now includes amendments to the Mono County General Plan.[10] Specifically, the proposed Plan Amendment would allow geothermal development where it was previously prohibited in the County. The RDEIR2 fails to include an analysis of alternatives to the proposed action or to state why it was reasonable for the County to forego analyzing Project alternatives that do not require an amendment to the General Plan.[11] The County's failure to study alternatives to the proposed Plan Amendment in the RDEIR2 precludes informed decisionmaking and public participation and violates CEQA. Moreover, the County's failure to identify alternatives to its proposed action to remove restrictions on geothermal development within the Hot Creek Buffer Zone is manifestly unreasonable in light of the purpose served by the 500-foot setback requirement.

The Conservation/Open Space Element of the Mono County General Plan provides:

> The principal issues faced by Mono County regulatory authorities during the administrative proceedings accompanying the applications for existing geothermal permits involved the question of whether geothermal operations would affect the fumaroles and geothermally included pools, streams, and springs in the Casa Diablo area, including Hot Creek Fish Hatchery.[12]

Energy Resources Goal 1, Objective D, Policy 1 of the Conservation/Open Space Element ("Policy 1") states "[g]eothermal exploration and development projects shall be sited, carried out and maintained by the permit holder in a manner that best protects hydrologic resources . . . ."[13] To implement this policy, the General

[7] *Citizens of Goleta Valley v. Board of Supervisors* (1990) 52 Cal.3d 553, 566.
[8] *See* CEQA Guidelines, § 15126.6 subd. (a).
[9] *See ibid.*
[10] RDEIR2, at pp. 33-34.
[11] *See* RDEIR2, at p. 19.
[12] Mono County General Plan Conservation/Open Space Element, at p. V-6.
[13] *Id.* at p. V-41.

Plan prescribes that all geothermal development must comply with Action 1.13, i.e., "No geothermal development located within the Hot Creek Buffer Zone shall occur within 500 feet on either side of a surface watercourse."[14] The County is required to analyze alternatives to removing this restriction on geothermal development from the Mono County General Plan.

12-03 Cont.

Lastly, the contention in the RDEIR2 that the proposed amendment simply "clarify[ies]" the County's preexisting intent and interpretation of its General Plan is contradicted by the plain text of the General Plan.[15] The Land Use Element of the Mono County General Plan provides that a variance from a development regulation may be granted if not in conflict with the "text of the general and specific plans policies of the County."[16] Because the 500-foot setback requirement is identified in Policy 1, the Land Use Element clearly states that a variance from this requirement is not allowed. The County now proposes to amend Policy 1 to make the prohibition on geothermal development within the Hot Creek Buffer Zone subject to a variance.[17] In this way, the proposed Plan Amendment would in fact reverse – rather than "clarify" – the County's prior legislation with respect to all future geothermal development in the County.[18]

IV. THE RDEIR2 FAILS TO IDENTIFY THE POTENTIALLY SIGNIFICANT EFFECTS OF THE PROPOSED PLAN AMENDMENT

12-04

"An EIR on a project such as the adoption or amendment of a comprehensive zoning ordinance or a local general plan should focus on the secondary effects that can be expected to follow from the adoption, or amendment . . . ."[19] However, the RDEIR2 does not analyze the secondary effects of the proposed Plan Amendment. The County's failure to analyze the Project's potentially significant impacts violates the CEQA.

The RDEIR2 concludes, without conducting any environmental analysis, that there would be no change to any potential future geothermal development within the Hot Creek Buffer Zone as a result of the proposed General Plan Amendment.

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[14] *Id.* at p. V-43.
[15] RDEIR2 at p. 34.
[16] *Id.*, at Land Use Element, § 33.010(D), at p. II-315.
[17] *See* RDEIR2, at p. 34.
[18] *See Families Unafraid to Uphold Rural El Dorado County v. Board of Supervisors of El Dorado County* (1998) 62 Cal.App.4th 1334,1335 (describing the General Plan as a "constitution for all future development" in a city or county).
[19] CEQA Guidelines, § 15146.

The rationale provided in the RDEIR2 is unsupported. The County provides three reasons why there would be no change to any potential future geothermal development. We discuss each one in turn.

First, the RDEIR2 states the proposed Plan Amendment will not result in any new impacts because no geothermal development may be approved, under the Mono County General Plan, unless the impacts of the proposed development have been reduced to less than significant.[20] As support for this contention, the County cites Energy Resource Goal 1, Objective B, Policy 1 of the Open Space Element of the General Plan.[21] The County's reasoning is incorrect. The cited provision of the Mono County General Plan **does not apply** to "projects in the vicinity of Casa Diablo and associated monitoring or mitigation wells or other facilities."[22] Thus, any geothermal development project proposed in the Casa Diablo geothermal complex – including the instant Project – may be approved even if the project would result in potentially significant impacts to the environment (such as development within the Hot Creek Buffer Zone), as long as the appropriate CEQA findings are made.

12-04 Cont.

Second, the RDEIR2 states:

> [T]he Casa Diablo area referenced in the General Plan Conservation/Open Space Element consists of the 90 acres of land owned by Ormat and under geothermal lease to MPLP on which the project site would be located and an adjacent approximately 194-acre parcel owned by the Los Angeles Department of Water and Power (LADWP). As illustrated on Figure 39, the LADWP parcel contains areas sufficient to accommodate geothermal development and processing facilities outside of the 500-foot setback from the blue-line stream channel (and more than 100 feet from exterior property lines). Thus, a variance under Chapter 33 would not be required in order to approve a future geothermal development project on the LADWP parcel.[23]

The County's conclusion that no future project would require a variance is invalid because it is unsupported. The County does not cite to any pending conditional use

[20] RDEIR2, at p. 35.
[21] *See ibid.*
[22] *See* Mono County Conservation/Open Space Element, at p. V-43.
[23] RDEIR, at p. 35.

permit applications. Thus, the County does not have any facts from which to conclude that a future project would not require a variance. Moreover, the County's conclusion is contradicted by information provided by Ormat. Although Ormat owns and leases a total of 90 acres of land in the Casa Diablo geothermal complex, Ormat maintains that due to the unique geothermal features of the area, there is only one economically feasible configuration for the proposed 5.7-acre M-1 Project.[24] Ormat's own experience demonstrates that the total acreage of a site (i.e., the 194 acres owned by LADWP) is not determinative. Many other factors, such as economic constraints and the location of the geothermal resource, will dictate any future proposal for geothermal development in the County and whether it may be sited within the Hot Creek Buffer Zone. The County simply cannot rule out the potential for a future proposal to construct a geothermal development project within the Hot Creek Buffer Zone.

12-04 Cont.

Third, the RDEIR2 states that because the granting of a variance is a discretionary act subject to CEQA, any future project seeking to develop within the Hot Creek Buffer Zone will be subject to environmental review.[25] The rationale provided in the RDEIR2 fails as a matter of law. The County may not defer Project environmental review to future project approvals. In *Laurel Heights Improvement Association v. Regents of the University of California*, the California Supreme Court held that CEQA requires an EIR to include "an analysis of the environmental effects of future expansion or other action if: (1) it is a reasonably foreseeable consequence of the initial project; and (2) the future expansion or action will be significant in that it will likely change the scope or nature of the initial project or its environmental effects."[26] Future development within the Hot Creek Buffer Zone is a reasonably foreseeable consequence of the proposed Plan Amendment because the Plan Amendment would remove the existing prohibition on such development. This conclusion is further supported by the fact that future geothermal development in the Casa Diablo geothermal area is highly likely.

The California legislature has mandated that one third of all retail sales of electricity come from renewable sources of energy.[27] Pursuant to law, the state's

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[24] Applicant's Variance Application (undated), Attachment Amended April 25, 2012 (**Attachment 1**); *cf.* Mammoth Pacific I Replacement Project Revised Draft Environmental Impact Report, February 2012, at p. 2-4.
[25] RDEIR2, at p. 35.
[26] *Laurel Heights Improvement Association v. Regents of the University of California* (1988) 47 Cal.3d 376, 396.
[27] *See* Pub. Util. Code § 399.11 subd. (a).

12-04 Cont.

largest investor-owned utilities are required to obtain a third of their electricity from renewables by 2020.[28] Geothermal resources are, and will continue to be, exploited for this purpose.[29] There are a total of seven Known Geothermal Resource Areas in the State,[30] and the California Energy Commission has determined that the geothermal resource found in Mono County is likely to generate an additional 111 megawatts above existing capacity.[31] However, the California Energy Commission has also concluded that the Long Valley Caldera of Mono County has the potential to provide thousands of megawatts in California.[32] To say that future geothermal development in the Casa Diablo geothermal complex is reasonably foreseeable may be an understatement. Any additional geothermal development proposal will be significant because it will surely change the scope or nature of the current degree of resource exploitation and will cause other stresses on the environment through new construction and power production activities. The County is required to prepare a revised EIR that analyzes the secondary effects of the proposed Plan Amendment.

12-05

V. PROCEDURAL VIOLATIONS

Pursuant to Government Code sections 65351 and 65352, during the preparation or amendment of the general plan, the County is required to provide notice and opportunities for involvement to citizens and local agencies.[33] Under Government Code section 65352(b), each entity receiving a proposal for a general plan amendment shall have 45 days to comment on the proposed amendment unless

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[28] *Ibid*; *see also* California Public Utilities Commission, Order Instituting Rulemaking to Continue Implementation and Administration of California Renewable Portfolio Standard Program, May 10, 2011, *available at* http://docs.cpuc.ca.gov/word_pdf/FINAL_DECISION/134980.pdf.

[29] *See, generally*, California Energy Commission, Integrated Energy Policy Report (2011), available at http://www.energy.ca.gov/2011publications/CEC-100-2011-001/CEC-100-2011-001-CMF.pdf (last visited August 6, 2012) (**Attachment 2**).

[30] California Renewable Resource Portal, Geothermal Resources https://calrenewableresource.llnl.gov/geothermal/ (last visited August 6, 2012) (**Attachment 3**); *see also* California Energy Commission, Map of Known Geothermal Resources Areas, http://www.energy.ca.gov/maps/renewable/geothermal_areas.html (last visited August 6, 2012) (**Attachment 4**).

[31] Sison-Lebrilla & Tiangco, California Energy Commission, Staff Paper, *California Geothermal Resources in Support of the 2005 Integrated Energy Policy Report* (2005), at p. 8 (**Attachment 5**).

[32] California Energy Commission, Background About Geothermal Energy in California, available at http://www.energy.ca.gov/geothermal/background.html (last visited August 6, 2012) (**Attachment 6**).

[33] Gov. Code §§ 65351, 65352.

12-05 Cont.

a longer period is specified by the lead agency.[34] The County has not complied with the aforementioned notice and comment requirements by limiting the review period for the proposed Plan Amendment to less than 45 days.

VI. CONCLUSION

We thank the County for this opportunity to comment on the RDEIR2 and further urge the County to prepare and circulate a revised EIR which adequately addresses the proposed Plan Amendment to the Mono County General Plan.

Sincerely,

Elizabeth Klebaner

EK: clv
Attachments 1-6

[34] Gov. Code §65352 subd. (b).

ATTACHMENT 1

Mono County
Community Development Department

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(760) 924-1800, fax 924-1801
commdev@mono.ca.gov

Planning Division

P.O. Box 8
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(760) 932-5420, fax 932-5431
www.monocounty.ca.gov

VARIANCE
APPLICATION

APPLICATION # ____________ FEE $ ____________

DATE RECEIVED ____________ RECEIVED BY ______

RECEIPT # ________ CHECK # ______ (NO CASH)

APPLICANT/AGENT Ormat Nevada, Inc., on behalf of Mammoth Pacific, LP

ADDRESS 6225 Neil Road CITY/STATE/ZIP Reno, NV 89703

TELEPHONE (775) 336-0173 E-MAIL rleiken@ormat.com

OWNER, if other than applicant Mammoth Pacific, LP

ADDRESS P.O. BOX 1584, MAMMOTH LAKES, CA 93546

TELEPHONE (760) 934-4893 E-MAIL lnickerson@ormat.com

PROPERTY DESCRIPTION:

Assessor's Parcel # 3705002 General Plan Land Use Designation "Resource Extraction" (RE)

PROPOSED USE: Describe in detail the variance, using additional sheets if necessary.

See attached, next page

NOTE: Variance applicants must clearly demonstrate that special circumstances – other than financial hardship – related to the property deprive the property owner of privileges enjoyed by others in the vicinity and in an identical land use district. Special circumstances are typically related to the property's physical characteristics such as its size, shape, topography or surroundings. Variances shall not: 1) constitute special privileges inconsistent with other properties in the vicinity or in the same land use district; 2) injure the public's welfare or be detrimental to property owners in the vicinity; or 3) conflict with the county's General Plan or Specific Plans.

I CERTIFY UNDER PENALTY OF PERJURY THAT I am: ☐ legal owner(s) of the subject property (all individual owners must sign as their names appear on the deed to the land), ☐ corporate officer(s) empowered to sign for the corporation, or ☐ owner's legal agent having Power of Attorney for this action (a notarized "Power of Attorney" document must accompany the application form), AND THAT THE FOREGOING IS TRUE AND CORRECT.

Ohad Zimron Digitally signed by Ohad Zimron

Signature ______________ Signature ______________ Date ______

Mono County
Community Development Department

P.O. Box 347
Mammoth Lakes, CA 93546
(760) 924-1800, fax 924-1801
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Planning Division

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Bridgeport, CA 93517
(760) 932-5420, fax 932-5431
www.monocounty.ca.gov

PROPOSED USE: Describe in detail the variance, using additional sheets if necessary.

Description of Proposed Use and Justification for Variance:

The MP-1 Replacement Project has been thoroughly described in a separate Use Permit application and in the Draft Environmental Impact Report (EIR) that is currently undergoing public review.

Applicable Mono County regulations (Development Standards, Chapter 15, Resource Extraction) call for a 100-foot setback from exterior property lines. As designed, the plant itself will comply with this requirement. However, the very front end of the plant will intrude up to approximately 12 feet into the setback area. This isn't the entire plant, it would be a section of the preheaters, a control and power shelter, and some piping (only a few feet into the setback area) – see the attached plant layout. In order to avoid this intrusion in the setback area, the entire plant would have to be moved further north into an area that has severe geologic, soil and geotechnical limitations and geothermal surface manifestations, as discussed in the environmental impact report. This would cause unwarranted environmental and other effects that can be avoided by a variance to allow this limited construction in the setback area.

Amended, April 25, 2012: In addition to the standard above, Development Standards Chapter 15 Resource Extraction also requires a variance to allow geothermal development to occur within 500 feet of a surface watercourse in the Hot Creek Buffer Zone. The entire MPLP property (along with the existing MPLP geothermal plants) is within the Hot Creek Buffer Zone. A "surface watercourse" is defined as a solid or broken blue line as shown on U.S. Geological Survey 7.5- or 15-minute series topographic maps As shown on the attached map, the distance to the streamcourse from the southwesterly corner of the M-1 site is about 275 feet, and therefore within that 500 foot distance. For the same reasons discussed above (geotechnical limitations, geothermal surface manifestations, and adverse environmental effects), the M-1 plant cannot be moved farther north or west out of the 500 foot distance.

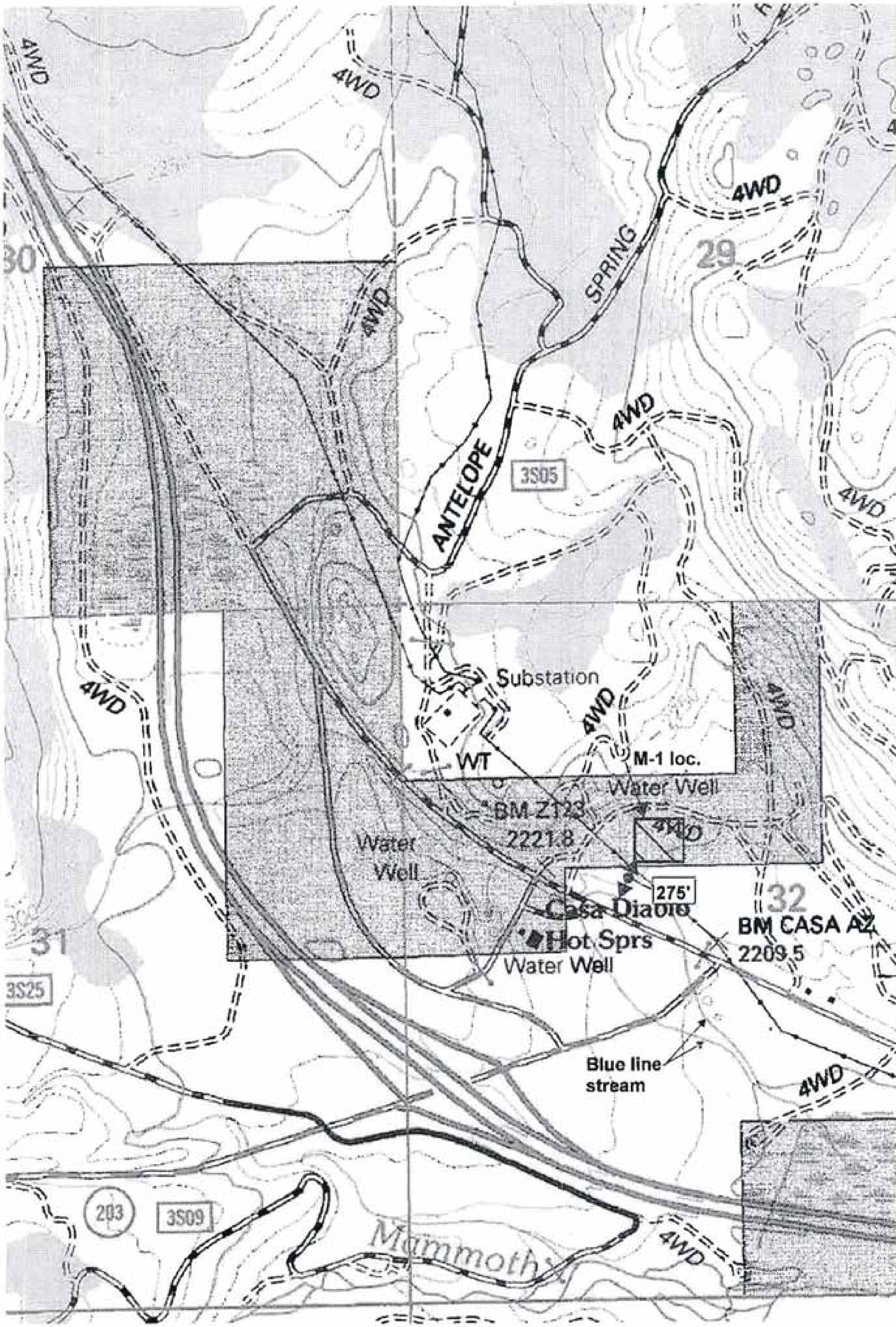
The Conservation/Open Space Element of the Mono County General Plan, at page V-5, in its discussion of geothermal resources states that fumaroles and other geothermally influenced natural features are significant resources. At page V-45 it states that applications for geothermal permits (which would include variances) may take into account national needs for alternative energy development.

The environmental effects that can be avoided by the proposed variance include effects to and from fumaroles, mud pots and thermal grounds/soils. Excavation in the area north of the currently designed plant would affect the surface expression of these natural features. Construction in that area would be much more environmentally intrusive, and very complex and expensive. For example, in addition to the geothermal surface manifestations, the soils are very soft, compressible clay. Construction would require at least 15 feet of fill, add unnecessary ground disturbance, and raise the height of the plant (thereby adversely affecting visibility).

Decisions on applications for variances must take into account the nature of the proposed use of the land, the existing use of the land in the vicinity and the conditions in the vicinity. The proposed use is the same as the existing use of the project area and the surrounding area. It is a geothermal development area that has been in production for over 25 years.

There are unique circumstances affecting the project site; namely, extreme topography (the fumaroles, mud pots and geothermally influenced soils). The variance is necessary for the efficient production of geothermal energy and the further enjoyment of a substantial property right of the applicant. There are already geothermal pipelines within this setback area, along the property line in question. The property on the other side of this line is managed by the US Forest Service and is covered by a geothermal lease to MPLP. The proposed land use is therefore consistent and compatible with the lands to the south of this property line.

The granting of a the proposed variance (1) will further the public's interest in alternative energy sources, (2) will not affect or be injurious to other properties in the area, and (3) will not alter the character of the area.



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BM Z123
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Casa Diablo
Hot Sprs
Water Well
BM CASA AZ
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Mammoth

ATTACHMENT 2

2011 IEPR

INTEGRATED ENERGY POLICY REPORT

CALIFORNIA ENERGY COMMISSION
EDMUND G. BROWN JR., GOVERNOR

CEC-100-2011-001-CMF

The 2011 Integrated Energy Policy Report is dedicated to

JAMES D. BOYD

Energy Commissioner
February 2002 – January 2012

With gratitude for his 50 years of dedicated public service and his unceasing efforts to develop and implement state policies contributing to California's achievements as a global energy leader.

CALIFORNIA ENERGY COMMISSION

Robert B. Weisenmiller, Ph.D.
Chair

Karen Douglas, J.D.
Carla Peterman
Andrew McAllister
Commissioners

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EXECUTIVE OFFICE

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Preface

Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002) requires the California Energy Commission to prepare a biennial integrated energy policy report that contains an assessment of 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 these assessments and associated policy recommendations every two years as part of the *Integrated Energy Policy Report*. Preparation of the *Integrated Energy Policy Report* involves close collaboration with federal, state, and local agencies and a wide variety of stakeholders in an extensive public process to identify critical energy issues and develop strategies to address these issues.

Abstract

The 2011 Integrated Energy Policy Report provides a summary of priority energy issues currently facing California. The report provides strategies and recommendations to further the state's goal of ensuring reliable, affordable, and environmentally responsible energy sources. Energy topics covered in the report include progress toward statewide renewable energy targets and issues facing future renewable development; efforts to increase energy efficiency in existing and new buildings; progress by utilities in achieving energy efficiency targets and potential; improving coordination among the state's energy agencies; streamlining power plant licensing processes; results of preliminary forecasts of electricity, natural gas, and transportation fuel supply and demand; future energy infrastructure needs; the need for research and development efforts to support statewide energy policies; and issues facing California's nuclear power plants.

KEYWORDS

Air Resources Board, biodiesel, bioenergy, biofuels, building and appliance efficiency standards, California Energy Commission, California Independent System Operator, California Public Utilities Commission, California's Clean Energy Future, clean energy economy, coal-fired generation, combined heat and power, crude oil imports, demand response, diesel, distributed generation, economic development, electric vehicles, electricity, electricity demand, energy efficiency, ethanol, gas-fired generation, gasoline, Governor Brown's Clean Energy Jobs Plan, greenhouse gas, jet fuel, job creation, Low Carbon Fuel Standard, natural gas demand, natural gas pipelines, nuclear power plants, once-through cooling, petroleum reduction, power plant licensing, Public Interest Energy Research Program, renewable, Renewables Portfolio Standard, resource adequacy, transmission, transportation fuel demand, zero net energy

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EXECUTIVE SUMMARY

Every two years, the California Energy Commission prepares an Integrated Energy Policy Report as directed by Senate Bill 1389 (Bowen, Chapter 568, Statutes of 2002). The report examines various aspects of energy supply, demand, distribution, and price and, based on these assessments, provides policy recommendations to ensure system reliability and safety, conserve resources, protect the environment, and contribute to a healthy economy.

This *2011 Integrated Energy Policy Report* provides an overview of policies that guide California's energy system and summarizes progress in implementing these policies. The report is built on a series of in-depth analyses of key aspects of the state's energy system and highlights issues that California must consider as it moves forward in meeting its energy goals. These issues fall into three general categories:

- Ensuring that the state has sufficient, reliable, and safe energy infrastructure to meet current and future energy demand as well as the state's clean energy goals. This will involve improved forecasting of demand for electricity, natural gas, and transportation fuels; promoting energy efficiency, demand response, distributed generation, and combined heat and power to reduce the need for additional central-station generation and transmission infrastructure; modernizing the electricity transmission and distribution system; evaluating the need for and developing new electricity, natural gas, and transportation fuel infrastructure to maintain energy reliability and support clean energy policies; streamlining and improving power plant licensing processes; and addressing safety and reliability issues associated with natural gas pipelines and nuclear power plants.

- Addressing challenges to achieving policy goals for energy efficiency, renewable energy, distributed generation, combined heat and power, alternative transportation fuels, and reduced greenhouse gas emissions. Goals include achieving all cost-effective energy efficiency; reducing energy use in existing buildings; promoting zero net energy buildings; increasing renewable electricity generation to 33 percent of retail sales by 2020; increasing the production and use of bioenergy resources; achieving Governor Edmund G. Brown Jr.'s Clean Energy Jobs Plan targets of 12,000 megawatts (MW) of renewable distributed generation by 2020 and 6,500 MW of combined heat and power by 2030; increasing the use of alternative and renewable transportation fuels to 26 percent of fuel consumption by 2022; and decreasing the carbon intensity of transportation fuels by at least 10 percent by 2020.

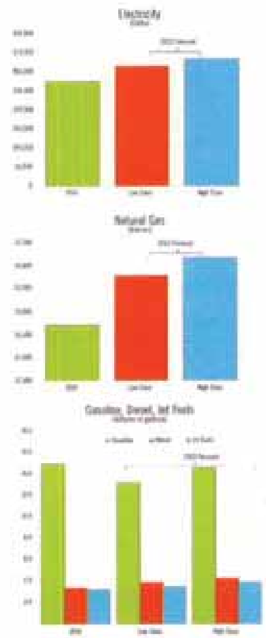
- Securing the economic development benefits of the clean energy economy by strategically targeting state funding investments for energy efficiency, renewable energy, the smart grid, alternative and renewable transportation fuels, and research and development to create jobs and leverage additional private investment. As Governor Brown noted in his 2012 State of the State speech: "California is leading the nation in creating jobs in renewable energy and the design and construction of more efficient buildings and new technologies . . . and California is positioned perfectly to reap the economic benefits that will inevitably flow."

California's Current and Future Energy Needs

Even in this economic downturn, California's demand for energy continues to grow. In 2010, Californians consumed about 272,300 gigawatt hours (GWh) of electricity; natural gas consumption (excluding fuel for electricity generation) represented almost 12,700 million therms. Energy Commission staff estimates that by 2022, California's electricity consumption will reach between 313,893 GWh and 332,514 GWh, an annual average growth rate of between 1.18 percent and 1.68 percent. Natural gas consumption is expected to reach between 13,773 million and 14,375 million therms by 2022, an average annual growth rate of between 0.7 percent and 0.94 percent.

On the transportation side, in 2010 Californians consumed 21.5 billion gallons of gasoline, diesel, and jet fuel, which represents a 7.2 percent decline from 2006 levels. Data for the first seven months of 2011 indicate that gasoline and diesel consumption was down about 2 percent from 2010 levels. This decline is due to a combination of sustained high fuel costs, low economic growth, declines in the value of real estate and equities, and continued high unemployment. Energy Commission staff forecasts of future gasoline consumption range from a decline of 15.6 percent from 2009 levels to an increase of 3.6 percent by 2030. The lower range is based on a low petroleum fuel demand scenario that assumes increased efficiency, more fleets using hybrids and diesel, and the introduction of alternative fuels. The higher range is based on a high petroleum demand scenario with

Figure E-1: California's Changing Energy Needs



Source: California Energy Commission

a recovering economy and lower fuel prices. Diesel consumption is forecasted to increase by between 27.2 percent and 58.4 percent compared to 2009 levels because of assumptions about steady economic growth along with the historical relationship between diesel demand and the movement of consumer goods by truck and rail.

Consumption of alternative transportation fuels is also expected to rise. Staff estimates that cumulative electric vehicle sales could increase to 440,000 vehicles in 2020 and as many as 1.4 million in 2025, although additional analysis is needed to estimate the number of battery electric and plug-in electric vehicles and total electricity consumption. Consumption of natural gas as a transportation fuel is also expected to increase at a compound annual rate of more than 3 percent, with natural gas consumption by 2030 representing 87 to 96 percent above 2009 levels. Staff also expects increased consumption of ethanol or advanced biofuels of between 2.2 billion and 3.2 billion gallons by 2030.

California's Energy Infrastructure Needs

Electricity Sector

By 2020, California could see retirement, replacement, or divestiture of more than 15,000 MW of fossil generation, which includes 13,000 MW of gas-fired generation and 2,000 MW of coal-fired generation. The state's policy to reduce once-through cooling in power plants – water that is pumped from the ocean, estuaries, rivers, or lakes through a steam turbine condenser and then returned to its source – may require more than 13,000 MW of existing gas-fired generation to comply with that policy by 2020. Most owners of California's plants that use once-through

cooling would prefer to repower them, according to implementation plans submitted in April 2011, but no owners indicated willingness to make the necessary investment without a long-term power purchase agreement. Similarly, plant owners say they would need long-term power purchase agreements to finance retrofitting their existing plants with alternative cooling technologies. Retirement of these plants will increase the need for new generating capacity to satisfy peak electricity demands and maintain appropriate reserves.

The Energy Commission also expects more than 2,000 MW of coal-fired generating capacity to be divested between now and 2023 as a result of Senate Bill 1368 (Perata, Chapter 598, Statutes of 2006), which limits long-term utility investments in baseload generation to power plants that meet an emissions performance standard. This divestiture will reduce the share of California's electricity needs met by coal-fired generation from roughly 20 percent to less than 4 percent.

At the same time, air quality constraints are restricting the development of new fossil fuel power plants that could replace retiring or divested generating capacity, particularly in the southern part of the state. That region will likely need to replace some older generating capacity with dispatchable, flexible fossil-fueled power plants when existing once-through cooling plants retire to satisfy local capacity requirements and help integrate variable renewable generation resources developed as a result of the state's Renewables Portfolio Standard. To better understand the potential conflicts between the need for new capacity and the scarcity of emission offsets to develop that capacity, Assembly Bill 1318 (V. Manuel Pérez, Chapter 285, Statutes of 2009) requires the California Air Resources Board to develop a report, in consultation with various agencies including the Energy Commission, to assess the need for new power plant capacity in the South Coast Air Basin and evaluate the need for emission offsets compared to available amounts. The report will also examine whether rule changes and other permitting mechanisms are needed to allow power plants to be developed while safeguarding air quality. The project has been underway since spring 2010, and the Air Resources Board anticipates providing a final report to the Legislature in the summer of 2012.

In addition to participating in the Assembly Bill 1318 study, the Energy Commission is assessing the electricity infrastructure needed to support California's transition to a low-carbon future while maintaining resource adequacy and reliability. This assessment, begun in the *2011 Integrated Energy Policy Report* proceeding and continuing as part of the *2012 Integrated Energy Policy Report Update* proceeding, is evaluating key factors that will affect the need for new generating and transmission infrastructure, including electricity demand growth; potential retirement of large amounts of generating capacity due to age or state water policies; limited availability of emission offsets for replacement generating facilities; retirement, replacement, or divestiture of coal-fired generation serving California; and achievement of state policy goals for increased use of energy efficiency, renewable resources, distributed generation, combined heat and power, and energy storage.

There are also infrastructure challenges associated with the state's licensing process for large-scale natural gas, solar, and other thermal power plants. Since 1996, the Energy Commission has licensed more than 16,000 MW of electricity generating capacity that is currently operating and delivering energy to California customers. In December 2010, after licensing more than 4,000 MW of solar thermal projects and 3,000 MW of natural gas plants, the Energy Commission began analyzing its permitting process to identify strategies to streamline and speed up the process without compromising transparency, effective participation, or environmental outcomes. During 2012, the Energy Commission's "lessons learned" proceeding will provide white papers and public workshops on a variety of issues that will be used to develop recommendations. Depending on the nature of those recommendations, the Energy

Commission may pursue changes to the regulations that guide and define the Energy Commission's power plant licensing process.

The Energy Commission is also working closely with federal, state, and regional agencies to improve power plant and transmission line permitting processes through the Desert Renewable Energy Conservation Plan and the U.S. Bureau of Land Management's Draft Solar Programmatic Environmental Impact Statement. The Desert Renewable Energy Conservation Plan planning effort brings together a large and diverse stakeholder group to develop conservation strategies that identify and map areas for renewable energy generation and transmission development and for long-term natural resource conservation. The Draft Solar Programmatic Environmental Impact Statement is intended to establish a solid foundation for long-term planning for solar energy development on public lands in California and five other western states and will promote better, smarter licensing of utility-scale solar projects while avoiding or minimizing conflicts with wildlife, and cultural and historical resources.

California's clean energy goals for energy efficiency, renewable resources, distributed generation, combined heat and power, and energy storage will also affect the need for upgraded and new energy infrastructure. Using energy more efficiently reduces electricity demand and therefore the need for new generation and transmission infrastructure. Increased amounts of distributed generation located near electric loads can also reduce the need for new large-scale power plants and transmission lines but will require upgrades to the existing distribution infrastructure. Meeting the state's Renewables Portfolio Standard target of 33 percent renewable electricity by 2020 will require new renewable power plants, transmission lines to bring power from those plants to the state's load centers, and other infrastructure like natural gas-fired power plants, energy storage, and demand response to support integrating high levels of variable renewables into the electricity system while maintaining system operations and reliability. Specific issues with California's clean energy policies are discussed later in this summary.

A final infrastructure issue in the electricity sector is the safety and reliability of the state's nuclear power plants. In 2010, nuclear power from the Diablo Canyon Power Plant and the San Onofre Generating Station provided 15.7 percent of California's in-state electricity generation. These plants are located near major earthquake faults and have significant inventories of spent nuclear fuel stored on site. Concerns about nuclear plant safety and reliability have increased because of recent large earthquakes in Japan, particularly the 9.0 magnitude quake in March 2011 and the resulting 45-foot tsunami that affected the Fukushima Daiichi plant. In July 2011, the Energy Commission and the California Public Utilities Commission conducted a joint public workshop on the implications of the Fukushima Daiichi accident for California's nuclear power plants and the utilities' progress in carrying out the recommendations made in a 2008 Energy Commission assessment of seismic hazard and nuclear plant vulnerabilities, which was required by Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006). After that workshop, the Energy Commission, in consultation with the California Public Utilities Commission, developed a set of specific recommendations in the *2011 Integrated Energy Policy Report* to address issues with California's nuclear power plants, including completion of seismic studies, improvements in spent fuel storage, lessons learned from the station blackout at Fukushima, new generation or transmission facilities needed to maintain reliability in the event of a long-term outage, and adequacy of emergency response planning.

Natural Gas Sector

The primary infrastructure issue in the *2011 Integrated Energy Policy Report* related to the natural gas sector is the safe and reliable operation of the state's network of natural gas pipelines. On September 9, 2010, a high-pressure natural gas transmission pipeline owned by Pacific Gas and Electric Company exploded under a neighborhood street in San Bruno, California, killing eight people and destroying 37 homes. In response, the California Public Utilities Commission and the National Transportation Safety Board both launched investigations into the explosion, and the Energy Commission provided Public Interest Energy Research Program funds for natural gas safety research.

The California Public Utilities Commission initially ordered pressure reductions and subsequently ordered Pacific Gas and Electric Company to reduce operating pressures on lines of similar vintage and characteristics as the failed segment. In June 2011, the California Public Utilities Commission directed Pacific Gas and Electric Company, Southern California Gas, San Diego Gas & Electric, and Southwest Gas to pressure test or replace all pipelines, which is expected to take several years. Until this is complete, pressure levels may be reduced below maximum allowable operating pressure or the utilities may implement other measures intended to assure safe operations. A formal report on hydrotesting efforts and preliminary results was the subject of an evidentiary hearing at the California Public Utilities Commission on November 22, and on December 15 the California Public Utilities Commission granted Pacific Gas and Electric Company's request to restore pipeline pressures on several key Bay Area lines after hydrotesting was complete. Since that time, the California Public Utilities Commission has issued a comprehensive staff report detailing its findings and making recommendations for changes at Pacific Gas and Electric Company.

The Energy Commission has closely monitored the testing schedule and operating pressures for any impacts on service to natural gas consumers, including the natural gas-fired power plants that California relies on for about 42 percent of its electricity. Pacific Gas and Electric Company has reported no curtailments to customers as a result of reducing the operating pressure. Two pipeline segments have failed hydrostatic testing, but in each case, as long as testing occurs outside high-demand periods, Pacific Gas and Electric Company should have the ability to reroute natural gas to continue service to customers, including gas-fired generating plants.

Energy Commission staff also analyzed the effect of flow reductions due to lower operating pressures on Pacific Gas and Electric Company's intrastate or "backbone" natural gas transmission pipeline systems. The key conclusion is that even if less gas is able to flow over backbone capacity, curtailments should be able to be avoided by relying more on gas from underground storage. This underscores the importance of filling not only Pacific Gas and Electric Company storage, but independent storage as well to make up for the constrained backbone capacity on days when colder than average conditions occur.

Transportation Sector

California must also ensure sufficient infrastructure to meet the state's conventional and alternative transportation fuel needs. Industries, commercial businesses, households, transit agencies, and government all rely on transportation fuels for movement of goods and people over highways, rail, waterways, and air. Transportation fuels also provide energy for off-road, industrial, agricultural, commercial, military, and recreational uses.

California oil production has fallen 47.2 percent since 1985, and Energy Commission staff estimates future declines ranging from 2.2 to 3.1 percent per year. The state's 20 oil refineries, which processed more than 1.7 million barrels of crude oil per day in 2010, continue to rely on crude oil imports by marine vessel from Alaska and a variety of foreign sources. Staff expects crude oil imports to rise by between 22 million and 158 million barrels per year by 2020 compared to 2010 levels.

Energy Commission staff believes there is sufficient existing spare import capability to meet the low estimate for crude oil imports and satisfy the state's need for conventional transportation fuels. There are two crude oil import infrastructure projects proposed in Southern California that are at early stages of development, Berth 408 at Pier 400 in the Port of Los Angeles, and Berth T126 at Pier Echo in the Port of Long Beach. Based on Energy Commission analysis, the Southern California market should require construction of only one of these crude oil import facilities over the forecast period. However, all imports at the high end of the range will require expanded capability to receive crude oil imports within the next four to five years to ensure sufficient supplies of conventional transportation fuels.

For alternative transportation fuels, demand for biofuels is expected to grow as a result of the federal Renewable Fuels Standard 2 mandates and the state's Low Carbon Fuel Standard. Certain biofuels (ethanol in low-level blends, biodiesel, renewable diesel, and renewable gasoline) will require only modest fueling infrastructure investment and little to no modifications to motor vehicles to enable greater use. California's infrastructure to receive, distribute, and blend ethanol is robust and adequate to accommodate a continued growth of ethanol use over the next several years. Although California's biodiesel infrastructure is currently inadequate to accommodate widespread blending of biodiesel, with sufficient lead time (12 to 24 months) modifications could be completed that would enable expansion of biodiesel use. An initial $100 million investment from the Energy Commission and private sources should accelerate the development of several biofuel production projects in California by 2017.

Other alternative transportation fuels like electricity, natural gas, and hydrogen will require considerable investment over the next several years in fueling infrastructure and vehicles that run on these fuels. Significant public and private investments are being made in California's electric charging infrastructure, and federal economic stimulus funds matched with Energy Commission program funds and other private and public funds are providing the charging infrastructure to support the deployment of plug-in electric vehicles in California. The Energy Commission has also allocated funds to upgrade and install fueling infrastructure for 28 natural gas stations, 11 hydrogen stations, and 10 E85 (85 percent ethanol) dispenser stations.

California's Clean Energy Goals

In his 2012 State of the State address, Governor Brown stated that "California is leading the nation in creating jobs in renewable energy and the design and construction of more efficient buildings and new technologies." This commitment to clean energy was echoed by President Obama in his 2012 State of the Union remarks calling for Congress to set "a clean energy standard that creates a market for innovation."

California's ambitious energy and environmental policy goals are important strategies to promote energy independence, increase energy reliability and safety, reduce statewide greenhouse gas emissions, and help create clean energy jobs. The *2011 Integrated Energy Policy Report* discusses issues associated with the state's clean energy goals to increase energy efficiency, renewable electricity, distributed generation, combined heat and power, and alternative and renewable transportation fuels. In addition, the report discusses the important roles that interagency coordination, and research and development will play in achieving these goals.

Energy Efficiency

Energy efficiency remains California's top priority for meeting new electricity needs and is a key strategy for increasing jobs and reducing greenhouse gas emissions from the electricity sector. Past and current government energy policies and programs have made California a national leader in energy efficiency. In the last three decades, California's policies, programs, and efficiency standards for buildings and appliances have contributed to keeping California's per capita electricity consumption relatively constant while use in the rest of the United States has increased 40 percent. The Energy Commission staff estimates that standards have also saved customers $66 billion in electricity and natural gas costs (in 2010 dollars) since 1975. President Obama, noting in his 2012 State of the Union address that more efficient use of energy saves money, asked Congress to send him a bill to: "Help manufacturers eliminate energy waste in their factories and give businesses incentives to upgrade their buildings. Their energy bills will be $100 billion lower over the next decade, and Americans will have less pollution, more manufacturing, and more jobs for construction workers who need them."

California's energy efficiency policies include achieving all cost-effective energy efficiency, reducing energy use in existing buildings built before the advent of building and appliance efficiency standards, and making all new residential construction in California "zero net energy" (a combination of greater energy efficiency and on-site clean energy production to reduce building energy use to "net zero") by 2020, and all new commercial construction zero net energy by 2030.

Achieving All Cost-Effective Energy Efficiency

To further California's goal of achieving all cost-effective energy efficiency, Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) requires the Energy Commission, in consultation with the California Public Utilities Commission, to develop statewide energy efficiency potential estimates and targets for California's investor-owned and publicly owned utilities and report on their progress toward these targets in the *Integrated Energy Policy Report*. In December 2011, the Energy Commission staff released the *Achieving Cost-Effective Energy Efficiency for California 2011–2020* final report, which summarizes utility progress and recommends improvements for publicly owned utility efficiency efforts. Investor-owned utilities reported 4,687 GWh of annual energy savings and 837 MW of peak savings for 2010, which exceeded the California Public Utilities Commission 2010 savings goals of 2,276 GWh and 502 MW. Reported natural gas savings were 45 million therms, just short of the California Public Utilities Commission's natural gas savings goal for 2010 of 48 million therms. Publicly owned utilities achieved 74 percent of the 2010 energy savings target and provided 523 GWh of electric energy savings, a decrease of 19 percent from 2009, and 94 MW of peak savings, 20 percent less than in 2009.

For future savings potential, the *Achieving Cost-Effective Energy Efficiency for California 2011–2020* report estimates 5,525 GWh of cost-effective savings potential for the publicly owned utilities for 2011–2020. This target, however, only represents about 42 percent of net annual savings from all publicly owned utilities. The two largest publicly owned utilities will be updating their savings potential and targets at a later date.

Forecasted savings from several individual utilities meet the AB 2021 goal of 10 percent savings over 10 years, but the combined publicly owned utility targets achieve only 6.8 percent savings from forecasted 2020 base energy use. For most utilities, market savings potential was calculated using a 50 percent customer measure incentive level. Energy Commission staff analysis indicates that when a 75 percent incentive level is used, nearly all utilities would meet the 10 percent consumption reduction goal contained in AB 2021. This suggests that the publicly owned utilities can meet the consumption reduction goal but may require a higher level of program effort and budget than was factored into their targets. However, the issue of cost-effectiveness is a key factor in setting incentive levels and determining which efficiency measures to include in programs. Increasing incentive levels to 75 percent may not be cost-effective for all utilities.

Reducing Energy Use in Existing Buildings

Existing buildings also provide a tremendous opportunity for low-cost energy savings, reduced greenhouse gas emissions, and job creation. More than half of California's 13 million residential units and more than 40 percent of commercial buildings were built before implementation of the state's building standards. Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) directed the Energy Commission to develop, adopt, and implement a comprehensive statewide program to reduce energy consumption in existing buildings and report on that effort in the *Integrated Energy Policy Report*.

Efforts by the Energy Commission, the California Public Utilities Commission, local governments, and utilities to coordinate residential and commercial building retrofit programs under the Energy Upgrade California™ brand are providing the foundation for the AB 758 program. Next steps are to complete needs assessments for both residential and nonresidential buildings, identify what must be done in program component areas (including lessons learned from pilot programs), and develop action plans for moving forward with AB 758 program development.

The Energy Commission will also work with the California Public Utilities Commission to emphasize joint efforts to achieve improved compliance with building and appliance standards to ensure that energy efficiency measures and equipment are properly installed and delivering savings. The Energy Commission will also develop regulations to improve compliance with appliance efficiency standards using its authority under Senate Bill 454 (Pavley, Chapter 591, Statutes of 2011), which allows the Energy Commission to adopt an enforcement process for violations of appliance efficiency regulations and impose civil penalties of up to $2,500 for each violation.

Achieving Zero Net Energy Homes and Buildings

The Energy Commission, the California Public Utilities Commission, and the Air Resources Board have adopted a goal of achieving zero net energy building standards by 2020 for residential buildings and 2030 for commercial buildings. According to the California Public Utilities Commission, California has more zero net energy buildings than any other state. To support the state's zero net energy goals, in September 2011 the California Public Utilities Commission released its *2010–2012 Zero Net Energy Action Plan* for the commercial building sector.

The Energy Commission is contributing to zero net energy goals by regularly updating its building efficiency standards to reflect new technologies and strategies with the goal of achieving 20 to 30 percent energy savings in each triennial update, and by updating appliance standards to include electronics and other devices plugged into electrical outlets that represent an increasing portion of California's energy use. In 2010, appliance efficiency standards alone saved an estimated 18,763 gigawatt hours of electricity, representing nearly 7 percent of California's electric load, and saved consumers about $2.6 billion in energy costs.

Governor Brown noted in his 2012 State of the State address: "Our state keeps demanding more efficient cars, machines, and electric devices. We do that because we understand that fossil fuels, particularly foreign oil, create ever-rising costs to our economy and our health." To meet the demand for more efficient electric devices, the Energy Commission in early 2012 adopted standards for the estimated 58 million battery chargers sold each year in California that, when implemented, will save state ratepayers an estimated $306 million each year, provide annual electricity savings of more than 2,000 GWh, and eliminate 1 million metric tons of carbon emissions.

Renewable Energy

California has more than 10,000 MW of renewable generating capacity on-line, with estimated technical potential (which does not reflect economic, environmental, or market constraints) of 18 million MW of additional resources. The state is the leading producer of renewable energy in the United States with nearly 16 percent of electricity supplies coming from renewable resources like wind, solar, geothermal, biomass, and small hydroelectric in 2010. California's leadership is due in part to strong state government policies and programs that have encouraged renewable development and helped reduce the costs of renewable technologies. For example, according to the National Renewable Energy Laboratory the per-watt price for solar modules has dropped from $22 in 1980 to under $1 today.

Renewables Portfolio Standard

California's Renewables Portfolio Standard requires utilities to procure 33 percent of their retail sales of electricity from renewable resources by 2020. In 2010, renewable generation represented about 16 percent of retail sales of electricity. Energy Commission staff estimates that generation from existing facilities combined with generation from utility contracts signed and pending could deliver enough renewable energy to meet the 33 percent target by 2020. However, it is uncertain whether existing renewable facilities will remain operational through 2020 and whether all contracts for new facilities will come to fruition given utility assumptions of a 40 percent contract failure rate.

To support the Renewables Portfolio Standard target, Governor Brown's Clean Energy Jobs Plan called for adding 20,000 MW of new renewable capacity by 2020, including 8,000 MW of large-scale wind, solar, and geothermal resources as well as 12,000 MW of localized renewable generation close to consumer loads and transmission and distribution lines. Governor Brown's Clean Energy Jobs Plan directed the Energy Commission to prepare a plan to "expedite permitting of the highest priority [renewable] generation and transmission projects" to support investments in renewable energy that will create new jobs and businesses, increase energy independence, and protect public health. In December 2011, the Energy Commission released the *Renewable Power in California: Status and Issues* report, which describes the status of renewable development in California and identifies challenges to meeting renewable goals.

Many of the challenges to renewable development relate to energy infrastructure needs, including addressing land use issues, and fragmented and overlapping permitting processes associated with building new renewable utility-scale and distributed generation facilities; building sufficient transmission needed to interconnect and deliver renewable generation, and upgrading the distribution system to reliably and safely support high levels of renewable distributed generation; developing supporting infrastructure like natural gas-fired plants, energy storage, and demand response measures to help integrate variable renewable resources; securing the necessary investment and financing to build new renewable facilities; and conducting research and development to develop new technologies and strategies to support renewable electricity infrastructure needs.

To address these challenges, the Energy Commission will work closely with other agencies and stakeholders to develop a renewable strategic plan in 2012 as part of the *2012 Integrated Energy Policy Report Update*. High-level strategies that will form the basis for the renewable strategic plan include: (1) prioritize geographic areas for development, (2) evaluate costs and benefits of renewable projects, (3) minimize interconnection costs and time, (4) promote incentives for projects that create in-state benefits; and (5) promote and coordinate existing financing and incentive programs for critical stages in the renewable development continuum.

Bioenergy Development

In addition to broad policy goals for increasing renewable electricity use, California also supports development of bioenergy to help achieve the state's clean energy goals. Biopower and biogas will contribute toward the goal of 12,000 MW of local distributed

energy generation, and biofuels and biogas will play important roles in reducing carbon emissions in the transportation sector. However, development of these resources has been slow. In March 2011, the Energy Commission adopted the *2011 Bioenergy Action Plan*, which noted that the biopower share of renewable electricity generation decreased from 28 percent in 2008 to 17 percent in 2010, and in-state biofuel production in 2010 represented only 5.6 percent of California's biofuel demand.

The *2011 Bioenergy Action Plan* identifies a number of strategies to support bioenergy, including: reauthorization of the Public Goods Charge to provide incentives to existing and emerging bioenergy technologies; developing biogas and biomethane for pipeline injection and on-site use in state; streamlined and expedited permitting; revising regulations that increase access to the electricity transmission and distribution grid and natural gas pipelines; providing incentives such as expanded feed-in tariffs, more favorable power purchase agreements, and research and development grants; and developing a plan and program to reduce costs associated with collection and transport of biomass residues.

The *2011 Bioenergy Action Plan* was intended to be updated and refreshed as needed to adapt to changing conditions. Parties are continuing to work on completing and updating measures, and the Energy Commission will report on updates and processes in future IEPRs.

Distributed Generation and Combined Heat and Power

In the right circumstances, distributed generation – small-scale power generation located close to electricity loads – can reduce or eliminate the need for new generation, transmission, and distribution infrastructure. Distributed generation can improve the efficiency of the electric system by avoiding transmission and distribution losses that occur when electricity travels over power lines. These systems can also improve reliability by providing electricity to a site regardless of what might occur on the power grid. Distributed generation that delivers during peak demand periods can free up other generating capacity and ease transmission bottlenecks and line congestion.

In a recent joint report by the Brookings Institution and the Hoover Institution, *Assessing the Role of Distributed Power Systems in the U.S. Power Sector*, George Shultz of the Hoover Institution noted that, "Many energy analysts have noted the potential for [distributed generation] to become a major part of our electricity infrastructure. ... But in this rapidly developing field, the great progress on the technological front has yet to be fully matched by progress in policy making. And major questions of affordability, integration, and security remain to be answered before we can determine what role distributed energy sources should play in our future energy system."

For the purposes of the 12,000 MW of renewable distributed generation by 2020 goal, distributed generation is defined as (1) fuels and technologies accepted as renewable for purposes of the Renewables Portfolio Standard, (2) sized up to 20 MW, and (3) located within the low-voltage distribution grid or supplying power directly to a consumer. California has about 3,000 MW of renewable distributed generation installed, with another 6,200 MW that is pending or authorized under existing state programs to support distributed generation. Meeting the Governor's target will require improvements in the permitting and interconnection processes affecting distributed generation facilities. It will also require upgrades to the state's aging distribution system to address physical challenges and maintain safety and reliability when interconnecting large amounts of distributed generation. These issues will be considered during the development of the Energy Commission's renewable strategic plan during 2012.

In addition to California's distributed generation goals, the Air Resources Board's *Climate Change Scoping Plan* originally called for development of

4,000 MW of new combined heat and power by 2020 to reduce greenhouse gas emissions, and the Governor's Clean Energy Jobs Plan includes a target of 6,500 MW by 2030. Combined heat and power, which is often a distributed generation resource, is an important part of California's energy mix. Combined heat and power facilities can reduce energy use by capturing waste heat associated with electricity production and using it to power industrial facilities, universities, hospitals, and other facilities. There is currently more than 8,500 MW of combined heat and power installed in California, making the state's fleet of combined heat and power facilities the second largest in the United States. These facilities improve the efficiency of the electric system by using less fuel to produce energy and can reduce air pollution and greenhouse gas emissions since less fuel is burned to produce each unit of energy output.

California's Qualifying Facility and Combined Heat and Power Program settlement, approved by the Federal Energy Regulatory Commission in June 2011, established a combined heat and power framework for the state's investor-owned utilities. The settlement resolved years of utility-generator litigation, established capacity targets, incorporated the investor-owned utility portion of the Air Resources Board's greenhouse gas reduction goal, revised the pricing calculation, included a competitive solicitation process to sign new power purchase agreements, and created an avenue for procuring combined heat and power in the future.

The Governor's policy goals for distributed generation and combined heat and power, along with the recent qualifying facility settlement, will have a major effect on future electricity demand and infrastructure needs. As part of the *2012 Integrated Energy Policy Report Update* and the *2013 Integrated Energy Policy Report* proceedings, the Energy Commission intends to update past assessments of the status and potential of combined heat and power in California and develop forecasting methods and scenarios that more accurately take into account the potential contribution of distributed generation and combined heat and power to the state's energy mix.

Transportation Fuels

California's transportation policies include increasing the efficiency of its transportation fleet, increasing energy security through the development of alternative transportation fuels and vehicles to reduce dependence on petroleum, and reducing greenhouse gas emissions in the transportation sector, which accounts for nearly 40 percent of the state's greenhouse gas emissions. In 2007, the Energy Commission and the Air Resources Board approved the *State Alternative Fuels Plan*, which recommended adopting alternative and renewable fuel use goals of 9 percent by 2012, 11 percent by 2017, and 26 percent by 2022. The state also has a goal of producing a steadily increasing share of its biomass-based transportation fuels from in-state sources between now and 2050. Other important transportation-related policies include California's Low Carbon Fuel Standard regulation to reduce the carbon intensity of transportation fuels used in the state by at least 10 percent by 2020, and the Air Resources Board's Zero Emission Vehicle regulations, which require manufacturers to produce increasing numbers of zero emission vehicles and plug-in hybrid electric vehicles in the 2018–2025 model years. Federal policies like the revised Renewable Fuel Standards also encourage the development and use of renewable and alternative fuels by mandating the volumes and types of renewable fuels that must be used nationally, with individual states required to meet proportional-share volumes.

California is making progress toward achieving its clean energy goals. The efficiency of the state's light-duty vehicle fleet is improving, with fuel economy increasing by 3 percent between 2004 and 2009, from 19.94 miles per gallon to 20.56 miles per gallon. Petroleum dependence in 2010 declined an estimated 5.8 percent from 2008 levels due to

the increased use of ethanol in gasoline. The use of alternative vehicles is increasing, with the number of registered hybrid vehicles growing from 0.83 percent of California's light-duty vehicle fleet in 2005 to 1.45 percent in 2009. During the same period, flex fuel vehicles – vehicles that can use gasoline containing any concentration of ethanol up to 85 percent – increased from 0.47 percent to 1.54 percent, and the number of natural gas-powered buses rose from just under 1,400 to more than 11,000.

According to Energy Commission staff projections, consumption of alternative transportation fuels is expected to increase between now and 2030. Staff forecasts indicate that annual transportation electricity consumption will increase at a compound annual rate of nearly 14.5 percent, largely as the result of substantial market penetration of plug-in hybrid electric vehicles. Similarly, consumption of natural gas for transportation is expected to increase at a compound annual rate of more than 2.8 percent, and consumption of E85 could be as high as 3.2 billion gallons by 2030. Additional analysis is needed to confirm consumption rates and the geographic location of market growth.

There are two programs in place that will support the development of alternative and renewable fuels and vehicles to meet future demand and help attain California's greenhouse gas emission reduction goals, both created by Assembly Bill 118 (Nuñez, Chapter 750, Statutes of 2007). The Air Resources Board's Air Quality Improvement Program, with an annual budget of $30 million to $40 million, supports development and deployment of zero-emission and reduced-emission light-duty vehicles and trucks. The Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program, with a budget of about $100 million annually through 2015, supports development and deployment of alternative and renewable fuels and advanced transportation technologies. This program invests in a wide variety of alternative and renewable fuels, including electric drive, biomethane, diesel substitutes, ethanol, natural gas, propane, and hydrogen, and funds workforce training. To date the Energy Commission has funded 86 projects totaling $204 million and approved plans for an additional $152 million allocation.

Under Assembly Bill 109 (Nuñez, Chapter 313, Statutes of 2008), the Energy Commission is directed to evaluate the benefits of the Alternative and Renewable Fuel and Vehicle Technology Program and report on progress as part of the *Integrated Energy Policy Report*. The results of the first such evaluation are reported in this *2011 Integrated Energy Policy Report*.

As a result of the Alternative and Renewable Fuel and Vehicle Technology Program, California now has the largest network of electric vehicle charging systems and hydrogen fueling stations in the country. In addition, compared to 2009–2010 levels, the program has more than doubled the number of E85 fueling stations in the state and has added 20 natural gas stations. Program investments will also add more than 1,400 alternative vehicles to the California fleet. The program has also helped bring additional investment to California, with $384 million leveraged from private financing and other public funding sources.

Other program benefits include significant estimated reductions in California's use of petroleum fuels. Program investments in electric drive technologies, production of biofuels, diesel substitutes, natural gas medium- and heavy-duty vehicles, and hydrogen fueling stations will contribute toward estimated petroleum reductions of 380.4 million to 1.4 billion gallons per year in 2020. Expected reductions in greenhouse gas emissions and criteria pollutants are also significant. In 2008, total on-road greenhouse gas emissions were estimated at 163.5 million tonnes of CO_2e (carbon dioxide equivalent). Program investments are estimated to reduce greenhouse gas emissions by 2.7 million tonnes of CO_2e to 9.7 million tonnes of CO_2e in 2020, and reduce emissions of criteria pollutants such as volatile organic compounds, carbon monoxide, nitrogen oxides, and particulate matter.

These benefits will have a positive impact in fulfilling California's transportation energy policy goals. Development and commercialization of the 86 projects funded to date have the potential to displace up to

6 percent of the estimated petroleum fuel demand in 2020 and reduce up to 4 percent of the estimated business-as-usual greenhouse gas emissions from transportation in that same year. In addition, commercialization of biofuel projects funded by the program will contribute toward achievement of the state goal to produce an increasing share of California's biofuel consumption from in-state sources by 2020.

Supporting California's Clean Energy Goals: Agency Coordination and Research and Development

Energy Agency Coordination

To achieve California's clean energy goals, state energy agencies must coordinate closely to maintain a broad perspective on energy policies and to identify policy overlaps, conflicts, potential consequences, and areas of concern that must be addressed. Recognizing the growing interdependencies among the state's energy and environmental agencies, in 2010 the Energy Commission, the Air Resources Board, the California Environmental Protection Agency, the California Public Utilities Commission, and the California Independent System Operator developed a vision, implementation plan, and roadmap to achieve a clean energy future for California. The *California's Clean Energy Future: Overview*, released in September 2010, focuses on 2020 but also considers the state's goal to reduce greenhouse gas emissions to 80 percent of 1990 levels by 2050.

The *Overview* focuses on four elements for achieving the state's 2020 electricity and natural gas goals: reducing peak energy demand through efficiency, demand response, and installation of distributed generation; increasing the amount of renewable energy in the state's portfolio by achieving the 33 percent by 2020 Renewables Portfolio Standard; ensuring that sufficient transmission and distribution infrastructure will be available to meet renewable goals and greenhouse gas emission reduction targets; and using supporting processes, including cap and trade, to provide opportunities for lower-cost greenhouse gas emission reductions and advancements in emerging technologies.

As part of the California's Clean Energy Future process, agencies jointly prepared publicly available "metrics" to show progress toward meeting the policies identified in the *Overview*. Metrics are posted on the California Clean Energy Future website and will be updated periodically to reflect new information. The agencies also plan to update the *Overview* to reflect significant developments since its release, including the passage of legislation to enact the 33 percent Renewables Portfolio Standard and Governor Brown's leadership in energy policy, and have committed in the *Overview* to review and revise strategies and targets biennially following each demand forecast update provided by the Energy Commission in the *Integrated Energy Policy Report*.

Research and Development

The invention and application of new technologies are essential to support California's clean energy and economic development goals. Private sector firms understandably tend to focus their research and development activities on projects that benefit their individual firms and bottom lines. In contrast, government research activities are targeted toward benefiting entire industries as well as society as a whole. President Obama, in his 2012 State of the Union comments on natural gas development, noted that "It was public research dollars, over the course of 30 years, that helped develop the technologies to extract all this natural gas out of shale rock – reminding us that government support is critical in helping businesses get new energy ideas off the ground. What's true for natural gas is true for clean energy."

Over the last 14 years, the Energy Commission's Public Interest Energy Research Program has funded energy-related research that responds to market needs and supports the state's energy policy goals. The program funds research across a broad spectrum of energy areas, including energy efficiency, renewable energy, advanced electricity technologies, energy-related environmental protection, transmission and distribution, and transportation technologies.

To further the state's goal of achieving all cost-effective energy efficiency savings, Energy Commission-funded research has supported technologies and strategies now included in the 2008 Building Efficiency Standards such as residential cool roofs (materials that effectively reflect the sun's energy from the roof surface) to reduce air-conditioning use, requirements to improve energy performance of air handlers and duct systems, and more efficient kitchen and underground pipe insulation. In addition, requirements in the 2007 and 2010 Appliance Efficiency Standards for external power supplies and flat-screen televisions resulted directly from Energy Commission-funded research. Overall, these measures will produce estimated annual energy savings of more than $1 billion for California electric and natural gas ratepayers when fully implemented.

The Public Interest Energy Research Program also funds research to bring products to the marketplace. Support for Adura® Technologies contributed to the development of a breakthrough wireless lighting control network that creates energy savings of up to 70 percent. Another example is demonstration of an innovative cooling system developed by Federspiel Controls (now Vigilent Systems) in eight data centers throughout California that reduced energy use for cooling by 19 to 78 percent and reduced annual energy costs by $740,000.

Research and development are also essential to support California's renewable energy goals. Energy Commission-funded projects have helped renewable technologies reach maturity and achieve faster market penetration, ultimately leading to more renewable energy in the state's electricity portfolio. One example is a new concentrating photovoltaic system developed by GreenVolts, Inc., originally funded by the Public Interest Energy Research Program, which is now in full production. There are six installations in California and Arizona and several additional sites under development including a 2.5 MW facility under construction in Byron, California.

Energy Commission research funding also supports technologies to improve management and operation of the electric grid. For example, synchrophasor measurement systems – which provide information to grid operators up to 30 times per second – are being used by the California Independent System Operator to help foresee and prevent power outages. In January 2008, one such system alerted grid operators about unusual grid oscillations that were causing grid instability, allowing the shutdown of a power line in time to avoid a major blackout. Prior to installation of this system, the California Independent System Operator probably would not have detected the irregularity. In the future, synchrophasor technologies are expected to save electricity consumers $310 million to $370 million per year by avoiding expensive power outages along with $90 million per year in reduced electricity costs.

A major challenge facing the Public Interest Energy Research Program is the expiration on January 1, 2012, of the state's Public Goods Charge to support energy-related research and development. There is support from the Governor and key legislative leaders to continue the Public Goods Charge, and in October 2011 the California Public Utilities Commission opened a rulemaking to evaluate potential continuation of public benefits funding. On December 15, 2011, the California Public Utilities Commission approved a decision to collect funds on an interim basis for renewables and research, development, and demonstration programs. Funds will be placed in balancing accounts and not disbursed until authorized by a final decision at the conclusion of Phase 2 of the proceeding, which will address more detailed program design, oversight, and administrative questions.

Economic Development and Job Creation

Governor Brown's Clean Energy Jobs Plan emphasizes that investing in energy efficiency and clean energy is a central element of rebuilding California's economy. California's energy policies continue to be instrumental in encouraging venture capital investments, attracting new companies, and growing new industries and jobs by creating market demand for clean energy technologies, products, and services. Governor Brown also noted in his 2012 State of the State address: "In the beginning of the computer industry, jobs were numbered in the thousands. Now they are in the millions. The same thing will happen with green jobs."

Energy efficiency standards promote investments in technology innovation to develop new products as well as job creation for the workforce needed to provide energy audits, home energy ratings, and building commissioning to identify efficiency improvements and products and support installation and testing of products and technologies. A 2008 report by Next 10 noted that California's efficiency policies have contributed to creating more than 1.5 million full-time equivalent jobs, including direct jobs created by services and products to support energy efficiency programs and indirect jobs created when customers redirect dollars saved from energy bills to other goods and services in the economy.

Clean energy policies to support renewable energy support clean technology investment in California, which leads to jobs both in clean tech industries and support industries like construction. According to a recent Ernst & Young, LLP, analysis, in the first quarter of 2011 alone, California received $637 million in venture capital investment for clean tech companies, representing 56 percent of national investments in the clean tech industry. A 2011 Brookings Institution report concluded that, nationally, the clean economy employs more people than the fossil fuels and biotech industries, with four of the five fastest growing clean tech segments between 2003 and 2010 in renewable energy, which added about 50,000 jobs in the solar thermal, solar photovoltaic, wind power, biofuels, fuel cell production, and smart grid industries. In California, a 2000 survey by the Center for Energy Efficiency and Renewable Technologies found that thousands of workers will be needed between now and 2015 to build renewable power plants being proposed in Southern California, with hundreds of operations and maintenance jobs needed for the next 20–30 years. In addition, it estimated that construction jobs to build 2,000 photovoltaic projects totaling 6,000 MW over a 10-year period would create a monthly average of 16,800 jobs.

California's investments in alternative and renewable transportation fuel projects are also contributing to job creation. While awards through the Alternative and Renewable Fuel and Vehicle Technology Program are still in the early stages, awardees expect to create more than 5,000 jobs throughout the market spectrum, including manufacturing, construction, engineering, and operations and maintenance. Using economic benefit multipliers, program investments in 1,000 manufacturing jobs alone could create from 3,000 to 5,000 indirect jobs in finance, transportation, supply chains, installation, and related businesses. Awardees also estimate that more than 800 California businesses will participate in their projects, more than half of which are small businesses. The program also leverages state investments with private financing and other public funding sources, with estimates of leveraged funds as high as $384 million.

Research and development activities to support the state's clean energy goals are also instrumental in bringing additional venture capital investments to California and creating clean energy jobs. Energy Commission staff estimates that research funded by the Public Interest Energy Research Program created more than 2,300 direct jobs, 1,250 indirect jobs

(resulting from entities doing the work purchasing goods and services), and 2,100 induced jobs (where business owners and employees purchase goods and services). Funding from the Public Interest Energy Research Program also leverages additional investments. For example, the Energy Innovations Small Grant Program has provided $30 million to awardees who went on to secure more than $1.4 billion in subsequent investment. Products developed through these grants are worth $1.3 billion to the private sector – more than 40 times the initial investment of program funds – and create jobs and other economic benefits for the state. In addition, in 2010 the Public Interest Energy Research Program successfully leveraged more than $500 million in federal stimulus funding under the American Recovery and Reinvestment Act of 2009 and $900 million in private investment using only $28 million of program funding.

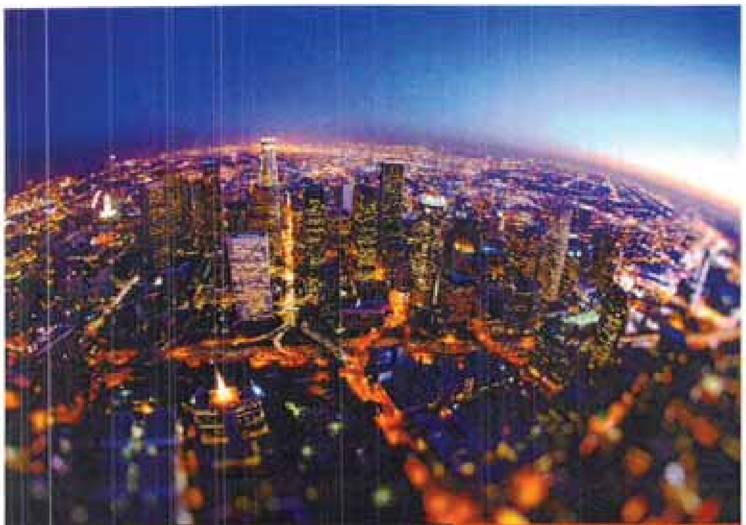
Conclusion

This *2011 Integrated Energy Policy Report* identifies the wide variety of issues that California must address to ensure safe and reliable energy infrastructure to meet increasing energy needs, achieve the state's clean energy goals, and promote economic development and job creation through a clean energy economy.

Significant infrastructure investments are needed to support the integration of renewable electricity, increase the use of alternative and renewable transportation fuels, and provide reliable and safe supplies of energy as demand increases. Investments in electricity transmission projects are needed to enable the flow of electricity from new renewable projects to meet the state's 33 percent Renewables Portfolio Standard goal. Additional investment is needed to upgrade the state's aging electricity distribution system to accommodate increasing numbers of distributed generation facilities. Continued investment is needed in energy efficiency, demand response, natural gas plants, and energy storage to help smooth the integration of variable renewable resources. Increased demand for alternative and renewable transportation fuels, as well as the continuing need for petroleum, will require investments in alternative vehicle fueling and charging infrastructure and facilities to accommodate imports of petroleum and ethanol fuels. California must also monitor the safety and reliability of energy infrastructure like natural gas pipelines and the state's nuclear plants and work closely with utilities as they address safety issues.

California must also address issues associated with meeting its clean energy goals. The state must continue its efforts to achieve energy efficiency savings in existing and new buildings, promote the development of zero net energy buildings, and ensure compliance with existing and new standards. California also needs to address challenges to achieve the Renewables Portfolio Standard target and other renewable electricity goals, as well as challenges to achieve the state's clean transportation fuel, bioenergy, and combined heat and power goals.

Finally, California must continue its commitment to securing the economic development and job creation benefits of the clean energy economy through targeted investments in energy efficiency, renewable energy, alternative and renewable transportation fuels, and research and development activities that support the state's clean energy goals.



CHAPTER 1

Introduction

As the United States recovers from the recent economic recession, it is more important than ever that California

[illegible]

Renewable Energy

[illegible]

Energy Efficiency

[illegible]

Improved Coordination and Planning Processes

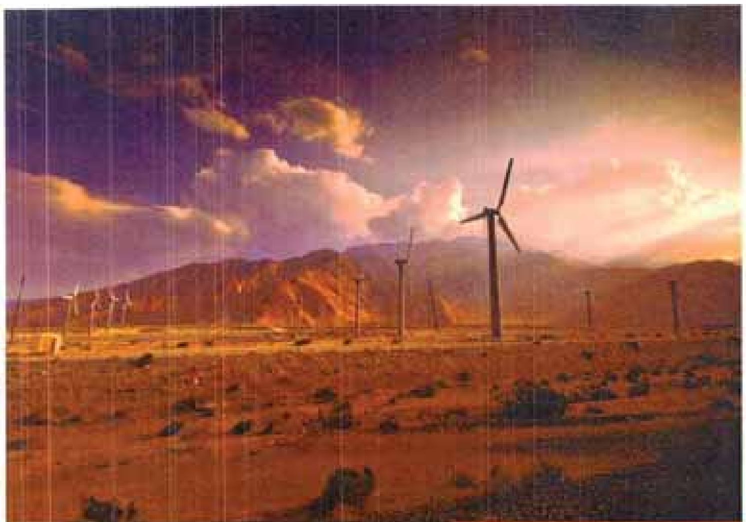
Energy Assessments and Forecasts

Alternative Fuel and Vehicle Development

Energy-Related Research and Development

Progress on Bioenergy Goals

California's Nuclear Power Plants



CHAPTER 2

Renewable Electricity Status and Issues

California has used renewable energy — energy from natural resources like sunlight, wind, rain, and the Earth's heat —

to help meet its electricity needs for more than a century. Renewable electricity provides many economic and environmental benefits, including local jobs in clean technology and construction industries, revenues from property and sales taxes, energy independence from using local energy sources and fuels rather than imported natural gas, reduced fossil fuel generation that has negative impacts on air and water quality, and reduced greenhouse gas emissions from the electricity sector to help meet state climate change goals. California has been a leader in expanding its consumption of renewable energy since the late 1970s when, under Governor Jerry Brown's first administration, the California Public Utilities Commission ordered utilities to establish standard offers for buying electricity from alternative suppliers ("qualifying facilities") at cost-based rates, with the price equal to the buyer's full avoided cost. By 1985, these standard contracts resulted in more than 11,000 megawatts (MW) of qualifying facilities on line in California, about half of which used renewable resources.

Now, Governor Brown is putting forth new and expanded targets. In his Clean Energy Jobs Plan, the Governor is emphasizing the importance of investing in renewable energy as a central element of rebuilding California's economy. The Governor directed the Energy Commission to prepare a plan to "expedite permitting of the highest priority [renewable] generation and transmission projects" to support investments in renewable energy that will create new jobs and businesses, increase energy independence, and protect public health. In December 2011, the Energy Commission released the *Renewable Power in California: Status and Issues* report, which describes the current status of renewable development in California and identifies challenges to meeting the state's renewable goals. This chapter summarizes that report and outlines high-level strategies to be included in a comprehensive strategic plan for renewable energy in California that will be developed as part of the *2012 Integrated Energy Policy Report Update*.

California's Renewable Electricity Targets and Status

In 2002, the California Legislature established the Renewables Portfolio Standard (RPS) to diversify the electricity system and reduce growing dependence on natural gas. At that time, the target was to increase the amount of renewable electricity in the state's power mix to 20 percent by 2017, which was subsequently accelerated to 2010 by legislation passed in 2006. In 2011, the RPS was further revised and expanded to require that renewable electricity should equal an average of 20 percent of the total electricity sold to retail customers in California during the compliance period ending December 31, 2013, 25 percent by December 31, 2016, and 33 percent by December 31, 2020.[18] To support these RPS targets, Governor Brown's Clean Energy Jobs Plan calls for adding 20,000 MW of new renewable capacity by 2020, including 8,000 MW of large-scale wind, solar, and geothermal as well as 12,000 MW of localized generation close to consumer loads. According to a recent presentation by Michael Picker, Senior Advisor to the Governor for Renewable Facilities, resources included in the 12,000 MW goal are defined as: (1) fuels and technologies accepted as renewable for purposes of the Renewables Portfolio Standard, (2) sized up to 20 MW, and (3) located within the low-voltage distribution grid or supplying power directly to a consumer.[19] Some parties have suggested that this definition be expanded to include other low GHG-emitting resources, such as fuel cells and high efficiency combined heat and power facilities. The Energy Commission will hold workshops during the *2012 IEPR Update* and *2013 IEPR* proceedings to discuss combined heat and power issues, and welcomes suggestions from parties on how to best ensure that the state's distributed generation and combined heat and power goals are complementary.

California appears to be on track to achieve the 20 percent average by 2013 RPS compliance period, with nearly 16 percent of statewide retail sales coming from

18 The California Public Utilities Commission recently established procurement quantity requirements for interim years of 21.7 percent (2014), 23.3 percent (2015), 27 percent (2017), 29 percent (2018), and 31 percent (2019). Decision 11-12-020, *Decision Setting Procurement Quantity Requirements for Retail Sellers for the Renewables Portfolio Standard Program*, December 1, 2011, docs.cpuc.ca.gov/WORD_PDF/FINAL_DECISION/154695.PDF.

19 Michael Picker, presentation at the December 8, 2011, California Foundation on the Environment and the Economy Energy Roundtable Summit on Distributed Generation, www.cfee.net/_documents/Picker.pdf.

Table 1: In-State Renewable Capacity and Generation (2010)

Renewable Resource	Utility-Scale Capacity (MW)	Wholesale Distributed Generation Capacity (MW)	Distributed Generation Capacity (MW)	Total Capacity (MW)	Total Generation (GWh)
Biomass	1,070	632	25	1,727	5,745
Geothermal	2,523	46	1	2,567	12,740
Small Hydro	313	1,080	9	1,395	4,441
Solar	408	149	1,070	1,827	908
Wind	No data	No data	8	3,027	6,172
Total	**4,314**	**1,867**	**1,102**	**18,343**	**38,885**

Source: California Energy Commission

A Sources of the data include the Energy Commission's Quarterly Fuel and Energy Report Database and [illegible]

B Solar PV systems under [illegible] staff calculation for [illegible] Energy Commission staff calculation for NSHP and Energy Commission staff calculation [illegible] the Self-Generation Incentive Program [illegible] and the Emerging Renewables Program [illegible]

C Wind turbines included in the Self-Generation Incentive Program [illegible] and the Emerging Renewables Program [illegible]

D Includes [illegible] MW of utility-scale and wholesale distributed generation wind capacity. [illegible]

E Total capacity in 2011.

renewable generation in 2010.[20] In-state renewable generation represented about 75 percent of total renewable generation from more than 10,000 MW of renewable generating capacity (Table 1).[21]

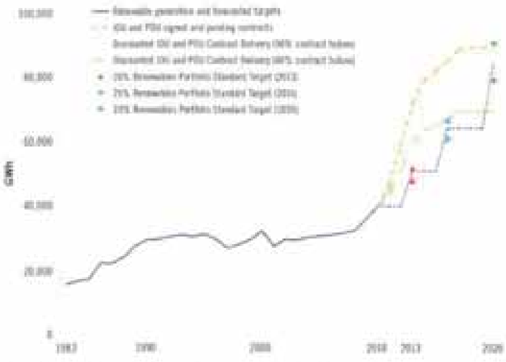
For the 33 percent by 2020 target, Energy Commission staff estimates that the state will need renewable generation in the range of 35,000 gigawatt hours (GWh) to 47,000 GWh in addition to generation expected from existing facilities. Utility contracts signed and pending to date are expected to deliver enough energy to reach the upper bound of this range if most or all of the contracted renewables are built and generating by 2020 (Figure 1).

This estimate includes a number of short-term contracts that may not be renewed, as well as existing facilities that may retire due to age or contract expiration, which could reduce the contribu-

20 Depending on the data source, total renewable generation varies between [illegible] and [illegible] percent of statewide retail sales from renewable generation in 2010. Procurement and generation sources include: the Power Source Disclosure Program, CPUC RPS Compliance Filings, Energy Commission RPS Tracking, and the Energy Commission's Total System Power.

21 The wholesale DG total in Table 1 was based on project size (20 MW or less) and excluded wind capacity due to lack of reliable data. The total will therefore need further refinement, given the revised definition of what meets the Governor's 12,000 MW goal, to screen out projects connected at the transmission level and include wholesale DG wind capacity.

Figure 1: Renewable Generation for California and Renewables Portfolio Standard Goals



Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

Dashed orange line showing expected renewable generation that will include potential generation from electric service providers, community choice aggregators, or small multi-jurisdictional utilities which are also subject to the RPS. In 2010, renewable generation from those entities represented only about 1 percent of statewide renewable generation.

flow from existing facilities.[22] There is also risk of contract failure; data from the Energy Commission's IOU contract database indicates that since the start of the RPS program, about 30 percent of long-term RPS contracts (10 years or more) approved by the California Public Utilities Commission (CPUC) have been cancelled.

The contract failure rate increases to about 40 percent when also considering contracts that have been delayed, and, at the September 14, 2011, workshop on the draft *Renewable Power in California: Status and Issues* report, two utilities indicated that they currently assume a contract failure rate of 40 percent.[23] This suggests it would be prudent for utilities to contract for renewable generation in the range of 55,000 GWh (contract failure rate of 30 percent) to 85,000 GWh (contract failure rate of 40 percent).[24]

22 According to metrics on the California Clean Energy Future website, contracts for roughly 22,000 GWh of renewable generation will expire before 2020. www.cacleanenergyfuture.org/documents/RenewableEnergy.pdf

23 Transcript of the September 14, 2011, Integrated Energy Policy Report workshop on the draft *Renewable Power in California: Status and Issues* report, comments by Valerie Winn, Pacific Gas and Electric Company (page 70) and Gary Stern, Southern California Edison (page 73). [illegible]

24 The Energy Commission acknowledges that historical contract failure rates are not predictive of future rates, which could be lower or higher.

Table 2: Preliminary Regional Targets for 8,000 Megawatts of New Renewable Capacity by 2020

Identified Transmission Line(s)	CREZ Served	Cumulative Renewable Deliverability Potential with New/Upgraded Lines (MW)	2010 Permitted Generating Capacity Associated with New/Upgrades (MW)	Additional Transmission Project Capacity (MW)
Sunrise Powerlink	Imperial North and South, San Diego South	1,700	760	940
Tehachapi and Barren Ridge Renewable Transmission Projects	Tehachapi, Fairmont	5,500	2,810	2,690
Colorado River, West of Devers, and Path 42 Upgrade	Riverside East, Palm Springs, Imperial Valley	4,700	1,825	2,875
Eldorado-Ivanpah, Pisgah-Lugo, and Coolwater-Inyo-Lugo	Mountain Pass, Pisgah, Kramer	2,450	1,470	980
Borden-Gregg	Westlands	800	185	615
South of Contra Costa	Solano	535	155	380
Carrizo-Midway	Carrizo South, Santa Barbara	900	800	100
			TOTAL	8,580

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

As a starting point for measuring progress toward meeting the Governor's 20,000 MW goal, the *Renewable Power in California: Status and Issues* report included preliminary regional targets for both utility-scale and localized renewable generation facilities. For the target of 8,000 MW of utility-scale renewables by 2020, Energy Commission staff identified rough regional targets based on new transmission lines and upgrades that have been identified by the California Independent System Operator (California ISO) for all of California's balancing authorities and potential renewable capacity in Competitive Renewable Energy Zones (CREZ) identified through the 2007–2010 Renewable Energy Transmission Initiative (RETI) that would be served by those lines and upgrades (Table 2).[25]

If these new lines and upgrades are permitted, built, and operating before 2020, they could allow generation from more than 16,000 MW of cumulative renewable capacity to flow across these lines.[26] In 2010, state and local entities issued permits for roughly 8,000 MW of new renewable capacity, about 4,000 MW of which is associated with the new lines and upgrades. This indicates that another 8,000 MW of renewable capacity could be sited in the CREZ associated with these lines in the future.

25 RETI was initiated in 2007 as a joint effort among the CPUC, the Energy Commission, the California ISO, utilities, and other stakeholders. Primary goals were to identify transmission projects needed to accommodate California's renewable energy goals, promote designation of corridors for future transmission line development, and make transmission and generation siting and permitting easier. *Renewable Energy Transmission Initiative Phase 2B Final Report*, RETI-1000-2010-002-F, May 2010. www.energy.ca.gov/reti/documents/index.html.

Figure 2: Renewable Distributed Generation Capacity Counted Toward 12,000 MW Goal

Source: California Energy Commission.

"Pending" capacity refers to projects approved under existing programs and in development but not yet completely installed. "Authorized" capacity refers to capacity allocated under existing programs that is not yet approved or installed. Existing programs include the Senate Bill 32 feed-in tariff, the Renewable Auction Mechanism, the Utility Solar Photovoltaic Program, and the California Solar Initiative. The Energy Commission acknowledges that the totals presented in this figure will need further refinement; for example, not all projects developed under the Renewable Auction Mechanism may qualify as wholesale DG under the definition of DG presented in this report.

For the 12,000 MW distributed generation (DG) target, Energy Commission staff developed preliminary regional targets for localized generation (Table 3), defined for purposes of the analysis at that time as renewable DG projects 20 MW and smaller interconnected to the distribution or transmission grid. The analysis was technology neutral and included solar, biomass, geothermal, wind, fuel cells using renewable fuel, and small hydropower. The analysis also assumed that renewable DG capacity installed would count toward meeting the 12,000 MW goal. California has roughly 3,000 MW of renewable DG capacity installed and, if existing state programs to support renewable DG are fully successful, the state could add about 6,200 MW of capacity in the next five to eight years (Figure 2). More information is needed to assess the legitimacy of the targets and the targets should be periodically updated. Given the trend of declining costs for solar photovoltaic (PV) technologies, the Energy Commission believes the focus should be on developing the "low-hanging fruit" in the next few years. Meanwhile, the state should focus on refining permitting and interconnection processes so that subsequent development of renewable DG installations can take advantage of cost reductions and improved regulatory structures in later years.

26 Written comments by Kern County and Critical Path Transmission on the draft 2011 IEPR suggested a transmission line which, if built, could potentially open up the West Mojave Desert to renewable energy development. The West Mojave Desert has been identified as an area of high solar insolation and the Energy Commission and other members of California's Renewable Energy Action Team have encouraged development there. The area also has lands with high conservation value, particularly for the Mohave ground squirrel and desert tortoise, and the Desert Renewable Energy Conservation Plan provides a forum for balancing energy and conservation needs in the area. Toward this end, the Energy Commission supports efforts by independent transmission developers to improve access to the West Mojave and will work with agencies and stakeholders involved in the Desert Renewable Energy Conservation Plan to address development and resource conservation options.

Table 3: Proposed Preliminary Regional DG Targets by 2020

Region	Behind the Meter (all technologies) (MW)	Wholesale (MW)	Undefined (mix of behind the meter and wholesale) (MW)	Total (MW)
Central Coast	280	50	0	330
Central Valley	830	1590	0	2,420
East Bay	420	30	0	450
Imperial	50	90	0	140
Inland Empire	480	430	0	910
Los Angeles City and County	970	860	2170	4,000
North Bay	220	0	0	220
North Valley	120	50	0	170
Sacramento Region	410	170	220	800
San Diego	360	50	770	1,180
SF Peninsula	490	20	330	840
Sierras	30	40	0	70
Orange	420	10	40	470
Total	5,210	3,470	3,310	12,000

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

Post-2020, additional investments in renewable generation may be needed to replace generation expected to decline over the course of the next decade, such as generation from expiring coal contracts. Generation from a number of these contracts, which currently represents about 18 percent of total generation serving California, is expected to decline by 62 percent between 2010 and 2020 due to constraints imposed by the Emission Performance Standard.[27] Remaining coal contracts are expected to expire between 2027 and 2030, which will require replacement power from a mix of renewable and thermal generation with storage to satisfy electricity needs while still meeting greenhouse gas emission reduction goals.

When signing the 2011 RPS legislation, Governor Brown indicated that the 33 percent by 2020 RPS target should be considered a floor rather than a ceiling. This is consistent with the need for additional renewable generation and other zero-carbon electricity resources to meet the state's long-term (2050) GHG emission reduction goals. Back-of-the-envelope estimates by Energy Commission staff indicate that if new renewables alone provided the zero-emission generation needed to meet electricity needs in 2050,

27 The Emission Performance Standard prohibits California utilities from renegotiating or signing new contracts for baseload generation that exceeds 1,100 lbs of carbon dioxide equivalent (CO_2e) emission per MWh. A number of contracts with coal generation facilities that exceed the Emission Performance Standard will expire within the decade and cannot be renewed with another long-term contract.

Table 4: California's Renewable Energy Potential

Technology	Technical Potential (MW)
Biomass	3,820
Geothermal	4,825
Small Hydro	2,158
Solar – Concentrating Solar Power	1,061,367
Solar – PV	17,000,000
Wave and Tidal	32,782
Wind – Onshore	34,000
Wind – Offshore	75,400
TOTAL TECHNICAL POTENTIAL	18,214,339

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

renewable generation could represent from 67 to 79 percent of total electricity sales in 2050.[28]

California's estimated renewable technical potential is 18 million MW (Table 4).[29] Although this figure does not reflect economic or environmental constraints, development of even one tenth of 1 percent of this potential would nearly meet the Governor's 20,000 MW renewable goal. Achieving this potential will depend on the ability of project developers to secure financing, permits, transmission, interconnection, local community acceptance, and power purchase agreements.

Despite these challenges, recent trends indicate increasing market interest in renewable development. The 2009 RPS solicitation by the investor-owned utilities (IOUs) drew bids from developers offering to supply enough renewable generation to meet half of the IOUs' total electrical load in 2020, and IOUs currently have signed contracts for roughly 14,000 MW of new renewable capacity. In 2010, state and local entities issued permits for 5,435 MW of renewable capacity and another 28,000 MW is being tracked in various

28 The 67 percent estimate assumes that electricity demand, the number of self-generation projects, and energy efficiency programs continue to grow at current rates; [illegible]

29 Technical potential refers to the amount of generating capacity theoretically possible given resource availability, geographical restrictions, and technical limitations [illegible]

permitting processes.[30] The California ISO's Interconnection Queue includes about 57,000 MW of renewable capacity, and there are 450 active interconnection requests for DG systems in the Wholesale Distribution Access Tariff queue totaling about 5,200 MW.

Issues Affecting Future Renewable Development in California

The *Renewable Power in California: Status and Issues* report identified a variety of issues that will affect the amount of renewable capacity ultimately developed, including environmental, planning, and permitting; transmission, grid- and distribution-level integration; investment and financing; cost; research and development (R&D); environmental justice; local government coordination; and workforce development. The report also discussed past and current efforts to address these challenges, which must be overcome to achieve California's renewable energy targets and goals.

Planning and Permitting Issues

For utility-scale renewable plants, the primary planning and permitting challenges are environmental/land use issues and fragmented and overlapping permitting processes. Renewable facilities can have a variety of environmental and land-use impacts depending on location and technology. Because the majority of new renewable development is proposed in the California desert, the *Renewable Power in California: Status and Issues* report focused on desert environmental impacts. These include impacts on sensitive plant and animal species, water supplies and waterways, and cultural resources like areas of historical or ethnographic importance. There are also land use concerns because the majority of desert lands in California are owned by the federal government and managed for multiple uses, including recreation, wildlife habitat, livestock grazing, and open space.

In terms of the permitting process, a variety of federal, state, and local agencies have licensing authority for different types of utility-scale renewable projects. This can lead to inconsistent environmental reviews and standards and variation in the extent of environmental evaluation, interpretation of results, and mitigation requirements. The result is that developers may have to satisfy more than one set of conditions, submit duplicate information, or face delays while agencies resolve their differences.

For renewable DG facilities, widely varying codes, standards, and fees among local governments with jurisdiction over these projects are a challenge for developers trying to meet permitting requirements. In addition, developers must get permit approvals from multiple local entities like fire departments, building and electric code officials, and local air districts, which can lead to duplication and inefficiency in the permitting process. Also, many local jurisdictions do not have energy elements in their general plan or zoning ordinances to guide renewable development and may have environmental screening and review processes in place only for large-scale renewables, not DG projects.

The state's Renewable Energy Action Team (REAT) is developing the Desert Renewable Energy Conservation Plan (DRECP) to help minimize environmental impacts of renewable generation and transmission

30 California Energy Commission, see: www.energy.ca.gov/33by2020/documents/renewable_projects/REAT_Generation_Tracking_Projects_Report.pdf

projects in the desert.[31] The DRECP's role is to identify areas in the Mojave and Colorado Desert regions suitable for renewable generation and transmission project development and areas that will contribute to the conservation of sensitive species and natural communities. The DRECP encompasses roughly 22 million acres in Kern, Inyo, Los Angeles, San Bernardino, Riverside, San Diego, and Imperial counties (Figure 3). It will promote development of solar thermal, utility-scale solar PV, wind, and other forms of renewable energy as well as associated infrastructure such as transmission lines.

Other efforts to improve permitting for utility-scale and DG renewable projects include:

- The REAT published the multidisciplinary *Best Management Practices and Guidance Manual: Desert Renewable Energy Projects* in December 2010, which helps project developers design projects that minimize environmental impacts.[32]
- The Energy Commission's Public Interest Energy Research (PIER) Program is funding research to help reduce the environmental impacts of renewable energy facilities, including strategies to diminish the effects of desert solar and wind projects on sensitive species. For more information about the role of the PIER Program, please see Chapter 12.
- The Energy Commission initiated an Order Instituting Informational Proceeding in December 2010 to evaluate lessons learned during the licensing of large-scale renewable facilities in 2010 with the goal of identifying innovative approaches to future planning and permitting (see Chapter 6).
- The U.S. Department of Energy's (U.S. DOE) Solar America Cities Program provided funding for cities that promote solar power and streamline interaction between local government and residents.
- The U.S. DOE's SunShot Initiative provides funding to encourage cities and counties to streamline and digitize permitting processes and to develop innovative information technology systems, local zoning and building codes, and regulations.
- California's Assembly Bill X1 13 (V. Manuel Pérez, Bradford, and Skinner, Chapter 10, Statutes of 2011), passed in 2011, requires the Energy Commission to, upon appropriation, provide $7 million in grants to qualified counties for developing or revising rules and policies (including general plan elements, zoning ordinances, and a natural community conservation plan) to promote the development of eligible renewable energy resources.
- Many jurisdictions are supporting renewable DG by identifying permitting barriers, developing expedited permitting processes, offering online permits for solar PV systems, and offering permit fee waivers for solar and wind projects. The California County Planning Directors Association is also coordinating a multi-stakeholder effort to draft a model ordinance for solar electric facilities for cities and counties across the state.
- The Ocean Protection Council recently passed a resolution recommending that "the Energy Commission should adopt an ocean renewable energy policy that guides the state's goals for the development of

31 Executive Order S-14-08, November 2008, directs state agencies to create comprehensive plans to prioritize regional renewable projects [illegible]

32 Renewable Energy Action Team, *Best Management Practices and Guidance Manual: Desert Renewable Energy Projects*, December 2010, [illegible]

Figure 3: Desert Renewable Energy Conservation Plan Area

Source: California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011.

these renewable energy technologies while balancing this development with the protection and conservation of ocean resources for broad public benefit" and to "consider adopting an ocean renewable energy policy for inclusion in the *2012 IEPR Update*."[33]

Transmission Issues

The primary transmission issues identified in the *Renewable Power in California: Status and Issues* report are the need to ensure interconnection of renewable generation projects, particularly those receiving federal stimulus funding; the need for coordinated land use and transmission system planning; and better use of the existing grid.

There are 11 major transmission projects that are critical for interconnecting and delivering the renewable generation needed to meet California's 33 percent by 2020 renewable mandate.[34] Six projects are licensed or under construction, while the remaining ones do not yet have active licensing applications. Many of these projects are needed to interconnect renewable generation projects that received funding through the American Recovery and Reinvestment Act (ARRA), which are essential to achieving the state's renewable goals. In addition, the state needs to strengthen the north-south 500 kilovolt (kV) "backbone" system to address bottlenecks arising from Southern California desert renewable energy resource areas and Central and Northern California load centers.

The second transmission issue is the need to streamline and coordinate transmission planning processes to build the most appropriate transmission projects to connect renewable resources while encouraging prudent land use and environmental considerations. Currently, identification of transmission routing issues and constraints does not begin until after the "wires" planning process is complete. This lengthens the transmission development process and increases the risk that approved projects will not be developed because of environmental issues. Stakeholders also identified the lack of transparent and consistent assumptions and processes used by transmission planning organizations as an issue that makes it difficult to participate effectively in planning processes.

The third transmission issue is how to make better use of the existing transmission grid. Currently, proposed renewable generation projects are evaluated in queue clusters and selected based on existing energy load needs. Allowing projects to be upsized beyond what is needed could provide unused capacity for future use, maximizing the value of land associated with already necessary transmission investment and avoiding future costlier upgrades to accommodate additional renewable development. There is also need for additional research to identify technologies that can improve the performance of the existing transmission system.

RETI was a statewide land use planning process intended to improve transmission planning by identifying transmission projects needed to meet the state's renewable energy goals.[35] RETI identified 30 CREZs throughout the state most likely for cost-effective and environmentally responsible generation development with corresponding transmission interconnections and lines. This process fed directly to the collaborative land-use planning occurring in the DRECP, and energy agencies are working together to ensure integration of land-use planning from the DRECP into the California ISO's annual transmission planning process.

Other efforts to improve transmission planning include:

33 www.opc.ca.gov/webmaster/ftp/pdf/agenda_items/ [illegible] .pdf

34 For a list of projects and detailed description of project status, see California Energy Commission, *Renewable Power in California: Status and Issues*, December 2011, www.energy.ca.gov/2011_energypolicy/documents/index.html.

35 For more information about the 2007–2010 RETI, see: www.energy.ca.gov/reti/.

- The California Transmission Planning Group, formed in 2009, is working to address California's transmission needs in a coordinated manner by developing a conceptual statewide transmission plan that identifies the necessary transmission infrastructure to meet the state's 33 percent by 2020 RPS goal.

- The California ISO has revised its transmission planning process to include transmission upgrades needed to meet California's policy mandates, with the *2010–2011 Transmission Plan* focusing on the RPS mandate in identifying policy-driven transmission projects.

- The California ISO received a one-time waiver from the Federal Energy Regulatory Commission to exempt upgrades associated with renewable projects receiving federal stimulus funding from further study in the 2010–2011 transmission planning process to allow generators to meet the construction start date of December 31, 2010.

Efforts to promote better use of the existing transmission grid include:

- The DRECP has a goal to support consolidation of renewable development, including transmission infrastructure, rather than scattered "leapfrog" development.

- The PIER Program has funded a wide variety of projects related to improving the performance of the existing transmission system. These include research to increase the carrying capacity of existing lines, reduce instabilities that are causing some transmission connections to be operated thousands of MW below maximum capacity, and develop transmission cables that can be operated at higher temperatures and allow more power to be transferred over existing transmission rights-of-way.

Integration Issues

Grid-Level Integration

Maintaining reliable operation of the electric system with high levels of intermittent resources will require a variety of strategies including, but not limited to, regulation to follow real-time ups and downs in generation output, voltage, or frequency caused by changes in generation or load; ramping generation from other units to follow potential up or down swings in wind or solar generation; spinning reserves[36] to provide standby power as needed; and replacement power for outages. System operators will also need strategies to address potential overgeneration issues that occur when there is more generation than there is load to use it and to improve forecasting of wind and solar technologies so they know how much capability to plan for.

Complementary technologies like natural gas-fired power plants, energy storage, and demand response provide various choices for flexible and rapid response for renewable integration. Natural gas units can provide quick startup, rapid ramping, regulation, spinning reserves, and energy when intermittent resources are not available. However, a challenge is the need to modify revenue streams to cover the incremental costs of shifting the use of these units from providing maximum energy production to providing flexible products, as well as potential environmental impacts and loss of machine life from cycling these units more frequently.

Energy storage can provide a variety of integration services, but additional evaluation is needed about cost-effectiveness, appropriate targets, and specific technologies to determine which can provide the rapid response and operational flexibility needed

36 Spinning reserve is the on-line reserve capacity that is synchronized to the grid system and ready to meet electric demand within 10 minutes of a dispatch instruction by the California ISO, see: www.caiso.com/docs/2003/09/08/2003090815475845.pdf

to provide regulation and load following.[37] Demand response – having electricity customers reduce their consumption at critical times or in response to market prices – can also play an important role by providing short-term load reductions and combining smaller loads to provide regulation or ramping through automatic controls that turn individual loads up or down as needed. Here, too, there is need for additional evaluation to determine how existing utility demand response programs might be used to provide renewable integration services.

Efforts to address grid-level integration issues include:

- The California ISO is working to improve its forecasting techniques to reduce uncertainty and the amount of standby capacity that will be needed to compensate for variations between generation and load.

- Formal planning for adding cost-effective energy storage to the electric system began with the passage of Assembly Bill 2514 (Skinner, Chapter 469, Statutes of 2010), which directed the CPUC and publicly owned utilities to evaluate the need for and benefits of cost-effective and viable energy storage systems, and determine appropriate targets by October 2013.

- Demand response is being used throughout the United States for ancillary services, and the California ISO offers two demand response products that are laying the foundation for the role of demand response in renewable integration efforts. The California ISO is also scheduled to implement a regulation energy market in spring 2012 that will allow demand response and energy storage to submit bids to provide ancillary services.

- The CPUC is evaluating integration costs as part of its Long-Term Procurement Plan proceeding for various scenarios.

- The Energy Commission's PIER Program is funding a wide array of projects intended to develop better forecasting tools for wind and solar generation, develop and demonstrate energy storage technologies, identify ways that demand response can support renewable integration, and develop the smart grid of the future.

Distribution-Level Integration

There are also issues with integrating large amounts of renewable DG into the distribution system, which brings power from substations to consumers. Much of today's distribution system still uses designs, technologies, and strategies that were developed to meet the needs of mid-20th century customers and move electricity in only one direction. The distribution system needs to be modernized and use technologies that easily allow for two-way flow of electricity as well as improved communication technologies, better protection systems, uniform standards, cyber security measures, and inverter standards. Better models and simulation tools are also needed to evaluate protection, control, and operational requirements of the grid with a high penetration of distributed generation resources. There are also process challenges associated with the increasing number of requests for interconnection and the need to reduce the complexity, expense, and length of time associated with that process.

Efforts to improve distribution-level integration include:

- In September 2011, the CPUC opened a proceeding on interconnection-related issues to review rules and regulations governing interconnecting generation and storage resources to IOU distribution systems.[38]

37 Load following is a utility's practice of adding additional generation to available energy supplies to meet moment-to-moment demand in the distribution system served by the utility or keeping generating facilities informed of load requirements to ensure that generators are producing neither too little nor too much energy to supply the utility's customers, see: www.energyvortex.com/energydictionary/load_following.html.

- California utilities are already modernizing their distribution systems by replacing equipment at the end of its useful life with new equipment that often has more advanced communication and functional capabilities. This modernization is likely to increase as a result of Senate Bill 17 (Padilla, Chapter 327, Statutes of 2009), which requires utilities to develop smart grid deployment plans.

- The CPUC has established the Renewable Distributed Energy Collaborative working group to help address interconnection issues.

- Fast-track processes are available within each of the state's interconnection processes to streamline interconnection of smaller projects, and utilities are providing information on their websites to help developers identify locations on the distribution grid where projects can be interconnected more quickly and at lower cost.

- The Energy Commission and the California ISO funded a study on renewable DG integration in Germany and Spain to identify strategies that can be applied to California's system.[39]

- Research funded through the PIER Program is focused on predicting the impacts of DG on distribution circuits, and developing smart grid and battery storage technologies that can support integration at the distribution level.

38 California Public Utilities Commission, see: docs.cpuc.ca.gov/PUBLISHED/FINAL_DECISION/144102.htm

39 Corfee, Karin, D. Korinek, C. Hewicker, M. Pereira Morgado, H. Ziegler, J. Zillmer and D. Hawkins, KEMA, *European Renewable Distributed Generation Infrastructure Study – Lessons Learned from Electricity Markets in Germany and Spain*, December 2011, California Energy Commission, Renewable Energy Office, available at: www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-400-2011-011.

Investment and Financing Issues

The primary financing challenge identified in the *Renewable Power in California: Status and Issues* report was the need to ensure adequate financing at critical stages of renewable project development. In particular, there are funding gaps at the R&D and early commercial stages. Private companies are often reluctant to invest in R&D to accelerate clean energy innovation due to the higher price of clean energy technologies, knowledge spillover risks, technology and policy uncertainty, the scale and long time horizon of many clean energy projects, and lack of widespread enabling clean energy infrastructure. Although overall R&D investment in the United States has grown annually by 6 percent, investment in energy-related research is about $1 billion less than a decade ago, with the private sector's share of energy R&D investment declining from nearly half in the 1980s and 1990s to about 25 percent today. At the early commercial stage, firms have traditionally used private equity, debt, and tax equity markets to provide financing, but since the financial crisis these options are either impractical given economic conditions, depend on government incentives to function well, or do not provide sufficient returns for investors.

Efforts to address financing issues include:

- National government laboratories are performing cutting-edge research on a variety of clean energy technologies, and the federal Advanced Research Projects Agency – Energy funds high-risk, high-reward technologies to bridge the gap between basic energy research and industrial application.

- Other federal government support mechanisms include tax incentives such as the business energy investment tax credit and the renewable production tax credit, as well as accelerated depreciation of renewable energy assets and loan and bond financing programs.

- State incentives include programs to support renewable DG, including the California Solar Initiative (CSI), the Emerging Renewables Program (ERP), the New Solar Homes Partnership (NSHP), the Self-Generation Incentive Program, and net energy metering, as well as sales and use tax exclusions under California's Advanced Transportation and Alternative Sources Manufacturing Sales and Use Tax Exclusion Program.[40]

- The PIER Program provided roughly $179 million for renewable energy research between 1997 and 2010, including seed funding for technology incubators that accelerate the growth and development of clean technologies.

- California's Innovation Hub initiative leverages research parks, technology incubators, universities, and federal laboratories to provide an innovation platform for startup companies, economic development organizations, business groups, and venture capitalists.

- The CPUC's Renewable Auction Mechanism streamlines the procurement process for developers, utilities, and regulators by allowing bidders to set their own price, providing a standard contract for each utility, and allowing projects to be submitted to the CPUC through an expedited regulatory review process.[41]

- Tools like feed-in tariffs provide a relatively guaranteed revenue stream, reduce transaction costs, and help support low-cost private financing. In February 2008, the CPUC made feed-in tariffs available for the purchase of up to 480 MW of renewable generating capacity from small facilities (1.5 MW or less). Senate Bill 32 (Negrete McLeod, Chapter 328, Statutes of 2009) increased eligible project size to 3 MW, and Senate Bill X1 2 (Simitian, Kehoe, and Steinberg, Chapter 1, Statutes of 2011) made additional amendments including how the feed-in tariff price would be determined. CPUC Rulemaking 11-05-005 is implementing these changes, with a ruling issued in January 2012 directing utilities to work together to create one standard contract for the revised feed-in tariff program and to file the contract with the CPUC by February 15, 2012.[42]

Funding for programs like the NSHP, the ERP, and the PIER Program, which help overcome financing challenges, expired at the end of 2011 and will be unfunded if the Public Goods Charge or alternate source of funding is not reauthorized. On December 15, 2011, the CPUC approved its Phase 1 decision instituting the Electric Program Investment Charge (EPIC) to collect funds on an interim basis for renewables and research, development, and demonstration programs.[43] Funds will be placed in balancing accounts and not disbursed until authorized by the CPUC's final decision at the conclusion of Phase 2 of the proceeding.

Cost Issues

Renewable technologies have a wide range of costs depending on the technology. Historically, technologies like solar thermal electric and solar PV were thought to have levelized costs greater than those of conventional generation. However, recent contract bids show that this is changing. According to the Energy Commission's RPS contract database, the majority of solar thermal power tower technology contracts signed and pending are below the 2009 Market Price Referent (MPR), a proxy for the levelized cost of a new 500-megawatt natural gas combined cycle.[44] For utility-scale renewable projects, the Energy Commission, California ISO, and CPUC are continuing to work together to evaluate transmission and renewable integration costs. While costs of both appear significant, they are certainly not insurmountable.

Renewable DG projects were once considered more costly due to higher transaction costs and lack of economies of scale. Now, standardization of contract terms and the way PV is manufactured and sold are reducing bids for DG systems, as shown by advice letters filed by Southern California Edison (SCE) with the CPUC stating that all contracts signed under their 2010 Renewable Standard Contract are below the 2009 MPR.[45] It is likely that there will be significant changes in the market in the next five to ten years as DG systems become more cost-competitive. While distribution system upgrades and modernization could be significant depending on the location of DG projects and the pace at which they are deployed, there are a variety of efforts underway to identify optimal locations for such projects and develop the smart grid technologies needed to ease integration into the distribution system.

In any discussion of the costs of renewable technologies, it is important to recognize that renewables provide important benefits that have not been adequately quantified, such as the value of having a diverse portfolio of generating resources that reduces costs and risk to ratepayers, provides business and economic development benefits, reduces dependence on natural gas and vulnerability to natural gas supply shortages or price spikes, and reduces GHG emissions.

Research and Development Issues

Continued public sector investment in energy-related R&D is an important tool to help address many of the challenges facing California's renewable industry. The Energy Commission's PIER Program has funded a wide variety of research to identify ways to address the environmental impacts of renewable energy facilities, develop technologies to improve the performance of the state's transmission and distribution systems, promote integration of renewable generating technologies at both the transmission and distribution level through the development of smart grid, energy storage, and demand response technologies, and reduce renewable technology costs while improving efficiency. With increasing levels of renewable resources in California's electricity mix, continued research will be required in each of these areas to provide the technological advancements needed to support the state's clean energy policy goals. Statutory collection of funding to support the PIER Program ended at the end of 2011 but funds are being collected on an interim basis pending a final decision by the CPUC.[46]

Environmental Justice Issues

Environmental justice (EJ) is defined in California law as "the fair treatment of people of all races, cultures, and incomes with respect to the development, adoption, implementation, and enforcement of environmental laws, regulations, and policies." The Energy Commission has considered EJ issues in its power plant licensing process since 1995, including reaching out to community members, identifying areas potentially affected by emissions or other environmental impacts, determining where there are significant populations of minority or low-income residents in an area potentially affected by proposed projects, and determining whether there may be a disproportionate effect on minority or low-income populations. However, EJ organizations have concerns about the types of power plants that will be built to meet increased electricity demand and replace aging power plants and plants that may retire as a result of the State Water Resources Control Board's policy on the use of once-through cooling in power plants, particularly in the southern part of the state, which has some of the worst air quality in the nation. There are also concerns about the types of fossil generation that may be built to support renewable integration, including flexible natural gas turbines ("peakers") that are less efficient than baseload resources and have increased emissions that may affect the communities in which they will be located.

EJ communities do see the value of renewable generating resources, particularly renewable DG such as rooftop PV, in their communities. Rooftop PV in urban environments can provide value to these communities by reducing the health and environmental impacts of fossil-fueled power and increasing economic revitalization and creation of local green jobs. However, rooftop solar is not always accessible to these communities due to the high upfront cost of these systems. In addition, many residents of EJ communities live in multiunit residential rental properties whose landlords may not see any benefits for allowing solar system construction, especially in situations where they are paying for the systems and additional wiring while tenants are receiving the benefits of reduced energy costs.

Efforts to help offset the costs of installing rooftop PV on affordable and low-income housing include:

- The Energy Commission's NSHP offers affordable housing projects higher incentives than standard market-rate housing projects. Of the overall 400 MW goal for the entire NSHP program, 36 MW will be made available for new affordable housing during the 10-year program.[47] As noted, this program relies on funding from the state's Public Goods Charge.

- Under the California Solar Initiative, the CPUC has two programs, the Single-Family Affordable Solar Homes Program and the Multifamily Affordable Solar Housing Program. The goals of these programs include improving energy use and the quality of affordable housing through use of solar and energy efficiency technologies and decreasing electricity use and costs without increasing monthly household expenses for residents. Programs provide solar incentives for qualifying affordable housing in the service territories of PG&E, SCE, and San Diego Gas & Electric.[48]

- The nonprofit Grid Alternatives Solar Affordable Housing Program provides training to install solar electric systems for low-income homeowners.[49] This program began in 2004 and as of January 2012 has installed 1,573 solar electric systems in partnership with low-income families throughout California. These systems represent nearly 4.2 MW of generating capacity and are reducing each family's electric bills by about 75 percent. Grid Alternatives has also trained more than 8,000 community volunteers and job trainees on the theory and practice of solar electric installation.

- The "Solar for All California" program, implemented by the California Department of Community Services and Development using funding from the Low Income Home Energy Assistance Program,[50] has a goal of installing 1,000 new PV systems on single- and multifamily low-income homes throughout California by October 2011. As of November 2011, the program has installed 472 single-family systems and has approved an additional 951 single-family systems and nine projects that will benefit 666 multifamily units.

- The Los Angeles Department of Water and Power (LADWP) recently relaunched its Solar Incentive Program with applications accepted beginning September 1, 2011. As part of the program, LADWP staff has been asked to investigate more options for making solar affordable to low-income customers with the goal of developing leasing options and other proposals for lower income households.[51]

Local Government Coordination Issues

Renewable development at the local level will be an essential component of the state's efforts to meet the goal of adding 12,000 MW of DG by 2020, which will be permitted at the local level. Local governments are closely involved in land use decisions, environmental review, and permitting for a wide range of renewable projects. Many local governments face constraints due to decreased staffing as a result of the economic downturn, limited expertise about renewable technologies, and lack of energy elements in their general plans and ordinances that could delay the processing of permits for renewable facilities, but many local jurisdictions are also showing strong leadership and innovation in promoting renewable energy development. The state needs to work closely with local governments to understand their needs and provide assistance where possible to help expedite the permitting and installation of renewable DG projects as well as renewable utility-scale projects that are under local jurisdiction.

There are several initiatives underway to streamline and standardize permitting processes for renewable DG projects:

- Through its Solar America Communities program, the U.S. Department of Energy (DOE) in 2007 and 2008 selected 25 U.S. cities, six of which are in California, as "Solar America Cities."[52] This unique federal-local partnership initiative aims to identify barriers to greater adoption of solar technologies and develop solutions to these barriers.

- As part of the overall strategy to reduce barriers to the adoption of solar technologies and to stimulate market growth, DOE has funded the Solar America Board for Codes and Standards to improve building codes, utility interconnection procedures, and product standards, reliability, and safety.[53]

- The DOE's $12.5 million "SunShot Initiative: Rooftop Solar Challenge" aims to reduce the administrative costs for PV systems.[54] This is a national competition for local and regional teams of government, utilities, installers, and others to "compete for funds to implement their plan to reduce administrative barriers to residential and small commercial solar

40 See www.gosolarcalifornia.ca.gov/, www.energy.ca.gov/renewables/emerging_renewables/index.html, www.cpuc.ca.gov/PUC/energy/DistGen/netmetering.htm, and www.treasurer.ca.gov/caeatfa/stl/index.asp.

41 See www.cpuc.ca.gov/PUC/energy/Renewables/hot/Renewable+Auction+Mechanism.htm.

42 California Public Utilities Commission, *Joint Assigned Commissioner's and Administrative Law Judge's Ruling Setting Workshop on a Utility Standard Form Contract for the Section 399.20 Feed-in Tariff Program*, January 10, 2012, docs.cpuc.ca.gov/efile/RULINGS/157920.pdf.

43 California Public Utilities Commission, News Release, December 15, 2011, see docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155616.htm.

44 www.energy.ca.gov/portfolio/contracts_database.html

45 [illegible]

46 docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/155616.htm.

47 Go Solar California website, www.gosolarcalifornia.ca.gov/affordable/nshp.php.

48 California Public Utilities Commission, CSI Single-Family Affordable Solar Homes Program website, see www.cpuc.ca.gov/PUC/energy/Solar/sash.htm, and CSI Multifamily Affordable Solar Housing Program website, see www.cpuc.ca.gov/puc/energy/solar/mash.htm.

49 Grid Alternatives website, see www.gridalternatives.org/impact-numbers.

50 California Department of Community Services and Development, Solar For All California website, see www.csd.ca.gov/Resources/Solar%20For%20All%20California.aspx.

51 Los Angeles Department of Water and Power, "LADWP to Relaunch Solar Incentive Program with Revised Incentive Levels and Streamlined Customer Service," press release, August 2, 2011, see www.ladwpnews.com/go/doc/1475/1153831/.

52 For a list of the 25 Solar America Cities, see solaramerica-communities.energy.gov/.

53 Solar America Board for Codes and Standards, see www.solarabcs.org.

54 www.eere.energy.gov/solarchallenge/

PV installations by streamlining, standardizing, and digitizing administrative processes.[55]

- The Energy Commission's *Energy Aware Planning Guide* provides information for local governments to use in encouraging DG in their jurisdictions and suggests a wide variety of implementation strategies to promote DG projects.[56]

Workforce Development Issues

As investment in the clean energy economy expands, there is increased need for a coordinated approach to workforce training that is closely aligned with labor demand. While growth in clean tech segments of the economy like wind, solar photovoltaics, and smart grid is creating demand for workers and there are a number of workforce training programs in place, the fragile economy has made employers hesitant about taking on more employees. This has resulted in low placement rates for some of these programs. In addition, expiration of federal stimulus funding for workforce development may make it difficult for community colleges, trade associations, and other training providers to continue their clean energy training curricula in the future.

Efforts to address workforce development challenges include:

- In 2010, a survey by the Center for Energy Efficiency and Renewable Technologies (CEERT) indicated that thousands of workers will be needed between 2010–2015 to build power plants being proposed in Southern California, with hundreds of operations and maintenance jobs needed for the next 20–30 years. CEERT also estimates that construction jobs to build 7,000 PV projects, totaling 6,000 MW over a 10-year period would create a monthly average of 10,400 jobs.[57]

- The Clean Energy Workforce Training Program, the largest state-sponsored green jobs training program in the nation, is training workers needed to operate large-scale renewable power plants and install PV systems. The program also provides grants that will establish community college and other training programs as part of established curricula, which will provide the basis for long-lasting and sustainable changes in clean energy workforce training in California.[58]

- The Clean Energy Workforce Training Program also has an interagency agreement with the Employment Training Panel which provided $4.5 million in grants for career advancement training. Grantees train incumbent workers in clean energy skills while also meeting a 90-day employment retention period after the training is completed. The program is set to train nearly 3,000 incumbent workers.

- The Green Innovation Challenge Grant program is helping community college students in the San Francisco Bay Area learn the skills to perform after-market repairs and maintenance to electric and alternative fuel vehicles, helping the San Diego region to develop college-level curriculum and certificates for workers in the biofuel industry, and helping to train PV solar installers, system designers, and marketing professionals.

- SBX1 1 (Steinberg, Chapter 2, Statutes of 2011) will provide up to $8 million in funding annually to the Superintendent of Public Instruction to implement and administer a grant program to fund clean energy partnership academies in public schools for grades 9–12. The partnership academies, which serve primarily at-risk students, will focus on preparing students for careers in energy and water conservation, renewable energy, pollution reduction, and similar technologies.

- The PIER Program invested $17 million in the California Partnership Academies' Green/Clean Initiative to build clean energy career pathways for students in grades 10–12.[59] This effort funded about 60 programs through the California Department of Education that integrated academic and career technical education, business partnerships, mentoring, and internships with a focus on green careers such as green buildings, sustainable design, and green engineering.

- The PIER Program provided cost share funding that helped leverage ARRA funding for the California State University, Sacramento, to develop a clean energy workforce curriculum for the electric power sector, specifically targeted toward training needed for jobs being created in smart grid applications. The PIER Program also sponsored research on the need for a National Center for the Clean Energy Workforce to provide a clearinghouse for information on best practices and technical assistance to translate this information into practical changes in workforce development strategies.

Public Leadership Issues

California has the potential to develop renewable energy systems on state-owned buildings, properties, and rights-of-way to help meet the state's renewable energy goals, create green jobs, and reduce greenhouse gas emissions and other harmful air pollutants. These investments will also reduce energy costs in state buildings and create new revenue for state government through the lease of vacant or unused land. State leadership will also demonstrate the benefits of renewable DG and help encourage larger-scale deployment throughout the state and across the country.

A number of state agencies entered into a memorandum of understanding in December 2010 to promote the development of renewable energy projects on state properties. As part of that effort, the Energy Commission staff released a draft report in April 2011 that identified current development of renewable on state properties, barriers and solutions to future deployment, opportunities for further development, and recommended next steps. The Energy Commission adopted the final report in early 2012.[60] Based on its inventory of state properties to identify opportunities for deployment of renewable DG systems, Energy Commission staff recommended a target of 2,500 MW of new renewable generating capacity on state properties by 2020.

Efforts underway by various state agencies that will contribute toward meeting these targets include:

- The Department of General Services (DGS) tracks energy use of state buildings to measure progress toward reducing energy consumption 20 percent by 2020 as called for by Executive Order S-20-04. DGS also released three requests for proposals to develop solar PV at state facilities and university campuses. The first solicitation resulted in the installation of 4.25 MW, the second awarded power purchase agreements for 21 MW, and the third solicitation is expected to result in about 30 MW, for a total of about 55 MW.[61]

- California Department of Transportation (Caltrans) is pursuing the installation of PV along the California highway system consistent with Governor Brown's support of the California Solar Highway. One project in Santa Clara County is in development. Caltrans has also identified 70 state-owned structures for installation of PV panels. 55 of these facilities are generating energy with the remainder expected to be producing energy by the end of fiscal year 2011–2012.

- The Department of Water Resources (DWR) is evaluating several renewable energy projects, including developing small hydroelectric generation in the State Water Project and assessing feasibility for a test project for in-aqueduct hydrokinetic generation. DWR is also negotiating with the University of California on a solar PV demonstration project along the California Aqueduct and next to one of its pumping plants, and is negotiating a power purchase agreement for wind energy with an annual output of almost 144 GWh.

- California's fairgrounds have installed solar PV at 25 of the 78 state fairgrounds ranging in size from 43 kilowatts to 1 MW, with a total installed capacity of 6.5 MW.

- The Department of Forestry and Fire Protection will continue to explore the feasibility of biomass facilities at conservation camps.

- The California Department of Corrections and Rehabilitation (CDCR) has two operational 1 MW PV ground-mounted solar arrays at state prisons with contracts to expand to nearly 9 MW. CDCR also has power purchase agreements for three additional sites, for a total of 21.5 MW at five sites, and is reviewing proposals for an additional 14 locations. CDCR's next solar effort will include sites that can be considered for wholesale generation, combined with providing on-site power to the prisons for systems ranging from 1 to 20 MW. CDCR is also implementing roof-mounted PV for several new building construction projects as well as a request for information for wind resource opportunities.

- The State Lands Commission manages thousands of acres of "school lands" as a revenue source for the State Teachers' Retirement System. Unlike the other agencies, the State Lands Commission is focusing on utility-scale development rather than DG. It has approved leases for renewable energy projects on these lands and is considering applications for new projects.

- As part of its effort to reduce greenhouse gas emission levels to year 2000 levels by 2014 and 1990 levels by 2020, the University of California has set aggressive energy efficiency targets, and has made substantial investments in combined heat and power plants. As of September 2011, the University of California had 8.4 MW of onsite PV installed or under construction and an additional 6.2 MW of biogas-powered generation.

Recommendations

Building on the Energy Commission's study, numerous public workshops, and the input of stakeholders from various communities and industries throughout California, the Energy Commission proposes five overarching strategies to guide the state as it works toward achieving the 33 percent RPS mandate, the 12,000 MW DG goal, and promoting economic recovery and job creation through investments in the clean energy sector.

1. Identify and prioritize geographic areas in the state for both renewable utility-scale and distributed generation development. Priority areas should have high levels of renewable resources, be located where development will have the least environmental impact, and be close to planned, existing, or approved transmission or distribution infrastructure. Prioritization should also include increasing efforts between state and local agencies to coordinate local land use planning and zoning decisions that promote the siting and permitting of renewable energy-related infrastructure.

2. Evaluate the cost of renewable energy projects beyond technology costs – including costs associated with integration, permitting, and interconnection – and their effect on retail electricity rates. This evaluation shall be coupled with a value assessment that could potentially lead to monetizing the various system and non-energy benefits attributable to renewable resources and technologies, particularly those benefits that enhance grid stability and reduce environmental and public health costs.

3. Develop a strategy that minimizes interconnection costs and time and minimizes integration costs and requirements at the distribution level (such as use of remote telemetry and other smart grid technologies) and the transmission level (such as improved forecasting, the development of an energy imbalance market, and procurement of dispatchable renewable generation), and that strives for cost reductions and improvements to integration technologies, including storage, demand response, and the best use of the state's existing natural gas-fired power plant fleet.

4. Promote incentives for renewable technologies and development projects that create in-state jobs and support in-state industries, including manufacturing and construction. In implementing this strategy, the state should evaluate how current renewable energy policies and programs are affecting in-state job growth and economic activity, how to optimize their effectiveness and transparency, and identify which renewable technologies rely on supply chains that provide the best opportunities for California businesses.

5. Promote and coordinate existing state and federal financing and incentive programs for critical stages including research, development, and demonstration, precommercialization, and deployment. In particular, the state should maximize the use of federal cash grants and loan guarantee programs by prioritizing the permitting and interconnection of California-based renewable energy projects (and their associated transmission or distribution infrastructure) vying for federal stimulus funds.

Detailed implementation strategies and action items will be developed in the upcoming *2012 Integrated Energy Policy Report Update* proceeding to provide further guidance on specific activities in which various state and local entities can engage to successfully carry out these high-level strategies in the near, medium, and long term.

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55 www.[illegible]energy.gov/solar/sunshot/[illegible]_solar_challenge.pdf.

56 California Energy Commission, *Energy Aware Planning Guide*, February 2011, www.energy.ca.gov/2009publications/CEC-600-2009-013/CEC-600-2009-013.PDF, Section [illegible].

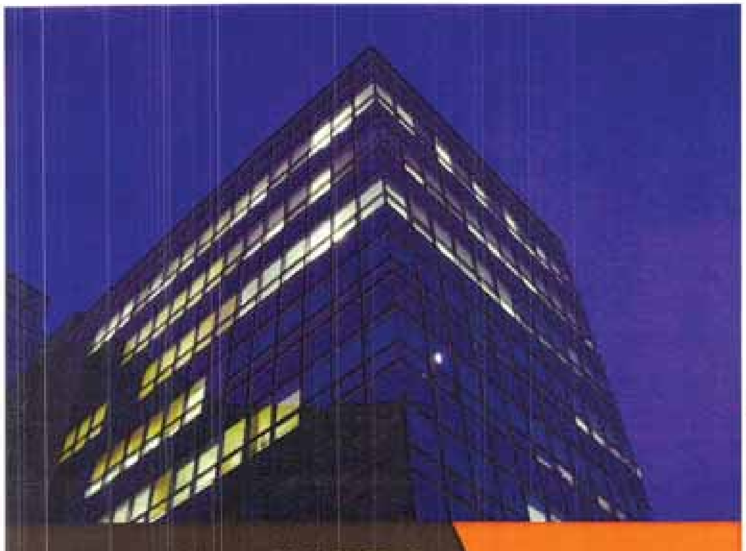
57 Center for Energy Efficiency and Renewable Technologies, presentation to Intersolar North America, July 12, 2011, www.ceert.org/PDFs/reports/[illegible].pdf.

58 For more information on the Clean Energy Workforce Training Program, see www.energy.ca.gov/cleanenergyjobs/.

59 Funding for this effort was appropriated by Assembly Bill 118 (Budget Committee, Chapter 757, Statutes of 2008).

60 California Energy Commission, *Developing Renewable Generation on State Property*, November 2011, www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002-LCF.pdf.

61 The majority of these DGS contracts are for CDCR facilities identified in a subsequent bullet and should not be double counted.



CHAPTER 3

Achieving Cost-Effective Energy Efficiency for California Assembly Bill 2021 Progress Report

This chapter summarizes the Energy Commission final staff report Achieving Cost-Effective Energy Efficiency for California *2011–2020*, including key points from the report, progress on utilities' energy efficiency savings and measurement and verification efforts, and policy recommendations.[42]

California has demonstrated a strong commitment to cost-effective energy efficiency for the last 30 years with the adoption of progressive policies, programs, and activities. In 2003, the state's first *Energy Action Plan* established the state's loading order, calling for electricity needs to be met first with increased energy efficiency and demand response. Assembly Bill 32 made customer-side energy efficiency a key strategy for reducing greenhouse gas emissions to 1990 levels by 2020.

42 California Energy Commission. *2011 AB 2021 Progress Report: Achieving Cost-Effective Energy Efficiency for California*. December 2011. www.energy.ca.gov/[illegible].pdf

In 2005, Senate Bill 1037 (Kehoe, Chapter 366, Statutes of 2005) made energy efficiency a priority strategy for electric utilities to meet their resource needs. SB 1037 requires the California Public Utilities Commission (CPUC) and the Energy Commission to identify potentially achievable cost-effective electric and natural gas energy efficiency savings and set goals for investor-owned utilities (IOUs) to achieve this potential.[43] Both agencies must review the procurement plans to ensure the consideration of energy efficiency and other cost-effective supply options. In addition, SB 1037 requires all publicly owned utilities, regardless of size, to report annually to their customers and to the Energy Commission on investments in energy efficiency programs.

Assembly Bill 2021 (Levine, Chapter 734, Statutes of 2006) added more specific legal directions for increasing California's energy efficiency programs. AB 2021 requires each publicly owned utility to:

- Beginning in 2007 and every three years thereafter, identify all potentially achievable cost-effective electricity energy savings. Using the efficiency potential estimates, establish annual targets for energy efficiency savings for the next 10-year period.
- Report on program cost-effectiveness and third-party energy evaluation, measurement, and verification (EM&V) of program savings.

AB 2021 directs the Energy Commission to:

- Include a summary of the publicly owned utilities' savings and evaluation, measurement, and verification (EM&V) studies in the *Integrated Energy Policy Report* (IEPR).
- In consultation with the CPUC as the regulator of IOUs' energy efficiency programs, provide a triennial statewide estimate of energy efficiency potential and targets for a 10-year period.
- Provide recommendations to publicly owned utilities, Legislature, and the Governor of possible improvements by the publicly owned utilities.

In response to AB 2021, the Energy Commission released the fifth annual final staff report *Achieving Cost-Effective Energy Efficiency for California 2011–2020 (2011 AB 2021 Progress Report)* on December 21, 2011. The following section provides an overall summary of the utilities' progress on energy efficiency program savings, EM&V reporting, and a more detailed description of setting energy efficiency targets, followed by recommendations for improvement of these efforts.

Staff Assessment of Utilities' Progress

Investor-Owned Utilities' Progress

The IOUs administer efficiency programs under the CPUC's Decision 09-09-047, which approved the IOUs' efficiency program portfolios for 2010–2012 with a total budget of $3.1 billion. The combined IOUs reported 4,607 gigawatt hours (GWh) of annual energy savings, 837 megawatts (MW) of peak savings, and 46 million therms of natural gas savings in 2010, which exceeded their 2010 CPUC-mandated goals. The 2010 natural gas savings fell just a bit short of the CPUC's natural gas goals for 2010.

The 2010 IOU savings numbers are still ex ante savings, that is, self-reported savings that have not been verified by third-party evaluators. Beginning with the 2006–2008 program implementation cycle, the CPUC instituted a more comprehensive process for capturing, retaining, and reporting ex post evaluation results. The CPUC's 2006–2008 EM&V results show a significant difference between reported and evaluated savings for that period. While the IOUs reported surpassing their energy savings goals, the evaluation report indicated that the utilities achieved between 37 percent and 71 percent of their goals for that period. However, the CPUC's *2009 Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period* verified that the IOUs achieved 141 percent of the GWh goal and 104 percent of the MW goal.[44]

A new CPUC *Potential and Goals Study* for efficiency is underway and expected to be completed in late summer 2012. The results of this study will be incorporated into the next AB 2021 report to be released in 2014.

43 The terms for energy efficiency "targets" and "goals" are used interchangeably. There is an established convention for lead since 2004 that the CPUC and IOUs use the term "goals." Publicly owned utilities have adopted the term "targets" since that is the term used in AB 2021.

Table 5: IOUs' and Publicly Owned Utilities' 2009 and 2010 Savings and Expenditures

	Investor-Owned Utilities		Publicly Owned Utilities	
	2009	2010	2009	2010
Gigawatt hours	3,778	4,610	844	573
Megawatt hours	759	839	137	94
Therms	54	46	–	–
Expenditures ($ Millions)	$721	$755	$144	$173

All savings data for both IOUs and publicly owned utilities are self-reported and have not been verified by third-party evaluators.

Source: Data obtained from the IOUs' Annual Reports for 2009 and 2010 [illegible] and SMUA, *Energy Efficiency in California's Public Power Sector: A Status Report*, March 2010 and March 2011 [illegible].

Publicly Owned Utilities' Progress

In 2010, all publicly owned utilities combined spent a total of $173 million on energy efficiency programs, a 15 percent decrease from 2009 and the first drop in energy efficiency program spending since 2006 (Table 5). Likewise, both energy and peak savings declined for the publicly owned utilities for the first time since 2006. In 2010, the 39 reporting publicly owned utilities provided 573 GWh of electric energy savings, a decrease of 15 percent from 2009. The publicly owned utilities achieved 74 percent of their 2010 energy savings target set in 2007. The decline in the 2010 numbers, however, is largely due to the completion of a large contracted lighting program at Los Angeles Department of Water and Power (LADWP).[45] Despite 2010's lackluster economic conditions, mid-sized

44 California Public Utilities Commission. *Energy Efficiency Evaluation Report for the 2009 Bridge Funding Period*. January 2011. www.cpuc.ca.gov/[illegible].pdf, p. 33.

45 In its December 23, 2011, written comments on the draft 2011 IEPR, LADWP noted that it is "evaluating an updated version of the lighting program, which will be targeted to capture additional energy savings from the small business market that are historically difficult to reach with efficiency programs." www.energy.ca.gov/2011_energypolicy/documents/[illegible].php

and small utilities performed reasonably well in both efficiency spending and savings.

This report contains metrics that measure the progress made by the publicly owned utilities in their energy efficiency programs, trends in reported energy efficiency expenditures, energy efficiency spending as a percentage of revenue, energy savings relative to adopted targets, energy savings as a percentage of total utility sales, and the cost-effectiveness of efficiency programs.

Energy Commission staff has requested information from the publicly owned utilities that would help to interpret data on efficiency progress. Their response to information requests has improved since 2008, but the Energy Commission is still not receiving some significant material. As staff learns their specific objections to data sharing, the Energy Commission and the publicly owned utilities can develop resolutions.

Evaluation and Verification of Publicly Owned Utilities' Efficiency Savings

The publicly owned utilities' savings reported in this document have not been modified as a result of independent verification studies. Unlike the IOUs, for which the CPUC can report evaluated savings, most publicly owned utilities do not yet have consistent evaluation methods. Since the passage of AB 2021 in 2006, nearly half of the publicly owned utilities have filed at least one EM&V impact study for program years 2007–2009. The Energy Commission developed EM&V guidelines in 2010 but learned in 2011 workshops that, for many publicly owned utilities, EM&V can impose costs without equal benefits. Not all publicly owned utilities provide earmarked funding for EM&V in their budgets so there can be tradeoffs between paying for third-party evaluation and providing program services. Other publicly owned utilities had difficulty meeting the Energy Commission's draft guidelines because diversity in size, resources, customer types, and program delivery approaches makes it difficult to meet "one-size fits-all" prescriptive guidelines for EM&V activities. Some utilities, however, did indicate benefits received from EM&V studies, including using study recommendations to improve data tracking systems and program delivery.

Status of Statewide Estimate of Energy Efficiency Potential and Targets for 2011–2020

AB 2021 requires publicly owned utilities to develop estimates of energy efficiency potential and targets on a triennial basis. Due to the unavailability of certain data, the Energy Commission could not set the statewide efficiency estimates for all utilities with the method directed in AB 2021. After the passage of AB 2021, the Energy Commission coordinated 10-year savings targets in December 2007 for both the IOUs and publicly owned utilities. In 2007, all the utilities had a recent potential study and set of approved targets and goals from which to develop the statewide savings potential estimate. In 2010–2011, however, the IOUs did not have revised potential estimates and goals available. Sacramento Municipal Utility District

Table 6: Estimated Potentials for Publicly Owned Utilities (Excluding SMUD and LADWP)

	Energy Potential – GWh			Demand Potential – MW		
	Technical	Economic	Market	Technical	Economic	Market
Current Analysis (2010), 2011–2020	10,833	5,525	2,143	2,351	1,293	575
Previous Analysis (2007), 2007–2016	5,460	4,038	2,320	737	587	222

Note: Excludes LADWP and SMUD.

Source: KEMA, Inc., POUs: Revised Energy Efficiency Potential and Targets, July 2010, CEC-200-2008-007-SF, May 2011.

(SMUD) did not have a revised potential study,[66] and LADWP did not have revised savings potential or targets.[67] As a result, the 2011–2020 efficiency target includes 67 percent of all publicly owned utilities' savings and 6 percent of all California's utility savings.[68] While this estimate includes the substantial majority of the publicly owned utilities, it does not represent the largest contributors to California's utility energy savings.[69]

The California Municipal Utilities Association (CMUA) coordinated 36 medium sized and small utilities that used the California Energy Efficiency Resource Assessment Model to develop technical, economic, and market level savings potentials. Taken together, SB 1037 and AB 2021 require targets to be cost-effective, feasible, and reliable. Target criteria were developed for these attributes and used in this evaluation. Methodological criteria were developed and used in evaluating the models and inputs.

Technical efficiency potential represents the complete penetration of efficiency measures where they are technically feasible. The estimate of technical energy savings potential is 10,833 GWh from 2011–2020. This estimate represents 33 percent of base energy consumption in 2020 and is 98 percent higher than the 2007 estimate of technical potential estimated for the decade 2007–2016 (Table 6). Economic efficiency potential is that percentage of technical potential that is cost effective. The economic savings potential estimated for the publicly owned utilities in the 2010 study is 5,525 GWh for 2011–2020, or 29 percent of base energy consumption. This estimate of economic potential is 136 percent higher than the 2007 estimate of economic potential for the decade 2007–2016.

The most significant level of efficiency potential is market savings potential, which is the percentage of economic potential that results when program designs, customer preferences, and market conditions are assessed. With a few exceptions, the publicly owned utilities used the market potential as their revised targets for 2011–2020. For the 36 utilities, the market potential was 39 percent of their economic potential. In the initial target setting in 2007, these same utilities derived targets (that is, market potential) that were roughly 50 percent of their economic potential. In general, while the 2010 estimate of technical and economic potential differed greatly from the levels developed in 2007, the targets derived by the utilities, and approved by their governing boards, were very similar.

While the forecasts of some individual utilities achieve 10 percent savings over 10 years, the combined publicly owned utilities' targets do not meet the AB 2021 consumption reduction goal, reaching 6.8 percent savings from forecasted 2020 base energy use. Only 3 of the 36 publicly owned utilities individually meet the 10-year goal, with 7 others falling only slightly short.

For most utilities, market savings potentials were calculated using a 50 percent customer measure incentive level.[70] Additional modeling indicated that when a 75 percent incentive level is used, nearly all utilities meet the 10 percent consumption reduction goal. This indicates that the publicly owned utilities can meet the consumption reduction goal of AB 2021 but may require a higher level of program effort and budget than most of them factored into their targets. However, the issue of cost-effectiveness is a key factor in setting incentive levels and determining which efficiency measures to include in programs. Increasing incentive levels to 75 percent may not be cost-effective for all utilities.

66 SMUD indicated in December 23, 2011, written comments on the draft 2011 IEPR that they are in the process of securing a contractor to do a revised potential study.

67 Energy Commission staff met with LADWP representatives in August 2011 and LADWP is in the process of developing targets and an updated potential study. LADWP also indicated in its December 23, 2011, written comments on the draft 2011 IEPR that they approved new energy savings targets in December 2011.

68 This is based on 2008 data from Achieving All Cost-Effective Energy Efficiency for California: An AB 2021 Progress Report, December 2008, CEC-200-2008-008, available at: www.energy.ca.gov/2008publications/CEC-200-2008-008/CEC-200-2008-008.PDF.

69 LADWP is working on a potential and target study with Global Energy Partners; its original due date was during fall 2010. SMUD does not have current plans to revise its efficiency potential estimates.

Recommendations

Information Requested to Interpret Efficiency Progress

- The most important data needed by staff to evaluate annual savings is the E3 Reporting Tool, which calculates savings potential for each publicly owned utility based on specific assumptions. In 2011, the publicly owned utilities stated that the reason for withholding the data tool was to protect customer identities. The Energy Commission is not interested in individual customers and is willing to accommodate an aggregation or redaction adjustment of the E3 Tool.

- The Energy Commission requests data by March 2012 on utility energy efficiency expenditures with other uses of Public Goods Charge (PGC) funding: low-income, research and development, and renewable energy projects.

- Staff requests that publicly owned utilities provide information by March 2012 on the role of energy efficiency in integrated resource planning in 2009. CMUA's *2009 and 2010 Status Reports* identified utilities that were allocating funds to efficiency programs beyond their PGC funding, but there is no indication that this allocation results from an integrated resource assessment. While some publicly owned utilities have performed recent integrated resource assessments, they usually treat efficiency as a load adjustment, not an equally comparable supply resource.[71]

70 "Fifty percent customer measure incentive level" means that the utility pays for 50 percent of the cost of the energy efficiency measure, such as through a rebate.

71 See public utility websites for their integrated resource plans; for example, LADWP's is at: www.ladwp.com/ladwp/cms/ladwp014725.pdf.

Publicly Owned Utility Efficiency Evaluation, Measurement, and Verification

- The publicly owned utilities should continue with their current plans for 2011 EM&V studies, especially the Southern California utilities that are working on their first EM&V studies since 2007. The Energy Commission is especially interested in working through the impact study process with LADWP staff because of the magnitude of their savings.

- The Energy Commission will engage with publicly owned utilities to develop versions of revised EM&V guidance documents, tools, and services appropriate for the three groups. These groups are stratified by three criteria: magnitude of savings, capacity to perform and manage EM&V studies, and program need for specific evaluation information. The Energy Commission will sponsor two EM&V workshops each year to increase agency and publicly owned utilities' understanding of practical EM&V; the next workshops will occur in late 2012.

Publicly Owned Utility Potential Estimates and Target Process in 2010–2011

- IOU goals will not be revised or approved until 2012.[72] The Energy Commission is coordinating with the CPUC post-2012 potential and goals process. The goal of both agencies is to better align the efficiency planning process of the IOUs and publicly owned utilities. The Energy Commission should identify these AB 2021 schedule issues, discuss them with the utilities and CPUC, and, if necessary, recommend an adjustment to the triennial deadline for statewide potential estimates and targets.

- While AB 2021 required all publicly owned utilities to submit efficiency potential estimates and targets by June 1, 2010, neither SMUD nor LADWP was in full compliance by that date.[73] In the future, revisions of potential and targets should anticipate AB 2021 deadlines.

- Estimates of technical savings potential for the publicly owned utilities in 2010 were substantially greater than those of 2007. The model used by the publicly owned utilities' consultant (Navigant) for estimating potential in 2010 was different from the model used by their 2007 consultant (Rocky Mountain Institute). There must be some continuity in method from one revision to the next to make sense of changes in potential estimates. If publicly owned utilities do not use the California Energy Efficiency Resource Assessment Model in the next potential study cycle, they should provide an accounting of method and data changes from one triennial revision to the next to maintain transparency in the process.

- The Energy Commission requests more documentation from the publicly owned utilities to understand the assumptions behind the potential estimates and energy efficiency targets adopted. Utilities should provide the Energy Commission with the version of the model that they used to calculate targets. The

72 Scope and schedule for the revised IOUs' post-2012 efficiency potential study and goals is available at: www.cpuc.ca.gov/CPUC%20PPT%2021312.pdf.

73 AB 2021 states that "on or before June 1, 2007, and by June 1 of every third 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." In its December 23, 2011, written comments submitted on the draft 2011 IEPR, SMUD indicated that it has established targets aimed at reducing energy use by 15 percent, 50 percent more aggressive than the 10 percent called for in AB 2021.

publicly owned utilities should document the ways in which they customized the model and the reasons for the customization.

- The analysis of energy efficiency potential and adopted targets clearly showed that some publicly owned utilities were more aggressive in pursuing energy efficiency than others to meet their load. The efficiency potential analysis showed that, for most utilities, providing higher customer incentives (of at least 75 percent) would achieve an important goal of AB 2021 by increasing savings sufficiently to reduce energy consumption by 10 percent in 2020.

CHAPTER 4

Achieving Energy Savings in California Buildings

This chapter summarizes the Energy Commission staff report Achieving Energy Savings in California Buildings: Saving

Energy in Existing Buildings and Achieving a Zero Net Energy Future.[74] The overview contains key points from the report, including background, strategies, and challenges in achieving the state's energy efficiency and climate change goals, and recommendations to help accelerate progress.

California has a long history of leadership in delivering the economic, environmental, and energy system reliability benefits that derive from its energy efficiency standards and programs. Expansion and acceleration of energy efficiency initiatives are at the forefront of the state's energy policy goals and mandates. The state's ongoing efforts to achieve all cost-effective energy efficiency in buildings are pivotal for achieving the state's goals for job creation, economic development, and environmental protection, including the following:

- The Energy Action Plan has guided California energy policy since the California energy crisis of 2000–2001 and is designed to improve energy system reliability and manage costs. The plan established the principle of following the "loading order" for new generation resources, directing that growth in energy needs must be met first by cost-effective energy efficiency improvements.

- The Global Warming Solutions Act (Assembly Bill 32 [Nuñez, Chapter 488, Statutes of 2006]) has been the foundation of California's efforts over the past five years to address climate change by reducing greenhouse gas (GHG) emissions to the state's 1990 level by 2020. The adopted *AB 32 Scoping Plan* recommended expanding and strengthening building and appliance standards and energy efficiency programs aimed at existing buildings.[75] The Energy Commission's *2007 Integrated Energy Policy Report* concluded that climate change is the most important environmental and economic challenge of the century. GHG emissions are the largest contributors to global warming, and California's ability to slow the rate of GHG emissions depends first on energy efficiency.

- California's Clean Energy Future (CCEF) initiative is a collaborative effort of the state's energy and environmental agencies and the California ISO to advance carbon-cutting innovation and green job creation. It articulates the importance of new investments in energy efficiency, as well as in electricity transmission, smart grid applications, and increased use of renewable resources.[76]

- Governor Brown's Clean Energy Jobs Plan (2010)[77] advocates focusing on renewable energy and energy efficiency technologies to achieve California's economic recovery and growth goals, creating more than half a million green jobs. In the area of building efficiency, the plan calls for:

  - Adopting stronger appliance standards for lighting, consumer electronics, and other products.

  - Creating new efficiency standards for new buildings.

  - Adopting a plan and timeline for achieving "zero net energy" homes and businesses through the building standards by integrating high levels of energy efficiency with onsite renewable electricity generation.

  - Increasing public education and enforcement efforts so that the gains promised by California's efficiency standards are realized.

  - Making existing buildings more efficient, especially the half of California homes that were built before the advent of modern building standards.

74 California Energy Commission, *Achieving Energy Savings in California Buildings: Saving Energy in Existing Buildings and Achieving a Zero Net Energy Future*, July 2011, CEC-400-2011-007-SD, available at: www.energy.ca.gov/2011publications/CEC-400-2011-007/CEC-400-2011-007-SD.pdf.

75 California Air Resources Board, *Climate Change Scoping Plan: A Framework for Change*, December 2008, page 16, arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm.

76 The California Air Resources Board, California Public Utilities Commission, the Energy Commission, and California Environmental Protection Agency are partnering with the California ISO to ensure California's continued leadership in clean technology over the coming decade. See *California's Clean Energy Future: An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond*, available at www.cacleanenergyfuture.org/.

77 Governor Jerry Brown, see www.jerrybrown.org/Clean_Energy.

- Providing energy performance information to commercial investors and homebuyers by requiring disclosure prior to the purchase of the building or home.

To respond to these policy expectations, the Energy Commission and other agencies are collaborating on strategies to achieve extensive energy savings in newly constructed and existing buildings, benefiting all Californians by reducing energy costs and the environmental and climate impacts of buildings.

Goals and Strategies for Newly Constructed Buildings

Zero Net Energy Buildings

The Energy Commission, California Air Resources Board (ARB), and the California Public Utilities Commission (CPUC) have adopted the policy goal, consistent with existing statutory authority, to achieve zero net energy (ZNE) building standards by 2020 for residential buildings and 2030 for commercial buildings through the *2008 Energy Action Plan*, *2007 IEPR*, and the *2008 California Long-Term Energy Efficiency Strategic Plan*. The CCEF initiative and Governor Brown's Clean Energy Jobs Plan also identify ZNE as a priority goal.

A ZNE building has zero net energy consumption. Consistent with the loading order, the goal is to minimize energy use as much as technologically possible through cost-effective efficiency measures, and then generate the balance of the building's energy needs with onsite renewable electricity generation such as solar photovoltaic systems or wind-driven electricity generators. The substantial energy efficiency improvements built into ZNE buildings contribute also to maintaining and improving the building's comfort and functionality.

While the ZNE idea is straightforward, translating the policy into standards, guidelines, and incentive structures requires collaboration between agencies and stakeholders. To maximize the alignment of ZNE with California energy system reliability and policy goals, the Energy Commission recommends the use of metrics that account for the societal value of energy, including the critical impact of avoiding peak demand and the value of avoided carbon emissions, and other energy system costs. These components are well-addressed in the time-dependent valuation of energy concept used by the Energy Commission for its efficiency standards and the CPUC for its valuation of efficiency program savings.[78]

Building Energy Efficiency Compliance and Reach Standards

California's mandatory Building Energy Efficiency Standards (Building Standards) are fundamentally performance standards that establish an "energy budget" for the entire building as an alternative to prescriptive requirements for individual components. This affords California builders, designers, and contractors the flexibility to achieve energy efficiency in buildings using a wide array of measures that fit their construction goals and meet the standards at the lowest cost.

The Building Standards are an important strategy for meeting the ZNE goal, as each subsequent standards update (done on a three-year cycle) will progressively raise the bar by requiring increased energy-saving features in building designs and

78 Under the time-dependent valuation of energy, the value of electricity differs depending on time of use (hourly, daily, seasonally) and the value of natural gas differs depending on season. Time-dependent valuation is based on the cost for utilities to provide energy at different times.

equipment. Using cost effective efficiency requirements, the Energy Commission's goal is to achieve a 20 to 30 percent energy savings for each triennial Building Standards update. As an initial step, the 2013 Building Standards will address high-efficacy building envelopes, lighting, and heating, cooling and water heating systems, and energy demand response management technologies.

No matter how much demand is reduced, however, some amount of onsite generation will be required. As part of its policy setting responsibility under Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) and its management responsibility for the New Solar Homes Partnership, the Energy Commission developed standards and tools for achieving high performance rooftop photovoltaic (PV) systems. These standards and tools are designed to promote high-efficiency solar energy system components, effective installation practices, and calculation and demonstration of expected system performance. They will serve as the foundation for considering upcoming building standards for rooftop PV systems.

The joint agency strategy for achieving the ZNE goals calls for establishing not only mandatory standards in each triennial update of the Building Standards, but voluntary "reach standards." The reach standards further a "market pull strategy" by establishing higher standards than required, which can be used when developing minimum standards in subsequent cycles. These reach standards are often met by a substantial portion of newly constructed buildings, demonstrating their feasibility, cost-effectiveness, and value in the market. In developing these standards, the Energy Commission collaborates with the CPUC and the utilities' new construction programs to incentivize builders to meet the reach standards. In addition, they are included as voluntary measures in the California Green Building Standards Code (Title 24, Cal. Code Regulations, Part 11).

Other governmental agencies incorporate the reach standards as locally mandated requirements in their regulations and programs. For example, local governments are including them in local green building and energy ordinances, and the California Tax Credit Allocation Committee has incorporated these standards in its regulations governing qualification for federal and state tax credits for affordable housing projects. Several benefits accrue when a substantial portion of the marketplace constructs buildings that meet the reach standards. Industry gains expertise in delivering greater building efficiency. Also, costs tend to decline for the more efficient features as they become mainstream rather than premium and as suppliers and installers compete to provide them.

Strategies for Existing Buildings

More than half of California's 13 million residential units and more than 40 percent of the commercial buildings were built before 1978, when the state first implemented Building Energy Efficiency Standards. These existing buildings, and the rest built under previous vintages of the Building Code, provide a huge opportunity for low-cost energy savings. The *AB 32 Scoping Plan* concluded that improving the energy efficiency of existing residential and commercial buildings is the most important way to reduce GHG emissions in the electricity and natural gas sectors. The CPUC's Long Term Energy Efficiency Strategic Plan set major goals for achieving deep, whole building energy savings in existing residential and commercial buildings. Efficiency improvements in existing buildings are also a priority goal of both the CCEF initiative and Governor Brown's Clean Energy Jobs Plan.

The Legislature at several points in time has directed the Energy Commission to develop policies and programs to pursue improved efficiency in

existing buildings, including to develop a statewide Home Energy Rating System Program (Senate Bill 1922 [Lewis, Chapter 553, Statutes of 1994]), develop and report to the Legislature recommendations for improving the energy efficiency of existing buildings in California (Assembly Bill 549 [Longville, Chapter 905, Statutes of 2001]), investigate options and develop a plan to decrease peak electricity demand for air conditioners across the state (Assembly Bill 2021 [Levine, Chapter 734, Statutes of 2006]), and establish a program requiring nonresidential building owners to benchmark the energy use of their buildings in comparison to other similar buildings and disclose the benchmarking data and ratings to prospective buyers, lessees, and lenders (Assembly Bill 1103 [Saldaña, Chapter 533, Statutes of 2007] and Assembly Bill 531 [Saldaña, Chapter 323, Statutes of 2009]). Building on this prior legislation, Assembly Bill 758 (Skinner, Chapter 470, Statutes of 2009) directed the Energy Commission to develop, adopt, and implement an ongoing, comprehensive, statewide program to reduce energy consumption in existing buildings, including the adoption of regulations for energy ratings and improvements in existing buildings.

This comprehensive portfolio of programs is required to implement a variety of complementary techniques, applications, and practices to achieve greater energy efficiency in homes and businesses. AB 758, for example, authorizes (among other things) the program to provide:

- Energy assessments to identify and recommend opportunities for saving energy use in individual buildings.
- Energy efficiency financing options and other financial incentives.
- Information and education to property owners to help them implement energy efficiency improvements.
- Systematic workforce training to ensure that workers employed to provide the services needed under the program will be well trained and supported to deliver high-quality work.

The Energy Commission is required to evaluate the most effective ways to report the energy assessment results and efficiency improvement recommendations to the property owners, including prioritizing the energy efficiency improvements and determining how different types of financial incentives and financing can be used to accomplish the improvements. The bill also directs the Energy Commission to evaluate the appropriate methods to inform and educate the public about the need for and benefits of making energy efficiency improvements.

AB 758 calls for the Energy Commission to develop and implement the program in collaboration with the CPUC and industry stakeholders. The CPUC is directed to investigate the ability of investor-owned utilities to provide financing to their customers for energy-efficiency improvements and to report to the Legislature the progress of the utilities in implementing the program.

Contemporaneously with the passage of AB 758, the federal government passed the American Recovery and Reinvestment Act (ARRA). ARRA funding provided California additional resources to develop and conduct programs aimed at saving energy, creating jobs, and contributing to California's economic recovery through energy efficiency upgrade projects in existing buildings. The Energy Commission designed the ARRA-funded programs to incorporate the same approaches that were called for by AB 758 as a way to pilot those approaches. The ARRA programs emphasized collaborations of local governments and industry to deliver energy assessments, ratings, efficiency improvements, and quality assurance. ARRA also funded the nation's largest workforce development effort, meshing the well-established state and local workforce development infrastructure with statewide

efforts to implement energy efficiency upgrades in existing buildings.

In an unprecedented collaboration, the Energy Commission, CPUC, local governments, and utilities came together to closely coordinate residential and commercial building upgrade programs under the Energy Upgrade California™ brand. The collaborative pilot programs provided a number of components authorized by AB 758, including:

- Public Awareness and Outreach
- Workforce Development
- Financing Options and Financial Incentives (Rebates)
- Energy Performance Ratings and Disclosure
- Efficiency Recommendations and Improvements (including Quality Assurance)

Major efforts have occurred all over California to implement and pilot each of these AB 758 program components. These efforts leveraged the ARRA funding to collaborate on the details of delivering energy efficiency upgrades in existing buildings. In the area of clean energy financing options, for example, the ARRA-funded programs have allowed California to establish revolving loan programs that will remain in operation after the ARRA funding ceases, provide loan loss reserves to encourage lenders to provide financing for energy efficiency upgrades, and pilot Property Assessed Clean Energy (PACE) financing in concert with local property assessments. On August 2, 2011, Governor Brown signed Assembly Bill X1 14 (Skinner, Chapter 9, Statutes of 2011), authorizing the State Treasurer to administer a new $50 million program to provide loan loss reserves for energy upgrades consistent with Energy Commission guidelines. This new program represents a major opportunity for the Energy Commission, State Treasurer's Office, CPUC, and other partners to create financing solutions for building owners wanting to implement energy upgrade projects. In addition, on January 10, 2012, the CPUC issued an Administrative Law Judge's ruling on energy efficiency financing requesting comments on a CPUC Energy Division staff proposal on energy efficiency financing activity in 2013–2014, a report prepared for the CPUC on energy efficiency financing needs and gaps, and a proposal by the Environmental Defense Fund on on-bill repayment.[79]

The Energy Commission's next steps are to complete needs assessments for both residential and nonresidential buildings, identify what must be done in each of AB 758's program component areas (taking advantage of the lessons learned from the ARRA piloting), and develop action plans for moving forward with AB 758 program development. The AB 758 program will be developed in three phases. Phase 1 (2010–2012) will include developing infrastructure and implementation plans. Phase 2 (2012–2014) will support market development and partnerships, and Phase 3 (2014 and beyond) will include development of statewide ratings and upgrades requirements.[80] The implementation plans developed under Phase 1 will include detailed schedules of activities, and each Phase will include ample opportunity for public input. Key areas of focus include recommending improvements to the Home Energy Rating System program, developing the Commercial Building Energy Asset Rating System (BEARS), and building strategies for effective rating, labeling, and disclosure of energy efficiency information. Attention will also focus on improving compliance with and enforcement of California's Building Energy Efficiency Standards requirements for alterations of existing buildings. As a condition for accepting ARRA State Energy Program funding, each state's governor

79 California Public Utilities Commission, Administrative Law Judge's Ruling Regarding Energy Efficiency Financing, January 10, 2012. docs.cpuc.ca.gov/efile/RULINGS/157347.pdf

80 For more information on the program, see www.energy.ca.gov/ab758/

committed to putting advanced state energy codes into effect (such as the Energy Commission's 2008 and subsequent Building Energy Efficiency Standards) and developing approaches to achieve high levels of compliance with these standards.

AB 758 directed the Energy Commission and the CPUC to collaborate on how to best deliver financing and design utility programs for upcoming funding cycles to advance the comprehensive AB 758 program.

Efficiency Improvements in Appliances

The Appliance Efficiency Standards (Appliance Standards) are another strategy for reducing energy use in newly constructed and existing buildings. While permanently installed equipment and appliances are a substantial part of the building's energy use,[81] electronics and other devices plugged into outlets make up a growing portion of California's energy use. Unfortunately, the energy use (and thus the true cost) of appliances and electronic devices is often invisible to the consumer, and manufacturers lack the direct incentive (of having to pay for the energy these products consume) to design products that use energy efficiently.

The Energy Commission's Appliance Standards can address this issue by setting cost-effective minimum efficiency requirements for appliances, electronics, and other devices. These efficiency standards set the bar at a level that affects only the least efficient products. Since 1976, the Energy Commission has adopted standards covering a wide range of appliances, including all major household appliances, air conditioners, furnaces, and water heaters. In many instances, California standards have subsequently been adopted as national standards by the United States Department of Energy (U.S. DOE).

Historically, California's energy efficiency standards have resulted in significant reductions in energy consumption. The Energy Commission estimates that appliance efficiency standards adopted between 1976 through 2005 saved 18,761 gigawatt hours (GWh) in 2010.[82] This represents 6.7 percent of California's electric load and is roughly the amount of energy produced by California's two largest power plants. At an average rate of 14 cents per kilowatt hour, appliance efficiency regulations saved California consumers about $2.68 billion in 2010.

Despite the success of appliance efficiency standards, the amount of energy consumed by devices plugged in by building occupants ("plug load") has been climbing rapidly.[83,84] To address these growing plug loads, the Energy Commission has initiated and completed several rulemakings covering products such as televisions, external power supplies (EPS), DVD players, and compact audio devices. These regulations provide minimum efficiency or maximum power use requirements for more than 76 million unit sales per year (TV: 4 million 2010, EPS: 20.6 million 2005, DVD: 3.5 million, compact audio: 3.1 million). The Energy Commission is also developing standards for the estimated 58 million battery chargers sold (2009) in California per year. The estimated energy savings for battery charger standards is 2,000 GWh per year,[85] of which 1,600 GWh will be attributable to reduced residential plug load energy demand and 400 GWh toward reduced commercial plug load energy demand. The battery charger standards will improve the efficiency of a wide range of plug loads, such as laptop computers, power tools, electric toothbrushes, cell phones, mp3 players, and golf carts.

The Energy Commission is developing a new scoping order to identify the appliance types that should be included in new standards and to upgrade levels of existing standards. Stakeholder proposals have identified up to 8,000 GWh in potential savings from new standards. Proposals include computers and computer servers, set top boxes, linear fluorescent fixtures, and outdoor lighting as key opportunities for new Appliance Standards.

Improvements to Lighting Efficiency

Lighting is the largest electrical load in both homes and businesses, accounting for 35 percent of commercial annual electricity use and 22 percent of residential annual use. Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007) requires an 11 percent reduction in electricity consumption from residential lighting and an 8.6 percent reduction from commercial lighting. Achieving these goals would reduce California's total electricity use by more than 6 percent.

Since the passage of AB 1109, the U.S. DOE has adopted new federal standards for general service fluorescent lamps and incandescent reflector lamps. California has exercised its discretion to implement the federal standards one year ahead of the federal schedule. The Energy Commission has also gone beyond the scope of the federal standards by adopting new standards for metal halide and portable luminaires, updated lighting efficiency, and design and use standards in the 2008 Building Energy Efficiency Standards, and will further address lighting efficiency in upcoming triennial updates. The above initiatives will advance the state's progress in meeting the AB 1109 residential lighting mandates. However, the challenge of meeting commercial lighting and outdoor lighting mandates must be addressed through additional standards and voluntary programs developed in collaboration with the lighting industry, consumers, the CPUC, and the state's utilities.

Light-emitting diode (LED) lamps are a promising example for advancing beyond current mandatory lighting standards. LEDs have enormous energy savings potential given their inherent efficiency at converting electricity to light. However, a number of challenges regarding cost, quality, and efficacy must be addressed. Rapid advancements in LED technology have led to a proliferation of products in a growing range of applications at lower prices. Research at the California Lighting Technology Center (CLTC) has revealed large variations in quality across a number of performance parameters, including light quality and longevity, which could reduce consumer acceptance of the technology. As with early efforts to bring compact fluorescent lamps to market, when similar performance quality issues severely dampened consumer demand, there is a risk that barriers to wide acceptance of LEDs could result if California consumers have negative experiences with low-performing products. To address this risk, the Energy Commission is working with CLTC engineers, industry, the state's utilities, and the CPUC to develop product quality specifications for LEDs that could serve as a basis for future utility incentive programs.

Achieving Better Compliance With Standards

Compliance with Building Standards is much better for new construction than for alterations to existing buildings, primarily because alterations are frequently made without the required permits. Without the oversight of local building officials, energy efficiency codes are rarely followed. For example, less than 10 percent of contractors pull building permits and abide by legal requirements for change outs of furnaces and air conditioners. In general, local building departments have limited resources for enforcing building codes, especially those beyond minimum health and safety requirements. The lack of compliance with standards can result in defective construction and installation, including improper installation of wall and duct insulation, HVAC systems, and other efficiency measures, all of which can drive up energy costs for home and building owners.

Widespread noncompliance with appliance regulations also has been brought to light through complaint filings by competing manufacturers and retailers as well as energy efficiency advocates and others. Recent market surveys reveal high rates of noncompliance with the Appliance Standards, finding large numbers of ineligible products being offered for sale in stores, through catalogs, and over the Internet. Addressing the issue of noncompliance has been extremely difficult because the Energy Commission has had limited authority to take enforcement actions against noncompliant manufacturers, distributors, and retailers. If an appliance was found to be noncompliant with a standard, the Energy Commission could conduct an administrative hearing to remove it from the database (if it were improperly certified). However, the Energy Commission was required to petition the Attorney General to seek injunctive or other relief from a court to forbid the sale of an appliance. This administrative process could take up to 390 days, and court actions can take many months or years.

On October 8, 2011, Governor Brown signed Senate Bill 454 (Pavley, Chapter 591, Statutes of 2011) into law, which will help address the challenge with widespread noncompliance by manufacturers and retailers. The legislation allows the Energy Commission to adopt an enforcement process for violations of appliance efficiency regulations and impose civil penalties of up to $2,500 for each violation. The bill establishes the Appliance Efficiency Enforcement Subaccount within the Energy Resources Program Account, where civil penalty funds will be deposited that can then be spent upon appropriation by the Legislature for public education and enforcement of the appliance efficiency standards.

The Energy Commission will use the following criteria in assessing a civil penalty:

- The nature and seriousness of the violation
- The number of violations
- The persistence of the violation
- The length of time over which the violation occurred
- The willfulness of the violation
- The violator's assets, liabilities, and net worth
- The harm to consumers and to the state from the amount of energy wasted because of the violation

Following these criteria will ensure that the Energy Commission imposes only appropriate penalties against violators based on specific circumstances. By providing this authority to the Energy Commission, the Legislature has helped ensure a level playing field for all regulated manufacturers.

Recommendations

Newly Constructed Buildings

- The Energy Commission and CPUC should work jointly on developing a definition of ZNE that incorporates the societal value of energy (consistent with the time dependent energy valuation approach used for California's Building Energy Efficiency Standards).
- The Energy Commission should adopt triennial building standards updates that increase the energy efficiency of newly constructed buildings by 20–30 percent in every triennial update to achieve ZNE standards for newly constructed homes by 2020.
- The Energy Commission should adopt reach standards for newly constructed buildings that provide best practices energy efficiency levels for the marketplace to strive for and serve as a means to pull the industry rapidly to the level needed to achieve ZNE goals.
- The Energy Commission, CPUC, local governments, the state's utilities, and builders should collaborate to encourage the building industry to reach these advanced energy efficiency levels in a substantial segment of the market through industry-specific training and financial incentives.
- The Energy Commission and CPUC should coordinate future investor-owned utility "new construction-related" programs with the Energy Commission's efforts to meet the ZNE goals through triennial updates of mandatory and reach standards. By offering incentives for achieving reach standards, providing technology demonstration and development, and conducting pilot programs for demonstrating ZNE solutions, new technologies and building practices will be integrated into upcoming triennial updates of the Building Standards quicker and with more success.
- The Energy Commission, CPUC, builders, and other stakeholders should collaborate to accomplish workforce development programs to impart the skills necessary to change building practices to accomplish ZNE in newly constructed buildings.

Existing Buildings

- The Energy Commission and CPUC should coordinate future investor-owned utility energy efficiency portfolios with the programs and rules developed in the Energy Commission's AB 758 proceeding. The Energy Commission, in collaboration with stakeholders, should develop an asset rating system for nonresidential buildings that can be used to rate the energy efficiency of commercial properties and provide owners and potential buyers with information about the energy efficiency of the buildings they own or are considering for lease or purchase. This will help drive market demand for efficiency. The Energy Commission also should consider how the cost-effectiveness of options to achieve greater energy efficiency in these buildings can be addressed in conjunction with building asset ratings. The Energy Commission, utilities, the CPUC, and other stakeholders should collaborate to pilot the implementation of the rating system through education and financial incentives.

81. The breakdown of 2009 annual household electricity consumption by end use is: lighting, 22 percent; refrigerators and freezers, 18 percent; television, computer, and office equipment, 15 percent; air conditioning, 7 percent; pools and spas, 7 percent; dishwasher and cooking, 4 percent; laundry, 4 percent; space heating, 2 percent; water heating, 3 percent; and miscellaneous, 11 percent. California Energy Commission, 2009 California Residential Appliance Saturation Study, October 2010, page 3, www.energy.ca.gov/2010publications/CEC-200-2010-004/CEC-200-2010-004-ES.PDF.

82. Savings from California's appliance efficiency standards are forecasted to grow to 27,118 GWh a year by 2020. This would represent 8.4 percent of projected load in 2020. At the current rate of 14¢ per kilowatt hour, this would save the state about $3.8 billion for 2020. See www.energy.ca.gov/2009_energypolicy/index.html.

83. S.B. Rolnig, C. Haley, R. Anderson, and L. Prutsch, November 2008, Building Alterative System Research Plan for Reduction of Miscellaneous Electrical Loads in Zero Energy Homes, National Renewable Energy Laboratory and U.S. Department of Energy, NREL/TP-550-43718, page 1, www.nrel.gov/docs/fy09osti/43718.pdf.

84. U.S. Energy Information Administration, March 28, 2011, Share of Energy Used by Appliances and Consumer Electronics Increases in U.S. Homes, available at www.eia.gov/consumption/residential/reports/electronics.cfm.

85. Future savings estimated to be achieved in any year after the entire stock of appliances that are covered by the standards meet the requirements of the standards. This would happen in a future year after all such appliances that were manufactured prior to the effective date of the standards are no longer in use because they have reached the end of their useful lives.

- The Energy Commission should review ARRA pilot programs to identify lessons learned and opportunities for improvements in rating systems, financial products, workforce development, consumer education, and program coordination.

- The CPUC, the Energy Commission, the State Treasurer, and other agencies should collaborate with local governments, the financial industry, and other stakeholders to promote the availability of financing products for the upgrade of all building sub-sectors.

- The Energy Commission should focus significant resources during the next Building Standards update on efficiency improvements in building additions and alterations.

Appliance Efficiency Standards

- The Energy Commission should adopt appliance standards that focus on reducing plug loads to enable California's ZNE goals to be achieved.

- The Energy Commission should continue to adopt standards for appliances that represent the most significant statewide energy savings potential.

- The Energy Commission and CPUC should collaborate on research to identify the most cost-effective opportunities for new appliance standards and to reevaluate existing standards to identify the most cost-effective opportunities for updates to achieve greater energy savings.

- The Energy Commission and CPUC, in collaboration with utilities and other stakeholders, should jointly develop a roadmap to meet the lighting energy savings mandated by AB 1109, including new appliance and building efficiency standards and market transformation programs to achieve higher levels of energy efficiency than required by standards.

- The Energy Commission should collaborate with industry to develop reach standards for appliances that set higher expectations in California for the quality and performance of key appliances.

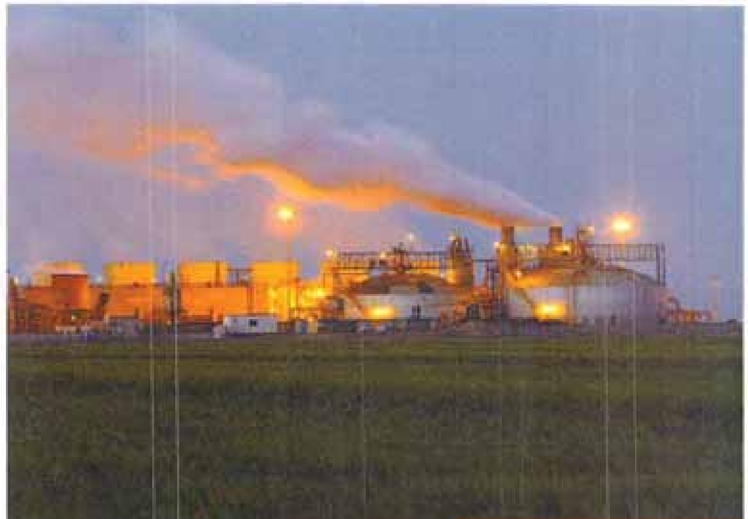
- The Energy Commission and CPUC should collaborate to develop voluntary LED quality performance standards.

- The Energy Commission should engage in DOE proceedings that are developing federal test methods and appliance standards.

Compliance With Standards

- The Energy Commission should immediately begin developing regulations to implement the enforcement authorities provided by SB 454 to increase compliance with the Appliance Standards.

- The Energy Commission and CPUC should emphasize joint efforts to achieve improved compliance with the Building Energy Efficiency and Appliance Standards.



CHAPTER 5

California's Clean Energy Future

This chapter reports on the status of the California's Clean Energy Future (CCEF) joint agency collaborative effort.

Recognizing the growing interdependencies among the state's energy and environmental agencies, the California Air Resources Board (ARB), California Environmental Protection Agency (Cal/EPA), California Energy Commission, California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO) developed a vision, implementation plan, and roadmap to achieve a clean energy future for California.[86] Launched in 2010, the planning effort focuses on 2020, with consideration of the goal to reduce greenhouse gas (GHG) emissions to 80 percent below 1990 levels by 2050.[87]

86 These documents are available at: www.cacleanenergyfuture.org

87 Executive Order S-03-05, gov.ca.gov/news.php?id=1861

The purpose of the CCEF effort is to:

- Compile existing policy goals to support inter-agency planning and management.

- Identify policy interdependencies, key milestones, and delivery risks to improve communications and cooperation.

- Use adaptive management practices "to identify policy overlaps, conflicts, unanticipated or unintended consequences, and to make necessary trade-offs and course corrections."[88]

The *California's Clean Energy Future: Overview* (*Overview*) outlines the agencies' vision for 2020. The agencies released the planning document in September 2010, but it has not yet been updated to reflect the goals of the Brown Administration. The agencies plan to refresh their planning efforts to reflect significant developments since its release, such as the passage of legislation to enact the 33 percent Renewables Portfolio Standard (RPS). Future planning efforts will also reflect findings coming from the Governor's July 2011 Conference on Local Renewable Energy Resources, the Energy Commission's report on *Renewable Power in California: Status and Issues*, and the Energy Commission's *RPW* and *Renewable Strategic Plan* that will be developed in 2012.

The *Overview* focuses on four elements for achieving the state's 2020 electricity and natural gas goals, with the first being energy demand. As currently drafted, the agencies target reductions of 5,000 to 8,150 MW on peak by 2020 with advancements in efficiency and demand response. This is in addition to the 2,300 MW (on-peak) committed energy efficiency savings already included in the 2009 demand forecast. The current version also calls for installing 5,000 MW of distributed generation (DG) by 2020, although the agencies recognize Governor Brown calls for 12,000 MW of localized renewable generation by 2020.

The second element is energy supply. The *Overview* envisions achieving a 33 percent RPS while maintaining reliability needs and meeting environmental goals, such as phasing out once-through cooling in power plants. The agencies put forward a goal of developing at least one utility-scale carbon capture and storage facility in California by 2020.

The third element is transmission, distribution, and operations. The agencies envision a coordinated effort for planning and permitting to ensure that sufficient transmission and distribution-level infrastructure will be available to meet renewable goals and GHG reduction targets. Investments in advanced metering and smart grid will empower customers to use energy more efficiently. Through agency-supported pilot studies, the agencies are targeting 1,000 MW of additional storage capacity by 2020 to promote renewable integration.

The fourth element is additional supporting processes, including cap and trade, to provide opportunities for lower-cost GHG reductions and advancements in emerging technologies. The *Overview* also recognizes that alternative fuel vehicles, and electrification of the transportation sector in particular, will be a central component to energy security and reduced GHG emissions. The *Overview* calls for California to "develop the infrastructure and operational capabilities necessary to absorb a targeted 1,000,000 fully electric and plug-in hybrid electric vehicles (PHEV) by 2020." In addition to efforts to reduce GHG emissions, California will need to plan for and adapt to actual changes in climate, such as temperature and precipitation changes and other impacts affecting energy supply and demand. Finally, the plan calls for engaging California's institutions and residents as partners in achieving these goals.

88 California's Clean Energy Future, 2010, Overview, page 1, see: www.cacleanenergyfuture.org/CACLEANENERGYFUTURE.pdf

CCEF Updates and Metrics

On July 6, 2011, the Energy Commission held an IEPR workshop jointly with the ARB, Cal/EPA, California ISO, and CPUC to discuss updates to the *California's Clean Energy Future* planning document. Updates provide an opportunity for incorporating new policy developments and identifying any areas that need course correction. The agencies anticipate the planning updates to include:

- 33 percent Renewables Portfolio Standard (RPS) legislation Senate Bill (SB) X1 2 (Simitian, Chapter 1, Statutes of 2011–12 First Extraordinary Session).
- The goals in the Governor's Clean Energy Jobs Plan, including:
  - 12,000 MW of localized energy by 2020.
  - 8,000 MW of large-scale renewable and associated transmission lines.
  - Develop 6,500 MW of combined heat and power (CHP) over the next 20 years.
- Metrics and data references to indicate progress toward achieving California's clean energy goals and indicate opportunities for the CCEF agencies to propose course corrections.

At the workshop, the IEPR Committee requested comments from stakeholders and the public on draft metrics and received 21 sets of comments. While the agencies could not reflect all the comments, the discussion below highlights the changes made to the metrics in response to stakeholder input. Below is a discussion of the metrics and how they were updated from the workshop.[81]

The agencies publicly posted the revised metrics on the CCEF website[82] on December 22, 2011. The agencies will be updating the metrics periodically to reflect new information.

GHG Emissions

The metric presented at the workshop shows historical and forecasted GHG emissions from 2000 to 2020. Emission forecasts provide a reference for assessing the effect of GHG reduction measures. In response to stakeholder comments, staff revised this metric to include information on GHG intensity, such as GHG emissions per capita and per gross state product, as suggested by Sempra. Other revisions include: adding a business-as-usual projection (per Environmental Defense Fund) and providing a graphic showing progress of GHG emission reductions for all sectors included in Assembly Bill 32 (Nuñez, Chapter 488, Statutes of 2006) (per Natural Resources Defense Council [NRDC] and Southern California Edison [SCE]).

Energy Efficiency

The metric presented at the workshop shows California investor-owned utilities' (IOUs) and publicly owned utilities' energy savings from 2006 to 2010. The metric also shows the IOUs' annual energy savings, peak savings, and natural gas savings in comparison with the goals set by the CPUC. For the publicly owned utilities, the metric shows net annual energy savings and net peak savings as reported by the utilities in comparison with efficiency goals set by the Energy Commission. Stakeholder comments on this metric included NRDC's suggestion to show indicators of net benefits of energy efficiency programs and energy efficiency codes and standards. Sempra suggested adding an indication of the energy intensity of existing and new buildings. Bostonique Knight Inc. supports adding the savings expected from zero net energy strategies included in the *California Energy Efficiency Strategic Plan*.[83] Staff revised the metric to provide indicators of cost effectiveness for utility energy efficiency portfolios, the energy intensity standards for California homes constructed after 2001, progress toward zero net energy homes, and energy savings from building codes and standards.

Demand Response

Demand response generally refers to a reduction in customers' electricity consumption over a given time interval in response to a price signal, other financial incentives, or a reliability signal. The demand response metric provides a historical view of the estimated levels of demand response for the IOUs from 2009 through 2011, and a projection to 2020, which assumes broad deployment of advanced metering infrastructure. Staff plans to modify this metric as more information becomes available through the CPUC's Smart Grid Rulemaking.

Renewable Energy

The metric presented at the workshop shows the amount of renewable generation for California, including large hydro, from 1983–2009 and estimates of the amount of renewable generation needed to meet the 2013, 2016, and 2020 RPS targets. Data are also provided showing historical generation by fuel type. Since the RPS calls for a specified percentage of retail sales served with renewable energy, the metric shows a range for the amount of renewable energy needed to meet the RPS target based on factors that can affect retail sales, including energy efficiency, self-generation, CHP, and economic and population growth.

Comments from stakeholders included a suggestion by the Sierra Club to add information on project failure by procurement program (SB 32, California Solar Initiative, Renewable Auction Mechanism, feed-in Tariff). Pacific Gas and Electric (PG&E) suggested adding indicators related to the CCEF goal that "a significant fraction of renewables will be dispatchable." SCE asked staff to clarify the impact of recontracting on progress toward RPS goals. In response to comments, staff added information on progress for each procurement mechanism and information to track dispatchable renewable resources. Also, staff revised the information on approved and pending RPS contracts to show only contracts for new resources. Finally, a graphic showing the development progress of new renewable projects under contract with the IOUs was revised to show estimated project feasibility based on the CPUC's analysis.[84]

Installed Capacity

This metric presented at the workshop shows on-line, nameplate capacity for all electricity generation resources in California by technology from 2001 to 2010.[85] If all contracts for new large-scale renewable energy facilities in California succeed, they will add more than 8,000 MW. In response to Independent Energy Producers' (IEP) suggestion to show growth rates, staff revised the metric to show that contracts for large renewable resources in California are scheduled to come on-line at an average annual growth rate of 18 percent per year from 2011–2016.

The CCEF includes a goal to add 1,000 MW of energy storage by 2020. In response to comments calling for more information about storage, staff shows that about 2,800 MW of pumped hydropower were on-line in 2010 in California. Nine additional projects in California with a combined capacity of 4,900 MW have received licenses from the Federal Energy Regulatory Commission. The goal to add 1,000 MW of new storage would be met if about 20 percent of the licensed capacity completes environmental permitting and comes on-line by 2020. Several hundred megawatts of distributed electricity storage facilities may come on-line by 2020 as well, depending on various factors. For example, one factor is the outcome of the CPUC's Assembly Bill 2514 proceeding (OIR R.10-12-007), which will determine whether and how the CPUC should further encourage storage. Other examples include the eligibility of storage for incentives, the results of utility storage demonstration projects, the cost of storage, and rate structure developments that could make storage more attractive.

Staff revised the metric to show estimates of CHP potential and a goal of adding about 6,500 MW of CHP by 2032. To achieve the goal, staff estimates that CHP would need to grow about 4.7 percent per year from 2012–2032.

Sempra stated that even if the energy efficiency goals are met, the goals for new electricity facilities cannot be met because supply would exceed demand for electricity.[86] In response to this comment, staff expanded the discussion of the interaction of goals for high levels of energy efficiency and the Governor's goals for renewable energy and CHP.[87]

Transmission Expansion

Twelve transmission projects are underway in the California ISO's footprint that will provide sufficient capacity for the state to achieve the 33 percent RPS.[88] The metric tracks the approval status, capacity, and expected on-line date of these projects.

Electric Vehicle (EV)

The metric presented at the workshop shows actual sales-to-date of EVs in California, a scenario of anticipated sales under the Zero Emission Vehicle program, and the potential sale of 1 million EVs consistent with the CCEF goal. For the Zero Emission Vehicle program, the metric reflects anticipated cumulative sales for both battery EVs and PHEVs. In response to stakeholder comments, staff plans to add information on efforts underway to advance deployment of infrastructure needed for the expanded use of plug-in electric vehicles in California.

Energy Demand

The metric on energy demand shows statewide electricity and natural gas consumption from 1990 to 2008 by end-use sector and shows electricity consumption by county. Staff also provided data on noncoincident statewide net peak[89] demand for 1990 to 2009, reflecting a combination of peaks that often occur at different times in different planning areas. In addition, staff provided data on coincident statewide peak demand, which is the peak demand for California at the same point in time.

Reserve Margin

A reserve margin is a measure of the amount of electricity imports and in-state generation capacity available over average peak demand conditions. The metric shows available reserve margins in comparison to California's 15 to 17 percent planning reserve target. The planning reserve margin target is intended to assure sufficient electricity supplies can meet real-time operating reserve requirements and ensure that outages occur no more frequently than one-day-in-ten-years.

System Average Rate

The system average rate is calculated by dividing the annual revenue requirement of the IOUs by their annual retail sales. This metric provides a nominal basis for assessing trends in utility costs over time, but it does not necessarily reflect actual rates or trends in those rates experienced by different customer classes.

Once-Through Cooling Phase Out

This metric provides information to track compliance with regulations to phase out once-through cooling (OTC) at 19 power plants in California. Of these, 16 plants totaling roughly 17,500 MW are in the California ISO Balancing Area Authority, and 3 are in the Los Angeles Department of Water and Power Balancing Area Authority. Compliance dates for the power plants range from 2010 to 2024. Staff added a description of the technologies and strategies that were part of the submitted OTC implementation plans in response to comments from NRDC.

81 At the workshop, staff presented seven metrics and four "data references" that were intended to provide supporting information to the metrics. The CCEF agencies ultimately chose to abandon the distinction between data references and metrics and refer instead to all as "metrics."

82 See www.californiaenergyfuture.org

83 California Energy Commission, July 6, 2011, workshop, comments available at: www.energy.ca.gov/2011_energypolicy/documents/2011-07-06_workshop/comments/

84 www.cpuc.ca.gov/NR/rdonlyres/[illegible].pdf

85 Nameplate capacity is the maximum possible output from a generation facility under specific conditions as designated by the manufacturer.

86 www.energy.ca.gov/2011_energypolicy/documents/2011-07-06_workshop/comments/Sempra_Energy_Utilities_Companies_Comments_on_Item_B_2011-07-20_TN-61463.pdf

87 If existing renewable energy facilities 20 MW and smaller (about 3,000 MW of wholesale and customer-side DG) are counted toward the 12,000 MW goal for localized renewable energy resources, the Governor's goals would add about 17,000 MW of new renewable energy facilities by 2020 and 1,000 MW of new energy storage. Using CPUC input assumptions, the California ISO study on 33 percent RPS modeled "trajectory case" scenarios, adding about 17,500 MW to 20,800 MW of new renewable facilities by 2020. The scenarios assumed a large amount of energy efficiency (more than 16,000 GWh) was achieved by 2020 beyond the levels included in the 2009 energy demand forecast. https://www.caiso.com/[illegible].pdf, Exhibit 3, Table 6.1 The CHP goal extends to 2032; depending on the renewable resource mix, the amount of energy efficiency achieved, and replacement of gas-fired power plants in California that use OTC, achievement of the CHP goal may not begin in earnest until after 2020. "Post 2020, additional investments in renewable generation may be needed to replace generation expected to decline over the course of the next decade, such as generation from expiring QF contracts. Generation from a number of these contracts, which currently represents about 10 percent of total generation serving California, is expected to decline by 63 percent between 2010 and 2020 due to constraints imposed by the Emission Performance Standard. Remaining QF contracts are expected to expire between 2017 and 2020, which will require replacement with a mix of renewable and thermal generation with storage to satisfy electricity needs while still meeting greenhouse gas emission reduction goals." www.energy.ca.gov/2011publications/CEC-200-2011-002/CEC-200-2011-002-LCF-REV1.pdf

88 The number of transmission projects (12) differs from the 13 projects described in Chapter 2 because this metric includes only projects within the California ISO balancing authority area.

89 Net peak is total electricity demand at peak on the customer side, plus utility transmission and distribution losses, minus peak demand met by self-generation.

Additional Metrics

Based on input from the workshop and written comments, the CCEF agencies added the following five metrics.

Expected Jobs

This metric provides a preliminary measure of job creation as result of CCEF renewable and efficiency initiatives. This approach takes into account comments from stakeholders that support tracking clean energy jobs in California and those cautioning that it is difficult to provide a precise measurement of the effect of energy policies on jobs.

The analysis estimates gross job creation and does not attempt to estimate job losses or jobs avoided. This analysis is in terms of a "job-year," which is a full-time job that lasts one full calendar year and includes estimates of direct, indirect, and induced jobs.

Private Investment

This provides a rough indication of the level of private investment from new transmission and renewable projects despite the economic downturn. For transmission, the total anticipated investment is on the order of $7.5 billion. The cost estimates are collected from interconnection studies and public filings.

Estimated private investment in central station renewable facilities is based on instant cost, generally referred to as "overnight cost" or "initial capital expenditures," for building a new power plant. Instant cost includes component, land, development, and permitting costs. It also includes connection equipment costs such as for transmission and environmental control. The instant cost is the most significant driver for the levelized cost of electricity, but it does not include the costs associated with the time it takes to build a power plant, such as the effort in securing construction loans.

Staff estimated investment in renewable distributed generation by applying the cost basis used by the United States Treasury for the federal program offering cash grants in place of the 30 percent investment tax credit. The estimate is reduced by 15 percent in 2013 and 2017 to reflect the continued downward trends in installed costs for photovoltaic systems.

Energy From Coal

This tracks reliance on coal to meet California's electricity demand. California Municipal Utilities Association (CMUA), Center for Energy Efficiency and Renewable Technologies, American Lung Association, NRDC, and Sierra Club supported tracking the reduction of coal and natural gas to generate electricity used in California. The metric shows that the electricity generated from coal and petroleum coke plants is expected to decline by 60 percent (32,800 GWh), and the associated greenhouse gas emissions are expected to drop from about 35 million tons of carbon dioxide equivalent (CO_2e) to 12 million tons between 2010 and 2020. The decline in coal contract deliveries is due to the constraints imposed by the Emission Performance Standard (Senate Bill 1368, Perata, Chapter 598, Statutes of 2006). The Emission Performance Standard prohibits California utilities from renegotiating or signing new contracts for baseload generation that exceeds 1,100 lbs of CO_2e emission per MWh. Several contracts with coal generation facilities that exceed the Emission Performance Standard will expire within the decade and cannot be renewed with another long-term contract. Some qualifying facility contracts for small power plants located in California that use coal and petroleum coke are slated to expire through the decade, but some owners are renegotiating contracts for an early termination or considering repowering to burn natural gas or biomass fuels.

Resource Flexibility

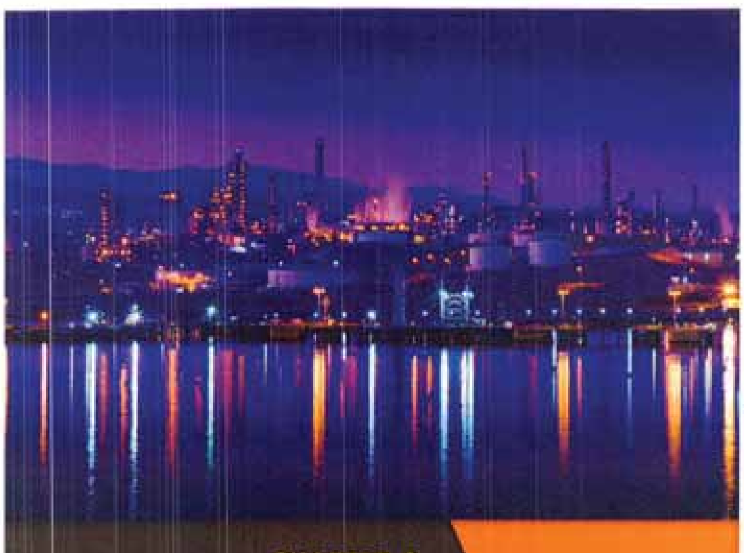
The agencies added a metric on resource flexibility for reliability in response to comments from the CMUA, IEP, and SCE, supporting an indicator of the flexibility of system operations. The metric shows that the resource flexibility needs increase with declining availability of nongeneric[102] resource capacity due to the once-through cooling retirements and the increasing amounts of variable renewable energy resources coming on-line. This metric shows the forecast for additional nongeneric resource capacity requirements to manage the changes based on 2020 renewable portfolio scenarios.[103] The metric shows both upward and downward flexibility requirements. Upward flexibility is provided by resources that are capable of responding to centralized automatic generation controls to increase output as needed to address balancing and load-following requirements. Conversely, downward flexibility involves resources capable of decreasing output.

Distributed Generation

As presented at the July 6 workshop, the installed capacity metric included information about renewable DG 20 MW and smaller (customer self-generation and wholesale), but the CCEF agencies made DG a separate metric to reflect more clearly the Governor's 12,000 MW goal for localized renewable generation.

102 Generic capacity would be that required to support energy requirements, as well as spinning and non-spinning operating reserves. Nongeneric capacity includes resources used for ramping, regulation reserve, and load following, as well as for voltage or inertia support when specifically needed in excess of energy requirements.

103 Rebuttal Direct Testimony of Mark Rothleder on behalf of the California Independent System Operator in CPUC Rulemaking proceeding R.10-05-006, https://www.cpuc.ca.gov/... [illegible] ...pdf, and Draft Technical Appendices for Renewable Integration Studies – Operational Requirements and Generation Fleet Capability at www.caiso.com/... [illegible] ...pdf.



CHAPTER 6

Power Plant Licensing Lessons Learned

The Energy Commission's power plant licensing process was established in 1974 to provide a comprehensive "one-stop" process for permitting thermal power plants 50 MW or larger. Currently the process takes about 12 to 18 months and includes an independent environmental and engineering assessment called a staff assessment (SA). The Energy Commission staff publishes the SA, working collaboratively with federal, state, and local agencies as well as Tribal governments. The assessment is the functional equivalent of a draft environmental impact report and includes all proposed mitigation that would be required by other state and local permits except for the Energy Commission's jurisdiction. In addition to developing the SA, the 12- to 18-month review period includes public workshops, exchange of data through a formal discovery period, evidentiary hearings, publication of the proposed and final decisions, and a final approval hearing.

In December 2010, the Energy Commission's Siting Committee initiated an Order Instituting Informational (OII) Proceeding on "lessons learned" during the licensing of American Recovery and Reinvestment Act (ARRA) solar projects and natural gas-fired power plants reviewed during 2009 and 2010. The OII Proceeding commenced with a scoping workshop attended by various stakeholders, including project proponents, project intervenors, environmental organizations, local government officials, advocacy organizations, elected officials, and the public. Stakeholders provided oral and written comments relevant to the licensing process that were primarily focused on the following topics:

- Timing/coordination with federal permits for large solar projects located on federal lands managed by the U.S. Bureau of Land Management (BLM)
- Staff's information requirements to develop the SA, such as:
  - The length of the SA and the complexity of the mitigation
  - The confusing intervention process and the cumbersome document filing procedures
  - Restrictions on communication between Energy Commission staff and the applicant on substantive issues
  - Local agency and public participation in the planning and permitting of large solar projects
- Siting process consistency between different solar project proceedings, including cumulative analyses determinations and definitions that affect significant impact determinations and associated mitigation
- California Environmental Quality Act (CEQA)/National Environmental Protection Act joint review and alternatives analyses coordination

In the months following the initial scoping workshop, Energy Commission staff began and will continue a process to assess challenges to effective environmental review and facility licensing. Staff also will develop proposed changes to eliminate these challenges, which will help streamline the process without compromising transparency and effective participation. As described below, staff is reviewing three subareas: development/drafting of the SA, evidence and hearings, and the public process.

In addition, staff involved in the OII is closely following the separate but related Desert Renewable Energy Conservation Plan and Programmatic Environmental Impact Statement processes to ensure that the OII lessons learned effort builds on other renewable energy and land use assessments.

Development and Drafting the Staff Assessment

The Energy Commission faces a challenge with the increased length and complexity of SAs and conditions of certification. This was especially true during 2010, when the Energy Commission reviewed several large solar projects – often jointly with the BLM – as part of the ARRA initiative. To help address this issue, staff is evaluating whether the SA can be "pared down" or better formatted in future proceedings, while still meeting the requirements of CEQA and Energy Commission regulations. Staff is comparing Energy Commission environmental documents to those of other state and local jurisdictions to identify effective strategies in drafting environmental analyses. This comparative analysis will help determine if staff documents are within the scope and depth of other agencies' environmental documents, or if Energy Commission documents are outliers. The Energy Commission is under different mandates and requirements than local authorities, including its all-encompassing license, which folds other jurisdictional determinations into its own "one-stop shop process" and ultimately affects the content of SAs and Energy Commission decisions.

Besides reviewing other jurisdictions' environmental documents, another prominent strategy that has transpired as part of the OII Lessons Learned Proceeding is staff training, which is already improving the overall quality of the SA and oral testimony at evidentiary hearings. The training is increasing the consistency between technical sections in the SA and clarifying staff member roles in the project review and document drafting.

Another siting process challenge is the amount of data required upfront in a project application versus what information could be provided during the discovery phase. Ideally, the project proponent (applicant) should file a well-developed project application for certification (AFC) and provide near complete data sets at the time of the AFC's filing, so that staff can efficiently determine the project impacts and develop appropriate mitigation measures to offset these impacts to less than significant levels. For various reasons, however, applicants are often unable to submit key components of their proposed project at the time of the AFC filing and have trouble providing the necessary information early, not only for data adequacy purposes, but during the discovery phase of the 12-month process. Staff is reviewing the information and data gathering process to ensure that any changes will balance the need for information with the ability to draft the SA in a timely manner.

A major cause of past project-licensing delays is from the proponent making significant changes to the project during staff's review and preparation of the SA. While changes often result in reducing the project's environmental impacts, changes that occur well into the process require reassessment for each technical analysis, causing delay. It is not uncommon to see major project changes in such critical areas as cooling technology, water sources, gas line routes, transmission line routes, or facility layouts late in the process, all of which cause delays. Projects that come in as complete as possible following the best practices guidelines should be able to complete the licensing process faster and with fewer mitigation costs, thereby assuring project proponents, investors, regulators, and the public of a project's viability and certainty in terms of its integration into the larger electrical system.

In addition, efforts are underway to improve the docketing process and to implement an e-filing process, which should increase the ease of submitting documents and reduce transaction costs for applicants.

Evidence and Hearings

The Energy Commission is making a concerted effort to review the evidentiary hearing process and development of the hearing record. Staff is in the process of answering the following questions:

- Are evidentiary hearings always needed?
- When a hearing is required, can the proceeding be more focused?
- What evidence is admissible versus what can be relied on for a decision?
- Does the public find the process user-friendly?

The goal is to create a process that is flexible enough to allow uncontested projects a more informal process while maintaining a formal hearing structure for projects with significant environmental issues or controversy.

Public Process

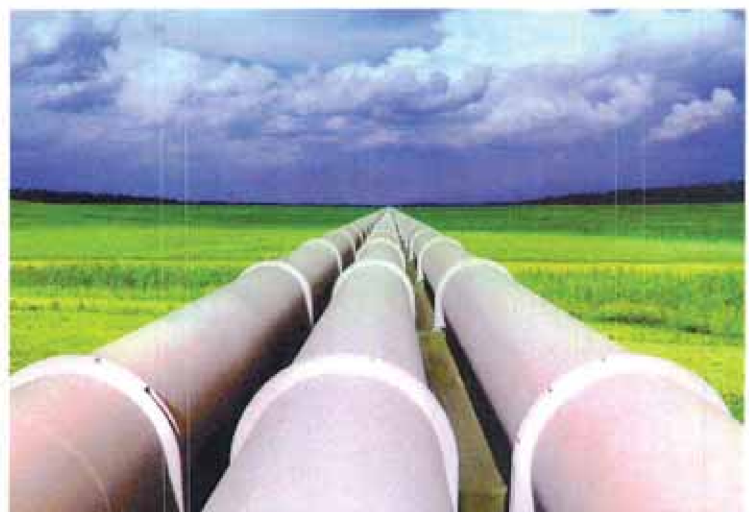
The Energy Commission's siting regulations require that "all hearings, presentations, conferences, meetings, workshops and site visits shall be open to the public" (emphasis added) (Cal. Code Regs., tit. 20, § 1710) and that "all meetings shall be noticed ..." no less than ten days in advance (Cal. Code Regs., tit. 20, § 1710). However, section 1710 (h) allows an applicant to "... formally exchange information or discuss procedural issues with Energy Commission staff without a publicly noticed workshop." This means that the Energy Commission has to notice any discussions related to substance (for example, mitigation) and hold a workshop.

The Energy Commission and other stakeholders question these particular meeting restrictions, since staff does not make the decisions, and these restrictions are typically greater than those on staff at other agencies (such as the CPUC). As expected, most intervenors have traditionally opposed relaxing the existing noticing requirements, as they take the position that staff is already working too closely with the applicant. Staff expects this issue to be a discussion topic at future workshops.

The relevant Energy Commission departments, including the Public Adviser's Office, are discussing potential regulations or changes in Energy Commission practice to balance transparency, public participation, and appropriate environmental analysis with efficiency and the desire to streamline the siting process. These topics and others will be discussed at future workshops.

Next Steps

The OII Proceeding will continue drafting various white papers and scheduling public workshops, leading to a process of publishing draft recommendations for the Committee and Energy Commission's consideration on the topics discussed above. The Energy Commission will also continue to evaluate policy issues associated with the power plant licensing process. Depending on the nature of resulting recommendations, there is the possibility that the Energy Commission may adopt an Order Instituting Rulemaking Proceeding for updating and augmenting the rules and regulations that guide and define the Energy Commission's Siting, Transmission, and Environmental Protection Division and its work.



CHAPTER 7

Natural Gas Assessment

This chapter summarizes the Energy Commission's staff 2011 Natural Gas Market Assessment: Outlookthat was

prepared in support of the *2011 IEPR*.[134] The Energy Commission, California Environmental Protection Agency, California Air Resources Board (ARB), California Public Utilities Commission (CPUC), and the California Independent System Operator (California ISO) recognize that natural gas plays a significant and ongoing role in California's energy supply, especially for electricity generation and for meeting the state's clean energy and environmental goals. Natural gas resources will continue to be essential in meeting California's energy demand, and procurement and resource adequacy programs will deliver resources needed for system and local reliability requirements and system operational needs.

134 California Energy Commission, *2011 Natural Gas Market Assessment: Outlook*, draft staff report, September 2011, www.energy.ca.gov/2011publications/CEC-200-2011-012/CEC-200-2011-012-SD.pdf. Final report expected March 2012.

As regulators and the market grapple with ways to integrate and back up renewable technologies, natural gas will play a role in supporting renewable integration, and therefore the existing thermal power plant fleet will have to be modified to provide increased operational flexibility, ramping capability and regulation services, lower operating limits, and more frequent start/stop operation. This modification will allow the state to integrate substantial amounts of intermittent renewable generation while generating the least amount of greenhouse gas (GHG) emissions. State agencies and the California ISO will develop the appropriate procurement and market rules to provide the revenues for implementing these changes and for covering additional operating and maintenance costs.

Natural gas production from shale formations in the United States is transforming the natural gas market. In the last five years, natural gas supply from shale plays has increased from 2.3 billion to 22.5 billion cubic feet per day (bcf/d). Shale gas now comprises roughly 34 percent of the total gas production in the United States. Experts in the governmental sector and the environmental community have raised numerous environmental concerns with the technology used to produce shale gas. These concerns range from the chemicals involved in the hydraulic fracturing technique to crack the shale formations where the gas is stored to the amount of water used in the process. Energy Commission staff is monitoring and will continue to monitor the potential impacts of hydraulic fracturing and possible new environmental protection requirements. At the state level, the Energy Commission will work collaboratively with the California Air Resources Board, the Department of Conservation's Division of Oil, Gas, & Geothermal Resources, and the California Environmental Protection Agency to address the above issues.

Future Role of Natural Gas in California's Economy and Energy Supply

California may have to retire, repower, replace, and/or mitigate more than 13,000 MW of natural gas-fired generation to comply with the State Water Resources Control Board's once-through cooling (OTC) policy by 2020. A major challenge with this transition is that these older power plants are typically located in transmission-constrained areas that require local generation. Remotely located renewable resources can provide some of the needed replacement capacity but a portion of these will require new or upgraded transmission lines to deliver electricity to the load centers. The advantage is that the new (or repowered) facilities (for example, solar thermal power plants) are more efficient than those they replace, which will help reduce GHG emissions.[135]

Over the long term, new natural gas-fired power plants (including combined heat and power plants), combined with energy efficiency, demand response, and central station and distributed renewable generation, will replace baseload generation from retiring out-of-state, coal-fired, and possibly nuclear power plants. Complex economic, environmental, and public safety issues make the magnitude and timing of these power plant retirements uncertain. Therefore, natural gas-fired power plants could be a viable option to address such contingencies.

135 California Energy Commission, *California's Clean Energy Future: An Overview on Meeting California's Energy and Environmental Goals in the Electric Power Sector in 2020 and Beyond*, CEC-200-2010-010, page 5, www.cpuc.ca.gov/NR/rdonlyres/[illegible]

The use of natural gas as a transportation fuel in compressed natural gas vehicles, and as a feedstock to make methanol additives for cleaner-burning gasoline, may give natural gas a "bridging" role in attaining California Clean Energy Future (CCEF) goals. However, the penetration of natural gas in the transportation sector is also uncertain. Due to its thermal efficiency, wide-scale delivery infrastructure, end-user familiarity and relatively clean combustion, natural gas will continue as a significant energy supply source for residential, commercial, and industrial end uses such as cooking, space heating, and to fuel boilers and process heaters. In the longer term, the role of natural gas in these sectors may diminish as energy efficiency and conservation, renewable substitutes such as solar thermal or biogas applications, and electrification become more cost-effective or play a larger role in meeting the state's climate change goals. While natural gas serves as a feedstock to manufacture plastics, fertilizers, antifreeze, pharmaceuticals, and fabrics, additional factors besides energy and environmental policies will determine future demand for these end uses.

Natural Gas Uncertainties

Whether by choice or necessity, natural gas will play a significant role in California's energy future. This conclusion prompts the following basic questions:

- To what extent will California's future energy supply include natural gas – what might be the demand for natural gas?
- What will be the cost to California of this demand for natural gas – at what price might it be available?
- What can be done to understand and to manage the risks associated with this role of natural gas in California's energy supply?

Most experts agree that it is not feasible to make single-point forecasts of future gas prices and other market activities, and that it may not be particularly useful. This is a necessary consequence of the gas market's complexity, large menu of competing options for actions, and deep uncertainties about future underlying conditions that are beyond anyone's control.

The Energy Commission has concluded that single-point forecasts of future natural gas prices are not only inaccurate, but not useful in focusing proper attention on the gas market's complexity and range of potential outcomes. Instead, the Energy Commission has, in this *IEPR*, focused on a range of plausible underlying conditions to develop conditional estimates of prices that could occur. This approach can decrease the chance of being unpleasantly surprised by a future not considered and the negative consequences resulting from actions taken under conditions that did not materialize.

Despite the inability of anyone to accurately predict future gas market outcomes, many people – including California's public policy makers – need to make decisions based on an expectation of what those outcomes might be. For example, the California policy to "implement all cost-effective energy efficiency" requires a cost-effectiveness analysis of potential energy efficiency measures and programs. So, having some expectation of future gas prices (and other effects of gas extraction, transportation, and use) is a requirement of this analysis and decision-making.

Staff is improving the analytical process on an ongoing basis and has committed to using its models to develop insights rather than simply quantitative results: comparing results of staff model runs to other relevant studies, evaluating alternative scenarios or futures using different sets of assumptions, explaining both what is known and unknown, and making every attempt to present the results fully and clearly.

Exploring California's Potential Gas Price Vulnerability

Natural gas is a heavily traded commodity in a market characterized by price volatility. Over the last decade, daily spot market prices for natural gas traded at Louisiana's benchmark Henry Hub have spiked several times. Figure 4 shows the prices over the past decade in current year or nominal dollars. The winter periods of 2000–2001 and 2003–2004 saw prices spike to $10.00 per million British thermal units (MMBtu) and $18.00/MMBtu, respectively. Cold weather, which increased demand and put upward pressure on prices, triggered these increases. In September 2005, hurricanes Katrina and Rita caused natural gas production wells in the Gulf Coast to be shut in, which lowered available supply and caused prices to spike to over $15.00/MMBtu.

Since late 2008, daily spot market prices have trended lower (in the $4.50 to $5.00 range) and only once did prices increase above $6.00 (in 2009). The lower prices following the 2008 price spike can be explained by two factors. The late-2008 economic recession reduced overall demand for natural gas, especially in the industrial and power generation sectors. This lower natural gas demand had a negative effect on prices. Secondly, large amounts of shale gas are now becoming technically and economically recoverable at relatively low costs. This injection of shale gas into the market increased the supply of gas available to consumers and thus helped to lower the price. Over the last year (April 2010–April 2011), Henry Hub daily spot prices have averaged $4.15/MMBtu.

The Energy Commission's *2011 Natural Gas Market Assessment: Outlook* explored how a plausible range of assumptions about underlying United States natural gas supply and demand conditions might affect the long-term annual average market price of natural gas.[136] Staff's analysis is based on the well-recognized global gas market expertise of consultant Dr. Kenneth Medlock III.[137] Dr. Medlock used the MarketBuilder platform to construct the Rice World Gas Trade Model (RWGTM). For this analysis, Dr. Medlock and staff worked closely together to modify the RWGTM for use in the *2011 IEPR* proceeding. Staff's analysis contains the following four cases that focus on potential future national natural gas market prices:

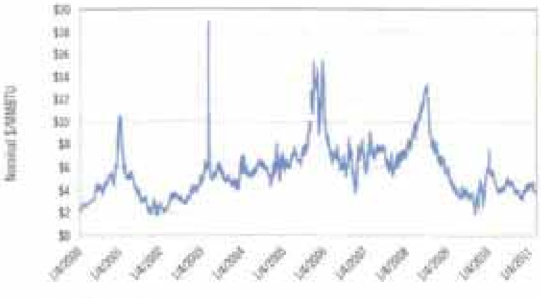
- **Reference Case:** assumes a "business as usual" starting point case
- **High Gas Price Case:** assumes higher gas demand and more constrained, higher cost gas resources
- **Low Gas Price Case:** assumes lower gas demand and less constrained, lower cost gas resources
- **Constrained Shale Gas Case:** assumes higher gas operations and maintenance costs to ensure that development is environmentally acceptable

In addition to the four cases outlined above, two additional cases were added to the analysis in response to stakeholder input suggesting that the estimated natural gas price range was too narrow as a result of keeping the cost of discovery constant across all cases. The two additional cases are:

136 Brathwaite, Leon D., Paul Deaver, Robert Kennedy, Ross Miller, Peter Puglia, William Wood, *2011 Natural Gas Market Assessment: Outlook*, California Energy Commission, Electricity Supply Analysis Division, Publication Number CEC-200-2011-012-SD. Final report expected March 2012.

137 Dr. Medlock is the James A. Baker III and Susan G. Baker Fellow in Energy and Resource Economics and Deputy Director of the Energy Forum of James A. Baker III Institute for Public Policy at Rice University in Houston, Texas.

Figure 4: Henry Hub Daily Spot Market Natural Gas Prices



Source: [illegible]

- **High Finding and Development Cost Case:** assumes that only a small amount of gas beyond what is currently proved will be added to the current stock due to high costs of finding and development, driving market prices higher. This case uses the High Gas Price Case as a starting point and changes only the discovery costs.

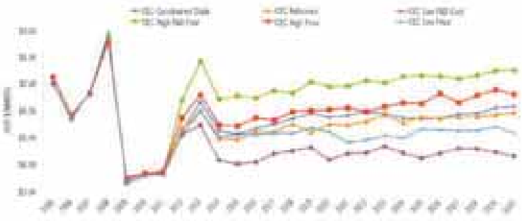
- **Low Finding and Development Cost Case:** assumes that a larger than average amount of gas beyond what is currently proved will be added to the current stock due to low costs of finding and development, driving market prices lower. This case uses the Low Gas Price Case as a starting point and changes only the discovery costs.

Key input assumptions for the Reference Case, highlighting those assumptions that change in at least one of the changed cases, include the following:

- Average annual growth rate in U.S. gross domestic product is 2.6 percent.
- The marginal cost curve for gas supplies reflects year 2011 vintage state of knowledge about the underlying gas resource base and production technologies.
- Average annual rate of "learning" improvement in gas technology is 1 percent.[illegible]
- Shale gas development in New York is constrained per current moratorium.
- Iran, Iraq, and Venezuela do not enter the market until 2020.

[illegible] "Learning improvement" means increased productivity achieved through practice, self-perfection, and minor innovations.

Figure 5: Henry Hub Annual Average Natural Gas Spot Market Prices



Source: Energy Commission Staff Final Analysis

- Liquefied natural gas exports are allowed to occur.[illegible]
- Pipeline capacity additions are allowed to occur.
- The future power generation mix for U.S. states follows current trends based on U.S. Energy Information Administration (EIA) state level historical data except renewable generation.
  - California meets its existing RPS target in 2020.
  - Other states with an RPS meet targets five years late.
  - Growth of renewable generation in states without RPS targets follows past trends.

[illegible] The phrase "allowed to occur" here means that their occurrence is not prohibited and that the feature may appear in a result in any case, dependent on the model's evaluation of the feature's commercial viability given the endogenous outlook for gas prices (past, present, and future) in that case.

The High Gas Price Case made plausible assumptions that would move natural gas market prices higher than in the Reference Case. On the demand side, the economy is growing strongly (at 3.5 percent annually), while 50 GW of retiring coal-fired power plants and a slowing of renewable generation programs in other states by 15 years are leading to increased natural gas demand for electric generation. On the supply side, some jurisdictions in the United States are restricting the development of natural gas resources, particularly shale formations. Also, in places where production continues, safety concerns over hydraulic fracturing, water use and disposal, and other potential impacts are causing environmental compliance costs to rise for conventional and unconventional gas production activities.

Technology development dominates the Low Gas Price Case. In this case, the technology learning improvement is held constant at one percent annually. On the demand side, the economy is weak, with annual Gross Domestic Product growth capped at 2.1 percent. All states with RPS programs are complying on time, thereby reducing the need for gas-fired generation. On the supply side, environmental concerns

are decreasing as technological developments allow deployment of adequate environmental mitigation without significant overall cost increases. Jurisdictions that restricted natural gas development are starting to ease regulations.

The Constrained Shale Gas Case is a sensitivity case to the Reference Case that assumes environmental concerns, particularly about the treatment and disposal of water used in the hydraulic fracturing process. These concerns prompt many jurisdictions to implement additional regulatory requirements on development of natural gas from shale formations. Regulatory compliance after 2013 adds another $0.40 per 1000 cubic feet (MCF) of natural gas to the cost of production of shale natural gas and $0.20/MCF on conventional production (2005 dollars). Figure 5 plots the annual average equilibrium price for spot gas purchases at Henry Hub for 2005 through 2030 for the six cases, in real 2010 dollars.[illegible]

Beginning in approximately 2012, the Reference Case price jumps from about $4.00 to $6.00/MMBTU, assuming the economy recovers and demand increases, thereby reestablishing a balance between supply and demand. A rush in investments occurs in the market, and the most economical shale plays are being developed first.[illegible] As these shale areas mature, they produce less gas, and the relatively more expensive shale plays start bringing supply to market. Beyond 2015, the price remains fairly flat, growing from about $5.00/MMBTU to just under the $6.00/MMBTU by 2030 (in 2010 dollars).

[illegible] The NGTM performs all of its calculations in real 2005 dollars. Its input assumptions are expressed in 2005 dollars as well. Staff converts its output to real 2010 dollars using the Demand Analysis Office's 2011 IEPR inflation series. This estimate of future inflation expectations may also be used to convert NGTM results to current year or nominal dollars.

[illegible] A shale play is a geographic area containing an organic-rich, fine-grained sedimentary rock displaying the following characteristics: Particles are the size of clay or silt, contains high percentage of silica (and sometimes carbonate), is thermally mature, has hydrocarbon-filled porosity and low permeability, is distributed over a large area, and economic production requires fracture stimulation.

The Henry Hub annual average spot price in the High Gas Price Case reaches $6.00/MMBTU by 2018 (12 years before the Reference Case hits that mark) and somewhat levels off below $6.80/MMBTU (in 2010 dollars) by 2030. The case projects that shale gas will be the marginal source of natural gas for the next 20 years and beyond. The higher environmental compliance costs assumed in the Constrained Shale Gas Case puts the resulting prices in between the Reference and High Gas Cost cases, as expected. The Low Gas Price Case Henry Hub prices hover around $3.00/MMBTU thru 2020, increasing to about $5.10/MMBTU afterward (in 2010 dollars).

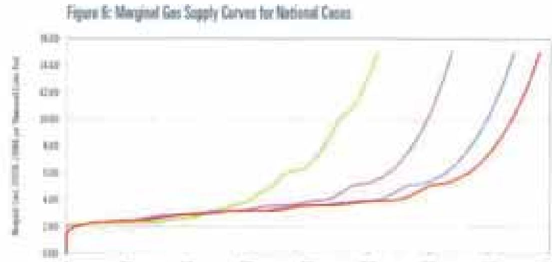
Participants in the *2011 IEPR* proceeding cautioned that staff's range of future annual average Henry Hub spot market prices might be too narrow – that future prices could possibly be higher or lower. El Paso offered a case that is lower than staff's Reference Case until 2017 but higher afterward. Staff and other parties generally agree that a significant contributing factor to staff's narrow price range is the underlying assumption that the gas resource marginal supply curves are all relatively flat and remain so, even across the cases that modify them significantly.

Figure 6 illustrates how staff's assumptions about marginal gas supply curves differ between *2007 IEPR* and *2011 IEPR* Reference Cases.

The curves represent the summation of all of the different supply curves for each natural gas play. The significant increase in gas supply reflects the industry's view about North American shale gas resources – that much more natural gas is available (and accessible at lower cost) than previously thought.

The 2007 and 2011 Reference Case curves make use of an "expected value" assessment of the quantities of recoverable gas resources (proved reserves plus a "P50" assessment of growth in known reserves and undiscovered resources). By industry convention, the P50 assessments mean there is a 50 percent probability that at least this much gas is recoverable from that play using current technology. To increase the spread of resulting gas prices, additional cases were run assuming higher probability but lower

Figure 6: Marginal Gas Supply Curves for National Cases



Source: California Energy Commission Staff Draft Analysis

Figure 7: EIA Annual Energy Outlook 2011, Annual Average Henry Hub Spot Market Prices

Sources: U.S. Energy Information Administration and California Energy Commission analysis.

resource amounts (a P90 case) and lower probability but higher resource amounts (a P10 case). Interpreting the result of these cases should be done carefully, however, as this method effectively introduces a one-sided bias into the resource assessment.[113]

Staff's marginal costs in the supply curves represent an overall finding and development cost environment that changes over time. Figure 6 also shows the cumulative effect on the Reference Case's marginal gas supply curve from changes in assumptions in the High and Low Gas Price cases (moving the supply curves to the left and right, respectively). The Constrained Shale Gas case uses the same marginal supply curve as the Reference Case. Its higher environmental mitigation costs are added to variable operating costs, which are not included in the supply curves. Assuming a wider range of environmental mitigation costs, or other variable operating costs, would be another way to increase the spread of resulting model prices.

Comparing the Energy Commission natural gas forecast to those produced elsewhere is a reasonable check for consistency. Ideally, the assumptions and methods used in the comparison cases are transparent enough for staff to assess their plausibility and compare them to the Energy Commission cases, and, as a result draw useful insights. The U.S. Energy Information Administration's *Annual Energy Outlook 2011* (*AEO 2011*) is a source of such useful comparisons.

Figure 7 compares annual average Henry Hub spot market prices for staff's Reference Case and High and Low Finding and Development Cost cases to the *AEO 2011* Reference Case and two other cases specifically designed to examine the effect on natural gas prices from uncertainties in factors related to underlying estimates of the technically recoverable shale gas resource base.

113 Some plays will be discovered to have more resources than the expected value and some fewer. The preferred method of simulating this would be to run the model stochastically, randomly drawing from the probability distribution of each resource curve, cumulating the results within the model.

The high shale resource case assumes the estimated unproved technically recoverable resource base (excluding inferred resources) is 50 percent higher than in the *AEO 2011* Reference Case: 1,230 trillion cubic feet (Tcf) instead of 827 Tcf. The low shale resource case assumes that the resource base is 50 percent lower than in the *AEO 2011* Reference Case: 423 Tcf instead of 827 Tcf.

- The High Shale EUR Case assumes the estimated ultimate recovery (EUR) per shale gas well is 50 percent higher than in the *AEO 2011* Reference Case due to better development and production techniques. The case's assumed lower cost per unit of production result in the lowest gas prices.

- The Low Shale EUR Case assumes the EUR per shale gas well is 50 percent lower than in the *AEO 2011* Reference Case, from faster than expected rates of decline in gas production. The case's assumed higher cost per unit of production results in the highest gas prices.

The range of Henry Hub prices from the *AEO 2011* modified resource base cases track very closely with the range of prices in staff's cases. The explanations for all of these cases are fairly consistent. The more extreme *AEO 2011* cases illustrate the effects on prices from changing assumptions related to gas resource supply curves. Stakeholders suggested staff's analysis did not stress this enough. While Figure 7 may provide a more useful picture of the potential range for annual average prices (between $4.50 and $9.50 in 2010 dollars), the process for developing these cases affects how they are interpreted and compared to others. The two outlying *AEO 2011* cases, along with the two outlying Energy Commission cases, are less likely to be observed than the other cases, simply because they were constructed by moving away from the currently "expected" value for those assumptions.

Managing Potential Natural Gas Risks

Given the significant role of natural gas in California, any decision involving an expectation of future energy prices or avoided energy costs will require an assumption about future natural gas prices.[114] Model-based natural gas market assessments can provide conditional estimates of these prices, but their utility depends on a transparent description of assumptions, an understanding of their inherent limitations, a useful design for alternative cases, and a reflective interpretation and use of results.

Considering the possibility and consequences of both high and low price outcomes helps guard against one-sided biases. Generally, when using a conditional estimate, it is prudent to examine the potential consequences of using one estimate for a specific purpose should the future estimate turn out to be different. This is especially true when the experts have no defensible argument for one estimate being more likely to occur than another (although outcomes not deemed "most likely" will still occur). For example, decisions based on assumptions that future gas prices will be low could have significant negative consequences if gas prices turn out to be high, and vice versa. The consequences depend on the specific use of the conditional estimates, whether it is an individual using the estimate to purchase a more energy-efficient furnace, or a utility assessing the cost-effectiveness of a proposed energy efficiency program.

114 For example, natural gas price assumptions can be key to understanding how to measure cost-effective energy efficiency measures and programs (and what consumers may choose to do); what it costs to add renewable central station or distributed generation to the energy portfolio; the value of carbon allowances; the value of Renewable Energy Credits; the cost of using more natural gas in vehicle fuel compared with the LCFS; the cost of electricity if gas is on the margin during hours when EVs are being recharged; and how consumers will perceive the cost of gas pipeline system retrofits/upgrades.

The users' own assessments of potential regret associated with their use of available alternative estimates may help them choose, based on their level of risk tolerance, the most prudent gas price estimate. What results is a decision that has a better chance of performing acceptably over a wide range of possible futures. Gas market analysts can advise these purpose-specific decision analyses but cannot conduct them, as they require knowledge and details about the specific uses of the estimates and how consequences play out.[115,116]

Potential Effects of the Gas Pipeline Explosion in San Bruno

On September 9, 2010, a 30-inch diameter, high-pressure natural gas transmission pipeline exploded under a neighborhood street in San Bruno, California. The explosion of Line 132, owned by Pacific Gas and Electric (PG&E), killed 8 people and destroyed 37 homes. In addition to the tragic loss of lives and destruction of a neighborhood, the explosion resulted in a temporary evacuation, longer-term community disruption, and widespread concerns regarding public safety. The CPUC and the National Transportation

115 For example, the question of which energy efficiency measure is cost-effective is about the conditional estimates of the proposed measure's cost and performance as much as it is about the cost of the fuel that measure may avoid.

116 For a discussion of how a regret analysis can help users of forecasts manage their risks of using forecasts that turn out to be inaccurate, see *Seeing Better Looking: Are Your Utility's Gas Price Forecasts Accurate?* National Regulatory Research Institute, May 2010. www.nrri.org/pubs/gas/NRRI_gas_price_forecasting_may10-09.pdf

Safety Board (NTSB) both launched investigations into the explosion. The Energy Commission responded by transferring Public Interest Energy Research Program funds to the CPUC, making them available for safety research, and by offering assistance to the CPUC, California ISO, and PG&E. As discussed below, the Energy Commission is closely monitoring for potential impacts to natural gas service or markets that might result from pressure reductions or lines being taken out of service for testing as the CPUC and the gas utilities work to assure the safety of California's pipeline system.

The CPUC initially ordered pressure reductions as an immediate response to the explosion. Then, in January 2011, the NTSB announced that the failed segment of Line 132 had been longitudinally seamed, contrary to PG&E's records showing the segment was seamless. As a result, the NTSB encouraged — and the CPUC ordered — PG&E to begin searching for "traceable, verifiable, and complete" records to confirm the features and maximum allowable operating pressure (MAOP) of its pipelines in "High Consequence Areas" (HCAs). The NTSB released the Pipeline Accident Report on August 30, 2011 (adopted August 30, 2011).[118] In the report, the NTSB identified a substandard and poorly welded pipe section that eventually led to the rupture of the pipeline. The CPUC also ordered PG&E to reduce operating pressures on lines of similar vintage and characteristics to Line 132 located in HCAs by 20 percent below the MAOP.

The CPUC expanded this order in June 2011 when it issued an order as part of Order Instituting Rulemaking 11-02-019 into new pipeline safety rules, directing PG&E, Southern California Gas, San Diego Gas & Electric, and Southwest Gas to pressure test or replace all pipelines, not just those in HCAs, for which the operators do not have "traceable, verifiable, and complete" records of MAOP. This testing is expected to take several years. Until this is complete, the utilities will adopt appropriate interim safety measures that include enhanced patrolling and leak surveys. As utilities pursue the extensive examination of pipeline system records, conduct hydrostatic testing, and replace pipelines, customers may experience reduced system pressures and capacity as well as occasional outages. The CPUC directed the noted utilities to prepare pipeline safety enhancement plans for their respective systems to describe how the pipeline testing would be carried out along with other safety enhancement measures.

PG&E then lowered operating pressures on several additional pipeline segments based on its June 20 "Class Location Study." The Class Location Study found that several of PG&E's pipelines were misclassified, leading to these pipeline segments operating at too high a pressure given the pipeline segment's proximity to homes and businesses.

On August 26, 2011, PG&E filed its Pipeline Safety Enhancement Plan as required by the CPUC. The first phase of the plan will run from 2011 to 2014 and calls for pipeline modernization, valve automation, records integration, and interim safety measures. The cost of the plan is estimated to be $2.2 billion over the next four years, and it remains to be seen how costs will be recovered pending CPUC approval of the plan. PG&E has already started work on the plan (pipeline testing and replacement), and costs incurred in 2011 will be borne by shareholders. All stakeholders will be given a chance to comment on PG&E's plan as part of the rulemaking procedure. A final decision on the plan from the CPUC is expected by June 2012.

SoCalGas and SDG&E also submitted its Pipeline Safety Enhancement Plan on August 26, 2011. The plan consists of several component phases with Phase 1A expected to extend from 2012 to 2015. Phase 1A calls for pipeline modernization, valve automation, enhanced incident detection and damage avoidance, and the development of a "blueprint" of a comprehensive asset management system. The direct cost of the plan for both SoCalGas and SDG&E is estimated to be about $1.6 billion (Phase 1A). Phase 1B will continue work started in Phase 1A and will span from 2015 to 2021

118 www.ntsb.gov/investigations/summary/PAR1101.htm

costing about $3.4 billion. The plan is still waiting for CPUC final approval as part of the rulemaking process.

The Energy Commission has closely monitored the testing schedule and operating pressures for any impacts on service to natural gas consumers, including the natural gas-fired power plants that California relies on for about 41.5 percent of its electricity. Such impacts could occur based on three key factors. First, reducing operating pressure in a pipeline effectively reduces the amount of natural gas that can be delivered through that pipeline in a given period. Such reductions in a high demand period could lead to curtailments in gas service and are analyzed further below. To date, PG&E has reported no curtailments to customers as a result of reducing the MAOP to pressures consistent with the location class study.

Second, lower pressures reduce PG&E's daily operating flexibility. This flexibility is embodied in what PG&E calls "pipeline system inventory." The inventory describes a minimum and maximum amount of natural gas that PG&E needs in the pipeline system to meet demand. Normally the range between the minimum and maximum is 600 million cubic feet (MMcf). With the additional pressure reductions necessitated by the findings of the Class Location Study, PG&E's 600 MMcf per day permissible inventory swing became 280 MMcf per day. PG&E was, as of July 1, 2011, issuing high and low inventory Operational Flow Orders (OFOs) simultaneously, which required customers to match their deliveries of gas into the PG&E system more closely with their daily usage than they do under normal conditions or incur imbalance penalties. While generators have asked the California ISO if they will be reimbursed for penalties or costs incurred as a result of the tighter balancing tolerances, and some third-party balancing service agreements may have been modified, staff has detected no impact on citygate or border prices paid by Californians as a result of the tighter balancing. Staff also notes that as of December 1, 2011, PG&E had returned the inventory swing to 450 MMcf, eliminating the need for the simultaneous high and low OFOs.

Third, hydrostatic testing means taking pipeline segments out of service for several days. If the test causes the pipeline to fail, then it must be replaced, during which time the segment remains out of service. To date, PG&E has had two segments fail hydrostatic testing, one near Bakersfield on Line 300A and one near Woodside on Line 132. PG&E also discovered via testing a leak on Line 137 in Palo Alto. In each of these cases, and as long as the testing continues to occur outside of high demand periods, PG&E should have the ability to reroute natural gas to continue service to nearby customers, including gas-fired electricity generating plants. The Energy Commission is working with its sister agencies to provide information and contingency planning support to address any potential outages during the testing.

By mid-summer, the aggregate effect of the lower operating pressure reduced capacity on the "backbone" portion of PG&E's transmission system by about 500 MMcf/d. With the possibility of such reductions lasting into December, staff analyzed whether the reductions could have an effect on service to customers and under what conditions these impacts might occur.[117] Staff first looked at whether the reduced flows would affect PG&E's ability to fill underground gas storage during summer months. Analysis showed that PG&E should be able to inject into storage most, if not all, of the gas it needs to protect service to core customers even with the reduced operating pressures and lower gas flows. As discussed at the September 27, 2011, IEPR Committee Workshop on natural gas, noncore customers would be prudent to use available backbone capacity to inject as much gas as possible into storage.

Staff then looked at whether the reduction in lower backbone transmission availability could affect the state's ability to meet monthly projected natural

117 The analysis is fully described in Chapter 4 of *2011 Natural Gas Market Assessment: Outlook*, Leon Brathwaite, 200-2011-012, www.energy.ca.gov/2011publications/CEC-200-2011-012/CEC-200-2011-012-SD.pdf

Table 7: PG&E High Demand Day Gas Requirements and Sources

MMcf/d	Dec 8, 2009 Recorded	Dec 9, 2009 Recorded	Winter Peak Day Forecast from 2010 California Gas Report A
Demand			
Core	2,849	3,024	2850
Industrial	677	692	422
Electric Generation	551	526	1018
Off-System	37	68	8
Total	**4,893**	**4,216**	**4,278**
Capacity & Supply			
Redwood	981	833	1,400B
Baja	1,031	1,051	713
Sherwin (CA Production)	175	135	130
PG&E Storage	1,344	1,179	1,308
Independent Storage	835	1,008	527
Total	**4,893**	**4,216**	**4,278**

Source: Compilation of data reported in PG&E Pipe Ranger, California Gas Report, and staff analysis.

A The capacity and supply data shown are Energy Commission staff projections [illegible]

B [illegible]

gas demand. The analysis suggests that PG&E's natural gas capacity reserve margin could be pushed to very close to zero in December and January, even under normal weather conditions, without using higher-than-average storage withdrawals. As of December 1, 2011, PG&E has returned the inventory swing to 450 MMcf.

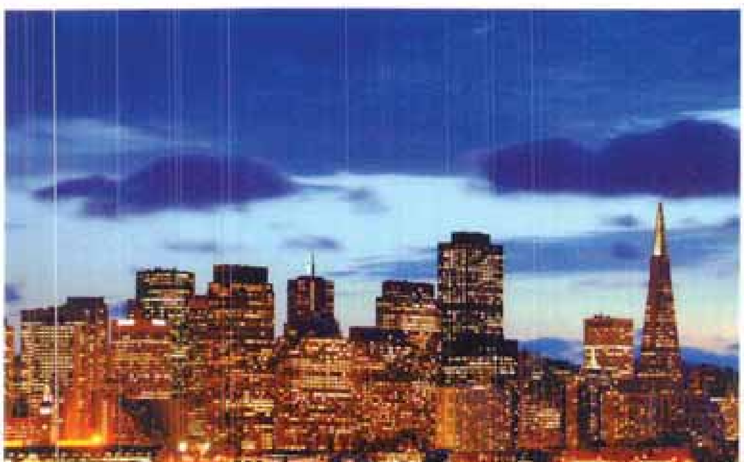
Finally, staff looked at what would happen under "Winter Peak Day" (WPD) conditions. The capability to serve WPD demand and a comparison to two cold days with demand close to WPD from December 2009 are shown in Table 7. The key conclusion is that curtailments should be avoided even if less gas is able to flow over backbone capacity with more reliance on gas from underground storage. This underscores the importance of filling not only PG&E storage, but independent storage to make up for the constrained backbone capacity on days colder than average conditions occur.

This analysis does not look at potential local area curtailments. PG&E completed hydrotesting on several key Bay Area lines and requested expedited review to restore pipeline pressures on those lines. The CPUC granted PG&E's request on December 15, 2011.

Since then, the CPUC has issued and held a workshop on a Staff proposal to consider how safety regulations should be changed. The CPUC has also issued a comprehensive staff report detailing its findings and making numerous recommendations for changes at PG&E.[18] The Energy Commission continues to offer its assistance as needed.

PG&E has been steadily restoring pipeline capacity and available inventory as pipe segments have been cleared through testing. As of November 28, 2011, system capacity along the Redwood Path was at 2220 MMcf/d – which is 98 percent of maximum capacity. System capacity along the Baja Path was operating at 72 percent of maximum capacity (872 MMcf/d). PG&E reports that as of December 5, 2011, available system inventory stands at 4,361 MMcf – an increase from 2009 MMcf due to pipeline testing. The increase in inventory is expected to eliminate the need to call high/low inventory Operational Flow Orders (OFOs.) However, it is expected that that calls for one-sided OFOs will continue on an ongoing basis as necessary. On November 4, 2011, PG&E reported that Northern California's storage inventory levels were higher than they have been in the last three years for this point in time of the storage season. Therefore, PG&E expects no limitations in regular withdrawal capabilities for the storage facilities located in PG&E's system this winter.

[18] California Public Utilities Commission Consumer Protection & Safety Division, *Incident Investigation Report, September 9, 2010 PG&E Pipeline Rupture in San Bruno, California*, January 12, 2012, [illegible]



CHAPTER 8

Electricity and Natural Gas Demand Forecast

Measuring California's energy use is the essence of a much broader analysis conducted every two years as part of the

Integrated Energy Policy Report (IEPR). This chapter summarizes the Energy Commission staff's *Preliminary California Energy Demand Forecast 2012–2022* (*CED 2011 Preliminary*).[19] The report's analysis characterizes the effects of economic and demographic trends, human behavior, emerging technologies, state and federal policies, and California's diverse climatic and geographic landscape on current and future energy needs. The chief product of this work is the California Energy Demand (CED) forecast of electricity and natural gas consumption over the next 10 years. Staff will release a revised forecast in mid-February and expects to adopt a final version in early spring 2012.

[19] Kavalec, Chris, Tom Gorin, Mark Ciminelli, Nicholas Fugate, Asish Gautam, and Glen Sharp. *Preliminary California Energy Demand Forecast, 2012–2022*. 2011. CEC-200-2011-011SD, available at www.energy.ca.gov/2011publications/CEC-200-2011-011/CEC-200-2011-011-SD.pdf.

Californians consumed around 272,300 gigawatt hours (GWh) of electricity in 2010. Natural gas consumption, including fuel for electricity generation, reached almost 12,700 million therms that same year. Forecasts of expected growth in energy demand underlie California's efforts to develop effective policy, conserve natural resources, protect the environment, and promote public health and safety while ensuring adequate energy supplies and economic growth. To that end, the Energy Commission's long-term forecast appears in many venues: as the foundation for policy recommendations to the Governor and Legislature through the IEPR; as a yardstick by which to measure the utilities' need for new generation resources in the California Public Utilities Commission's (CPUC) Long-Term Procurement Planning proceeding; as a reference point in the Air Resources Board's *AB 32 Scoping Plan*; as a benchmark for assessing the state's progress toward meeting its Renewables Portfolio Standard (RPS); as a baseline for estimating energy efficiency savings potential; and as an input into the Energy Commission's infrastructure needs assessment.

The forecast is also used by the CPUC and the California ISO in annual resource adequacy proceedings addressing capacity needs, which depend on projected peak demand. Demand for electricity varies over time with daily, weekly, and seasonal cycles and fluctuates even within a given hour. It is generally lower at night and on weekends and holidays, with the maximum usually occurring on hot summer weekday afternoons. Expected peak demand is a critical factor in electricity and transmission planning, since it determines generation and transmission capacity requirements.

Such an analysis cannot be conducted in isolation. The Energy Commission augments its own expertise with input from other government agencies, utilities, advocacy groups, and consultants. Regular meetings of the Demand Analysis Working Group, formed by the Energy Commission in 2008, provide stakeholders the opportunity to share information, data, ideas, and methods, and to suggest changes in the existing process.

In the most recent forecast and accompanying report, *CED 2011 Preliminary*, staff incorporated stakeholder feedback on a number of important issues, including the uncertainty surrounding near-term economic conditions (which are difficult to predict) and the relative impacts of various efficiency efforts (which are difficult to measure). Staff devoted public workshops to consider all stakeholder opinions on these two issues, as they carry sufficient consequence.

Demand Forecast Results

The *CED 2011 Preliminary* forecast includes three demand scenarios: high, mid, and low. The high demand case incorporates relatively high economic/demographic growth, low electricity and natural gas rates, and low efficiency program and self-generation impacts. The low demand case includes lower economic/demographic growth, higher assumed rates, and higher efficiency program and self generation impacts. The mid-case uses input assumptions at levels between the high and low cases.

Table 8 compares projected electricity consumption and noncoincident[*] peak demand under the three forecast scenarios. Historical and forecasted values from the previous IEPR forecast (2009) provide points of reference.

Figure 8 compares projected consumption under the three scenarios alongside *California Energy Demand 2010–2020, Adopted Forecast (CED 2009)*. Consumption grows at a faster average annual rate from 2010 to 2020 in the mid- and high-energy

[*] A region's coincident peak is the actual peak for the region, while the noncoincident peak is the sum of actual peaks for subregions, which may occur at different times.

Table 8: Statewide Electricity Demand Forecast Comparison

Consumption (GWh)	CED 2009 (December 2009)	CED 2011 Preliminary High (August 2011)	CED 2011 Preliminary Mid (August 2011)	CED 2011 Preliminary Low (August 2011)
1990	228,473	227,586	227,586	227,586
2000	264,238	265,408	265,408	265,408
2010	280,843	272,342	272,342	272,342
2015	298,471	298,821	292,288	286,133
2020	314,380	321,268	313,462	301,532
2022	—	332,514	318,295	313,493
Average Annual Growth Rates				
1990–2000	1.48%	1.56%	1.56%	1.56%
2000–2010	0.62%	0.45%	0.45%	0.45%
2010–2015	1.29%	1.76%	1.42%	0.99%
2010–2020	1.20%	1.67%	1.32%	1.11%
2010–2022	—	1.68%	1.32%	1.18%
Noncoincident Peak (MW)	**CED 2009 (December 2009)**	**CED 2011 Preliminary High (August 2011)**	**CED 2011 Preliminary Mid (August 2011)**	**CED 2011 Preliminary Low (August 2011)**
1990	47,321	47,520	47,520	47,520
2000	53,703	53,703	53,703	53,703
2010*	62,458	60,455	60,455	60,455
2015	66,864	66,565	65,713	64,246
2020	71,157	72,658	69,818	68,498
2022	—	74,228	71,283	69,738
Average Annual Growth Rates				
1990–2000	1.23%	1.23%	1.23%	1.23%
2000–2010	1.52%	1.19%	1.19%	1.19%
2010–2015	1.37%	1.95%	1.68%	1.22%
2010–2020	1.31%	1.76%	1.45%	1.28%
2010–2022	—	1.72%	1.38%	1.20%

Historical values are shaded blue.

Source: California Energy Commission

*The 2011 forecasts use 2010 weather normalized peak rather than actual to estimate growth.

Figure 8: Statewide Annual Electricity Consumption

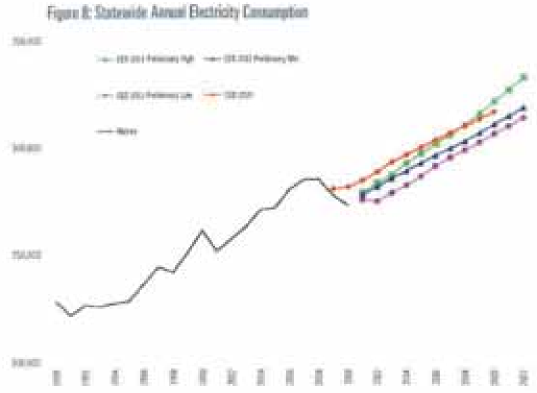


Figure 9: Statewide Annual Noncoincident Peak Demand

Source: California Energy Commission

demand cases (1.32 and 1.67 percent, respectively) compared to *CED 2009* (1.20 percent). In the low demand scenario, annual growth is higher than in *CED 2009* after 2012. Higher projected growth rates in the 2011 forecast reflect a deeper recession in 2009 than assumed as well as a very mild weather year in 2010 and therefore faster growth in reverting to expected long-term weather and economic trends. Forecast consumption reaches *CED 2009* projected levels by 2018 in the high-demand scenario and surpasses the 2020 *CED 2009* projection in the mid-case by 2022. By the end of the forecast period, California's electricity consumption is expected to reach between 313,000 and 333,000 GWh.

Consumption is the main driver for peak demand projections, so the depiction in Figure 9 of the preliminary peak forecast scenarios looks much like Figure 8. Growth in peak demand from 2010–2020, relative to a weather normalized 2010, is faster in the high and mid cases (1.76 percent and 1.45 percent, respectively) than in *CED 2009* (1.31 percent). Statewide peak demand is projected to reach the *CED 2009* level by 2017 in the high-demand scenario and to surpass the 2020 *CED 2009* projection in the mid-case by 2022. Average annual growth rates from 2010–2020 relative to actual peak in 2010 are projected to be 1.41 percent, 1.10 percent, and 0.91 percent, respectively, in the high-, mid-, and low-demand scenarios. By 2022, peak demand is expected to reach between 69,700 and 74,200 MW.

The *CED 2011 Preliminary* natural gas forecast parallels the electricity consumption forecast. Historical data is incorporated up through 2010, and the same models are used to produce three scenarios (high-, mid-, and low-demand) under the same economic/demographic assumptions developed for the electricity forecast. Historical consumption in 2010 is higher than the value projected by *CED 2009*. Projected growth rates are higher, too, such that all three demand scenarios project greater consumption in 2020 than previously expected. By 2022, consumption is expected to reach between 13,773 million and 14,175 million therms. Table 9 compares projected natural gas consumption under the three scenarios.

Modifications to Forecast Method

Additional consumption data became available after publication of the *2009 Integrated Energy Policy Report*. The *CED 2011 Preliminary* adjusted the timeline so that 2010 is the historical base year and the forecast horizon extends to 2022, compared to 2020 in *CED 2009*. Beyond this routine adjustment, staff made several significant modifications to the *2011 IEPR* demand forecast method.

For one, staff developed the major economic sectors – residential, commercial, and industrial – by combining the Energy Commission's traditional end-use models and a new econometric approach launched by staff in 2011. Additionally, staff developed peak projections using its Hourly Electricity Load Model and a new econometric model. Staff made adjustments to results from existing models based on the econometric estimations. For example, price elasticities estimated in the residential and industrial econometric models replaced previous end-use elasticities. Recommendations from a recent evaluation of the demand model method motivated staff to develop a robust, multi-resolution modeling approach to demand forecasting.

Staff forecasted residential adoption of photovoltaic (PV) systems and solar water heaters using a predictive model rather than a trend analysis (as in previous forecasts). The new method is based on estimated payback periods and cost effectiveness determined by upfront costs, energy rates, and various incentive levels. Staff developed scenarios using varied assumptions about electricity rates and new home construction.

Finally, *CED 2011 Preliminary* incorporates potential global climate change impacts more comprehensively. The Energy Commission demand forecasting process typically models these impacts by adjusting

Table 9: Statewide End-User Natural Gas Forecast Comparison

Historical values are shaded blue

	Consumption (MM Therms)			
	CED 2009 (December 2009)	CED 2011 Preliminary High (August 2011)	CED 2011 Preliminary Mid (August 2011)	CED 2011 Preliminary Low (August 2011)
1990	12,858	12,855	12,855	12,855
2000	13,512	13,514	13,514	13,514
2010	11,762	12,865	12,865	12,665
2015	12,750	13,372	13,128	12,891
2020	12,930	13,832	13,789	13,512
2022	—	14,275	13,282	13,173
Average Annual Growth Rates				
1990–2000	0.75%	0.78%	0.78%	0.78%
2000–2010	-1.34%	-0.94%	-0.94%	-0.94%
2010–2015	0.55%	1.09%	1.04%	0.58%
2010–2020	0.67%	1.45%	0.85%	0.08%
2010–2022	—	0.54%	0.83%	0.72%

Source: California Energy Commission

upward the number of cooling and heating degree days in the forecast period, based on the historical ratio of degree days in the last 12 years to that of the last 30 years. The result of this adjustment is an increase in the projected amount of cooling and a decrease in heating relative to the historical period. This correction attempts to account for the likelihood of a general warming trend.

However, temperatures assumed in the peak forecast (an average of daily temperatures over a 30-year period) are not affected by the adjustment, so the forecast may not fully capture the impact on peak demand of possibly more frequent heat storm weather events, in the form of higher maximum temperatures in a given year. Therefore, using climate change scenarios for maximum temperatures developed by the Scripps Institute, staff applied these to the peak econometric model (which includes a coefficient for maximum temperature) and used the projected climate change impacts to adjust the existing end-use peak model results.

The *CED 2011 Preliminary* describes these changes, along with forecast results and modeling methodologies, in much greater detail.[23]

Energy and the Economy

Economic projections are one of the key inputs to the demand forecast. For the *CED 2011 Preliminary* forecast, staff examined multiple economic and demographic scenarios. The intent was to quantify the impacts from a reasonable range of assumptions on electricity demand. Staff selected three sets of economic projections from Moody's Economy.com and IHS Global Insight. Staff chose scenarios that captured the highest and lowest projected levels of economic growth.

Figure 10 shows historical and projected levels for nonagricultural employment, a key economic driver of the commercial and industrial forecasts. A comparison of the projections illustrates consistent expectations about the future of California's economy. Each case assumes California will experience a period of rapid growth as the economy begins to recover from the 2008 crisis, followed by a return to modest long-term growth at rates similar to those seen in recent history.

The most significant discrepancy between these economic projections lies in the duration of the recession and in the timing and rate of the recovery. Energy consumption trends with employment and other economic indicators, so these transitions are important factors, particularly in characterizing energy use over the next few years. Despite a great deal of economic uncertainty surrounding the current recession (for example, when and how California will recover), the alternative scenarios show a relatively narrow band by the end of the forecast period. This narrowing tends to reduce the differences among the forecast energy scenarios later in the forecast period, all else being equal.

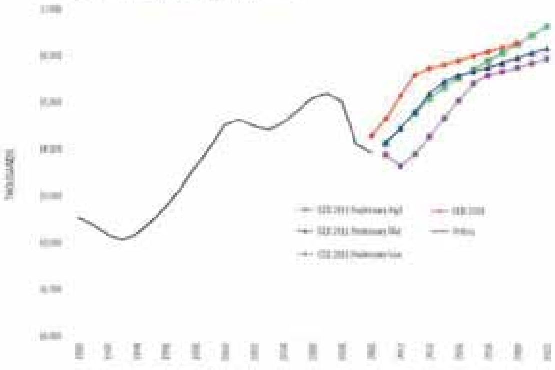
Traditional indicators such as employment, personal income, and population are important, but are not the only economic factors that could affect the forecast. On January 19, 2011, the Energy Commission hosted a public workshop where several expert economists, researchers, policy makers, and business owners discussed ways in which the future of California's economy may deviate from its historical pattern. Staff considered some key points made during the discussion:

- The substantial drop in housing prices may affect migration patterns, specifically increasing in-migration. It is likely that California will not experience the same pattern of depressed population growth as seen in previous recessions.
- Changes to average home size and location may have a significant effect on demographic drivers.
- Over the coming decade, climate change may introduce constraints on water supplies.
- Alternative indicators, such as personal debt, may become more valuable at providing insight into energy consumption patterns.

As California's economy recovers and changes, it is critically important that the Energy Commission adapts its demand forecasting models appropriately. Staff will consider incorporating such factors in future IEPR forecasts while continuing to engage with a variety of economic and demographic experts.

[23] Kavalec, Chris, Tom Gorin, Mark Ciminelli, Nicholas Fugate, Asish Gautam, and Glen Sharp, 2011, op. cit.

Figure 10: Statewide Employment Projections



Source: California Energy Commission

Self-Generation Impacts

The *CED 2011 Preliminary* forecast includes the impacts of on-site distributed generation (DG) used in large-scale facilities and of the major incentive programs designed to promote self-generation. The forecast uses a trend analysis to project self-generation, except in the case of residential PVs and solar water heaters, where it uses a new predictive model. The incentive programs include:

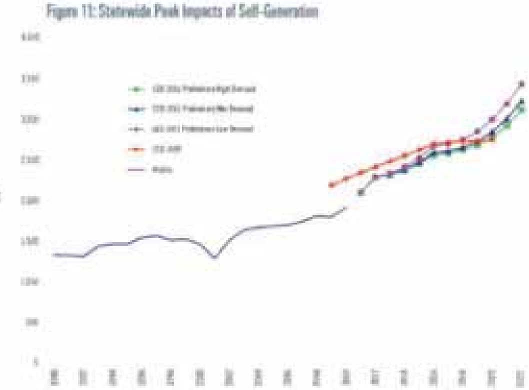
- Emerging Renewables Program (ERP). This program is managed by the Energy Commission.
- California Solar Initiative (CSI). This program is managed by the CPUC.
- Self-Generation Incentive Program (SGIP). This program is managed by the CPUC.
- New Solar Homes Partnership (NSHP). This program is managed by the Energy Commission.
- Utility Incentives. Administered by publicly owned utilities such as Sacramento Municipal Utility District (SMUD), LADWP, Imperial Irrigation District, Burbank Water and Power, City of Glendale, and City of Pasadena.

The general strategy of the ERP, CSI, SGIP, and NSHP programs is to encourage demand for self-generation technologies, such as PV systems, with financial incentives until the market increases and achieves economies of scale and decreases the capital costs. The extent to which consumers see real price declines will depend on the interplay of supplier expectations, the future level of incentives, and demand as manifested by the number of states or countries offering subsidies.

Figure 11 shows historical and expected peak impacts of self-generation, which are projected to reduce peak load by more than 3,000 MW by 2022. Historical impacts were revised downward because some self-generation data was found to be misclassified, so *CED 2009* projections begin well above estimates of historical impacts. Higher projections for PV peak impacts in both the residential and commercial sectors drive total self-generation peak above *CED 2009* levels by 2020 in all three scenarios. The temporary flattening of the curves after 2016 corresponds to expiration of the CSI program.

Table 10 shows historical and projected statewide electricity consumption from self-generation, and is broken out into PV and non-PV applications. For traditional combined heat and power (CHP) technologies, self-generation is assumed constant, so that

Figure 11: Statewide Peak Impacts of Self-Generation



Source: California Energy Commission

Table 10: Electricity Consumption From Self-Generation (GWh)

	1990	2000	2010	2015	2020	2022
Non-Photovoltaic Self-Generation	8,242	9,179	9,651	10,266	10,852	11,063
Photovoltaic, Low Demand	3	10	1,130	3,163	4,691	5,093
Photovoltaic, Mid Demand	3	10	1,118	3,074	4,118	5,256
Photovoltaic, High Demand	3	10	1,118	2,417	3,894	4,896
Total Self-Generation, Low Demand	8,245	9,189	10,781	13,429	15,543	13,175
Total Self-Generation, Mid Demand	8,245	9,189	10,781	13,148	14,941	16,325
Total Self-Generation, High Demand	8,245	9,189	10,781	13,429	14,718	15,924

Source: California Energy Commission

retired CHP plants are replaced with new ones with no net change in generation in the current forecast. Given the Governor's policy goals for CHP and DG and the recent qualifying facility settlement for CHP, in future IEPRs there will be a more comprehensive assessment of the status of CHP in California. As part of this effort, the staff will be developing scenarios for this technology for the revised forecast. Growth in non-PV self-generation comes mainly from recent increases in the application of fuel cells and other low emissions technology, projected forward.

Energy Efficiency Impacts

California's energy policy identifies energy efficiency as the "resource of first choice" for meeting California's future energy needs. As such, efficiency codes and standards, programs, and other policies play a central role in California's energy procurement and transmission plans and are a strategic element in the state's greenhouse gas emission reduction goals. Unlike other resources that are deployed to meet demand, energy efficiency reduces consumption and is therefore considered in the demand forecast, either embedded directly within the forecasting models or as an incremental effect subtracted from the model output. In both cases, staff is ensuring that the demand forecast reflects reasonable levels of efficiency from a comprehensive set of efforts expected to occur.

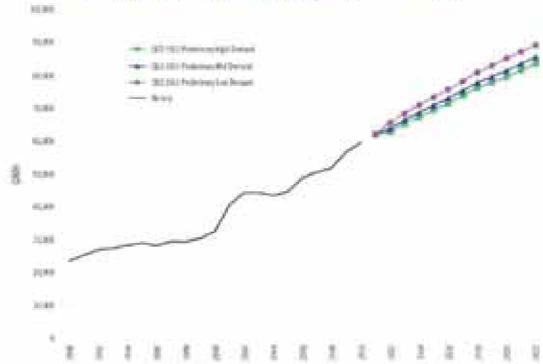
The *CED 2011 Preliminary* forecast continues the long-standing practice of distinguishing between two types of "reasonably-expected-to-occur" savings – committed and uncommitted. Committed efforts to reduce demand include authorized utility programs, finalized building and appliance standards, and other policy initiatives that have implementation plans, firm funding, and a design that can be technically assessed to determine probable future impacts. Committed savings also include price and market effects, which represent savings from rate increases and other market effects not related directly to standards and programs. These savings are incorporated directly into the forecast. Uncommitted savings – which, while plausible, have a great deal of uncertainty surrounding the method, timing, and relative impact of their implementation – are considered separately within the *CED 2011 Preliminary* analysis.

The Energy Commission developed the demand forecasting models in a way that promotes the inclusion of building and appliance efficiency standards. The models distinguish among vintages of floor space, housing, and equipment. As a new building or piece of equipment is added, the model assumes its energy use characteristics meet – at a minimum – the applicable standards. Following the effective implementation date, standards gradually affect an increasingly larger proportion of the total building and appliance stock. Each cycle of progressively tightened standards can be evaluated to determine the additional energy savings contributed from each vintage of standards by comparing model outputs.

Measuring the effects of utility programs poses a greater challenge, as customer participation is voluntary and is motivated by a complex set of interactive effects. Also, customers may replace appliances well before the end of their usefulness, and while data may be available on the efficiency of new appliances, the reference level of efficiency is often unknown for the replaced appliances.

To better measure program impacts, staff leveraged the CPUC's most recent efforts to measure utility program savings. The CPUC Energy Division's evaluation-based estimates of program savings from the 2006–2008 program cycle, as well as additional evaluation for 2009 programs, represent the most thorough and comprehensive effort to date. This unprecedented level of detailed evaluation data, however, applies only to programs implemented within the last four years. Therefore, staff modeled the uncertainty surrounding the performance of future programs using scenario analysis.

Figure 12: Statewide Committed Consumption Efficiency and Conservation Impacts



Source: California Energy Commission

Because a clear, consistent record of evaluated efficiency program achievements is not readily available,[112] there is a great deal of uncertainty around any estimate of historical program impacts. This uncertainty, along with uncertainty around attribution of savings among standards, programs, and price effects, has been the subject of debate in recent Demand Analysis Working Group meetings. Some parties have insisted that Energy Commission demand forecasts incorporate historical program impacts that are vastly underestimated and/or credit too much savings to standards and price effects, especially before 1998. A recent staff paper summarizes the positions of various parties.[113]

Staff believes that the forecasting process yields reasonable estimates of total savings but acknowledges and shares concerns voiced by stakeholders about savings attribution. Therefore, the *CED 2011 Preliminary* provides no attribution among the three sources (programs, codes and standards, and price and market effects) except for estimates of standards impacts. In other words, it provides no specific estimates of program and price effects. Staff will continue to work with stakeholders on these issues, with the goal of showing attribution for at least some years in future reports. Figure 12 shows total historical and projected committed efficiency savings from the three sources starting in 1990. Annual totals are relative to conditions in 1975, before the state implemented the first efficiency standards.

Beyond these committed impacts, the CPUC, Energy Commission, California Air Resources Board, and the Legislature have set efficiency goals without approval of specific program designs or authorization of actual program funding levels. Staff must consider long-term utility savings goals, future updates to Title 20 and Title 24 codes and standards, and statewide policy initiatives in determining incremental uncommitted energy efficiency impacts – impacts that are in addition those already included in the baseline forecast.

During the *2009 IEPR* cycle, at the request of the CPUC, staff began to assess the effects of incremental uncommitted energy efficiency policy initiatives. Staff included policy initiatives in the analysis similar to those originally evaluated by Itron and adopted by the CPUC in the *2008 Energy Efficiency Goals Update Report* (*2008 Goals Study*).[114] The incremental uncommitted analysis for *CED 2011 Preliminary* also relies on the *2008 Goals Study* but is updated to account for the passage of time. Therefore, some initiatives considered uncommitted in 2009 are now incorporated in the committed forecast. (Figure 12 includes estimated savings.) The newly committed initiatives include Assembly Bill 1109 (Huffman, Chapter 534, Statutes of 2007) and the 2010 Title 24 Building Code Revisions. In addition, the *CED 2011 Preliminary* extends uncommitted analysis to publicly owned utilities. The uncommitted efficiency initiatives in *CED 2011 Preliminary* include:

- Utility programs beyond 2012, including residential, commercial, and industrial.
- Further updates to state Title 20 and 24 standards along with updated federal appliance standards.
- The CPUC's Big Bold Energy Efficiency Initiatives.

As in the *2008 Goals Study*, *CED 2011 Preliminary* presumed various levels of commitment to these policies to create three scenarios of uncommitted efficiency savings – high, medium, and low. By 2022, consumption in the mid-demand case would be reduced 3.3 percent if adjusted by the low savings scenario and 6.2 percent using high incremental uncommitted savings. For peak, the reductions range from 4.8 percent to 5.5 percent, higher than consumption because the end uses targeted by these initiatives tend to have higher than average peak-to-energy consumption ratios.

Combining the high demand case with the low incremental uncommitted efficiency scenario and the low-demand case with the high efficiency scenario gives a range of "managed" forecasts. Statewide, adjusted consumption ranges from around 294,000 GWh to 322,000 GWh, compared to 311,000 GWh to 332,000 GWh for unadjusted consumption. For peak demand, the adjusted range is 63,000 MW to 71,000 MW, compared to the unadjusted range of 70,000 MW to 74,000 MW. In these adjusted mid- and low-demand cases, peak demand begins to drop slightly by the end of the forecast period. Peak demand in the low case drops slightly below the actual 2010 statewide (noncoincident) level.

The CPUC's new *Potential and Goals Study* is underway and is expected to be completed in late summer 2012. This schedule does not allow the study to be fully incorporated in the revised or final adopted IEPR demand forecasts, but CPUC staff intends to use interim study results to recommend changes to the incremental uncommitted efficiency impacts developed from the *2008 Goals Study*. Thus, the uncommitted results will likely differ in the revised and adopted IEPR forecasts compared to the preliminary.

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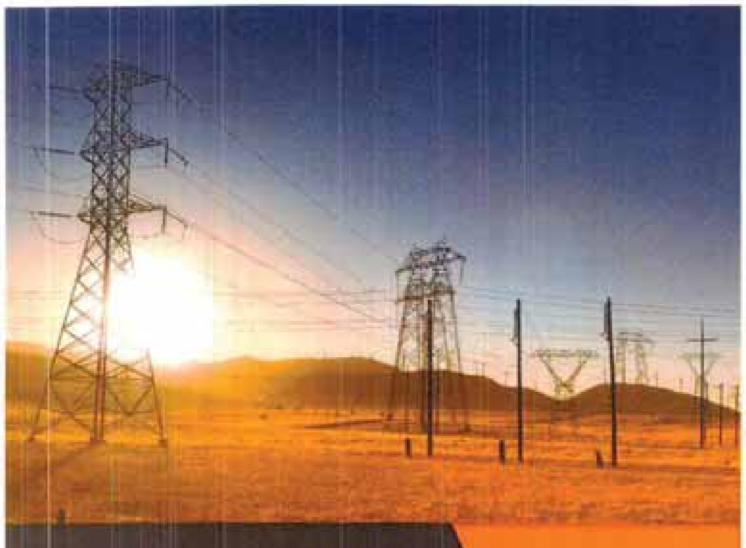
112 See discussion of EM&V requirements over time in Kavalec, Chris and Don Schultz, May 2011. *Efficiency Programs: Incorporating Historical Activities into Energy Commission Demand Forecasts*, draft staff paper, California Energy Commission, Electricity Supply Analysis Division, CEC-200-2011-005-SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-005/CEC-200-2011-005-SD.pdf.

113 California Energy Commission, Electricity Supply Analysis Division, Chris Kavalec. *Energy Efficiency Program Characterization in Energy Commission Demand Forecasts: Stakeholder Perspectives and Staff Recommendations*. Draft Staff Paper. August 2011. CEC-200-2011-010-SD, available at: www.energy.ca.gov/2011publications/CEC-200-2011-010/CEC-200-2011-010-SD.pdf.

114 Itron, Inc., *Assistance in Updating the Energy Efficiency Savings Goals for 2012 and Beyond*, adopted by CPUC in March 2008, www.cpuc.ca.gov/NR/rdonlyres/D72B6523-FC20-4964-A913-A0AE33D8406B/0/GoalsUpdateReport.pdf.



CHAPTER 9

California's Electricity Infrastructure

Part One: Once-Through Cooling and Assembly Bill 1318

This chapter of the *2011 Integrated Energy Policy Report* provides an update on progress made by the Energy Commission and other energy agencies on implementation of the State Water Resources Control Board's (SWRCB) once-through cooling (OTC) policy and related emission offsets concerns (Part One) as well as a status report on Energy Commission electricity infrastructure activities (Part Two). This summary also highlights some challenges facing energy and environmental agencies for resolving some key issues, provides the next steps, and makes a recommendation for going forward.

Reducing the impacts on the marine and estuarine environments from the use of OTC technologies in older power plants and the scarcity of emission offsets for new fossil power plants are two of the most important challenges facing the electricity generating industry. To reduce impacts, many of the owners of California's aging power plants are choosing to retire rather than make capital investments in the facility, causing a need for new capacity to satisfy peak

demand and appropriate reserves.[125] However, licensing new power plants is difficult, given the scarcity and corresponding cost of offsets required to avoid harmful impacts on air quality. Even repowering of the site of an aging power plant has its challenges. So, while policies to reduce the use of OTC are increasing the demand for new power plants, air quality constraints are restricting the development of fossil fuel power plants. This complexity is especially apparent in those areas of the state where existing air quality fails to satisfy ambient standards. Air pollution is a serious problem that has adverse health and economic effects. The South Coast Air Basin, for example, is experiencing the full effects of these opposing forces. To satisfy local capacity requirements (LCR)[126] and help integrate variable renewable generation, the region will have to replace some of its older capacity with dispatchable, flexible fossil power plants when existing OTC power plants retire. The *2009 Integrated Energy Policy Report* discussed the South Coast Air Basin's situation in detail and made recommendations to address the challenges, but uncertainties continue.

OTC is a form of power plant turbine condenser cooling technology that was considered conventional design when steam boiler power plants were built in California in the 1950s through the 1970s. This technology pumps water from a source (ocean, estuary, river, or lake) through a steam turbine condenser and then returns it to the source. The problem is that fish and small marine mammals are impinged and can suffocate and die on screens designed to keep them and people out of the water intake structure. In addition, smaller organisms are entrained in the cooling machinery itself and killed by turbulence, the pump, or the temperature increase of the water.[127] The federal Clean Water Act, Section 316(b), has long required existing power plants or other industrial facilities to reduce these environmental impacts, but the United States Environmental Protection Agency (U.S. EPA) and state agencies have been slow to act due to industry resistance to costly refits. In response to delays in U.S. EPA actions, the SWRCB undertook developing its own OTC policy and adopted a final policy in May 2010, which became effective on October 1, 2010.

For many years, local air quality districts, with some oversight from California Air Resources Board (ARB) and U.S. EPA, have developed and administered emission reduction mechanisms to prevent harmful impacts to air quality from new industrial facilities. Under these mechanisms, new facilities have had to "offset" their emissions by shutting down existing sources (or using offsets from previously shutdown sources), thus reducing overall net emissions and actually improving air quality. Yet, while the offset mechanism creates an incentive for older, inefficient, and unprofitable industrial facilities to retire, the amount of emission offsets that can be created by this approach in any region may be diminishing. In the South Coast Air Basin, where South Coast Air Quality Management District (SCAQMD) administers the air quality permitting and attainment programs, commercially available offsets have essentially disappeared for some criteria pollutants, since few existing power plants and refineries are willing to shut down just to provide offsets to new development.

Part 1 of this chapter provides a progress report and highlights some key challenges as these two topics are resolved in the electricity policy and planning processes of energy and environmental agencies.

125 Many power plants will be "repowered," meaning they will essentially be torn down and a new one constructed on the same site. Some power plants are attempting to "refit" by modifying ocean water intake structures to reduce environmental impacts sufficient to satisfy the OTC policy.

126 Local capacity requirements define the minimum amount of generating capacity that must be available within the boundaries of a local capacity area. Such areas exist because the transmission system serving them is inadequate to satisfy loads under extreme peak load conditions.

127 For a more detailed description of potential impacts of OTC technologies, see California Energy Commission, *Issues and Environmental Impacts Associated with Once-Through Cooling at California's Coastal Power Plants*, Staff Report, June 2005, www.energy.ca.gov/2005publications/CEC-700-2005-013/CEC-700-2005-013.PDF.

OTC Policy Implementation

The SWRCB's adopted OTC policy incorporates the recommendations jointly proposed in 2009 by the Energy Commission, California Public Utilities Commission (CPUC), and California Independent System Operator (California ISO). The May 2010 OTC policy essentially has two dimensions – stringency of requirements and compliance timing. SWRCB determined that evaporative cooling towers (roughly a 93 percent reduction of water usage compared to OTC) should be established as a performance benchmark. Recognizing that compliance would probably result in the shutdown of existing power plants and not wishing to threaten reliability, SWRCB established compliance dates for specific power plants based on an initial review of the time horizon needed to get replacement infrastructure on line.[128] Further, the OTC policy allows the interagency advisory committee to propose revisions to these dates, if necessary.[129]

Since the state adopted the policy, there have been two proceedings to revise compliance dates for power plants owned by Los Angeles Department of Water and Power (LADWP). In December 2010, SWRCB tabled LADWP's effort to extend the compliance schedule for: 1) any combined cycle power plant, or 2) any power plant that, once repowered, eliminates use of ocean water. On July 19, 2011, SWRCB modified the OTC policy (based on another proposal made by LADWP as part of its generation implementation plan filed with the SWRCB on April 1, 2011) to include: (a) an acceleration of two power plant repowering projects and a delay in the remainder of LADWP's repowering projects, compared to the compliance dates in the May 2010 OTC policy; and (b) broadening criteria for accepting compliance dates beyond 2022 for any generator that will entirely eliminate the use of ocean water for cooling, even as makeup for evaporative cooling towers. The delayed compliance dates for the three LADWP power plants will be examined again in 2012–2013 through mechanisms established in the policy.

The state required all generators to submit implementation plans on April 1, 2011, showing how they intended to comply with the OTC policy. Many generators provided plans conditional upon action by others. For example, most generator owners said they intended to repower if a CPUC-jurisdictional load-serving entity (LSE) would enter into a long-term power purchase agreement (PPA) with the generating unit. This presumes the CPUC will authorize procurement authority and establish oversight that leads to such a PPA. Without a PPA, no generator was willing to invest the money required to repower or refit intake structures to comply, thereby resulting in a plant shutdown. Some said matching the CPUC/LSE procurement mechanism with the existing SWRCB OTC compliance date for their power plant required the CPUC to establish procurement authority and provide direction to LSEs as part of a final decision in the 2010 Long-Term Procurement Plan (LTPP) – R.10-05-006.

Whether the CPUC does this, which would translate into opportunities to repower existing OTC capacity, depends upon finding a need for new dispatchable fossil power plants. Two likely justifications exist. One is the need to add capacity from highly flexible advanced single cycle or combined cycle power plants that can start and stop readily, and ramp over a wide

128 The SWRCB's action applies primarily to fossil fuel plants using OTC. California's two nuclear power plants, Diablo Canyon and San Onofre, also use OTC and will be subject to SWRCB action, but they will be on different, still-to-be-defined schedules for compliance. During 2012, the California ISO will continue studying the electricity system effects of OTC phase-out of the nuclear plants.

129 The Statewide Advisory Committee on Cooling Water Intake Structures (SACCWIS) includes staff representatives of the Energy Commission, CPUC, California ISO, Air Resources Board, State Lands Commission, California Coastal Commission, and SWRCB.

Constrained Emission Offsets in South Coast Air Basin

Challenges

Table 11: Generation Project Development Timeline

Long-Term Procurement Proceeding	2012
Request for Offers Design	2013
Request for Offers and Contracting	2014
Interconnection and Permit Preparation	2015–2016
Permitting	2016–2017
Construction	2018–2019

Source: California ISO, Energy memo to California ISO board, 8/18/2011

Table 11 reproduces the expected time frame for power plant development as presented to the California ISO Board in August 2011 for an OTC power plant with a nominal 2020 compliance date. The California ISO staff pointed out to their Board that decisions need to be made soon if major new generation projects are to be operational by 2020. If construction of new gas plants in the Western L.A. Basin is deferred, but the expected incremental energy efficiency and demand response results are not achieved, the infrastructure will not be ready in time if it turns out to be necessary. As a result, reliability standards would not be satisfied, and various transmission or generation outages, if encountered, would result in higher probabilities of customer outages or greater extent of customer outages (or both). Although California ISO's analysis uses the same deliverability risk assessment concept as that first articulated by CPUC staff in their 2008 LTPP proposal, the California ISO assumed that no incremental demand-side policy impacts were obtained. In contrast, the CPUC guidance to IOUs (issued in the 2010 LTPP rulemaking) reflected a reduced amount of impacts being used for resource planning compared to aspirational goals, but not an elimination of such impacts altogether.

Renewable integration assessments and extensions of local capacity requirements out to 10-year time horizons are not fully mature analytic activities, so it is not yet apparent to what extent preferred resource types (energy efficiency, demand response, distributed generation [DG], combined heat and power generators, and forms of energy storage), occurring at the levels identified in the CCEF vision statement or Governor Brown's 2010 jobs/energy plan, reduce the need for dispatchable fossil generation. Analyses underway will reduce that uncertainty, shifting focus to the hard policy choices that have to be made in light of the benefits and costs of the choices.

Next Steps

The state must complete analyses and make certain policy decisions before a clear path forward exists for retiring and/or repowering aging power plants.

Analyses

The interagency team must complete two remaining key analytic steps to accomplish the emission offset mechanism review as required by AB 1318. In preparing these analyses, the interagency team is addressing numerous uncertainties by designing a "bounding" assessment that would lead to the largest and smallest credible amounts of offsets required. First, the interagency team must complete its initial assessment of LCR out to the 10-year time horizon for at least South Coast Air Basin and ideally some other areas of SP26.[140][141] Replacement infrastructure has already been identified and is in the planning/permitting pipeline for most OTC power plants in the rest of the state. Second, the team must complete its translation of the new capacity identified in these reliability-oriented studies into projected emissions for various criteria pollutants that would have to be offset in the permitting processes. These offset requirements will be compared against existing offsets available for power plants to use.

The interagency team plans to accomplish both steps so that the ARB can include a preliminary analytic result in the draft AB 1318 project report. The report would undergo appropriate public review and management oversight in the early months of 2012. Since these initial results will likely reveal a wide range of required capacity additions and offsets, the interagency staff may have to identify the most likely portion of this range during the first three quarters of 2012, due to its relevance to policy decisions and so that the CPUC's 2012 LTPP proceeding can issue appropriate procurement authority to the IOUs by the end of 2012. Such a decision would put the timeline of Table 11 into motion.

Although these analyses are highly overlapping with review of OTC power plant compliance dates for Southern California, there are also OTC issues in other portions of the state outside the South Coast Air Basin. More than 3,000 MW of fossil OTC capacity is operating along the Central California coastline with current OTC compliance dates between 2015 and 2017. No viable plans to replace this amount of capacity on this schedule are apparent. In its newly released studies, the California ISO did not assume retirement of all this capacity. The interagency OTC Technical team has identified further needed assessments to determine whether the full amount of capacity can be retired without creating local, zonal or system reliability issues.

Policy Decisions

Five interacting sets of policy decisions must be made once the analysis provides a range of offset requirements.

- Agencies (Energy Commission and CPUC), the California ISO, and SCAQMD should adopt a consistent approach to relying on load reductions resulting from demand-side policy initiatives for reliability planning purposes.

- Energy agencies (Energy Commission and CPUC), local land-use agencies, and the Legislature have some influence over resource development strategies, perhaps still implemented through competitive market mechanisms, which affect the extent of renewable development to satisfy local capacity area requirements. Governor Brown's renewable DG goals are reshaping the thinking about remote versus local resource development, which could affect the need for central station power plants in urbanized areas to satisfy the local capacity component of reliability standards.

- The California ISO and transmission owners have an ability to influence the extent to which local capacity area requirements can be diminished through transmission system development, upgrades, and modifications.[142] Is it feasible for the California ISO to identify transmission system upgrades that IOUs can implement to reduce LCR requirements and provide greater geographic flexibility for generation additions?

- SWRCB has the ability to shift OTC compliance dates to affect the timing of existing power plant retirement and development of replacement capacity requiring offsets. Will SWRCB do so if it allows demand-side policies to defer fossil generation or enables greater use of remote renewable generation dependent upon transmission development?

Numerous agencies are involved in making these decisions. The initial track record of energy agency cooperation is good for developing a proposal for preliminary schedules and periodic review of compliance dates, along with SWRCB's acceptance of this approach in its OTC mitigation policy. The AB 1318 effort has broadened the OTC focus to address the offset issues, which are at the heart of any "solution." More entities must become involved as the issues turn to assessing criteria pollutant offsets needed and available and how to decide scarce amounts among competing interests. Devising common planning assumptions and better integration of planning processes is one means of getting multiple agencies "on the same page." The state agencies have embarked upon improved coordination of efforts through the CCEF process, but tighter coordination will be needed to surmount the challenges of OTC policy implementation while satisfying ambient air quality standards.

Conclusion

The analyses released by California ISO in December 2011 brought an abundance of improved information about the long-term need for new power plant capacity to replace OTC units for satisfying LCR, given various assumptions about the future. These results differ from ones previously released by suggesting that not all of the L.A. Basin OTC capacity has to be replaced, and that much of San Diego OTC capacity does have to be replaced. The magnitudes of these results differ depending upon the CPUC-defined renewable development scenario that was assumed, reflecting uncertainty about what mix and location of renewables will be developed to satisfy California's 33 percent by 2020 requirements. The next round of analyses planned for early 2012 will provide additional information about the extent to which capacity needed for renewable integration is incremental to that needed for LCR purposes. It will also inform assumptions used in the AB 1318 effort to estimate future offsets in the South Coast Air Basin for power plants that must be located in areas subject to SCAQMD's permitting requirements.

- Interagency coordination should continue on broader policy decisions that are inappropriate to the more narrow focus of a single agency. Interagency coordination should focus on achieving consistent decision making in the proceedings that are underway.

Part Two: Status of Energy Commission Electricity Infrastructure Activities

California's commitment to reduce GHG emissions to 20 percent of 1990 levels by 2050[143] requires developing demand-side resources (for example, energy efficiency and demand response programs), retiring or divesting high-emission generation, and developing renewable and other zero- or low-carbon resources. To this end, California has placed energy efficiency at the top of the state's loading order[144] and requires the utilities to limit long-term investments to power plants that meet the Emission Performance Standard (EPS). As a result, the Energy Commission expects more than 2,060 MW of capacity and 17,600 gigawatt hours (GWh) of energy to be diverted between now and 2026,[145] reducing the share of California's electricity needs met by contracts with/ownership of coal-fired generation from roughly 18 percent to less than 4 percent. In addition, California's Renewables Portfolio Standard means that greater amounts of renewable energy will be needed over the longer term to realize GHG reduction targets. Finally, the SWRCB's policy on the use of OTC by power plants may encourage or require the retirement of as much as 13,300 MW of gas-fired generation by 2020.[146]

The potential retirement, replacement, or divestiture of more than 15,000 MW of fossil generation[147] requires an assessment how much replacement capacity will be needed to assure electric system reliability and ease the transition to a low-carbon electricity sector through 2020 and beyond. While California's energy needs will be increasingly met by renewable resources over the next decade and the development of dispatchable renewable resources (for example, geothermal and biomass) over the longer term, the existing system requires threshold amounts of such capacity to ensure system and local reliability. This need has three facets, which are described as follows:

- **Total capacity:** Given load growth (net of energy efficiency and demand response programs) and the capacity provided by other generation resources (both in- and out-of-state), sufficient capacity from in-state gas-fired resources must be available to meet systemwide capacity requirements. As the penetration of variable energy resources increases, this may require planning and operating reserve margins in excess of those historically held to provide desired levels of reliability.

140 Although San Diego and Ventura areas are outside the South Coast Air Basin, they [illegible] requirements to provide offsets under SCAQMD rules do not apply to such capacity, these areas are linked to South Coast Air Basin electrically both for zonal and perhaps even local capacity area requirements. [illegible] in which capacity development in San Diego or Ventura areas can substitute for capacity in the Western L.A. Basin. Further, transmission system changes [illegible] upgrades of existing lines could reduce the capacity requirements in the actual boundaries of transmission-constrained local areas.

141 Path 26 is the limiting transmission path between Northern and Southern California, so SP26 refers to the region "south of Path 26" within the California ISO balancing authority area.

142 For example, the Tehachapi Transmission project, mainly thought of as a means to bringing wind power into load centers, also has the consequence of greatly reducing local capacity area requirements in the Antelope/Big Creek and L.A. Basin load pockets.

143 Executive Order S-3-05, June 1, 2005, available at: gov.ca.gov/news.php?id=1861.

144 See State of California Energy Action Plan (2003), page 3, available at: www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF. Also see State of California Energy Action Plan II, September 21, 2005, available at: www.energy.ca.gov/energy_action_plan/2005-09-21_EAP2_FINAL.PDF.

145 This includes the expiration of relationships with the Boardman (OR), Four Corners (NM), Reid Gardner (NV) and Navajo (AZ) coal plants, reduced procurement from the Intermountain (UT) facility, and the expiration of contracts with 11 in-state qualifying facilities (totaling 359 MW) that burn coal or petroleum coke.

146 The policy also requires that 1,451 MW of gas-fired generation capacity at LADWP's Haynes, Scattergood, and Harbor, as well as Diablo Canyon and San Onofre nuclear facilities (4,486 MW) come into compliance during 2015–2029.

147 This total does not include an additional 2,214 MW of gas-fired generation that is 33 years old or more, identified by Energy Commission staff in 2009 as candidates for retirement. See Resource, Reliability and Environmental Concerns of Aging Power Plant Operations and Retirements, California Energy Commission, draft staff white paper, August 13, 2010, CEC-200-2010-[illegible], available at: www.energy.ca.gov/publications/displayOneReport.php?pubNum=CEC-200-2010-[illegible]

- **Location:** Gas-fired generation capacity is needed in specific geographic areas to meet zonal (NP26,[148] SP26) and local capacity requirements. The California ISO has identified 10 local capacity areas (and 41 subareas); three of these areas (Los Angeles, San Diego, and Big Creek – Ventura) contain significant amounts of capacity that use OTC; most of these facilities are located in subareas within the larger area. There are also local capacity requirements for the LADWP's balancing authority area in the Los Angeles Basin.

- **Operational characteristics:** Gas-fired generation capacity must have the operating characteristics that allow it to provide the ancillary services necessary to integrate large amounts of renewable resources while maintaining reliability. This includes fast start capability, allowing resources to cycle off when not needed and to "opt in" to ancillary service markets as close to real time as possible; the ability to efficiently operate over as wide a range as possible and change output levels as quickly as possible, allowing a resource to provide substantial amounts of spinning reserves and load following services; and operation under automated generation control, allowing the resource to provide regulation services.[149] In addition, gas-fired generation resources vary in their provision of inertia, needed to provide voltage support and stabilize the system when sudden component outages cause changes in frequency.[150]

The *2011 IEPR* Scoping Order calls for an assessment of needed additions to California's electricity infrastructure to transition to a low-carbon future while maintaining resource adequacy and reliability.[151] Other discussions have taken place regarding infrastructure needs, including transmission to support central station renewables and upgrades to the distribution system to allow for the development of large amounts of distributed generation (DG).

This chapter of the *2011 IEPR* discusses the major uncertainties that affect estimates of the needed gas-fired generation to help integrate variable energy resources over the coming decade while maintaining system and local reliability. These uncertainties include:

- Demand growth.
- Potential retirement of generation units that use once-through cooling.
- Renewable energy development, including wind, central station solar PV, solar thermal with and without storage, geothermal, and renewable DG.
- The need for dispatchable generation capacity to provide ancillary services in support of renewable resource integration, and the availability of other resources, such as energy storage or geothermal plants, which may need a different market to be economically run.

148 Path 26 is the limiting transmission path between Northern and Southern California, so NP26 refers to the region "north of Path 26" within the California ISO balancing authority area.

149 For a discussion of the services provided by gas-fired generation, see *Framework for Evaluating Greenhouse Gas Implications of Natural Gas-Fired Power Plants in California*, consultant report, MRW & Associates, LLC, December 2009, CEC-700-2009-009-F, available at: www.energy.ca.gov/2009publications/CEC-700-2009-009/CEC-700-2009-009-F.PDF. For a discussion of the role gas-fired generation plays in integrating variable energy resources, see chapter 5 of *Renewable Power in California: Status and Issues*, August 2011, CEC-150-2011-002, available at: www.energy.ca.gov/2011publications/CEC-150-2011-002/CEC-150-2011-002.pdf.

150 Inertia maintains system stability and reduces frequency deviations or oscillations. Inertia is provided through sufficient spinning mass (rotating turbines), for example, that effectively reduces frequency changes.

151 California Energy Commission, *Committee Revised Scoping Order, 2011 Integrated Energy Policy Report* proceeding (Docket 11-IEP-1), March 30, 2011, page 5.

Table 12: Comparison of Forecasts of California ISO 2020 Peak Demand

	Required for LTPP (2009 IEPR Unmanaged)	IOU Common Case for LTPP	Preliminary 2011 IEPR Forecast	2011/2012 Transmission Planning Process	CPUC Required High	CPUC Required Low
Unmanaged CAISO Peak Demand	55,728	60,653	54,568	55,728	60,878	49,764
Uncommitted Energy Efficiency	5,830	4,215	NA	—	5,087	5,861
New CHP	673	578	NA	—	613	673
CAISO Peak Net of EE and CHP	48,725	55,851	NA	55,728	54,323	43,262
Demand Response	5,141	6,950	NA	NA	5,141	5,141

Source: CPUC Rulemaking 10-05-006, PG&E, SCE, and San Diego Gas & Electric (SDG&E) System Resource Plan Joint IOU Supporting Testimony, July 1, 2011, p. A-44 and workpapers; California ISO 2011/2012 Transmission Planning Process, Unified Planning Assumptions and Study Plan, Final – May 18, 2011; Energy Commission 2012-2022 Preliminary Staff Electricity and Natural Gas Demand Forecast, coming in fall 2011.

Notes: Unmanaged forecast for the CPUC Required case uses the 2009 IEPR demand forecast (CEC-200-2009-012-CMF, December 2, 2009) and uncommitted DSM from the mid case of Incremental Impacts of Energy Policy Initiatives Relative to the 2009 Integrated Energy Policy Report adopted demand; use of demand response impacts in the 2011/2012 TPP remains under consideration.

- The necessary composition of new gas-fired generation, including its ability to provide inertia.
- Combined heat and power development.

The remainder of this chapter discusses how these uncertainties affect electricity planning and the analysis needed during the current planning cycle to develop planning assumptions.

Demand Growth

The California ISO integration studies and the CPUC's Long-Term Procurement Proceeding (LTPP) are using the *2009 IEPR* demand forecast and associated estimates of the capacity value of uncommitted energy efficiency in their analyses of infrastructure needs.[152] The Energy Commission completed this forecast in late 2009 and, therefore, relied on historical data only through 2008 and economic projections that are now more than two years old. The Energy Commission staff is preparing a revised forecast that is expected to be completed in February 2012; it will be accompanied by uncommitted demand-side management (DSM) scenarios based on any updated assessments of energy efficiency potential that are available at that time.[153]

152 "Uncommitted" energy efficiency refers to programs that have yet to be funded (or perhaps even designed) but whose funding and implementation can be reasonably expected to occur for planning purposes. Failure to consider uncommitted energy efficiency in planning can lead to the financing and construction of surplus generation capacity at ratepayer expense.

153 The final demand forecast to be adopted by the Energy Commission will not be completed until spring 2012.

Meanwhile, the IOUs have included in their LTPP filings an IOU case (the IOU Common Case) using an alternative, higher demand forecast with lower uncommitted demand side impacts. Table 12 compares the peak demand forecast for 2020 for the base and DSM impacts.

Two of the most significant uncertainties regarding demand growth are economic assumptions and demand-side impacts. The preliminary demand forecast is 3.4 percent lower than the *2009 IEPR* forecast because the effects of the recession have been more severe than previously predicted. Conversely, the IOU Common Case demand forecast is 7 percent higher than the *2009 IEPR*. In addition to higher growth in the base forecast, the IOU Common Case forecast assumes lower impacts from energy efficiency, self-generation, and demand response programs. The difference of 1,600 MW in energy efficiency is because the IOUs have found that some programs are not cost effective and found issues associated with replacement of program decay. Energy Commission and utility staff are addressing these and other technical issues, including appropriate assumptions for incremental demand growth from electric vehicle penetration. Also, an updated analysis of goals is scheduled to be completed in late 2012, which will be incorporated into the uncommitted energy efficiency scenarios.

The *2012 IEPR* Update demand forecast will provide updated information regarding demand growth. (See Chapter 8 of this report for more details.) The potential need for gas-fired generation to meet local capacity requirements requires assessing the combined impacts of demand growth, energy efficiency, demand response, and DG at a much finer geographic resolution than was needed for traditional resource planning. Staff has begun working with utilities and the California ISO to develop the detailed data sets to account for demand side impacts at the local area/substation level.

OTC Retirements and Local Capacity Requirements

The state's policy for addressing the effects of once-through cooling will greatly influence the need for new gas-fired generation capacity during the coming decade. The policy applies to 14,733 MW of existing gas-fired generation and may require 13,300 MW of this to comply with OTC policy by 2020.[154] Table 13 shows that a large share of this capacity is located in California ISO-defined local reliability areas or the transmission-constrained portion of the LADWP control area.

In May 2010, the SWRCB adopted a final policy that can be interpreted as requiring the phase-out of OTC; this policy became effective on October 1, 2010. SWRCB determined that evaporative cooling towers should establish the performance benchmark (using roughly 93 percent less water compared to OTC). Generation units can comply by reducing intake flow rates to this benchmark level (Track 1 compliance) or, if unable to do so, decrease impingement mortality and entrainment of marine life by reducing intake flow rates using a combination of structural and operational controls (Track 2 compliance).

There exists substantial uncertainty about when and how units will comply with the OTC policy. Owners filed compliance plans on April 1, 2011, but only a handful provided firm plans for the retirement and

154 On July 19, 2011, the SWRCB ruled that the compliance deadlines for 1,492 MW of capacity owned by LADWP would be extended to 2024 (Scattergood 1–3, 347 MW) and 2029 (Haynes 1–2, 444 MW; Haynes 8, 16; 575 MW; Harbor 5, 65 MW).

Table 13: OTC Capacity With Compliance Deadlines in or Before 2022

Local Capacity Area	MW
Los Angeles Basin	4,540
San Diego	958
Big Creek/Ventura	1,347
Bay Area	1,302
LADWP	585
SUBTOTAL	10,124
None	3,180
TOTAL	13,284

Source: Energy Commission staff

replacement of existing capacity.[155] These include the following:

- Dynegy believes that its Moss Landing 1–2 units (1,020 MW) are already in compliance; the SWRCB must rule upon this contention.
- The owners of 10 units at 5 facilities totaling 4,237 MW are considering compliance through the use of structural and operational controls (Track 2).[156] It is uncertain, however, that (a) such measures can bring the units into compliance, and (b) that if they result in compliance, they will allow enough operational flexibility to provide ancillary services or do so on a scale that yields a revenue stream sufficient to warrant the necessary investment. Planning entities will work with the SWRCB over the coming months to determine if imposing structural and operational controls is a compliance option for these resources. Where Track 2 compliance is likely to be infeasible (for either of the above reasons), planners should consider their retirement and the need to replace them as a planning assumption.

Merchant owners indicated that much of the existing capacity will be retired, with replacement capacity being built only if they can procure long-term power purchase agreements. While studies have indicated the need for capacity in subareas containing El Segundo, Huntington Beach, and Encina,[157] the state must refine estimates of LCR through 2020. The LCR process has historically focused on near-term (one to three years) needs. During this planning cycle, the Energy Commission, CPUC, and the California ISO will develop long-run LCR estimates in conjunction with assisting the SWRCB in implementation of its OTC policy and assessing emission reduction credit needs in the South Coast Air Quality Management District (SCAQMD) under Assembly Bill 1318 (V. Manuel Pérez, Chapter 285, Statutes of 2009).[158]

More than 2,850 MW of aging, non-OTC gas-fired power plants in California are candidates for retirement. Some are owned by publicly owned utilities and

155 Contra Costa 6–7 (674 MW) will be replaced by Marsh Landing (760 MW combustion), expected to come on line in 2013; El Segundo 3 (335 MW) will be replaced by new units (550 MW) at the same site expected to come on line in 2013; LADWP is replacing Haynes 5–6 (531 MW) and Scattergood 3 (450 MW) with roughly equivalent amounts of capacity in 2013 and 2015, respectively.

156 Morro Bay (650 MW), Mandalay (430 MW), Ormond Beach (1,516 MW), Encina 4–5 (628 MW) and Moss Landing 6–7 (1,510 MW).

157 The California ISO's 2013 – 2015 Local Capacity Technical Analysis indicates local capacity requirements in 2015 as follows: the El Nido subarea (in which El Segundo is located) of the Los Angeles Basin needs 111 MW (net of existing qualifying facilities); the Ellis subarea (in which Huntington Beach is located) of the Los Angeles Basin needs 498 MW; the Encina subarea (in which Encina is located) of San Diego needs 20 MW.

158 For a more detailed discussion of interagency efforts related to OTC and emission reduction credits in the Los Angeles Basin, see Part One of this chapter.

Renewable Energy Development

Renewable Integration Needs

The Technological Characteristics of Gas-Fired Generation

Combined Heat and Power Development

planning period (2020). It assumes new CHP in place by 2020 is roughly half of the 4,000 MW originally targeted by the ARB.[177]

The amount of new CHP developed through 2022 will depend upon a number of factors besides the effect of the QF settlement. Although many existing CHP generators provide GHG reductions compared to the benchmark established in the QF settlement, some do not. The IOUs may meet their share of the emissions reduction target in part by terminating contracts with CHP resources that fail to meet the benchmark so these resources may or may not continue to operate. While failing to procure the remaining share of the 3,000 MW target cannot be based on conventional resources being lower cost, best fit, such consideration could be used to justify not reaching the GHG reduction target set forth in the settlement.[178] Further, although the settlement maintains a must-take obligation for CHP up to 20 MW in size, it has been more difficult to develop small CHP despite programs designed to encourage its development. Table 14 summarizes these programs and their yield to date.

Discussions with CHP generators and developers indicate that continued regulatory uncertainty and the lack of resolution on the high costs associated with standby charges and departing load fees negatively affect private sector CHP investment decisions in California. The largest barrier, especially for large CHP developers, continues to be uncertainty relating to GHG regulations and costs under AB 32. Others include local permitting issues, CHP program delays due to slow implementation and prolonged legal conflicts, and long waits for interconnection.

Energy Commission staff has commissioned an update of the 2009 Public Interest Energy Research (PIER)-funded *Combined Heat and Power Market Assessment*, which will be discussed at a staff workshop in February 2012.[179] This analysis will provide information for projections regarding potential ranges of CHP development in aggregate, as well as information on potential CHP development in local capacity areas, and thus the residual need for new, conventional gas-fired generation both systemwide and in local areas. Staff also plans to produce a white paper on CHP development and related issues in early 2012 and is working with CPUC staff to assess the potential disposition of existing CHP projects under the QF settlement. This body of work, along with input from stakeholders in future IEPR proceedings, will provide information for assessments of likely CHP development through 2022, the policy measures that will encourage development during this period, and reaching 2030 targets.

177 The 4,000 MW is reduced to 3,762 MW to account for new CHP assumed in the Energy Commission demand forecast. This number is then halved (to 1,877 MW) with 938 MW on both the supply- and demand sides, in keeping with ARB assumptions. Slightly more than 80 percent of this (1,500 MW) is allocated to the California ISO balancing authority area; the remainder is assumed to be developed in the four other balancing authority areas in the state.

178 See Section 6.3 of the QF settlement agreement.

179 ICF International, Inc., *Combined Heat and Power Market Assessment*, CEC-500-2009-094-F, April 2010, available at www.energy.ca.gov/2009publications/CEC-500-2009-094/CEC-500-2009-094-F.PDF

Table 14: Programs for Small CHP

	Technology	Program Cap	Capacity to Date (MW)	Installed Capacity CHP (MW)	Number of CHP Projects
AB 1969 FiT[A]	Small Hydro, CHP, PV	750 MW	38.1	17.1	18
AB 1613[B]	CHP Only	N/A	0	0	0
Self-Generation Incentive Program[C]	Wind, Fuel Cells, Gas Turbines, IC Engines, Microturbines, Energy Storage	Limit Based on Program Funding	351	171	222
CHP/QF Settlement[D]	CHP Only	3,000 MW			
SMUD FiT Solicitation[E]	Solar & CHP	0–100	100	0	0

A AB 1969 was revised by SB 32; subsequent development is included.

B Program is still pending due to controversy over contract terms.

C The SGIP Proposed Decision brings back the inclusion of internal combustion engines, gas turbines, and microturbines that were all dropped from the program in 2008.

D The 3,000 MW is divided among the three IOUs based on load served: [illegible] for PG&E, [illegible] for SCE, and [illegible] for SDG&E. In addition, there is a GHG reduction target that may require additional capacity to be procured, but that amount is unknown at this time.

E Capacity is not yet in place, but the program is fully subscribed ([illegible]).

CHAPTER 10

Transportation Energy Forecasts and Analysis

This chapter provides a brief background and analysis of transportation energy issues with an emphasis on challenges that have the potential to affect the availability and market price of transportation fuels over the near to mid term. California's transportation energy sector provides residents and businesses with the means and mobility for many essential activities. Industry, commercial businesses, households, transit agencies, and government all rely on transportation energy and expect that needed supplies will be available for movement of goods and people over highways, rail, waterways, and air. Transportation fuels also provide energy for off-road, industrial, agricultural, commercial, military, and recreational uses.

Any source of energy for transportation has economic, environmental, security, and infrastructure dimensions. Petroleum fuels refined from crude oil, currently the dominant transportation energy source in California and globally, have historically had many advantages. These include high energy content, portability, storability, established vehicle fleet and equipment stock, and established refining, transportation, storage, and distribution infrastructure. Until

Transportation Energy Demand and Policy Impacts

Transportation Energy Demand — Historical and Forecast

Federal Regulation — Renewable Fuels Standard (RFS2)

more attractive since they generate more credits. Substantial U.S. and California investments in low CI ethanol and other fuels would further offset initial price differentials for the lower CI ethanol. Indeed, there are indications that such substantial investments have been occurring. It is anticipated that such investments will continue to occur if California, through the Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program, maintains its leadership role in transforming the transportation fuels sector and consistently sends clear market signals that provides investors with certainty.

The second challenge associated with the RFS2 is the ability of the biofuels industry to provide sufficient quantities of cellulosic biofuels necessary to achieve compliance with the federal annual minimum target volumes. Further technological advances are needed to overcome higher production costs relative to the costs for conventional biofuels such as corn-based ethanol. As a consequence, the U.S. EPA has had to downgrade the minimum cellulosic fuel requirements by 94 percent between 2010 and 2012. Staff has elected to use a lower projection of cellulosic fuel availability than the minimum standards set forth by Congress. Staff's proportional share RFS2 compliance analysis incorporated the cellulosic biofuel projections provided by the Energy Information Administration (EIA). A continuation of the slow pace of progress for commercialization of large volumes of cellulosic ethanol may present challenges for meeting California's LCFS towards the end of the decade. Energy Commission and ARB staff will continue to coordinate on these scenarios to refine them and identify additional scenarios that can be used to meet the LCFS goals beyond 2017–2018 and to anticipate the various challenges that may arise.

Another set of concerns about the higher mandated levels of biofuel use prescribed by the RFS2 includes effects on water use and water quality. A study sponsored by the National Academies of Science has identified several areas of uncertainty with regard to such impacts, including amount of added irrigation needed to provide mandated biofuels, types and amounts of fuel feedstocks required, additional fertilizer and pesticide requirements for feedstock crops, potential changes in farming methods, and water requirements of biorefineries.[184] Cellulosic feedstocks may have the potential to reduce some of these impacts. Staff should continue to monitor research into these subject areas, including any that are specific to California, and incorporate findings into future reports.

State Regulation – Low Carbon Fuel Standard

The LCFS requires a 10 percent reduction in the average CI (as measured by both direct and indirect life cycle carbon emissions) of California transportation fuel between 2010 and 2020.[185] Staff has prepared case analyses to assess the feasibility of compliance with the LCFS using various types of biofuels and LCFS credits for transportation electricity and natural gas. Prices were projected for all of the biofuels included in the analysis and generally show an increase in value throughout the forecast due to an assumed rising value for fuels that have lower carbon intensities than traditional biofuels. The ARB approved amendments to the LCFS regulation on December 16, 2011, and presented fourteen plausible scenarios of potential low-carbon fuel options to achieve regulation compliance.

Compliance with LCFS throughout the entire forecast period will evolve over time and presents challenges not yet examined. It should be noted that 2011 is the initial year of CI reductions under any of

184 National Academy of Science, *Water Implications of Biofuels Production in the United States*, 2008, available at www.nap.edu/catalog.php?record_id=12039.

185 Please see the California Air Resources Board website that contains background information and regulations at: www.arb.ca.gov/fuels/lcfs/lcfs.htm.

the cases examined, and it is difficult to forecast with accuracy compliance with the LCFS over the long term. For these cases, Energy Commission staff assumed that all uses of electricity and natural gas for transportation would generate carbon credits for regulated parties. However, this assumption depends on ARB completing its assessment of what portion of existing transit electricity use may be eligible for credits and at what levels. Aggregate statewide compliance with the standard is achieved when the quantity of carbon credits (as measured in metric tonnes) yielded from the use of biofuels, electricity, and natural gas exceeds the quantity of carbon deficit generated from petroleum-based gasoline and diesel fuel.

The main challenge associated with the LCFS is ensuring that production and delivery to California of sufficient quantities of low-CI biofuels are ramped up to help achieve compliance in the latter years of the program.

Biofuel Availability

Staff analyses for LCFS compliance cases assume that LCFS compliance feasibility through 2017 was accomplished through the use of up to 50 percent of the nation's available supply of cellulosic gasoline forecast by EIA.[186] If up to 50 percent of the other cellulosic biofuels (cellulosic ethanol and cellulosic diesel) forecast by EIA to be available in the United States were also used in California, compliance with the LCFS could be extended through 2019. A continuation of the slow pace of progress for commercialization of large volumes of cellulosic ethanol may present challenges for meeting California's LCFS toward the end of the current compliance period. The Energy Commission's Alternative and Renewable Fuel and Vehicle Technology Program (ARFVT Program) has awarded $45 million to fund the initial stages of 17 biofuel projects in California that could produce up to 408 million gallons of advanced biofuels by 2020 if full-scale commercialization occurs in each project.

The diesel scenarios depend, in part, on relatively large quantities of renewable diesel from inedible tallow and biodiesel from corn oil. For example, staff has assumed that 50 percent of the feedstock that is theoretically available is used to produce these two types of biofuels and all of this production is sold to California for use in the LCFS program. Staff has calculated in Case 3 that 22 percent of the carbon credits generated by 2017 would be obtained from renewable diesel alone, underscoring their importance for compliance, assuming credits are not sufficiently available in the market.

There are several challenges to any reliance on higher biodiesel blends. The challenges include ensuring adequate volumes of specific fuel types, need for ensuring infrastructure compatibility with higher biodiesel concentrations, and manufacturer vehicle engine warranty concerns for biodiesel blends in excess of 10 percent. While these considerations present challenges to the increased use of biodiesel, particularly at the higher blends, sufficient time, testing and investments are expected to address these concerns. ARB also has identified the potential for increased oxides of nitrogen (NO_x) emissions at higher biodiesel blends but has expressed its intent to address and mitigate this potential when it pursues a rulemaking to establish standards for biodiesel blends greater than 6 percent by volume during the latter portion of 2012.[187]

The final challenge for biofuel availability has to do with Brazilian ethanol. Energy Commission

186 During the November 14 workshop, staff incorrectly noted during the LCFS presentation that "cellulosic fuel availability increased to 50 percent of U.S. supply" as one of the assumptions for Case 1. The correct assumption should have read "Cellulosic gasoline availability increased to 50 percent of U.S. supply." See slide 6 from the following link: www.energy.ca.gov/2011_energypolicy/documents/2011-11-14_workshop/presentations/Schremp-LCFS.pdf.

187 California Air Resources Board, *California Air Resources Board Guidance on Biodiesel Use*, October 2011, page 2. A link to the regulatory guidance advisory is as follows: www.arb.ca.gov/fuels/diesel/altdiesel/20111003Biodiesel%20Guidance.pdf.

scenario analysis shows that California could be using more than 1 billion gallons of Brazilian ethanol by 2016, which is nearly 75 percent of the record for Brazilian exports to the world during 2008 of 1.35 billion gallons. In this scenario, nearly 11 percent of the credits generated during 2016 are from Brazilian ethanol. These historical figures are all pre-LCFS, so it remains to be seen to what extent Brazilian ethanol production can be ramped up. Energy Commission and ARB staff will continue to monitor volumes of biofuels coming into California to ensure that adequate steps are taken to bring in sufficient quantities of advanced biofuels.

Biofuel Costs

Transportation fuel costs for consumers and businesses are forecast to continue rising due to higher crude oil prices. To the extent some biofuels may be more expensive to produce than the petroleum and renewable fuels they displace, at least in the early years of the RFS2 and the LCFS, consumers and businesses may be affected. For example, the estimated price to deliver Brazilian ethanol to California has averaged about $1 more per gallon greater than ethanol delivered to California from the Midwest during 2010 and about $1.50 per gallon greater[188] compared to ethanol delivered to California from the Midwest during the first eight months of 2011. The federal import tariff and ad valorem tax expired at the end of 2011, which could decrease the cost of importing Brazilian ethanol to California beginning in 2012. Given the historical variation in the price of Brazilian ethanol and the uncertainty of future tariffs, it is difficult at this time to make reliable projections on future impacts on fuel prices.

Although there are no prices yet for transactions involving cellulosic ethanol, the RFS2 program has a well-established credit trading platform that provides some insight into the potential incremental costs of this type of biofuel compared to traditional corn-based ethanol. Between January and August 2011, cellulosic ethanol Renewable Identification Number credits have averaged about $1.00 more when compared to traditional ethanol. This translates into a price of roughly $700 per ton of carbon credits produced, attributable to the federal RFS2 program alone.

Biodiesel is another example of a biofuel that currently costs more than conventional diesel. Its increased use in California is a natural result of the RFS2 volume mandates, and the LCFS will benefit from that increased use because of biodiesel's reduced GHG emissions. Prices of biomass-based biodiesel (such as soy biodiesel) have averaged nearly $3.00 more per gallon when compared to petroleum-based diesel fuel during 2011. California regulated parties may prefer to avoid the use of soy biodiesel due to the higher carbon intensity of that fuel and focus demand on biofuels that use corn oil and used cooking oil as feedstocks. These other types of biofuels may command an even higher premium than soy biodiesel. The extent to which these biofuels may cost more is unknown since there is no LCFS credit trading platform currently active that would establish a range of carbon values in the marketplace that could be used to estimate incremental costs for these lower CI biofuels. It should be noted that the ARB adopted regulatory amendments on December 16, 2011, that contain provisions for its Executive Officer to develop reporting requirements of prices for LCFS credit transactions, so staff will have a better idea of carbon intensity values as the market matures.[189]

The above discussion notwithstanding, substantial investments in advanced biofuels can significantly increase the volumes of such fuels being

188 The current higher cost of Brazilian ethanol is, in part, due to an import tariff imposed by the United States. This form of protectionism increases the cost of supplying ethanol to the United States market by at least 60 cents per gallon and is a type of trade challenge not applied to other types of foreign imports such as crude oil, gasoline, jet fuel, and diesel fuel.

189 California Air Resources Board, *Board Book*, page 44, see: www.arb.ca.gov/board/books/2011/121611/bbrpt.pdf.

delivered into California. That would have the benefit of lowering prices of these advanced biofuels, thereby reducing and offsetting the effects noted above. The ARFVT Program is one source of funding to stimulate development of California biofuel production plants. ARB staff has committed to evaluating improvements and refinements in the LCFS program with the express intent of incentivizing the substantial increase in advanced biofuel and alternative fuel production.

Expansion of Similar Standard Outside California

California is the only state with an active LCFS program. However, 22 other states are developing or considering LCFS programs that equate to 3.7 times the quantity of gasoline consumed in California and 7.2 times the quantity of diesel fuel consumed in California during 2009. One possible result is that the incremental demand for the same type of biofuels used to comply with California's LCFS program could increase if any other region of the United States carried out implementation of an LCFS-like program. This could increase competition and raise the market-clearing prices of these biofuels for California, if the volume of biofuels does not increase accordingly. This is an area of fundamental importance and uncertainty; that is, will increased demand for different types of biofuels increase fuel prices or induce production of these fuels at levels where economies of scale can reduce the price effects of higher demand, and over what time period will adjustments occur?

Next Steps

Staff will continue to assess compliance feasibility scenarios as part of its continuing analytical efforts associated with the current IEPR and beyond. This additional work will include an assessment of the potential effects of price changes for biofuels on LCFS compliance costs and the potential sources and likelihood of excess credit generation. Further work will be undertaken to assess the potential costs of compliance with both the RFS2 and the LCFS. Additionally, the ARB's recently adopted amendments to the LCFS regulation regarding the handling of high carbon intensity crude oil may affect overall LCFS compliance, and the Energy Commission staff will work with ARB staff in their assessments of these provisions.

On December 29, 2011, the U.S. District Court for the Eastern District of California issued several rulings in the federal lawsuits challenging the LCFS.[190] One of the court's rulings preliminarily prohibits the ARB from enforcing the regulation. While ARB intends to appeal these rulings and to seek an order staying the preliminary injunction, as long as the injunction remains in effect, ARB will withhold enforcement of the LCFS requirements. The potential effect on the regulation's enforcement and the behavior of LCFS obligated parties during the remaining period of litigation is uncertain. Energy Commission staff will continue to monitor additional legal developments and ARB regulatory advisories.

Finally, ARB's initial implementation period for the LCFS was projected up to 2020, with plans to revisit the program before then to consider long-term refinements to ensure the program can sustain/maintain CI reductions beyond 2020. Moreover, the LCFS regulation itself mandates a minimum of two formal program reviews, with the opportunity for ARB staff to conduct additional informal program reviews. These program reviews will help ensure that the LCFS program is monitored closely and, as necessary, adjustments can be made to the program to ensure long-term sustainability. Energy Commission staff will work closely with ARB during these formal and informal reviews.

190 Low Carbon Fuel Standard (LCFS) Supplemental Regulatory Advisory 10-04B, California Air Resources Board, Regulatory Advisory, December 2011, page 1. A link to this document is as follows: www.arb.ca.gov/fuels/lcfs/123111lcfs-rep-adv.pdf.

Transportation Energy Infrastructure Requirements

Renewable and Alternative Fuels Supply and Infrastructure

Demand for biofuels in the United States is expected to grow due to the RFS2 mandates, while the demand in California is forecast to grow at an even higher rate due to the LCFS. Certain biofuels (ethanol in low level blends, biodiesel, renewable diesel, and renewable gasoline) will require only modest fueling infrastructure investment and little to no modifications to motor vehicles to enable greater use. However, electricity, natural gas, and especially hydrogen are examples of alternative transportation energy that will require billions of dollars of investment in fueling infrastructure and initially higher prices for vehicles that run on these fuels over the next several years. The challenges faced by these types of alternative fuel technologies may restrict the extent of penetration in the transportation sector without continued and expanded government assistance to help defer some of these incremental costs. Although natural gas prices have declined to a substantial advantage over petroleum fuels and the cost of off-peak electricity – taking into account the greater efficiency of electric vehicle energy use – is very competitive with gasoline prices, the high retail price of hydrogen will also need to be overcome for expansion of FCV markets over the near to mid-term. The ARFVT Program's incentives can promote the development and use of alternative fuels through cofunding of projects in public/private partnerships. The Clean Fuels Outlet program indicates the program is feasible for hydrogen stations at prices for hydrogen ranging from roughly two or three times that of gasoline.

Ethanol Infrastructure

California ethanol use is widespread and blended with gasoline at a concentration of 10 percent by volume. The state's infrastructure to receive, distribute and blend ethanol is robust and adequate to accommodate a continued growth of ethanol use over the next several years. Foreign sources of ethanol (from Brazil and Caribbean Basin Initiative countries) are expected to play a more pivotal role for both RFS2 and LCFS compliance and have recently reappeared with deliveries of Brazilian ethanol to Florida and to California from El Salvador during July 2011. However, the inability of Brazil to routinely provide sufficient incremental exports of ethanol to the United States may require additional swapping of Midwest ethanol in exchange for Brazilian ethanol. Domestic fuel costs could rise, with no corresponding decline in total global carbon emissions; in fact, the increased tanker traffic could raise emissions. Much of Brazilian sugarcane has been recently diverted from ethanol production to sugar production because of attractive global sugar prices, which has already increased Midwest exports of ethanol to Brazil. Thus, there are multiple factors that may affect the global distribution of ethanol.

Rail imports have accounted for about 91 percent of California ethanol supply over the last seven years, followed by marine imports (5 percent) and in-state production (4 percent). There were no marine imports of ethanol during 2010 due to unfavorable economics in foreign source countries. However, marine imports could increase in the future if California transitions to greater use of lower-carbon intensity ethanol from Brazil or Caribbean Basin Initiative countries. There are two pathways for foreign ethanol to enter California: marine vessels directly from Brazil and rail shipments from another marine terminal outside California. A proposed Sacramento renewable fuels hub terminal, if constructed, could greatly increase the marine ethanol import capability of Northern California and be more than sufficient to receive Brazilian ethanol over the near to mid-term period. Alternatively, ethanol from Brazil could be imported

through the Houston ship channel and transferred to rail cars before delivery to California. Kinder Morgan has examined this business development scenario and could complete the necessary modifications in less than six months upon gaining sufficient client commitments.

Biodiesel Infrastructure

Biodiesel use has been minimal in California and the RFS2 mandates will not compel a significant increase in biodiesel demand. However, the LCFS is expected to result in greater biodiesel use due to the quantity of carbon credits that can be generated under the program. Unlike ethanol, California's biodiesel infrastructure is not nearly as developed and will need to be expanded to accommodate widespread blending of biodiesel. However, with sufficient lead time (12 to 24 months), modifications could be undertaken and completed to enable an expansion of biodiesel use. Indeed, Kinder Morgan has already undertaken steps to accommodate increased biodiesel volumes by converting all CARB diesel tanks at its Colton facility for use in storing and blending B5 (5 percent biodiesel) by mid-2012. A limited number of other terminals may follow suit, although the number of such facilities is unknown at this time. The majority of biodiesel use in California is believed to originate from production facilities located within the state. Roughly 5.4 million gallons of biodiesel were used as transportation fuel during 2010, less than 7 percent of the state's biodiesel production capacity. California's RFS2 obligations for biomass-based diesel can be met by the 16 existing biodiesel production facilities in California. However, the increased demand for biodiesel under various LCFS scenarios will require quantities that exceed the state's production capacity, necessitating imports from other domestic or foreign sources, which appear adequate to meet these needs and could be delivered in rail cars. These scenarios also may compel expansion of biodiesel production in California. Most distribution terminals would also need to be modified so that the biodiesel could be received and transferred to segregated storage tanks at the terminals, work that could require a minimum of 18 to 24 months to complete.

Retail diesel fuel dispensers and underground storage tanks are certified to handle diesel fuel that contains biodiesel at concentrations of up to 5 percent by volume, but not up to 20 percent. However, the California State Water Resources Control Board (SWRCB) has issued a temporary variance from this restriction. Assuming biodiesel fuel blends in California do not exceed 20 percent, required retail station modifications should be negligible. According to original equipment manufacturers' statements on the National Biodiesel Board website, 18 vehicle models sold in the United States accept B5, 15 models accept B20 (20 percent biodiesel), and few accept B100 (100 percent biodiesel).

Electric Vehicle Infrastructure

Plug-in electric vehicles (PEVs) will play an increasing role in the future transportation mix. Significant public and private investments are being made in California's electric charging infrastructure. A recent study by Next 10 reports that California took in $467 million in global EV venture capital investment in the first half of 2011 and that investment in this area has grown 717 percent since 2006 in the state.[illegible] The federal government's economic stimulus funds, matched with Energy Commission program funds and other private and public funds, are providing the charging infrastructure to support the deployment of PEVs in California. Table 15 summarizes the planned deployment of PEV charging infrastructure in four strategic regions.

The consulting firm ICF International estimates that in the early market years, roughly 95 percent of charging will take place at home or at fleet facilities.

[illegible] Next 10, *Powering Innovation: California is Leading the Shift to Electric Vehicles From R&D to Early Adoption*, December 2011, available at: [illegible]

Table 15: PEV Public Charging Infrastructure Deployment by California Region

Region	Existing Public/Commercial Stations	Planned Public/Commercial Points	Planned DC Fast Charge Stations	Planned Battery Switch
S.F. Bay Area	98	510	55	5
Los Angeles	237	572	–	–
San Diego	16	1,452	60	–
Sacramento	56	494	–	–
Other	28	3	2	–
Total	433	3,037	111	6

Source: California Energy Commission and Nissan. Information based on estimates of known deployments planned through 2013.

However, a major challenge is that while the actual charging panels may take only a few hours to install, the overall residential charging infrastructure may still face a costly and protracted permitting, installation, and inspection process. To help overcome this issue, the California PEV Collaborative has identified actions, including the development of online tools and increased information dissemination, which can help standardize and consolidate the technical and administrative processes. The Energy Commission also is providing up to $2 million in grant funding to support regional plans to support PEV readiness under the ARFVT Program.

Natural Gas Vehicle Infrastructure

Primary barriers to the penetration of natural gas vehicles (NGVs) are the lack of a widespread fueling infrastructure and the costs required to upgrade aging existing facilities and install new fueling stations. Today, the use of NGVs is largely limited to medium- and heavy-duty vehicles, which can use CNG/LNG stations on a regular route. Ford Motor Company and other manufacturers plan to offer a suite of light-duty natural gas vehicles for 2012 and beyond, including vans, wagons, pickups, and utility vehicles. Currently there are 190 public and 428 private CNG fueling stations, and 12 public and 19 private LNG sites in the state. The Energy Commission has allocated funding to upgrade existing sites and install new natural gas fueling infrastructure closely tied toward identifiable needs, such as those of school districts and local governments, long-haul LNG goods movement corridors, and pairing new CNG stations with high-volume fleets that intend to convert from diesel to CNG. This funding will support 28 new stations and/or existing station upgrades.

According to the Board of Equalization, California users consumed about 27 million gallons of propane for transportation fuel in 2010. Propane can be a by-product of either natural gas processing or petroleum refining. However, current research is showing promise in the production of propane from renewable resources, such as sugarcane and corn. Propane is very attractive in terms of pricing compared to both diesel and gasoline. There are about 228 propane fueling stations already in place for vehicles in California. These numbers can be expanded with the addition of fuel capacity, a tank pump, and metering

equipment at virtually any propane distributor or station in California, for between $37,000 and $52,000 per site. Propane can play an especially significant role in rural communities, where it is already widely available. The primary obstacles to further adoption of propane as a transportation fuel are vehicle availability, incremental vehicle costs, and ARB propane quality certification. At this time, there are four light-duty vehicles certified by the U.S. EPA and ARB. The incremental cost for purchasing a light-duty propane vehicle ranges from $7,500 to $10,400.

Hydrogen Vehicle Infrastructure

Currently, there are roughly 250 hydrogen FCVs operating in California, but only 25 were registered with the California Department of Motor Vehicles (DMV) in 2009. The *2011-2012 Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program* identifies high fuel and vehicle costs as a major challenge for this technology. It also states that vehicle production and fueling infrastructure are still at a precommercial stage. However, costs are decreasing for both vehicles and fuel infrastructure. Discussions between original equipment manufacturers (OEMs) and Energy Commission staff indicate the costs of FCVs have declined to the $100,000 mark, and several OEMs plan to lease vehicles to the public at more publicly attractive lease rates. The Energy Commission has also seen the infrastructure cost per fueling station decrease, from a range of $3 million to $6 million to a range of $1 million to $2.5 million, over only a few years. Through a competitive solicitation released in June 2010, 11 stations that were strategically located in areas where automakers have committed to significant numbers of FCV deployments were awarded $15.7 million by the Energy Commission to develop fueling infrastructure.

In 2009, the ARB began investigating the possible modification of its Clean Fuels Outlet regulation to address the lack of fueling infrastructure available for vehicles meeting the ZEV Regulation. The current regulation requires that certain owner/lessors of retail gasoline stations equip an appropriate number of these stations with clean alternative fuels. The regulation does not require retail outlets for a designated clean fuel until the number of designated clean fuel vehicles projected to be certified on that fuel reaches 20,000 in a given year. Owner/lessors would be removed from the regulation language and a new definition added for "refiner/importers," which includes companies that produce in or import into California 500 million gallons or more of gasoline per calendar year. Proposed amendments planned for ARB adoption in 2012 would modify the regulation to apply only to dedicated clean fuel vehicles that operate on ZEV fuels. Once implemented, the regulation would pertain only to hydrogen and fuel cell vehicles; however, in the future it could be applied to electricity for plug-in hybrids and BEVs, depending on the outcome of a BEV needs assessment.

Petroleum Supply and Infrastructure

California's 20 refineries processed more than 1.7 million barrels per day of crude oil in 2010. Most of this crude oil must be imported by marine vessel, historically from Alaska and a variety of foreign sources.

Crude Oil Import Outlook

The quantity of crude oil imported into California is determined by the rate of decline of California oil production, processing capacities, and operating rates of refineries. California oil production has fallen 47.2 percent since 1985, and staff estimates a range of future decline of between 2.2 and 3.1 percent per year. In contrast to historical trends of gradually increasing state refinery oil processing capacity, staff now estimates that capacity in the future will range from flat to declining, largely as a result of declining demand for gasoline. Staff expects crude oil imports compared to 2010 levels to rise by between 22 million and 104 million barrels per year by 2020. At the high end, this increase is solely the result of declining California crude oil production, since refining capacity remains fixed. The forecast for the low end is driven primarily by the assumption of declining refining capacity reducing the need for crude oil supply.

Staff believes higher oil imports will require expanded marine import within the next four to five years. California's marine import infrastructure for crude oil can receive a little more than 400 million barrels per year. Since waterborne imports of crude oil during 2010 amounted to nearly 376 million barrels, there should be sufficient existing spare import capability that the low estimate for imports could be met. However, petroleum marine terminals in the Ports of Los Angeles and Long Beach operate under long-term leases with staggered expiration dates and have periodically come under pressure either to be shuttered or relocated to make way for other types of port commercial activity. Moreover, "spare" import capacity should also be viewed as a type of insurance policy to ensure continuity of operations during potential natural or human-caused contingencies, which applies not just to crude oil, but all petroleum and renewable fuel import capacity.

Currently, there are two crude oil import infrastructure projects proposed in Southern California that are at early stages of development, Berth 408 at Pier 400 in the Port of Los Angeles and Berth T126 at Pier Echo in the Port of Long Beach. Based on Energy Commission analysis, the Southern California market should only require construction of one of these crude oil import facilities over the forecast period, not both.

High-Carbon-Intensity Crude Oils

The ARB has included provisions in the existing LCFS that regulate the use of new crude oil types that have significantly higher carbon intensities associated with their production when compared to the average mix of crude oil used by refineries in California during 2006. These types of crude oils are referred to as High Carbon-Intensity Crude Oils (HCICOs) and can include crude oil that is sourced from bitumen mines, crude oil upgraders, fields that use thermally enhanced oil recovery techniques, and countries that have excessive flaring of natural gas associated with their crude oil production operations. As originally proposed, the HCICO provisions had the potential to affect crude oil selection decisions, increase refinery operating costs, and cause a portion of the imported crude oil to be from sources from greater distances, a phenomenon referred to as "crude shuffling." Staff has been concerned that California refiners might not use potential HCICOs due to the difficulty of offsetting the carbon deficit incurred from their use and questioned whether HCICO requirements would induce oil producers outside of California to invest in projects to reduce the carbon intensity of their operations.

The ARB approved amendments to the LCFS regulation on December 16, 2011, to simplify and enhance the HCICO provisions with a "California Average Crude CI" approach. This approach involves the establishment of a baseline crude CI based on a specified baseline year relative to the CI standard. A "baseline deficit" would be charged to all regulated parties for CARBOB and CARB diesel because the baseline crude CI is expected to be above the CI standard. The annual average crude CI would then be calculated for each year, starting in 2012, to reflect the overall CI of the crude oil that is delivered to and processed by California refiners in a given year. If the annual average crude CI does not exceed the baseline crude CI in a given year, the California producers would not realize an "incremental deficit" — just the baseline deficit. ARB staff has also proposed to establish a method, through the rulemaking process, to enable parties that implement innovative methods to reduce emissions for crude oil recovery using technologies such as carbon capture and sequestration to earn LCFS credits.[230]

[230] Air Resources Board, *Staff Report: Initial Statement of Reasons for Proposed Rulemaking: Proposed Amendments to the Low Carbon Fuel Standard*, October 2011, page 26, www.arb.ca.gov/board/books/2011/121611/lcfsamn.pdf

Energy Commission staff will continue to work with ARB staff to evaluate potential impacts of the HCICO provisions as these provisions continue to evolve to achieve optimal results for the environment and public health while providing the petroleum refining and marketing industry with additional flexibility.

Energy Security

Energy security in transportation fuels policy has received greater attention in recent years. Energy security can be defined in many ways: for instance, as a peculiar vulnerability of excessive reliance on foreign crude oil imports, or more generally on imports of any fuel or feedstock from foreign sources, including nonpetroleum fuels. This might take the form of reliance on countries that are not currently on especially good terms with the United States, but it might also hinge on dependence on sources that are risky geopolitically, economically, or from other potential disruptions or supply limitations. The Energy Commission last held a workshop on the peak oil debate in 2003, indicating it may be desirable to raise the topic in a future iteration of the Energy Commission's forecast of transportation fuel supply and demand.

All else being equal, diversification of sources of supply adds to energy security, if it equates to additional sources of supply to meet a given demand. If, however, diversification occurs as a result of limiting supply from some existing or potential sources through sanctions or regulations, then the energy security implications are more uncertain. If energy markets are inhibited from procuring lowest cost supplies, the first direct impact would be economic. Should the proposed policy actions limit foreign sources and avoid fair trade issues, there might be positive balance of trade effects that could offset higher direct costs. In some cases, diversification might viewed as an insurance policy against potential disruptions that might occur for a variety of reasons, but even prudent insurance is not free.

Staff's analysis has raised some issues that have energy security considerations. The LCFS appears to incentivize California regulated parties to pursue biofuels that have lower carbon intensities than the traditional corn-based ethanol sourced from numerous domestic producers located throughout several states. Energy Commission staff analysis shows that this current reliance on a diverse supply of domestic ethanol may need to shift to one that significantly increases demand for Brazilian sugarcane-based ethanol. On the other hand, reliance on Brazilian sugarcane is not the only strategy that can be employed by regulated parties under the LCFS. There is a host of responses industry may choose, including bringing in lower CI corn ethanol, which is the approach they are currently employing, and it will likely continue to play an important role for the next several years. Indeed, corn ethanol production processes registered with ARB indicate CIs that are significantly lower than anticipated at the onset of the LCFS.

Another example is that of crude oil refined from Canada's oil sands resources, a potential HCICO. Energy security might arguably be enhanced by developing Canada as an increased source of crude oil for California refiners, as current sources are predominately Middle Eastern and Latin American. Also, lengthy tanker trips for Canadian crude oil to less regulated East Asian refineries may result in more greenhouse gas emissions. However, achieving energy security and achieving GHG reductions are not mutually exclusive. The ARB staff anticipates that adopted amendments to the LCFS regulation will increase refiners' flexibility in securing a variety of crude oils, including HCICOs from Canadian oil sands. Further, the amendments include important incentives that recognize petroleum producers' efforts to employ innovative strategies to reduce GHG emissions, even from HCICOs, including carbon sequestration and other innovative technologies. Energy Commission staff should continue to work with ARB staff to advance the goals of energy security and carbon reduction.

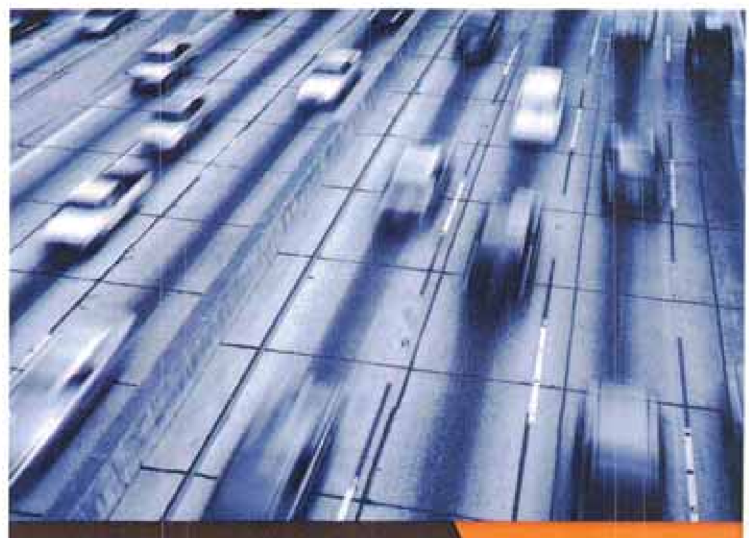
Challenges and Opportunities

California faces several challenges and offers multiple opportunities to meet alternative fuel and carbon reduction goals in the transportation sector, including:

- Uncertainties in forecasting what future levels of alternative and renewable vehicle purchases and fuel use will be attained.
- Questions about the effect of RFS2 on California's ability to accomplish energy security objectives through diversifying transportation fuel supply and increasing alternative fuel options.
- Availability of sufficient low-carbon biofuels to comply with the LCFS at a reasonable cost to California consumers.
- Uncertainties of whether increased demand for different types of biofuels will increase fuel prices or induce production of these fuels to levels where economies of scale can reduce the price effects of higher demand.
- High initial investments required for infrastructure and vehicles to bring substantial electricity-, natural gas-, and hydrogen-fueled technologies into the transportation sector, technologies that could go a long way to achieving LCFS compliance.
- Supporting the development and use of alternative fuels and vehicles in California through incentives such as the ARFVT Program and local air district funding programs and federal incentives.
- Balancing renewable fuel and carbon reduction goals with energy security and other policy objectives.

The Energy Commission's forecasting and analytical units have attempted to estimate current and future transportation energy use for a range of technologies under a wide variety of assumptions. This work will continue, including consumer vehicle purchase and travel behavior surveys, vehicle and fuel demand modeling for multiple transportation energy technologies, and renewable fuel, carbon reduction, and energy security policy analysis, with the intentions of continuing to broaden interagency collaboration and stakeholder contributions. A variety of forums will be considered to make information publicly available on this important underlying technical analysis.

Further, the ARFVT Program (AB 118, Nuñez, Chapter 750, Statutes of 2007), discussed in the next chapter, has enabled considerable strides to be made in deploying alternative, renewable, and advanced transportation technologies in California. These include electric drive, biomethane, diesel substitutes, ethanol, natural gas, propane, and hydrogen technologies. Program investments have incentivized 4,375 public and residential electric charging sites, 85 E85 refueling sites, 70 natural gas stations, and 11 hydrogen fueling sites, as well as 1,437 electric and natural gas cars and trucks, leading to substantial petroleum, greenhouse gas, and air pollution reduction benefits.



CHAPTER 11

Benefits From the Alternative & Renewable Fuel & Vehicle Technology Program

This chapter summarizes projects funded through the Energy Commission's Alternative and Renewable

Fuel and Vehicle Technology Program (ARFVT Program) and expected benefits from petroleum and greenhouse gas (GHG) emissions reductions, as well as economic benefits, and some of the challenges.

The California Legislature created the ARFVT Program in 2007 through passage of Assembly Bill 118 (Núñez, Chapter 750, Statutes of 2007). The statute authorized the Energy Commission to develop and deploy alternative and renewable fuels and advanced transportation technologies to help attain the state's climate change policies. AB 118 similarly authorized the ARB to develop the Air Quality Improvement Program (AQIP) to support development and deployment of zero emission and reduced emission light duty vehicles and trucks.[33] The Energy Commission's ARFVT Program has a budget of about $100 million annually, while the ARB's AQIP has a budget of $30 million to $40 million annually.

[33] Air Resources Board, *2010 Biennial Report to the Legislature on the AB 118 Air Quality Improvement Program*, January 2011, available at www.arb.ca.gov/msprog/aqip/reports/january-2011-aqipprogram-report.pdf.

The Legislature amended the ARFVT Program with Assembly Bill 109 (Núñez, Chapter 313, Statutes of 2008), which requires the Energy Commission to evaluate the efforts and benefits of the program every two years. The Energy Commission released the draft of the first of these evaluations (the *Benefits Report*) in December 2011, which listed the funded projects, reported progress in achieving project goals and expected benefits, including contributions toward reducing GHG emissions and petroleum dependency in California, identified challenges facing the projects, and made recommendations intended to overcome these challenges.

Through the ARFVT Program, the Energy Commission is providing incentives to accelerate the development and deployment of clean, efficient, low-carbon alternative fuels and technology projects that will help reduce California's use and dependence on petroleum transportation fuels and increase the use of alternative and renewable fuels and advanced vehicle technologies. The Energy Commission produces an investment plan or update for each funding cycle to establish priorities and guide program funding allocations. This public process entails public workshops and features a multistakeholder Advisory Committee, which includes representatives from industry trade associations, academic institutions, nongovernmental environmental, public health, and alternative energy organizations, labor, and other state energy and environmental agencies.

This summary provides a status report on the funded projects and expected benefits. It describes increases in the numbers of fueling infrastructure (including electric charging) and vehicles between 2009 (the baseline year for the program) and 2011. It also estimates a range of total potential petroleum reduction and GHG emissions reductions for each major fuel category — electric drive, natural gas, biofuels, and hydrogen — between 2010 and 2020. Finally, it summarizes job creation and workforce training benefits to California that result from the funding.

Summary of Program Funding

The Energy Commission has developed and adopted three investment plans since 2008 that guide $362 million in total funding for the first four years of the ARFVT Program. Table 16 shows the distribution of funding from the first investment plan for fiscal years 2008–2009 and 2009–2010 according to primary fuel category, plus funding for workforce development and program support. Using funds from this first investment plan, plus a portion of funds from the second investment plan, the Energy Commission has funded 86 projects totaling $198.4 million to date.

The ARFVT Program emphasizes projects in the commercial deployment phase of technology development but has also funded a number of vehicle and fuel projects in the research/feasibility, development, and demonstration phases. The program has allocated two-thirds of its funding (totaling $128.9 million) for fiscal years 2008 to 2010 to commercial deployment and production projects and about 23 percent to precommercial demonstration, research, and development projects.

AB 118 directs the Energy Commission to leverage state public investments against private financing and other public funding sources. Non-ARFVT Program contributions to the 86 projects total about $375.5 million, for a funding ratio of roughly 1:1.9. The largest public funds leveraged by the program thus far have been the federal dollars available through the American Recovery and Reinvestment Act (ARRA) of 2009. The ARFVT Program funded nine projects totaling $36.5 million that received a total of $285.3 million in ARRA funding. The South Coast Air Quality Management District, Bay Area Air Quality Management District, San Diego Air Pollution Control District, and San Joaquin Valley Air Pollution Control District have also partnered in funding projects supported by the program.

Table 16: Program Investments by Fuel Type

Fuel Type and Program Area	Total Funding Encumbered by September 2011 ($ millions)	No. of Projects
Electric Drive	62.4	31.5[A]
Biomethane[B]	38.8	18
Diesel Substitutes	8.1	8
Ethanol[C]	20.1	7
Gaseous Fuels (Natural Gas and Propane)	31.3	13.5[A]
Hydrogen[D]	20.7	5
Workforce Development	13.8	3
Program Support[F]	3.1	8
Totals	**198.4**	**86**

Source: California Energy Commission

A. This agreement provides funds for both electric drive and natural gas infrastructure.

B. This includes an interagency agreement for biofuels feedstock evaluation.

C. Project count includes the California Ethanol Producer Incentive Program's [illegible] offers to [illegible] potential recipients at one point.

D. The ARFVT Program's gaseous fuels vehicle incentive program [illegible] natural gas vehicle incentives, propane school bus incentives, and natural propane vehicle incentives. To date, 10 [illegible] manufacturers made reservations for these incentives.

E. Includes an interagency agreement with the Division of Measurement Standards within the California Department of Food and Agriculture for the development of retail standards for hydrogen.

F. Includes technical support contracts, memberships, [illegible], and a vehicle [illegible] survey.

Increases in Alternative Fueling Infrastructure and Vehicles Between 2008 and 2011

An early indicator that California's fuel and vehicle markets are shifting toward alternative and renewable fuels and advanced vehicle technologies is the growth of key alternative fuel vehicle and infrastructure sectors. Although still in its early years, the ARFVT Program is playing a crucial role in accelerating this progress (as indicated in Table 17). California now has the largest networks of electric vehicle (EV) charging systems and hydrogen fueling stations in the country.

Table 17: ARFVT Program Funding Impact on Alternative Fueling Stations and Alternative Vehicle Deployment in California

	Fuel Area	Existing 2009–2010 Baseline Levels	Additions from ARFVT Program Funding	Percent Increase
Alternative Fueling Infrastructure	Electric	1,270 charging stations	4,525 charging stations (public and residential)[A]	344%
	E85	38 fueling stations	83 fueling stations	128%
	Natural Gas	443 fueling stations	20 stations	5%
	Hydrogen	6 public fueling stations[B] (plus 5 more under construction)	11 fueling stations	183%
Alternative Fuel Vehicles	Electric Cars	13,268	370	3%
	Electric Trucks	1,439	183	13%
	Natural Gas Trucks	13,895	859	6%

Source: Extrapolated from 2009 Department of Motor Vehicles data, plus actual deployment data. Electric truck and natural gas trucks extrapolated from 2009 data.

A. Based on project estimates for all electric vehicle supply equipment funded with ARFVT Program or match funds.

B. Based on Energy Commission and ARB staff estimates. Public accessibility of these stations may vary.

Estimated Benefits From ARFVT Program Investments

California's shift to a transportation system that is less dependent on petroleum fuels and more reliant on a suite of lower carbon alternative fuels and vehicles will take time and require substantial investments from the private and public sectors. The ARFVT Program investments of $198.4 million will produce tangible benefits through 2020 and beyond, but it is a modest investment compared to the billions of dollars that car and truck manufacturers and fuel producers are investing in next generation electric and fuel cell vehicles (FCVs), natural gas-fueled trucks, and sustainable, low-carbon biofuels.

Methods and Analytic Approach

It is likely that market dynamics for alternative fuels and vehicles will continue to be uncertain because of new technology breakthroughs and evolving state regulations. Moreover, the ARFVT Program is in its initial phase, and most of the funded projects have only begun their construction or implementation. Accordingly, the following series of analyses illustrates a low and high range of potential petroleum reduction and GHG emissions benefits resulting from the fuels and technologies supported by initial ARFVT Program investments in electric drive, natural gas, biofuels, and FCVs for the period from 2010 to 2020. The low-range scenarios reflect challenging market and technology conditions and continued high initial incremental costs for emerging alternative fuels and vehicles when compared to petroleum-based fuels.

and vehicles. The high range scenarios reflect optimal market conditions, a robust regulatory regime that mitigates market participants to consume or fund low carbon fuel and vehicles, higher costs for petroleum-based fuels, and continuing reductions in production and retail costs for alternative fuels and vehicles.

Staff calculated the estimates of alternative fuel increase (and resulting petroleum displacement) for each fuel type first and subsequently calculated the corresponding GHG and air pollutant reductions based on these numbers. Data for the analyses comes directly from ARFVT Program awardees, vehicle manufacturer surveys, the ARB, and published reports. The analyses for electric drive and FCVs are based primarily on vehicle deployment forecasts and surveys developed by industry or third-party stakeholders. The analyses for biofuels are based primarily on information provided by program awardees, regarding both their immediate expectations and their plans for expansion, while the analysis for natural gas is based on a combination of these methods.

The Energy Commission expects each project to be successful, and makes substantial and essential investments to achieve the successes. In most instances, the ARFVT Program accelerates progress in the development and use of alternative fuels and vehicles. The Energy Commission also acknowledges that other parties contribute investments (since most projects require comparable matching funds), and multiple sources are responsible for the benefits.

Estimated Petroleum Reduction Benefits

Electric Drive Vehicles

The increased deployment of plug-in electric vehicles (PEV) in California will improve air quality by reducing criteria pollutants, address climate change by reducing GHG emissions, advance energy security by reducing dependence on petroleum, and stimulate the California economy by providing a new industry and jobs. PEVs can help major vehicle manufacturers achieve ARB's Zero Emission Vehicle (ZEV) regulation mandate and California's mandated GHG and petroleum reduction goals. The Energy Commission's $62.4 million investment in PEVs covers a broad spectrum of technology commercialization, including market-ready chargers and vehicles, manufacturing support, component and battery development, and all-electric truck prototypes.

To estimate the potential range of petroleum and GHG reductions resulting from PEVs, a high and low EV deployment projection has been developed through 2020. The California Plug-in Electric Vehicle Collaborative's estimated range of 500,000 to 1,000,000 EVs on the road in California by 2020[194] bends the high and low deployment cases. The Collaborative developed this range with input from automakers in consideration of the ARB's ZEV regulation.[195] The ARB's estimated scenario of compliance for the ZEV mandate falls between these low and high scenarios for PEV deployment.

For this analysis, the projected PEV population is separated into two categories: battery electric vehicles (BEVs) that rely entirely on batteries and PHEVs that use both electricity and gasoline. Using the ARB's prediction of the likely compliance scenario for the ZEV mandate, the EV population will be about 26 percent BEVs and 74 percent PHEVs by 2020.[196]

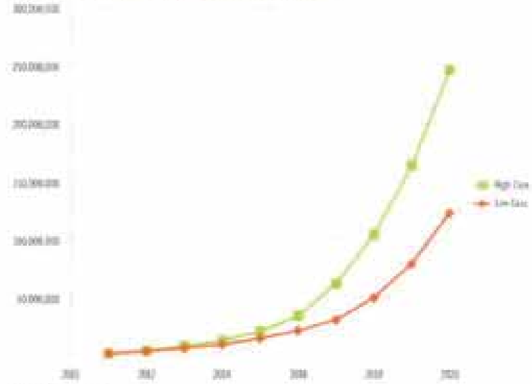
Figure 13 shows the potential petroleum reductions resulting from these vehicle populations. By

194 California Plug-In Electric Vehicle Collaborative, *Taking Charge: Establishing California Leadership in the PEV Market*, 2010. www.evcollaborative.org/sites/all/themes/pev/files/docs/Taking_Charge_final2.pdf

195 The Energy Commission has also conducted a separate analysis of consumer survey data, which suggests roughly 45,000 BEVs and 1.8 million PHEVs on the road by 2020.

196 California Air Resources Board, "ZEV Regulation 2010: Staff Proposal." www.arb.ca.gov/msprog/zevprog/2011zevreg/11_16_slides.pdf

Figure 13: Annual Petroleum Displacement From PEVs (Gallons)



Source: California Energy Commission

2020, potential reductions range from a low case of 123.4 million gallons per year to a high case of 246.7 million gallons.[197]

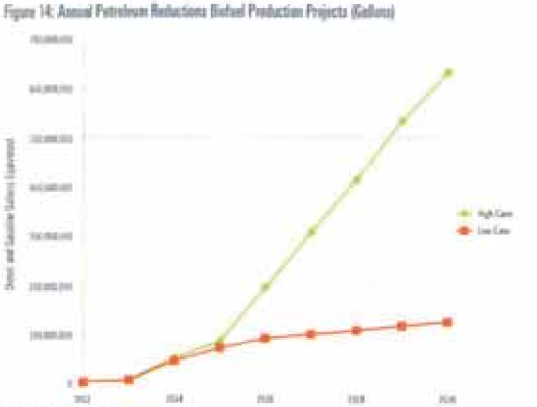
The ARFVT Program has helped address many of the challenges to PEV deployment identified by industry, such as the need for early investments in fueling infrastructure, vehicle demonstrations, vehicle purchase incentives, and manufacturing. The program's investments will help enable the PEV market to overcome these challenges and accelerate vehicle deployment. There are now roughly 1,700 Nissan Leaf BEVs and 1,200 Chevrolet Volt PHEVs in California, roughly one-half and one-third respectively of these vehicles nationwide.

197 BEVs are assumed to displace a vehicle consuming 331 gallons of gasoline per year (assuming 8,000 miles traveled per year at 22 miles per gallon). PHEVs are assumed to displace roughly 136 gallons of gasoline per year (assuming 12,000 miles traveled per year, 22 miles per gallon, and 36 percent of miles are driven by electricity).

Biofuels Production

Increasing the use of low-carbon, sustainably produced biofuels will help California achieve state and federal policy goals for GHG reduction, petroleum reduction, and biofuel use. For air quality purposes, California requires about 1.6 billion gallons per year to satisfy the oxygenate blendstock requirements for reformulated gasoline. At present, corn-derived ethanol is the only biofuel commercially available at industrial scales to meet this need. Through the ARFVT Program, the Energy Commission is investing heavily in companies that are developing low-carbon biofuels from waste-based biomass resources or alternative feedstocks that reflect lower GHG emissions, lower environmental impacts, and better

Figure 14: Annual Petroleum Reductions Biofuel Production Projects (Gallons)



Source: California Energy Commission

land use choices. Combined annual volumes of in-state, waste-based resources have the technical potential to be converted into 2.1 billion gallons of diesel gallon equivalent or 3.1 billion gallons of gasoline gallon equivalent each year.[198,199]

The ARFVT Program invested $44.8 million in the development and production of biofuels that use waste-based feedstocks or alternative bioenergy crops that can displace corn as an ethanol feedstock. The biogas production projects, with $35.2 million of program funds, use waste streams such as woody biomass, agricultural or dairy residues, wastewater treatment plant residues, preLandfill diverted municipal solid waste, or landfill gas. The program funded five diesel substitute production projects at $4.3 million, three of which use waste streams as feedstocks, while the other two are testing or demonstrating algae-based feedstocks. Three advanced ethanol awards, funded with $5.4 million, include the state's first cellulosic ethanol pilot production facility using agricultural waste feedstocks, the first commercial feasibility evaluation of sweet sorghum as a potential bioenergy crop, and an important feasibility evaluation of sugar beets coupled with agricultural residues to produce a carbon neutral mix of ethanol and biogas. These types of projects reduce GHG emissions by a

198 California Energy Commission, *2012–13 Investment Plan*, Table 21.

199 Based on data from the California Biomass Collaborative at UC Davis, the Energy Commission estimates that biomass waste-based feedstocks in California have the potential to displace up to 3.1 billion gallons of gasoline per year, or 2.1 billion gallons of diesel fuel. California consumes about 16 billion gallons of gasoline and 4 billion gallons of diesel fuel annually.

high percentage (typically 75–85 percent) compared to the petroleum baseline.

This analysis estimates the high and low range of biofuels production potential for the 17 ARFVT Program projects funded to date. The estimates come directly from the grant proposals and follow-up surveys and interviews with each company or public agency.

The estimated petroleum reduction by 2020 from these 17 biogas, diesel substitutes, and advanced ethanol development and production projects ranges from 124.1 million gallons to 632.8 million gallons (Figure 14).

In the high case, the rapid growth after 2015 represents the shift of several funding recipients from precommercial work into commercial-scale production. Since this analysis includes only projects funded by the ARFVT Program to date, it represents a conservative estimate of the true biofuel production potential within the state. For comparison, the in-state capacity for ethanol production is nearly 261 million gallons per year (of which 170 million gallons per year is on-line), while the in-state capacity for biodiesel production is roughly 81 million gallons per year (from which fewer than 5.5 million gallons were produced in 2010).[200,201]

Natural Gas Vehicles

The medium- and heavy-duty transportation sector represents a prime opportunity for the development and rollout of alternative fuel vehicles. The current fleet of such trucks totals about 632,000, about 4 percent of the state's total vehicle fleet, yet it accounts for about 16 percent of total fuel consumption and GHG emissions. Natural gas vehicles are an attractive alternative to medium- and heavy-duty fleet owners and operators who have concerns with the cost of diesel fuel resulting from price volatility and the economic downturn, as well as compliance with air quality standards. Additionally, natural gas vehicles have been shown to have GHG reductions of between 13 and 16 percent compared to their diesel counterparts. If using waste-derived biomethane instead of conventional natural gas, however, these vehicles can achieve GHG reductions of roughly 85 percent below diesel counterparts.

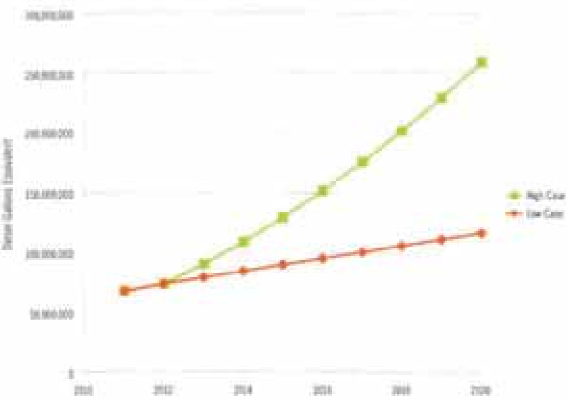
The ARFVT Program's investments in new natural gas applications for medium- and heavy-duty vehicles has helped increase the number of natural gas-powered vehicles on the road and the growth rate of the overall vehicle population. The ARFVT Program has directed investments toward developing and deploying new natural gas vehicle technologies, addressing established business needs, and expanding California's current medium- and heavy-duty natural gas fleet. To date, the program has funded the deployment of 898 medium- and heavy-duty natural gas vehicles. In addition, the program has funded the production of technologies that will increase the availability of natural gas engines for specialized fleet applications. The ARFVT Program has also funded an additional 19 compressed and liquefied natural gas (LNG) fueling stations, which will further promote the adoption of medium- and heavy-duty natural gas vehicles.

The Energy Commission developed two scenarios for the rollout of medium- and heavy-duty natural gas vehicles in California through 2020. The low scenario represents a "business-as-usual" deployment model, which incorporates the 898 vehicles funded by the ARFVT Program, and the growth rate remains

200 Kavalec et al. 2011. *Transportation Energy Forecasts and Analyses for the 2011 Integrated Energy Policy Report*. California Energy Commission. CEC-600-2011-007-SD. www.energy.ca.gov/2011publications/CEC-600-2011-007/CEC-600-2011-007-SD.pdf

201 Smith, Charles, Mike Roberts, Jim McKinney. 2011. *2011–2012 Investment Plan for the Alternative and Renewable Fuel and Vehicle Technology Program*. Commission Report. California Energy Commission, Fuels and Transportation Division. Publication Number: CEC-600-2011-006-CMF. www.energy.ca.gov/2011publications/CEC-600-2011-006/CEC-600-2011-006-CMF.pdf

Figure 15: Annual Petroleum Displacement From Natural Gas Trucks (Gallons)



Source: California Energy Commission

relatively steady.[252] The high scenario represents estimated new vehicle sales, as reported by awardees and based on expected fleet adoption rates. This scenario assumes the awardees' vehicle sales are wholly sold in addition to the expected normal population growth for the industry, and assumes the existence of optimal market conditions allowing for the sale of all vehicles available from the manufacturer. The petroleum displacement associated with these scenarios is presented in Figure 15.[253]

Hydrogen Fuel Cell Vehicles

FCVs that use hydrogen as fuel are a prominent prospect for encouraging the deployment of alternative fuels. One of the greatest benefits of FCVs is that they emit no GHG emissions or air pollutants from the tailpipe. Like the other alternative fuel

252 Vehicle counts from Energy Commission analysis of Department of Motor Vehicle data.

253 The duty cycles for medium- and heavy-duty trucks are much more variable than for light-duty vehicles, so the amount of petroleum displaced by an individual natural gas truck will also vary. Under the low scenario, natural gas vehicles are assumed to displace 4,750 gallons of diesel per year (based on historical averages). The incremental increase under the high scenario assumes that natural gas trucks expand into heavier duty cycles, displacing 10,750 gallons per year.

vehicle technologies, they can also reduce California's dependence on foreign imports of crude oil since hydrogen can be derived from domestic sources.

One major challenge to ensuring the deployment of these vehicles is the development of sufficient fueling infrastructure. To meet the needs of anticipated FCVs, the Energy Commission provided funding for 11 new and upgraded hydrogen fueling stations. The total cost per station ranged from $2 million to $3 million, a significant drop from the range of $3 million to $5 million per station from just a few years earlier. All of these stations are located in regions identified by automakers as high-priority, early-adopter markets. Once constructed, these stations will represent about 73 percent of the statewide public fueling capacity.

A low case and high case for FCV deployment can be derived from the ARB's ZEV regulation and automaker surveys. Under the low case, the cumulative number of FCVs increases to 20,200 by 2020, displacing about 16.5 million gallons of gasoline per year. According to surveys of major automakers, the number of in-state FCVs will expand rapidly in the current decade, from roughly 250 in 2011 to more than 50,000 by 2017. Accordingly, the ARB has developed a scenario for 2017–2020, based on automakers' compliance with the ZEV regulation, in which the total on-road number of light-duty FCVs within California will reach roughly 124,000 by 2020.[254] This equates to roughly 67.6 million gallons of gasoline per year displaced by FCVs by 2020.

By providing fueling infrastructure early on, the Energy Commission's investments provide critical early support for expanded vehicle populations, to a point where private infrastructure suppliers can independently finance and construct additional stations to serve the increased numbers of vehicles.

254 California Air Resources Board. Staff Report: Initial Statement of Reasons, Advanced Clean Cars, 2012 Proposed Amendments to the Clean Fuels Outlet Regulation. December 8, 2011. www.arb.ca.gov/regact/2012/cfo2012/cfoisor.pdf.

Total Estimated Petroleum Reduction Benefits

The total estimated petroleum reduction associated with the fuels and vehicle technologies supported by the 86 ARFVT Program funded projects range from roughly 388.4 million to 1.2 billion gallons per year in 2020. This estimated potential petroleum reduction cannot be directly attributed to the program's investment but should be considered as the range of future benefits in a market influenced by ARFVT Program funding. To put these estimates in context, current petroleum fuel consumption in California totals roughly 18.8 billion gallons per year.

Estimated GHG and Air Pollution Reduction Benefits

The petroleum reductions by alternative fuels and vehicle technologies (mentioned above) also serve as the basis for determining the estimated GHG emission and air pollution reductions associated with these fuels and technologies. Accordingly, the benefits associated with electric drive, hydrogen, and natural gas trucks still represent the overall market-level benefits of these alternative fuels that are supported by the ARFVT Program, while the benefits associated with biofuel production represent the projects (and their possible expansions) that are directly funded by the ARFVT Program.

To calculate GHG emission reduction benefits, the amount of fuel displaced is multiplied by the relative carbon intensity for each alternative fuel type, as provided by the Low Carbon Fuel Standard.[255] This calculation incorporates an energy efficiency ratio for electric drive and FCVs to account for the greater efficiencies of PEVs and FCVs in translating fuel energy

255 Where appropriate, the Energy Commission applied estimates of carbon intensity for projects that use fuel pathways not explicitly established by the LCFS.

Table 18: Annual Petroleum, GHG, and Criteria Emission Reductions by 2020 – Low Case

	Petroleum Reductions (Million Gallons)	GHG Reductions (CO2e)	(Metric Tons) VOC	CO	NOx	PM10
Electric Drive[a]	123.4	938,960	943.1	7,184.3	620.3	320.2
Biogas Production[b]	100.7	1,151,214	73.1	-3.6	15.7	2.4
Biodiesel Production[c]	9.4	100,402	9.4	20.5	-27.9	15.6
Ethanol Production[d]	14.0	115,676	11.4	71.6	-0.6	-0.3
Natural Gas Trucks[e]	116.4	349,032	64.1	-4.2	38.2	2.8
Hydrogen[f]	33.5	302,095	125.0	1,053.8	78.6	33.6
Total	388.4	3,166,025	1,218.3	8,303.8	754.3	376.8

Source: California Energy Commission

a. Electric drive GHG emissions from the LCFS' "marginal electricity" pathway.

b. Biogas production GHG emissions based on an estimated average 11.4 g CO_2e/MJ for awarded biogas projects.

c. Biodiesel production GHG emissions based on an estimated average 19.4 g CO_2e/MJ for waste-based and algae-derived diesel substitutes for awarded projects.

d. Ethanol production GHG emissions based on an estimated average 25.4 g CO_2e/MJ for waste-based and algae-derived diesel substitutes for awarded projects.

e. Natural gas GHG emissions based on an average of 73.3 g CO_2e/MJ, assuming a split of 70 percent CNG vehicles and 30 percent LNG vehicles.

f. Hydrogen GHG emissions estimated from the average carbon intensity of hydrogen infrastructure projects funded by the ARFVT Program (69.8 g CO_2e/MJ).

(or power) into miles traveled.[256] GHG emissions are reported in carbon dioxide equivalents (CO_2e).

Staff uses a similar approach for calculating urban criteria pollutant reductions. The amount of fuel displaced by each alternative fuel type is multiplied by the relative criteria pollutant reduction of that alternative fuel against a petroleum baseline.[257] Estimated criteria pollutants include volatile organic compounds (VOC), carbon monoxide, nitrogen oxide (NOx), and particulate matter of 10 microns in diameter (PM10).

Looking forward to 2020, the low case estimate for annual petroleum displacement, GHG emission reductions, and reductions in criteria air pollutants are summarized in Table 18.

This includes 388.4 million gallons of petroleum fuels displaced, 3.1 million metric tonnes of CO_2e GHG emissions reduced, and 11,269 metric tonnes of urban air pollutants reduced each year by 2020. Table 19 presents the high case, with 1.4 billion gallons of petroleum

256 The energy efficiency ratio (EER) for electric drive is assumed to be 3.4, and the EER for fuel cell vehicles is assumed to be 2.5. These values were established during the December 2011 ARB LCFS revisions.

257 TIAX, LLC. August 2007. Full Fuel Cycle Assessment: Well-to-Wheels Energy Inputs, Emissions, and Water Impacts. California Energy Commission. CEC-600-2007-004-REV. www.energy.ca.gov/2007publications/CEC-600-2007-004/CEC-600-2007-004-REV.PDF.

Table 19: Annual Petroleum, GHG, and Criteria Emission Reductions by 2020 – High Case

	Petroleum Reductions (Million Gallons)	GHG Reductions (CO2e)	(Metric Tons) VOC	CO	NOx	PM10
Electric Drive	388.7	1,861,533	1,894.2	15,576.1	1,341.8	684.4
Biogas Production	355.5	2,132,201	141.9	-7.3	30.5	4.2
Biodiesel Production	378.1	4,038,139	202.5	873.1	-1,120.7	628.4
Ethanol Production	59.2	486,620	48.2	328.2	-2.6	-1.3
Natural Gas Trucks	255.4	777,664	388.3	-9.3	40.3	6.2
Hydrogen	67.6	415,215	513.4	4,138.1	322.9	143.3
Total	1,208.1	8,741,418	3,178.8	28,838.1	611.2	1,425.1

Source: California Energy Commission

fuels displaced, 5.7 million metric tonnes of CO_2e GHG emissions reduced, and 26,066 metric tonnes of urban air pollutants reduced each year by 2020.

The economic and environmental benefits resulting from the first round of ARFVT Program funding awards establish a good foundation and measurable progress toward achieving multiple state policy goals. The ARFVT Program funding can help achieve a goal of sourcing 26 percent of California's total transportation fuel from alternative sources by 2022. By 2020, diesel and gasoline demand is expected to reach roughly 18 billion gallons per year; the ARFVT Program projects will support alternative fuels that can displace 2 to 6 percent of these 18 billion gallons by 2020. Additionally, fuels and technologies supported by ARFVT Program projects can also reduce greenhouse gas emissions, representing a 1 to 4 percent decrease in expected transportation (business-as-usual) emissions by 2020. Furthermore, the commercialization potential of California biofuel production plants funded by the ARFVT Program represents 15 percent to 77 percent of the capacity needed to achieve a *Bioenergy Action Plan* goal to produce 40 percent of expected California biofuel consumption from in-state sources by 2020.

Workforce Training Benefits

Workforce development and training are critical elements in the Energy Commission's efforts to develop California's clean transportation market. A trained workforce is required to develop and respond to new technologies, improve efficiencies, minimize waste, and reduce the cost of production. A well-trained workforce will be critical to the industry's ability to manufacture low-emission vehicles and components, produce alternative fuels, build fueling infrastructure, service and maintain fleets and manufacturing equipment, and provide information for on-going innovation and refinement that will serve to increase the market acceptance of alternative fuels and new vehicle technologies.

The Energy Commission has allocated $15.8 million in program funding to support workforce development and training in the first two investment plans for the ARFVT Program. The Energy Commission used the funds to establish interagency agreements with California's top workforce training agencies, including the Employment Development Department (EDD) at $4.5 million, the California Community Colleges Chancellor's Office (CCCCO) at $4.5 million, and the Employment Training Panel (ETP) at $6.8 million. The interagency agreements have been structured to fund alternative fuel and low-emission vehicle specific training as a portion of the partner agencies' broader workforce projects. The EDD and ETP interagency agreements deliver workforce training, while the EDD and CCCCO interagency agreements provide workforce training development support activities, including surveying industry training needs, assessing existing training programs and resources, developing curriculum and training materials, instructor training, and regional industry cluster support planning grants.

To date, EDD and ETP have awarded 8 regional training grants, 4 regional industry cluster planning grants, and 12 direct employer training contracts to train more than 5,300 individuals. The grants and contracts awarded through the interagency agreements have also secured more than $13 million in worksite matching funds.

Job Creation Benefits

Since the projects funded by the ARFVT Program are almost entirely in the early stages of implementation, this summary represents projected job benefits. The Energy Commission obtained projected jobs data through an electronic survey of its awardees, which was followed with telephone survey interviews. The

Table 20: Projected Job Creation by Type, as Reported by Recipients

	Short Term	Long Term	Total
Manufacturing	436	618	1,054
Construction	618	1306	1,924
Engineering	341	284	625
Operations and Maintenance	55	410	465
Other	462	864	1,326
Total	1,912	3,482	5,394

Source: California Energy Commission

survey respondents anticipate that they will create nearly 5,400 jobs to help implement their program-funded projects. Respondents expect job creation throughout the market spectrum, but especially in manufacturing, construction, engineering, and operations and maintenance, as shown in Table 20. As defined in the survey, short-term jobs include jobs expected to last for 1 to 18 months, while long-term jobs include jobs that last 18 to 60 months.

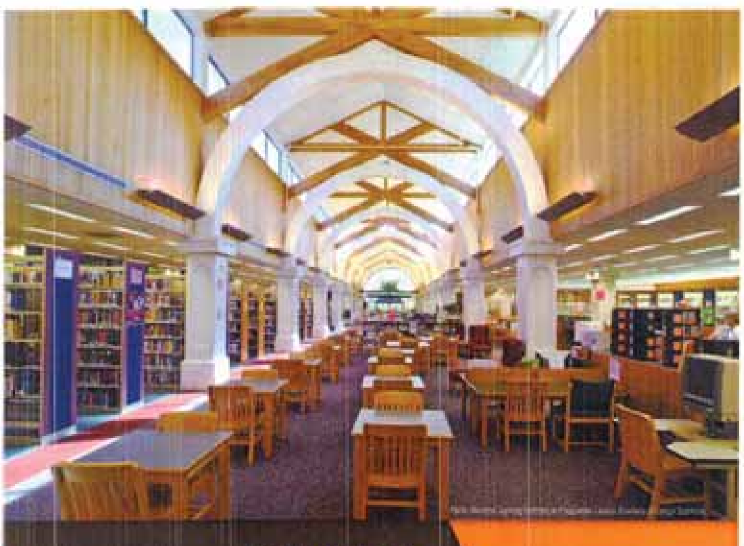
Respondents anticipate the highest numbers of jobs in manufacturing and construction, driven heavily by the construction of fuel production facilities and the production of batteries and components for the electric drive industry. Manufacturing and construction are universally recognized as two of California's most important industry sectors and the hardest hit in the recent economic downturn. As such, the ARFVT Program's investment is a timely benefit to these vital industries. The number of jobs anticipated by survey respondents can also be sorted based on the commercialization phase of the technology involved in the project, when reported (Figure 16).

Figure 16: Estimated Number of Jobs by Supply Chain Phase

Source: California Energy Commission

The economic benefit is compounded beyond the initial funding when the program's investments promote additional outside investment, stimulate business expansion, and create new jobs. Using economic benefit multipliers, the Energy Commission's investment in 1,054 manufacturing jobs alone could actually create anywhere from 3,056 to 5,270 indirect jobs.[18]

In addition to jobs data, survey respondents also provided information on the number of businesses involved in the implementation of their program-funded projects. The respondents estimated that over 800 California businesses would participate in the projects, with 548 of those businesses identified as small businesses (100 or fewer employees).



CHAPTER 12

Bringing Energy Innovation to California

Through the Public Interest Energy Research Program

This chapter of the 2011 IEPR provides an overview of the Public Interest Energy Research (PIER) Program.

The research portfolio continues to evolve and be flexible to address current energy and economic challenges to enhance the benefits to customers – the organizations, businesses, governmental agencies, residents, and others that make up California's energy marketplace.

Over the last 14 years, the PIER Program has responded to market needs and the state's energy policy goals. The program initially focused on research involving individual components and has progressed to emphasize integration of multiple energy technologies to maximize synergies and benefits. As an example, there are now energy research, development, and demonstrations (RD&D) involving large-scale integration of energy-efficiency renewable energy such as residential photovoltaics, and consumer technologies such as electric vehicles to build a smart grid that ensures reliability.

The Public Goods Charge (PGC) that provided funding for energy research and development expired on January 1, 2012. However, the Governor and key legislative leaders support continuing this charge.[99] and in October 2011 the CPUC opened a rulemaking to evaluate potential continuation of public benefits funding. On December 15, 2011, the CPUC approved the collection of an Electric Program Investment Charge (EPIC) to fund renewables and energy research, development, and demonstration programs on an interim basis, pending a final decision in Phase 2 of the proceeding.[100] The Energy Commission expects renewed research funding to continue, but if this does not happen, the state will lose a valuable source of funding support for businesses, clean energy technology innovation and development, job creation, energy-related environmental research, and increased electricity reliability.

PIER Program Makes a Difference

The PIER Program contributes to advancing electricity and natural gas science and technologies that may not have otherwise led to market acceptance. For example, the PIER Program was instrumental in bringing distributed generation (DG) to the California market. In 1996, the market structure did not support the interconnection of photovoltaic and other DG. Since that time, PIER-funded research established interconnection rules and standards[101] and helped establish benefits and devices to make DG practical and safe. For example, in 2003 PIER-funded research with Reflective Energies helped overcome interconnection barriers associated with combined technologies, such as net metered and non-net metered systems and network distribution system interconnection, and DG equipment certification requirements.

[99] Press release of Governor Brown's letter to CPUC President Peevey, September 28, 2011, gov.ca.gov/news.php?id=17213

[100] California Public Utilities Commission. News Release, December 15, 2011, docs.cpuc.ca.gov/PUBLISHED/NEWS_RELEASE/156628.htm

[101] California Rule 21 Generating Facility Interconnections; Institute of Electrical and Electronics Engineers (IEEE) 1547 Series of Interconnection Standards; and Underwriters Laboratories (UL) 1741 - Inverters, Converters, Controllers and Interconnection System Equipment for Use With Distributed Energy Resources.

Contributions to Job Growth and Private Investment in the Clean Energy Economy

By investing in innovative, energy-related RD&D projects, the PIER Program attracts and grows businesses and creates jobs. Below are some of the PIER Program's success stories in the area of job creation.

- **Jobs Created From Successful Research Projects:** Significant job growth occurs when research results in the selling of advanced technologies in the marketplace. PIER Program staff interviewed representatives of 10 companies who attributed the creation of 1,347 jobs at least in part to PIER funding. These jobs created an additional 1,983 jobs as the firms and employees purchased goods and services, according to an estimate using IMPLAN®, a widely recognized economic impact assessment program.

- **Venture Capital Investment and Jobs From PIER-Funded Small Grants:** Since the PIER-funded Energy Innovations Small Grant (EISG) began in 1999, awardees have garnered more than $1.4 billion in subsequent investment, including $1.3 billion in private, nonutility investment. PIER-funded research has significantly contributed to the development of products worth $3.1 billion to the private sector – more than 40 times the $78 million that the EISG program invested. These new companies or new lines of business create private sector output and jobs.

Energy RD&D Successes and Breakthroughs

Improving the Status Quo Through Energy Efficiency

The Energy Commission develops California's energy efficiency standards for appliances (California Code of Regulations, Title 20, Sections 1601 through 1608) and buildings (Title 24, Part 6). PIER-funded research plays a key role in developing and providing supporting data to justify the energy efficiency standards. For example, the 2008 Building Efficiency Standards used results of PIER-funded research including a compliance credit for residential cool roofs to help reduce air conditioning use; heating, ventilation, and air conditioning (HVAC) fan efficiency requirements to improve the energy performance of air handlers and duct systems; an attic duct model to evaluate the interaction of all measures that affect the heat flow in the attic; and more efficient kitchen and underground pipe insulation. In addition, the 2010 Appliance Efficiency Standards included requirements for flat-screen televisions and the 2007 Appliance Efficiency Standards included requirements for external power supplies – all of these resulted directly from PIER-funded research. Overall, these seven measures will produce an estimated annual cost savings of more than $1 billion for California electric and natural gas ratepayers when fully implemented.

For the upcoming 2013 Building Efficiency Standards, PIER-funded research is contributing to potential measures for vent cooling using outside air, hot water distribution systems for centrally heating hot water heaters and pipe insulation, HVAC controls, economizers for small commercial systems, daylighting, and lighting.

In addition to the research associated with supporting the standards, the PIER Program funded breakthrough energy research that successfully brought products to the marketplace. For example, the PIER Program's recent support of a small business called Adura® Technologies contributed to the development of a wireless lighting control network that creates energy savings up to 70 percent. This breakthrough in lighting control is a perfect technology for building retrofits that led Adura to receive $20 million in subsequent venture capital. Another example is an initial PIER-funded demonstration of an innovative way to control cooling energy use in data centers developed by Federspiel Controls (now Vigilent Systems). As a result, this company received an American Recovery and Reinvestment Act grant to install this technology in eight data centers throughout California. The cooling energy use in these eight data centers was reduced by 19 to 78 percent or about $290,000 annually. These cooling control systems are used in data centers throughout California and the United States.[102]

The PIER Program has supported several energy-efficient products and technologies that help reduce electricity, natural gas, and water consumption, save money for California consumers, and improve the environment. The following systems are now available in the marketplace:

- Integrated office and classroom lighting systems (Figure 17)
- Hybrid smart wall switch and luminaire for hotels
- Bi-level stairwell and corridor lighting
- Smart lighting controls for outdoor lighting
- Advanced evaporative air conditioners for California climate
- Radiant floor cooling
- Under-floor air distribution systems

[102] https://www.vigilent.com/news.php

- Cool roof materials for homes
- Hybrid optimized water heaters
- Advanced solar water heating components and distribution systems
- Commercial cooking equipment for restaurants
- Reverse Annular Single-Ended Radiant Tube (RASERT) for efficient, cleaner process heat burners
- Electrodialysis for tartrate stabilization in wine-making processes
- Advanced gas-fired drum dryer for food processing
- Cooling control technology with wireless network sensors
- ThermoSorber Gas-Fired Hot Water Heat Pump
- Ultra-low, nitrogen oxides (NOx) burner control technology for boiler

In addition to new products and technologies, the PIER Program also funded research to improve energy efficiency through better design and construction practices, development of tools and strategies, and analysis of data that support future building and appliance standards and utility incentive programs. Examples include:

- Identifying the potential energy savings in California's existing commercial buildings using cost-effective retrofit daylighting strategies that focus on occupant comfort
- Strategies to increase residential hot water heating efficiency
- Fault detection and diagnostic tools for commercial rooftop heating, ventilating and air conditioning systems
- Energy auditing tools and energy use reduction strategies for existing buildings and wastewater treatment facilities
- Standardized building commissioning tools
- Cost-effective efficiency strategies for affordable housing
- Community-based strategies to increase energy efficiency and environmental quality

Breaking Barriers to Achieve California's Renewables Portfolio Standard

Since its creation in 1996, the PIER Program has helped California increase its use of renewable energy. The program performed initial resource assessments to help determine California's resource potential so that developers could find the best locations to site their renewable energy systems. PIER-funded research focused on wind and solar technology development, solar forecasting, and further assessments of California's solar, wind, geothermal, and biomass resources. Helping renewable technologies reach maturity led to faster market penetration and ultimately to more renewable energy in the state's overall electricity portfolio.

The PIER Program continues to refine its focus and support the state's increasingly aggressive renewable energy policies such as the RPS, the California Solar Initiative, and the Million Solar Roofs program. In the mid- to late 2000s, the PIER Program initiated the Intermittency Analysis Project, which evaluated transmission constraints to renewable energy development and recommended interconnection solutions. In 2009, the PIER Program initiated the Renewable Energy Secure Community (RESCO) program, which is helping communities overcome renewable energy deployment and integration challenges. The RESCO program is providing technical solutions – such as local energy action plans and pilot projects – so that communities can rely more on locally available renewable resources tailored to community resources and preferences.

Figure 17: Integrated Classroom Lighting System

Photo Credit: Finelite

Figure 18: Concentrating Photovoltaic System

Photo Credit: GreenVolts, Inc.

The PIER Program's Energy-Related Environmental Research is helping the state address concerns relating to the environmental impact of energy production on air quality, water resources, terrestrial resources, and climate change. In particular, this research is assisting with sound practices for permitting renewable and nonrenewable generation.

One of the most daunting barriers renewable energy project developers face at every level is the high up-front costs. A way to address this challenge is by developing lower cost and higher-efficiency generation technologies. Additionally, innovative applications for waste by-products can result in additional benefits that translate into cost savings. For example, PIER Program participant GreenVolts, Inc., developed a new concentrating photovoltaic (CPV) system with low-cost installation, low-cost manufacturability, technical performance improvements, minimal ground footprint, and comprehensive "system" delivery.

This new CPV system will speed the deployment and adoption of CPV technology in various applications. Originally funded by the PIER Program, GreenVolts received $40 million in venture capital funds to demonstrate and commercialize the product. The technology is now in full production, with six installations in California and Arizona (totaling 400 kilowatts) and several sites in development ranging in size from 200 kilowatts to 1 megawatt. A 2.5-megawatt operation is under construction in Byron, California. The development of these projects resulted in 100 jobs at Green Volts, 20 manufacturing jobs, and more than 30 jobs for various installation contracts. Figure 18 shows one of GreenVolts's CPV installations.

The PIER Program has supported the following renewable energy projects to help overcome barriers that limit the deployment and integration of renewable energy into California's grid:

- Powerlight Corporation's photovoltaic (PV) tracker which tracks the sun to maximize the amount of energy produced by a photovoltaic system
- Advanced Energy Recovery System (AERS) converting green waste to clean biogas, which feeds fuel cells
- Tecogen Inc.'s combined heat and power system coupled with inverter-based technology
- Clean Energy Systems' turbine using oxy-combustion technology
- Improved forecasting for variable solar and wind generation projects to optimize development and operation of the transmission grid system
- UC Davis West Village, a multiuse zero net energy community using on-site renewables and efficiency to optimize distributed energy resources
- Developing utility-scale solar concentrating systems on closed landfills
- Biomass to energy projects to create biogas for on-site electrical production
- Piloting the integration and use of renewables to achieve a flexible and secure energy infrastructure by integration of PV, electric vehicle charging, and thermal energy storage

Integrating Renewable Energy Through Smart Grid Infrastructure Development

PIER-funded research is making strides in the areas of advanced generation, transmission, distribution, and smart grid to promote renewable integration. For example, a recent PIER-funded solicitation resulted in contracts that developed a definition for California's Smart Grid of the Future from three perspectives: investor-owned utilities, publicly owned utilities, and the electric industry. In December 2010, the Energy Commission conducted a joint workshop with the California Public Utilities Commission (CPUC) to highlight the PIER Program's three smart grid RD&D road mapping projects that will support the state's goals to develop a smart grid and provide a research framework for smart grid deployment plans.[113] The Energy Commission will combine the three perspectives to create a definition for a single, coordinated "California Smart Grid." This effort is helping the state meet multiple energy policy goals established under Assembly Bill 32, Senate Bill 17, and Senate Bill 1250, as well as various technology and integration challenges. This effort also established a roadmap for technology development for the PIER Program to fill key technology gaps.

Synchrophasors Help Integrate Renewables and Reduce Power Outages

Variable generation causes anomalies in the electric power system that if not handled properly may lead to unplanned outages. Grid operators need real-time information to better manage and operate the electric grid.

Synchrophasor measurement systems on transmission lines provide detailed information about the electric system to help forecast and prevent power outages. The PIER Program funded the Phasor Real Time Dynamic Monitoring System (Phasor-RTDMS)

113 Workshop presentations and a full transcript are available at www.energy.ca.gov/2011_energypolicy/documents/index.html#12132010.

from Electric Power Group, LLC, which provides synchrophasor information to the California Independent System Operator (California ISO) at a rate of up to 30 times per second. The status quo Supervisory Control and Data Acquisition system only reports a status every four seconds. This new technology represented a game-changing environment for future grid management with respect to system reliability and renewable integration.

In January 2008, the Phasor-RTDMS system alerted California ISO operators about unusual oscillations that were making the electric system unstable. The California ISO temporarily shut down a major power line at the center of these oscillations to avoid a major blackout. The California ISO probably would not have detected this oscillation irregularity before the installation of the Phasor-RTDMS product. This event demonstrated the clear benefit of having this technology solution available for grid management.

The PIER Program expects synchrophasor technology to save future electricity consumers about $210 million to $370 million per year in avoided outage costs and $50 million per year in reduced electricity costs. Support from the Energy Commission and the United States Department of Energy was essential to this research. Without PIER Program leadership and active stakeholder involvement, synchrophasor and associated development would not have progressed to where it is today, it would not be tailored to California needs, and California might face serious problems integrating renewable generation and electric vehicles.

The PIER Program funded research in the following areas to develop a smart grid infrastructure and support renewable integration:

- Demand response as a spinning reserve, a key ancillary grid requirement
- Solar and wind forecasting
- Electric vehicle-to-grid services
- Microgrids
- Distribution upgrades and monitoring
- Utility-scale energy storage
- Real-time grid reliability management

Improving the Safety of Natural Gas Pipelines

The PIER Program responds to energy issues that are of concern to Californians, such as safety and reliability. The PIER Program is funding projects to support research on the safety and security of the state's natural gas system infrastructure, as California is the second largest natural gas-consuming state in the United States, making this a priority issue. The growing demand for natural gas and the aging natural gas pipeline infrastructure pose significant challenges for the state's natural gas users. The state needs public interest energy research to explore opportunities and apply new and emerging technologies that provide innovative options for natural gas pipeline integrity, operations, and safety.

Events following the September 2010 natural gas explosion in a Pacific Gas and Electric's (PG&E) pipeline in San Bruno led to two PIER-funded projects to help improve gas pipeline evaluation and monitoring. One project will develop a baseline assessment of current technologies used in California to manage pipeline integrity and safety including current methods to prevent, detect, and respond to pipe leaks and/or ruptures. Another project will design, build, and test a family of next generation microelectromechanical systems (MEMS) devices that measure pressure, inspect seam welds, and detect corrosion in natural gas pipes with wireless communications for condition-based monitoring. These prototype devices can operate inside regular pipes during normal operations to monitor pipeline safety and integrity.

The Evolving PIER Program

Over the years, the PIER Program has continually evolved through increased transparency and by encouraging active stakeholder engagement.

Policy Advisory Board and Advisory Groups

The PIER Program convened three publicly noticed Policy Advisory Board (PAB) meetings over the past year to increase public participation and to provide transparency in PIER Program planning. The PAB includes Legislative members, energy agencies, utilities, and environmental, consumer, and business organizations.

The Energy Commission also formed three Policy Advisory Groups (PAGs) to augment the PAB and focus on three research program areas – Energy Efficiency, Renewable Energy, and Smart Infrastructure. The PAGs review and ensure relevancy of the PIER Program's research initiatives to the marketplace, find synergy and end-user opportunities, and avoid research duplication. Staff held public workshops in June 2011 with each PAG to discuss the proposed research initiatives for the upcoming fiscal year (2011–2012). The workshops brought together utilities, researchers, manufacturers, end users, and policy makers from state agencies, federal agencies, and the public. The results of the meetings provided information for the PIER Program's future research portfolio and solicitations.

RD&D Benefits Assessment

Energy Commission staff is refining how public benefits are assessed from PIER-funded RD&D projects and the overall program. The PIER Program developed a program-wide approach to benefit and cost assessment, which includes integrating benefits assessment elements into work plans and databases, evaluating interviews and surveys, identifying required benefits metrics, and requiring researchers to provide a subsequent report on these metrics.

For example, in the first quarter of 2011, the Energy Commission calculated that PIER-funded research activities directly created 2,128 jobs. These jobs are assigned to projects providing the full time equivalent (FTE) of 978 job-years. Analysis using IMPLAN®, an economic analysis software tool for predicting regional economic effects, estimates that these 2,128 jobs lead to 1,258 indirect jobs, where the entities doing the work have to purchase goods and services, and 2,180 induced jobs, where business owners and employees purchase goods and services. About 5,600 people were employed at least part time over the course of these PIER-funded contracts. Based on the FTE job-years worked, the IMPLAN model estimates state and local governments collected $7.2 million in taxes.

Public Outreach

The Energy Commission has considerably streamlined the report and publication process for project fact sheets to disseminate important research results to the public. To communicate the program's successes, the Energy Commission published a brochure, *PIER: How Public Research Powers California*,[114] along with many fact sheets, reports, and other brochures targeting success in specific topic areas such as smart infrastructure, overcoming renewable energy barriers, and efficiency projects.

114 California Energy Commission. *PIER: How Public Research Powers California*. CEC-500-2011-030-BR. July 2011. www.energy.ca.gov/2011publications/CEC-500-2011-030/CEC-500-2011-030-BR.pdf.

In August 2011, the PIER Program held a Venture Capital Forum in Sacramento to increase levels of California venture capital market investments in PIER-funded emerging technologies. The goal of the forum was to learn from venture capitalists how they evaluate prospective technologies, how to better invest and leverage PIER funds, and how to encourage higher levels of venture capital investment in PIER-funded technologies to help bolster the path to market. Because of the success of this forum, the program plans to have additional forums in the future.

On the Horizon

The PIER Program is committed to working with stakeholders and policy makers to tackle ongoing energy issues associated with the Renewables Portfolio Standard, Zero Net Energy buildings, smart grid implementation, environmental barriers to renewable energy implementation, and the Governor's goal for DG. Staff will also continue to fine-tune the administration of the PIER Program with the goal of maximizing its value to California businesses and residents.

From November 2010 through January 2012, the PIER Program released the following solicitations:

- Industrial, Agricultural, and Water – Emerging Technologies Demonstration Grant Program II
- Environmental Issues Related to Clean Energy Systems
- Hybrid Generation and Fuel-Flexible Distributed Generation/Combined Heat and Power/Combined Cooling, Heat, and Power Systems
- Liquefied Natural Gas Vehicle Infrastructure Improvement Research and Development

The PIER Program is also planning to release the following solicitations in 2012:

- Community Scale Renewable Energy Development, Deployment, and Integration
- PIER Buildings Grant Solicitation

While the Energy Commission is confident that research funding will emerge next year, if this does not happen, the agency will have to discontinue vital research and impartial evaluation, and will lose coordination of energy RD&D that benefits the entire state.

Recommendations

The Energy Commission recommends that California continue funding public interest energy research that helps meet state energy goals. Advancing energy RD&D activities in California will attract new businesses, create jobs, and allow California companies and research institutions to compete for and successfully attain federal funds.

The Energy Commission recommends continuing to manage a public interest energy research program in California because it advocates for Californians by acting as impartial evaluator when providing RD&D funding to California researchers. The Energy Commission also has the unique ability to select and coordinate research across various types of researchers (private businesses, institutional, government agencies, and so forth) to maximize the effectiveness of the program and ensure consistency with state policy goals.

Furthermore, the Energy Commission recommends the following for a renewed PIER Program:

- Prepare a Five-Year Strategic Investment Plan with active stakeholder engagement, which is guided by state energy policy and would achieve a balanced portfolio of investments including technology demonstrations and the more fundamental and applied research.

- Design metrics around strategic plan objectives that are tangible, quantifiable, and measurable. The metrics, when combined with periodic evaluations, will help refine programs, increase program effectiveness, make tough decisions to drop ineffective program elements, and develop credible evidence that communicates the value of the program to stakeholders.

- Increase outreach and awareness of RD&D projects and results by holding workshops, research forums and conferences, press events, and other activities with the public and stakeholders.

Conclusion

The state should continue funding public interest energy research. The state's public interest RD&D program plays a critical role in providing jobs and innovations for California by helping startup businesses move technologies from demonstration to deployment and meet state policy goals.

As administrator of the PIER Program, the Energy Commission will ensure that research supports and follows state energy policy, provides solutions for California's future energy problems, and provides benefits to Californians. The Energy Commission remains committed to continuing this clean energy incubator program.

CHAPTER 13

2011 Bioenergy Action Plan

This chapter summarizes the Energy Commission's 2011 Bioenergy Action Plan, prepared for the Bioenergy Interagency Working Group (Working Group)[233, 234] and adopted in March 2011, and outlines current activities and priorities of the Working Group during 2011. The summary includes key points from the report, background information, objectives for achieving state bioenergy goals, challenges, key findings and recommendations, and action items to be taken in the next two years.

Development of bioenergy supports state policies and goals. There are four types of bioenergy identified for California's Renewables Portfolio Standard, and biopower and biogas have the potential to provide renewable energy to help meet Governor Brown's Clean Jobs goals of 12,000 MW of local distributed energy generation. Biofuels and biogas can also play an important role in reducing the lifecycle carbon emissions from transportation fuels, helping California achieve the state's Low-Carbon Fuels Standard.

Bioenergy is energy produced from biomass in the form of electricity (biopower), renewable gas (biogas, biomethane, or synthetic natural gas), or liquid transportation fuels (biofuels). California has abundant biomass resources from the state's agricultural, forest, and urban waste streams. Increased bioenergy production could provide the state with several economic, environmental, and reliability benefits. For example, bioenergy creates clean energy jobs, enhances rural economic development, and promotes local economic stability. It can also help the state meet its climate change targets and ensure a more stable supply of energy by reducing the state's dependence on imported fossil fuels. Biopower can increase grid reliability because it is not intermittent and can therefore support the current "baseload" or other continuous energy demand.

Despite the state's policies to promote renewable energy and bioenergy, biomass is currently underused as an energy source, and increasing bioenergy production faces many challenges. Following publication of the *2006 Bioenergy Action Plan*, new bioenergy facilities were proposed and constructed, some idle facilities were restarted. However, by 2011, most of these biopower capacity gains were lost due to adverse market conditions, high transportation fuel costs, and, in some cases, competition with fossil fuels. Lower cost renewables may also make it difficult for biomass to compete in the RPS competitive bid process. However, biopower should be able to compete in the new Renewable Auction Mechanism, since the program is designed to separate bids into different product types (such as base load, intermittent peak, and intermittent off peak).

As part of the *2011 Plan*, Energy Commission staff developed five objectives to help accelerate the development of bioenergy projects by building on the successes and lessons learned from the *2006 Plan*. The five objectives are:

- Encourage increased bioenergy production at existing facilities.

- Promote and expedite the construction of new bioenergy facilities.

- Promote and encourage the integration of bioenergy facilities.

- Fund research and development.

- Remove statutory hurdles and streamline the regulatory process.

Developing the potential for new energy production in each objective will require overcoming many of the challenges facing the industry. The challenges to bioenergy have been discussed through workshops and forums held by the Energy Commission, California Integrated Waste Management Board (now CalRecycle), the California Department of Food and Agriculture, the Department of Forestry and Fire Protection (CAL FIRE), ARB, State Water Resources Control Board, the California Biomass Collaborative, the United States Environmental Protection Agency (U.S. EPA), industry groups, and others for many years. Through these forums, developers, stakeholders, and state and federal agencies have identified opportunities and challenges to increased bioenergy development in the state.

233 The full report can be accessed at: www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF

234 The Working Group consists of the following state agencies: California Energy Commission, Air Resources Board, Environmental Protection Agency, Resources Agency, Department of Resource Recovery and Recycling, Department of Food & Agriculture, Department of Forestry and Fire Protection, Department of General Services, California Public Utilities Commission, and Water Resources Control Board.

Key Findings and Recommendations

The *2011 Plan* identifies a number of key findings on how the challenges have affected in-state bioenergy development. The *2011 Plan* also finds that biomass is an abundant resource that can help the state achieve clean energy goals, but aggressive actions must be taken to increase biomass use. The findings are as follows:

- California has abundant biomass resources from the state's agricultural, forest, and urban waste streams. Increasing the state's bioenergy production will help California achieve the state's waste reduction, renewable energy, and climate change goals with a sustainable and dependable resource.

- Bioenergy has many benefits, both as a renewable energy source and an alternative disposal option for biomass. The benefits of bioenergy include displacing fossil fuels with a dependable renewable resource, providing distributed energy near demand, reducing greenhouse gas emissions, and providing green jobs in rural communities. The use of biomass has added benefits to surrounding communities by providing agriculture, industry, and forestry an alternative disposal option for biomass residues, indirect jobs needed to collect and transport the biomass, reduced demand on landfills, and improved water quality and ecosystem health.

- Market-based pricing mechanisms for electricity, transportation, and waste management do not currently consider all of the benefits bioenergy provides to local communities.

- There is a need for continued state research and funding to commercialize biomass technologies.

- Electric grid and natural gas pipeline interconnection challenges have inhibited the development of distributed biomass electricity and biogas projects. California must address these challenges to increase development of bioenergy projects.

- The cost to collect and transport biomass feedstock remains an economic challenge to the development of bioenergy projects in California.

- Regulatory uncertainty continues to reduce options to finance projects in the predevelopment stage, further inhibiting the development of bioenergy and other distributed energy projects.

- Efforts to streamline the permitting process, especially for anaerobic digesters using dairy and urban waste, continue to be supported by state agencies, local air districts, regional water control boards, and the U.S. EPA. However, additional actions will be needed by the Bioenergy Interagency Working Group and the Legislature to streamline permitting for distributed energy projects.

The *2011 Plan* makes recommendations to support the key findings and help provide solutions to the challenges facing the bioenergy industry. The following recommendations are supported by members of the Working Group:

- Action is needed by the California Public Utilities Commission to continue the Energy Commission's public interest research program and to develop programs that offset the cost of new and emerging biopower technologies. Members of the Working Group support funding for a new biopower commercialization program to develop agricultural, forestry, and urban bioenergy projects.

- Increased development of biofuels is important to fulfill goals established by the Low Carbon Fuels Standard and the AB 118 program. The state should continue to evaluate bioenergy feedstocks and markets to promote technologies, programs, and policies needed to enhance biofuels development.

- The Bioenergy Interagency Working Group will work with California gas utilities and other stakeholders through a public process to address real and perceived barriers to the development of biogas and landfill gas, and the injection of biomethane into the California natural gas pipeline.

- Permitting agencies will continue to improve coordination in the permitting process to reduce the time frame and costs to developers. The Working Group will take additional steps to expedite permits through programmatic environmental impact reports and creating a web-based portal for permit contacts.

- Explore various options to quantify the benefits bioenergy provides ratepayers and surrounding communities.

- Develop sustainable feedstock standards and waste use targets for biomass resources to ensure that its use supports California's renewable energy, the Low Carbon Fuel Standard, recycling and waste reduction goals, and creates new jobs.

- Develop a plan to reduce the cost of collection and transportation of biomass residues.

- Continue to convene regular meetings of the Working Group to continue agency coordination and collaboration.

- In cooperation with other state agencies, the Energy Commission should continue to monitor progress toward achieving the state's bioenergy goals through the Working Group.

Status of Biofuels

In 2010, California consumed roughly 1 billion gallons of biofuels (gasoline gallon equivalent [gge]), primarily as ethanol blended into gasoline as an oxygenate. Federal and state policy mandates will necessitate an increase in the consumption of renewable fuels for transportation in California. Biofuel development is more completely addressed in Chapter 10 on Transportation.

California has 150 million gge of annual ethanol production capacity, with less than 50 million gge produced in 2010. When the ethanol blend in California reformulated gasoline increased to 10 percent in 2010, the state's total ethanol use grew to nearly 1.5 billion gallons. However, California ethanol facilities contributed less than 4 percent of the state's needs in 2010. Since 2000, five corn ethanol refineries have been built in California. All five of these plants were idle for most of 2009 and 2010 due to adverse market conditions. Only one of these corn ethanol refineries produced fuel in 2010 with two more coming on line in the first half of 2011. Total in-state biodiesel capacity is capable of producing 100 million gge per year. However, less than 5.7 million gge were produced in 2010. Table 21 summarizes the biofuel production and capacity in California. Biofuel consumption is expected to grow over the next decade.

In-state biofuel production will make up just 5.6 percent of California's estimated 1 billion gge biofuel demand in 2020, far below the biofuel goal of 20 percent (200 million gge).

Over the past two years, the Energy Commission, through its ARFVT Program, has begun investing in new projects to develop and deploy additional in-state biofuel production projects. To date, the Energy Commission has invested roughly $64 million toward biofuel production, fueling infrastructure, and related projects. This represents just over one third of the total ARFVT Program awards.

Of the $64 million allocated toward biofuels projects, $45 million has gone toward projects that will accelerate or expand the production of next generation biofuels. These 17 projects will use waste-based feedstocks or alternative bioenergy crops (such as sugar beets, sweet sorghum, and algae), rather than corn or soy. While the carbon intensity of the resulting fuels will vary, they will typically range from 70 percent to 85 percent below the diesel and gasoline baseline.

Table 21: In-State Biofuel Production (millions gge)

	2006	2007	2008	2009	2010
Ethanol Production	37.7	27.7	90.4	20.1	<30
Biodiesel Production	25.8	18.6	12.4	7.3	5.7
Total In-State Biofuel Production	63.5	46.3	103	27.4	<35
Total Biofuel Consumption	815	652	702	688	1,017
Percent In-State Production to Total Biofuel Consumed	7.8%	7.1%	14.6%	4.0%	<3.5%

Source for in-state biofuel production: California Energy Commission; source for total biofuel consumption, California Energy Commission staff analysis of Board of Equalization taxable gasoline figures.

Most of these projects are still in their early stages, but the Energy Commission's survey of awardees indicates their potential for market growth. The survey responses included a low and high range for the projects' market entrance and expansion, which ranged from a total of 123 million to 632 million gallons per year of petroleum displacement (either gasoline or diesel fuel) from new biofuel production by 2020. If achieved, this level of production would represent a significant step toward achieving the goal of having 40 percent (or roughly 870 million gge) of in-state biofuel consumption coming from in-state resources by 2020.[237]

Status of Biopower and Biogas

In 2010, most of the biopower in California was generated from solid-fuel biomass and landfill gas. Other biopower sources include dairy digesters, solid-fuel thermochemical conversion facilities, organic waste digesters, and wastewater digesters.

Since 2006, 22 new biopower facilities were built in California (15 landfill gas and 7 digester facilities), representing 44 MW of generating capacity. Although no new solid-fuel biomass facilities were constructed, four idle facilities restarted, including an idle coal facility converted to biomass.

Cofiring biomass or biogas at conventional power plants has been a growing trend since 2008. Three in-state coal facilities have begun cofiring with biomass and have plans to convert to biomass as their sole energy resource by 2012. These facilities will contribute up to 130 MW of renewable capacity to the grid. Two additional coal facilities have indicated an interest in switching to renewable feedstocks, although the Energy Commission does not have an expected start date on the conversion. If successful, these facilities could add another 80 MW of renewable capacity. The conversions of in-state coal facilities will significantly reduce greenhouse gas emissions, allow the facilities to continue generating combined heat and power, and retain well-paying jobs in economically depressed communities. In addition, 10 in-state natural gas power plants began cofiring with pipeline biomethane produced and injected into the interstate natural gas pipeline out-of-state, with an effective capacity of 50 MW.

[237] O'Neill, Garry, John Nuffer, *2011 Bioenergy Action Plan*, California Energy Commission, Efficiency and Renewables Division, CEC-300-2011-001-CTF, available at: www.energy.ca.gov/2011publications/CEC-300-2011-001/CEC-300-2011-001-CTF.PDF

By the end of 2010, nine solid-fuel biomass facilities were idle, representing 100 MW. The facilities have idled for various reasons, such as poor economic conditions in the lumber industry and low contract prices for energy. Seven dairy manure digesters also idled due to financial difficulties and, in some instances, difficulties meeting San Joaquin Valley Air Pollution Control District nitrogen oxide (NOx) emission standards with purchased equipment. The capacity idled since 2006 is 100 MW.

Biopower generation increased 18 percent from 2006 through the end of 2010. Much of the generation increase came from out-of-state biopower facilities and in-state biomass cofiring at coal and biogas burned in natural gas facilities and restarted solid-fuel biomass facilities. While the total generation used to meet California load has increased since 2006, in-state biopower generation has remained level. The biomass share of renewable electricity generation in California has decreased from 20 percent to 17 percent.

In-state biopower generation is expected to increase in the short term as coal facilities complete full fuel conversion to biomass by the end of 2012. Additional biopower capacity has recently been proposed as the remaining existing in-state coal facilities look to convert to biomass by 2015. In addition, the Energy Commission expects that a small number of facilities that shut down due to low short-run avoided cost energy prices in 2009 and 2010 will restart if contract renegotiations are successful. While new projects have been proposed, they are not expected to contribute significant generation in the next two years.

Opportunities exist at public works projects, municipal wastewater treatment plants, and landfills to collect and capture fugitive methane emissions and produce biogas or biomethane. At this time, much of this potential energy resource is flared due to difficulties obtaining air permits and meeting air quality standards in some California air districts, and the economics of power generation. While on-site power generation may not be possible because of increases air pollutants compared to flaring, cleaning and upgrading this gas to meet pipeline or transportation fuel standards would allow beneficial use of this resource for energy production.

Progress on Implementing the 2011 Bioenergy Action Plan

The *2011 Bioenergy Action Plan* was intended to be updated and refreshed as needed to adapt to changing conditions. Parties are continuing to work on completing and updating measures, and the Energy Commission will report on updates and processes in future IEPRs.

Actions underway and completed are listed below.

Table 22: Biopower Generation Used to Meet California Load

	2006	2007	2008	2009	2010
In-State Biopower Generation (GWh)	5,735	5,358	5,726	5,910	5,514
Out-of-State Biopower Generation (GWh)	550	818	851	895	1,340
Total Biopower Generation (GWh)	6,285	6,176	6,577	6,805	6,854
Total Renewable Generation (GWh)	32,225	32,314	32,532	35,791	39,756
Percent of Renewable Generation	19.5%	19.2%	19.8%	18.7%	17.3%

Source: California Energy Commission Total System Power

Actions Initiated in 2011

- **Action:** Governor's Office and the Bioenergy Interagency Working Group are developing the *2012 Bioenergy Action Plan*.
Completion Date: January 31, 2012

- **Action:** California Department of Food and Agriculture has convened a state, federal, stakeholder working group of federal, state, and regional agencies and stakeholders to promote the development of dairy digesters. The working group is developing specific recommendations on actions that will streamline permitting, and address technology challenges and economic incentives or programs needed to finance projects.
Lead Agency: California Department of Food and Agriculture
Completion Date: Preliminary Report, March 2012

- **Action:** The Sierra Nevada Conservancy (SNC) is providing state agency leadership in working with a diverse group of stakeholders and government entities to promote small-scale bioenergy projects that are consistent with forest restoration, economic development, and social equity objectives.
Completion date: Ongoing

Actions Underway

- **Action 1.1:** Develop a website to provide local governments with permitting, planning, and technical assistance documents for siting and developing new renewable facilities.
Lead agency: Energy Commission
New completion date: March 31, 2012

This action was changed to develop a program to offer planning and permitting assistance to local permitting agencies. The new completion date reflects the need to hold a stakeholder workshop in early 2012.

- **Action 1.2:** Develop a comprehensive website to provide new project developers with permitting guidance, links, and contacts to permitting agencies.
Lead agency: Energy Commission
New completion date: March 31, 2012 (to fit in with the work plan of Action 1.1.)

This action will be included in the development of the Local Government Assistance Program in Action 1.1.

Actions Completed

- **Action 2.6 (a):** The *Program Environmental Impact Report for Anaerobic Digestion of Organic Wastes* was completed, certified, and submitted to the State Clearinghouse in June 2011. This document is designed to expedite the permitting on anaerobic digestion projects within California.

- **Action 2.6 (g):** CalRecycle has updated guidance documents that outline how CalRecycle regulations are applied to anaerobic digesters and the statutory requirements that CalRecycle and local enforcement agencies have regarding anaerobic digesters when solid waste is used as a feedstock.

- **Action 5.4:** This action involved monitoring changes to federal bioenergy policies and regulations. In May 2011, U.S. EPA issued a stay delaying the effective date of the standards for major source boilers and commercial and industrial solid waste incinerators (also referred to as the Boiler MACT rules). On January 9, 2012, the U.S. District Court vacated the U.S. EPA's May 2011 stay, declaring that the reconsideration was unlawful. The effect of the ruling is that the March 2011 Boiler MACT Rules went into effect on May 20, 2011. It is unclear at this time whether the court is allowing the U.S. EPA to revise the rules before the new standards are incorporated into the State Implementation Plan (within 3 to 5 years of the effective date of May 2011). New sources constructed after June 4, 2010, will have to comply upon startup.

CHAPTER 14

Nuclear Issues & Status Report on Assembly Bill 1632 Report Recommendations

This chapter discusses the implications of recent events in Japan for California's nuclear plants regarding seismic and tsunami hazards, spent fuel pool safety, potential station blackouts, liability coverage, long-term power outages, and emergency response planning.

In 2010, nuclear power provided 15.7 percent of California's in-state electricity generation and 13.9 percent of the entire California power mix (which includes out-of-state imports).[178] The electricity generation comes from three plants: the Diablo Canyon Power Plant (Diablo Canyon) and the San Onofre Generating Station (SONGS) in California, and the Palo Verde nuclear power plant in Arizona.[179]

178 See energyalmanac.ca.gov/electricity/index.html, Electricity Generation by Resource Type (1997 – 2010, Excel file).

179 Diablo Canyon is located near San Luis Obispo and is owned by Pacific Gas and Electric Company. SONGS is located near San Clemente on land leased from the U.S. Marine Corps at the north end of Camp Pendleton. It is co-owned by Southern California Edison, San Diego Gas & Electric, and Riverside Public Utilities. The Palo Verde nuclear power plant, located near Phoenix, Arizona, and partially owned by Southern California Edison, the Los Angeles Department of Water and Power, and a consortium of Southern California municipal utilities.

These nuclear power plants are important to California's electricity supply and meeting the state's greenhouse gas emissions reduction goals and policies for climate change reduction. However, Diablo Canyon and SONGS are older plants located near major earthquake faults and have significant inventories of spent nuclear fuel stored onsite. Concerns about their safety and reliability have increased with the recent large earthquakes in Japan.

In 2007, a major earthquake resulted in the loss of nearly 8,000 MW of power at the Kashiwazaki-Kariwa nuclear power plant in Japan, with most of its units remaining shut down four years after the event. This event followed the California Legislature's passage in 2006 of Assembly Bill 1632 (Blakeslee, Chapter 722, Statutes of 2006), which required the Energy Commission to assess the vulnerability of California's major baseload plants to a major earthquake or plant aging.[220] As required by AB 1632, the Energy Commission completed *An Assessment of California's Nuclear Power Plants: AB 1632 Report* (*AB 1632 Report*) in 2008, which provided an independent scientific assessment of the seismic hazard and plant vulnerabilities at Diablo Canyon and SONGS.[221]

In 2008, Pacific Gas and Electric (PG&E) announced that the United States Geological Survey (USGS) had discovered the Shoreline Fault less than a mile offshore from Diablo Canyon. In 2003, the San Simeon earthquake (magnitude 6.5) occurred about 35 miles north of the Diablo Canyon site, and the tectonic setting where this earthquake occurred appears similar to the local tectonic setting at Diablo Canyon.[222] Better understanding of the fault zones in the vicinity of Diablo Canyon and SONGS is significant for plant engineering vulnerability assessments for these plants. The deep geometry of faults that bound the San Luis-Pismo block, where Diablo Canyon sits, is not understood sufficiently to rule out a San Simeon-type earthquake directly beneath the plant.[223] Similarly, data that has become available since SONGS was built indicate that the site could experience larger and/or more frequent earthquakes than anticipated in the plant design and the earthquake design basis for the plant may underestimate the seismic risk at the site.[224,225] To help resolve uncertainties about the seismic hazards at these plants, the Energy Commission's *2008 IEPR Update* recommended that PG&E and Southern California Edison (SCE) complete enhanced seismic and tsunami hazard and plant vulnerability studies including using three dimensional seismic reflection mapping and other advanced techniques to supplement seismic research at the plants.[226]

On March 11, 2011, a magnitude 9.0 earthquake and tsunami in Japan knocked out power and emergency electrical equipment at the Fukushima Daiichi nuclear plant in Japan, resulting in reactor meltdowns, explosions, fires, and widespread radioactive contamination. Although a 9.0 magnitude earthquake from a subduction zone is not thought to be possible near Diablo Canyon and SONGS, the Fukushima accident heightened concerns about seismic and tsunami hazards as well as safety issues for California's coastal nuclear plants. On July 26, 2011, two Commissioners from the Energy Commission and two from the CPUC jointly conducted a public workshop on the implications of the Fukushima Daiichi accident for California's nuclear power plants and the utilities' progress in carrying out the *AB 1632 Report* recommendations.[227] Three panels of experts representing PG&E, SCE, state and federal agencies, the nuclear industry, and public interest groups participated in this workshop along with members of the public. In addition, the utilities prepared responses to 2011 IEPR Committee data requests on nuclear issues.[228]

[220] Pacific Gas and Electric Company. 2010a. Diablo Canyon Power Plant, Response to Kashiwazaki-Kariwa Nuclear Power Station Lessons Learned. March 18, 2010.

[221] California Energy Commission and MRW and Associates. *An Assessment of California's Nuclear Power Plants: AB 1632 Report*, and *AB 1632 Assessment of California's Operating Nuclear Plants: Final Consultant Report*. Available at: www.energy.ca.gov/ab1632/documents/

[222] California Energy Commission. *2008 Integrated Energy Policy Report Update*. www.energy.ca.gov/2008_energypolicy/index.html, page 67.

[223] *AB 1632 Assessment of California's Operating Nuclear Plants: Final Report*, consultant report, p. 4.

[224] California Energy Commission. *2008 Integrated Energy Policy Report Update*. www.energy.ca.gov/2008_energypolicy/index.html, page 67.

[225] California Coastal Commission. www.coastal.ca.gov/energy/E-10-024-2nrc.pdf, page 19.

[226] California Energy Commission. *2008 Integrated Energy Policy Report Update*. www.energy.ca.gov/2008_energypolicy/index.html

[227] Meeting notice, agenda, transcripts, panel submittals, and public comments for the July 26, 2011, workshop at www.energy.ca.gov/2011_energypolicy/documents/index.html#07262011.

[228] Utility responses to the 2011 IEPR Data Request on Nuclear Issues can be found at: www.energy.ca.gov/2011_energypolicy/documents/data_nuclear_power_plants/

Events at Fukushima Daiichi and Implications for California Nuclear Plants

The 9.0 magnitude earthquake on March 11, 2011, in northern Japan and an estimated 40-foot tsunami run-up at the Fukushima Daiichi plant site resulted in spent fuel meltdowns at three of the plant's six reactors, overheating and damage to spent fuel storage pools, explosions and fires, large scale releases of radioactive materials to the environment, and the evacuation of an estimated 80,000 people. The Japanese government rated the crisis at a Level 7, the highest possible level on the international scale for evaluating the seriousness of nuclear reactor incidents, equivalent to the 1986 Chernobyl plant accident in the Ukraine. The policy decisions resulting from the lessons learned studies from these events will shape the next few decades of nuclear energy policies throughout the world.

Fukushima demonstrated that extraordinary and extreme events can pose unexpected challenges for nuclear plants. Historically, the Nuclear Regulatory Commission's (NRC)[229] emergency guidelines (instituted in the 1990s) for nuclear plants, including the Severe Accident Mitigation Guidelines, have been voluntary and not part of its program overseeing reactor safety.[230] After Fukushima, however, the NRC established a task force to evaluate what lessons might apply to the safety of U.S. reactors and instructed NRC plant inspectors to conduct immediate, independent assessments of each plant's level of emergency preparedness. NRC's regional and resident inspectors found several deficiencies at Diablo Canyon.[231]

The Fukushima events will likely cause increased industry vigilance and expanded federal government oversight of nuclear power plant safety. In 2011, NRC's Near Term Task Force issued post-Fukushima recommendations for enhancing reactor safety and a priority list of actions.[232] The NRC Chairman, Gregory Jaczko, has urged an expedited timeline to work through the recommendations, but the industry is asking for more time to access the lessons learned from Fukushima and the cost to plant owners from making the recommended changes.[233] There is no consensus yet among NRC Commissioners regarding the need for expedited action.[234]

[229] The Nuclear Regulatory Commission is the federal agency responsible for regulating nuclear power plant safety in the United States.

[230] Nuclear Regulatory Commission. *NRC Inspection Manual*. Temporary Instruction, 2515/184, issued April 29, 2011, pbadupws.nrc.gov/docs/ML1112/ML11115A053.pdf.

[231] Natural Resources Defense Council, Tom Cochran, July 26, 2011, IEPR workshop on California Nuclear Power Plant Issues.

Seismic and Tsunami Hazards

The recent earthquakes that affected the Fukushima Daiichi plant in March 2011, and the North Anna plant in Virginia on August 23, 2011, exceeded the levels assumed in plant designs and underscored the importance of updating seismic hazard estimates for reactor sites.[235] No significant safety concerns from the earthquake were identified at North Anna and the plant was restarted in November 2011. Fukushima experienced higher ground motion than the plant was designed to withstand. An international study combining monitoring data from around the world to estimate the scale and fate of radioactive emissions from Fukushima suggested that there was structural damage to the plant and radioactive material releases following the earthquake even before the tsunami hit.[236] The majority of faults in California are not considered capable of generating a magnitude 9.0 earthquake except for the subduction zone that begins north of Mendocino.[237] However, the significant uncertainties regarding geologic conditions near Diablo Canyon and SONGS warrant additional seismic studies.

For SONGS, the largest uncertainty for determining seismic hazard and plant vulnerability pertains to the offshore (and potentially onshore) thrust fault systems.[238] The existing seismic network in Southern California has few monitoring stations near SONGS. Therefore, detailed studies similar to those that led to the discovery in 2008 of the Shoreline Fault near Diablo Canyon are not possible. Similarly, the existing global positioning system (GPS) network in Southern California has few stations near SONGS, and no ocean floor GPS monitoring stations are in the vicinity of the plant.[239]

For Diablo Canyon, the largest uncertainty is the seismic hazard potential for the plant's identified fault systems. The existing seismic monitoring network in Northern California has numerous onshore stations in and around Diablo Canyon. However, there are no offshore stations west of the Hosgri and Shoreline faults. Sea floor seismometers west of these faults would greatly increase the ability to accurately locate known and unknown offshore faults by determining the precise locations of earthquake (most often microearthquake) epicenters.

To better understand crustal strain in the offshore environment, permanent GPS monitoring stations should be placed on the offshore sea floor. Offshore GPS stations are needed to measure crustal strain to better understand where the sea floor is deforming/moving.[240]

For years, scientists considered the Hosgri Fault as the dominant source of seismic shaking that could affect Diablo Canyon. Then the San Simeon earthquake in 2003 demonstrated the potential of strong seismic shaking on previously unidentified blind thrust faults in the region.[241] Identification of the Los Osos Fault indicated a San Simeon-style earthquake could occur very near or beneath the plant. The USGS' analysis of earthquake epicenters near Diablo Canyon led to the discovery of the previously unknown Shoreline Fault directly offshore from the plant in 2008. The USGS is also examining whether the Hosgri Fault is continuous with the San Simeon-San Gregorio Fault and ultimately tied into the San Andreas Fault in Bolinas. The results of these studies could change the magnitude of the maximum probable earthquake on the Hosgri Fault. Similarly, studies are being conducted to assess the continuity (as opposed to segmentation) of the Shoreline Fault and its potential connection to the Hosgri Fault, increasing the likelihood that an earthquake rupture may simultaneously occur along both faults.

The NRC's Task Force has noted an increased understanding of seismic hazards within the United States and is recommending an upgrade of the design basis and flooding protection of structures, systems, and components (SSCs) for each operating reactor (with a re-evaluation of the design basis every 10 years). The NRC is reviewing the adequacy of seismic safety margins of all U.S. plants with PG&E's and SCE's participation.[242] The additional seismic studies for Diablo Canyon and SONGS, as recommended by the *AB 1632 Report*, will contribute to these updated seismic evaluations.

Spent Fuel Pool Issues

Due to the unavailability of offsite storage or disposal facilities, most spent fuel is stored at reactors in cooling pools in far greater densities than original plant designs and in significantly less protected buildings than the reactor cores. In 2003, an independent study of safety issues associated with spent fuel pool storage raised concerns about the trend toward higher-density spent fuel storage in pools and the possibility that under certain conditions in which the water is drained from a pool, the fuel could overheat, ignite the fuel cladding, and release large quantities of radioactive materials.[243] The National Academies in 2006 at the request of Congress completed a study on spent fuel safety and security and reported on the

[232] Nuclear Regulatory Commission. *Recommendations for Enhancing Reactor Safety in the 21st Century: Near-Term Task Force Review of Insights from the Fukushima Dai-ichi Accident*. July 12, 2011.

[233] Reuters. "Analysis: After Fukushima, Slow of Change Seen for U.S. Nuclear," July 11, 2011. Roberta Rampton and Eileen O'Grady.

[234] Bloomberg. "Jaczko Votes for NRC Fukushima Report, Opens Curb to Delay," August 10, 2011. Brian Wingfield.

[235] On August 23, 2011, following an earthquake, the two-reactor North Anna nuclear plant in Virginia shut down. The dry cask storage containers during the earthquake moved several inches. The earthquake exceeded design parameters for the plant. NRC is asking Dominion to demonstrate to the Energy Commission that no functional damage occurred to features necessary for continued operation without undue risk to the health and safety of the public. The NRC will complete a safety evaluation regarding restart of the plant.

[236] Stohl, A., P. Seibert, G. Wotawa, D. Arnold, et. al. "Xenon-133 and Caesium-137 Releases into the Atmosphere from the Fukushima Dai-ichi Nuclear power Plant: Determination of the Source Term, Atmospheric Dispersion, and Deposition", *Atmos. Chem. Phys. Discuss.*, 11, 28319–28394, 2011, www.atmos-chem-phys-discuss.net/11/28319/2011/doi:10.5194/acpd-11-28319-2011.

[237] California Coastal Commission, Mark Johnsson, presentation at Energy Commission's July 26, 2011, workshop.

[238] United States Geological Survey, William Ellsworth, "Overview of Earthquake Hazards in California and Current Research Aimed at Reducing Uncertainty," presentation at Energy Commission's July 26, 2011, workshop.

[239] Ibid.

[240] United States Geological Survey, William Ellsworth, recommended at the July 26, 2011, workshop research for improved understanding of seismic hazard affecting the Central Coast including high-resolution bathymetry (marine), LIDAR (land), aeromagnetic surveys, marine and land gravity surveys, new and reviewing oil or industry's seismic reflection surveys, adding land-based and ocean bottom seismic stations, detailed geologic investigations to establish slip rates and to date fault offsets, adding land and ocean floor GPS, high-resolution seismic surveys and compiling marine deposits.

[241] The December 22, 2003, San Simeon Earthquake was a magnitude 6.5 earthquake on the Central Coast of California, about 7 miles northeast of San Simeon.

[242] Nuclear Regulatory Commission, Draft Generic Letter 2011-XX, GI-199, "Seismic Risk Evaluations for Operating Reactors," issued for public comment on September 1, 2011, Agencywide Documents Access and Management System (ADAMS) Accession No. ML111710783 "Implications of Updated Probabilistic Seismic Estimates in Central and Eastern United States on Existing Plants."

[243] Alvarez, Robert, "Reducing the Hazards from Stored Spent Power-Reactor Fuel in the United States," *Science and Global Security* 11: 1–51, 2003.

Station Blackout

Nuclear Plant Liability Coverage

Replacement Power and Reliability

Emergency Response Planning

The NRC is working with federal, state, and local authorities on a revised emergency preparedness rule. The NRC and Federal Emergency Management Agency require two emergency planning zones (EPZs) around commercial nuclear power plants: (1) a 10-mile EPZ where exposure to a radioactive plume would likely occur; and (2) a 50-mile EPZ for monitoring and protecting the public from secondary radiation exposure from contaminated food, milk, and surface water. Roughly 7.4 million people live within a 50-mile radius of SONGS, and about 842,000 people live within a 50-mile radius of Diablo Canyon.

PG&E recently examined how potential earthquake damage to roads and bridges around Diablo Canyon could affect evacuation plans. The study concluded that little or no damage would likely occur to the majority of bridges and roadways serving as evacuation routes.[173] Overall, PG&E found that the estimated evacuation time did not exceed what would be unacceptable.[174] SCE periodically reviews the roadways surrounding SONGS and has concluded they are adequate for emergency personnel access and for evacuation during an emergency.

In light of the long-range contamination and lessons learned from Fukushima and NRC's recommended 50-mile evacuation zone for U.S. citizens in Japan, both California plants must re-evaluate the adequacy of current evacuation and emergency response plans. In addition, the California Department of Health Services and Lawrence Livermore National Laboratory should consider the possibility of multi-reactor events in their radiation dose pathway assessments. PG&E noted that it will consider the impacts from multiple events,[175] while SCE reports to have procedures to handle multiple extreme events such as earthquake and flooding.

173 Pacific Gas and Electric, Response to 2011 IEPR Nuclear Data Request, June 9, 2011, page 9.

174 California Energy Commission, transcripts from July 26, 2011, IEPR workshop, page 205.

175 Ibid., page 183.

Nuclear Waste Issues

For decades, the United States has planned to eventually dispose of spent fuel in a permanent federal waste repository and forgo reprocessing due to nuclear weapons proliferation concerns. In 2010, however, the Obama Administration, in conjunction with the U.S. DOE, took important steps to terminate the license application process for a waste repository at Yucca Mountain, Nevada, citing a lack of public acceptance and a political stalemate surrounding the site. Even if Yucca Mountain again becomes a disposal option, an additional site must be found, as the United States already has more nuclear waste than a Yucca Mountain-type repository can hold.

Diablo Canyon and SONGS have generated about 2,839 metric tons of spent nuclear fuel or together about 94 metric tons annually. Through their current 40-year license period, both plants will generate about 4,228 metric tons of spent nuclear fuel. Through possible 20-year plant license extensions, they will generate another 2,140 for a total of 6,368 metric tons if they obtain 20-year license extensions. Until the United States develops a repository or away-from-reactor storage facility, this waste will continue to accumulate.

Spent fuel storage issues include the safety of long-term storage of high burn-up fuels and how these fuels might affect the integrity of fuel and fuel cladding, especially in corrosive marine environments, as well as the long-term storage costs. PG&E has not performed cost/benefit studies for long-term storage at Diablo Canyon and has assumed spent fuel will be stored onsite until the federal government removes it. PG&E has developed a dry storage facility to store

the waste away from the reactor but plans to rely on pool storage for spent fuel generated during a 20-year license extension.

The federal government's Blue Ribbon Commission is rethinking the national policy for waste management and has recommended a new waste management plan that calls for developing one or more national geologic disposal facilities and one or more consolidated interim spent fuel storage facilities.

Plant Safety Issues

It is essential that plants establish and maintain a work environment where management and employees are dedicated to putting safety first. The NRC conducts annual safety assessments of the nation's nuclear power plants, including Diablo Canyon and SONGS. The third consecutive assessment of Diablo Canyon found that the plant is still facing human performance issues regarding identifying and resolving problems.[176] NRC found that PG&E has made some progress in this area, but more work is needed. PG&E completed a safety culture survey in February 2011.

Diablo Canyon, since 1988, has had an independent safety committee, established by the CPUC as part of a settlement agreement reached by CPUC's Division of Ratepayer Advocates, California's Attorney General, and PG&E. PG&E testified that the Diablo Canyon Independent Safety Committee (DCISC) is providing independent safety oversight to make certain that PG&E is examining the right things in assessing the lessons learned from Fukushima.[177] SONGS does not have an independent safety committee. The DCISC, as recommended by the *2009 IEPR*, completed an assessment in 2011 of the reactor pressure vessel integrity and pressurized thermal shock of Diablo Canyon in the context of seismic hazards. It concluded that the plant can operate out to 60 years, if relicensed, without the pressurized thermal shock posing a threat to plant safety that would violate NRC regulations.

For many years, SONGS has been under NRC scrutiny for failure to address several longstanding safety culture issues. On March 2, 2010, the NRC issued SONGS a "Chilling Effect" letter in response to employees expressing difficulty or inability to use the corrective action program, a lack of knowledge or mistrust of the Nuclear Safety Concerns Program, a substantiated case of a supervisor creating a chilled work environment in their work group, and a perceived fear of retaliation for raising safety concerns. During 2009, the NRC received an elevated number of safety conscious work environment allegations from SONGS. The NRC conducted focus group interviews with about 400 workers in 2010 and found "a continued degradation in the safety conscious work environment." The NRC advised SCE that these results potentially affect several safety-critical areas concerning human performance. The NRC has raised this issue in seven consecutive safety assessment periods. However, in September 2011 following NRC's inspections at SONGS and a significant reduction in safety culture allegations in 2010 and 2011, NRC determined that SCE has made reasonable progress in addressing the worker safety culture issues.[178] NRC will continue to monitor work environment conditions at SONGS. SCE has stated that it is committed to preserving and improving a strong safety culture at SONGS and encouraging workers to raise nuclear safety concerns.

176 NRC letter to M. Conway, *Annual Assessment Letter for Diablo Canyon*, March 4, 2011.

177 Loren Sharp, testimony at July 26, 2011, IEPR workshop.

178 NRC letter to Peter Dietrich, SONGS, September 6, 2011.

Progress in Completing AB 1632 Report Recommendations

The CPUC and the Energy Commission determined that Diablo Canyon and SONGS should complete the *AB 1632 Report* recommended studies as required for the license renewal feasibility studies and review.[179] In June 2009, the CPUC directed PG&E and SCE to complete these studies so that the CPUC can meet its obligations to ensure plant reliability and, in turn, grid reliability, in the event of a prolonged or permanent outage.[180] This section summarizes progress on these recommendations and studies.

Seismic Studies Update

PG&E and SCE have provided periodic updates to the Energy Commission and the CPUC regarding their research plans, and preliminary results of their *AB 1632 Report* recommended studies, including seismic research efforts and updates.

Diablo Canyon

PG&E completed a study of the Shoreline Fault in January 2011 for the NRC, which asserted that (based on newer seismic information) the plant can withstand more severe shaking than estimated when the plant was designed in 1977.[181] As required, PG&E will conduct additional seismic studies to identify the association between the Shoreline and Hosgri Faults and evaluate the existence/configuration of the southern continuation of the Shoreline Fault. Seismic studies are needed in the vicinity of Diablo Canyon including onshore faults. PG&E also intends to install submarine seismometers to enhance the understanding of the locations of coastal zone earthquakes and install GPS monitoring stations to measure crustal strain in the offshore environment. In addition, PG&E will use the updated Uniform California Earthquake Rupture Forecast (UCERF) model to better understand seismic hazards at the plant.[182]

SONGS

Throughout the operating history of SONGS 2 and 3, SCE has periodically assessed the adequacy of seismic safety margins based on new information. In 2010, SCE updated the SONGS probabilistic seismic hazard analysis (PSHA).[183] The results are comparable to the 1995 PSHA, indicating that the SONGS seismic hazard risk has not changed. SCE's ongoing Seismic Hazard Analysis Program periodically reviews and updates SONGS' seismic hazards, and SCE's advisory board of seismic experts reviews the plant's seismic information and identifies the need for additional research. SCE plans to use the most recent UCERF database to complete the seismic studies,[184] the results of which will be provided to the NRC as part of its regulatory process.

To decrease the seismic uncertainty at Diablo Canyon and SONGS, USGS and California Geological Survey scientists have recommended additional studies to identify active faults and determine seismic potential and the recency of faulting.[185-186] In addition, the Energy Commission recommended in 2008 that SCE should develop an active seismic hazards research program for SONGS similar to PG&E's Long Term Seismic Program to assess whether there are sufficient design margins at the plant to avoid major power disruptions.[187]

Tsunami Studies Update

Diablo Canyon is located on top of a high coastal bluff at an elevation of 85 feet above mean sea level. PG&E's plant design basis is for a combined tsunami, storm wave, and tidal wave height of about 25 feet.[188] Tsunami Inundation Maps show the plant to be outside the tsunami inundation zone.[189] In 2010, PG&E published a study of tsunami hazard for Diablo Canyon,[190] which considered the combined effects of tsunamis, storms, and tides and included the effects of submarine landslides, which were not specifically considered in the Diablo Canyon licensing analyses. While this study was done differently than previous analyses, it did not identify new hazard information that warranted inclusion into the Diablo Canyon design and license basis. PG&E concluded that a deterministic approach that combines the tsunami generated by a rare local submarine landslide with a large storm wave would lead to an unreasonably rare combination of events.

SCE and NRC evaluated the tsunami run-up and inundation for SONGS during plant licensing. More recent assessments conclude that, "... large local-source tsunamis could be generated by mechanisms other than those considered during licensing for SONGS Units 2 and 3, the basis for the 1995 SCE report." However, SCE reports that no local run-up studies based on these mechanisms are widely agreed upon, and certainly none for the SONGS site. The University of Southern California, in conjunction with the California Emergency Management Agency, is preparing tsunami runup maps for San Diego County but they are not currently available.[191] The potential for landslide-generated tsunamis is uncertain, and SCE reports that additional studies are required to evaluate how such tsunamis may affect SONGS. It seeks approval of funding to perform additional seismological and tsunami studies, as recommended by the Energy Commission in the *AB 1632 Report*.[192]

179 The 2009 IEPR; letters from Michael Peevey, President, CPUC, June 25, 2008, to Peter Darbee, President and CEO of PG&E and Alan Fohrer, Chairman and CEO.

180 Ibid.

181 Original estimates based on the Hosgri Fault.

182 The updated model, UCERF-3, will include the Shoreline Fault and other new seismic data.

183 Southern California Edison, *Southern California Edison's Evaluation of California Energy Commission AB 1632 Report Recommendations*, February 2011.

184 Southern California Edison, *Committee Workshop on California Nuclear Power Plant Issues, Responses to Questions for July 26 Energy Commission Workshop*, Energy Commission Docket No. 11-IEP-1J, August 8, 2011.

185 United States Geological Survey, William Ellsworth, *Overview of Earthquake Hazards in California and Current Research Aimed at Reducing Uncertainty*, Presentation to 2011 Integrated Policy Report Committee – Nuclear Issues Workshop, June 13, 2011.

186 California Geological Survey, Chris Wills, presentation at the Energy Commission's July 26, 2011, IEPR workshop, www.energy.ca.gov/2011_energypolicy/documents/2011-07-26_workshop/presentations/.

187 California Energy Commission, *2008 IEPR Update*, page 78.

188 Pacific Gas and Electric, comments at the July 26, 2011, IEPR workshop, page 70.

189 Recently released by the California Emergency Management Agency, California Geological Survey, and the University of Southern California.

190 Pacific Gas and Electric, *Methodology for Probabilistic Tsunami Hazard Analysis: Trial Application for the Diablo Canyon Power Plant Site (PTHA)*, April 2010, available at: peer.berkeley.edu/tsunami/fpdfs/PG&E Tsunami Hazard analysis/.

191 California Coastal Commission, Mark Johnsson, *The Tohoku Earthquake of March 11, 2011: A Preliminary Report on Implications for Coastal California*, March 16, 2011.

192 Southern California Edison, *Response to Questions for July 26, 2011, Workshop*, August 8, 2011, page 3.

In February 2011, SCE presented an updated tsunami hazard analysis to the CPUC and the Energy Commission.[233,234] The map provides a "credible upper bound" to the potential tsunami inundation for any location along the Southern California coastline. At SONGS, the map indicates a maximum tsunami inundation elevation of 17 to 20 feet above sea level or an equivalent elevation of 19.9 to 22.9 feet above lower low water.[235] SCE has concluded that SONGS is protected, with the top of the wall 7.2 to 10.2 feet higher than the credible upper bound elevation of tsunami inundation, and with the North Industrial Area protected by 5.3 to 8.2 feet of sea wall above the inundation elevation.

Studies of Seismic Vulnerability of Plant Components

In March 2010, a PG&E report evaluated the probability of a prolonged post-earthquake outage at Diablo Canyon from damaged reliability-related structures, systems, and components (SSC). The report concluded that all of the SSCs are designed to the appropriate seismic criteria[236] and meet the required Design Earthquake and Double Design Earthquake criteria for accident mitigation or safe shutdown. The SSCs were found to withstand a 7.5-magnitude earthquake on the Hosgri Fault.

SCE completed a study to identify any "important-to-reliability," nonsafety-related SSCs that could cause a prolonged outage at SONGS from a seismic event.[237] The study evaluated those required for power generation, which are considered important to reliability. Additionally, SCE evaluated the nonpower block buildings needed to support power generation. SCE conducted further evaluation to assess the seismic capacity of offshore discharge conduits and reported on their findings in August 2011.[238]

SCE has not performed studies of the fragility of nonsafety-related SSCs when relocated for refueling or plant maintenance but did perform studies for plant operating conditions.

License Renewal

NRC issues operating licenses for commercial power reactors for up to 40 years and allows 20-year license extensions with no limit on the number of renewals. The operating licenses for California's nuclear plants will expire in 2022 (SONGS Units 2 and 3), in 2024 (Diablo Unit 1), and in 2025 (Diablo Unit 2). PG&E submitted a license renewal application for Diablo Canyon on November 24, 2009, to continue operations until 2044/2045. In June 2011, the NRC issued the *Safety Evaluation Report* for the license renewal

233 Letter to Michael Peevey, President of the CPUC, "SCE's Evaluation of Energy Commission AB 1632 Report Recommendations," Appendix C, February 2, 2011.

234 National Oceanic and Atmospheric Administration, California Geological Survey, California Office of Emergency Services and the University of Southern California Tsunami Research Center, "Tsunami Inundation Map for Emergency Planning," published June 1, 2009.

235 The average of the lowest low water height of each tidal day observed over the National Tidal Datum Epoch.

236 Enercon Services, Inc., *Seismic Assessment of Diablo Canyon Power Plant Non-Safety Related Structures, Systems, and Components*, March 2010.

237 Southern California Edison letter, "Evaluation of California Energy Commission AB 1632 Report Recommendations," submitted to the CPUC and Energy Commission on February 2, 2011. See section on "Seismic Reliability Evaluation" with an appendix providing the study titled, *Seismic Reliability Study of San Onofre Generating Station Non-Safety-Related Structures, Systems, and Components*.

238 Southern California Edison in a letter to Michael Peevey dated August 9, 2011, regarding its assessment of the conduits' seismic capacity concluded that the offshore discharge conduits "would be expected to maintain their integrity under the SONGS review level earthquake and would not be the cause of a prolonged outage."

application.[239] NRC has postponed its license renewal proceeding by 52 months to allow time for PG&E to complete the additional seismic studies. SCE has not yet applied for renewal and will continue to assess options for the timing of CPUC and NRC license renewal filings.[240] NRC issued license renewals for Palo Verde Units 1, 2, and 3 on April 1, 2011.

A major concern is whether the license reviews adequately address issues relevant to California (including seismic vulnerability). The NRC license renewal review process determines whether a plant meets the NRC license renewal criteria, including aging plant issues and environmental impacts related to an additional 20 years of plant operation. However, the process consistently excludes issues such as seismic vulnerability, plant vulnerability to terrorist attacks, and the adequacy of emergency evacuation plans.

Several California officials have requested the NRC to address a broader range of issues during nuclear power plant license renewal reviews that are of concern for California's operating plants. These issues include post-Fukushima safety issues, seismic and tsunami hazards, emergency response plans and evacuation timeliness, plant security, and spent fuel storage. NRC ultimately determined that the existing regulatory process was sufficient and that it considers these issues on an ongoing basis in connection with its oversight of operating reactors.[241]

California has a legitimate role in license renewal decisions in its broad authority to set electricity generation priorities based on economic, reliability, and environmental concerns. Both utilities must obtain CPUC approval to pursue license renewal before receiving California ratepayer funds to cover the costs of the NRC license application process. In addition, the California Coastal Commission must review the project for consistency with the federal Coastal Zone Management Act.

The CPUC considers whether it is in the best interest of ratepayers for the nuclear plants to continue operations another 20 years. Its proceedings address issues that are important to electricity planning but are not included in NRC's license renewal review, such as the cost-effectiveness of license renewal compared with alternatives. In letters to PG&E and SCE in June 2009, the CPUC stressed that the utilities must address in their feasibility assessments all issues raised in the *AB 1632 Report* and that this information is needed to allow the CPUC to properly undertake its obligations under AB 1632 to ensure plant reliability and, in turn, ensure grid reliability in the event Diablo Canyon or SONGS has a prolonged or permanent outage.[242] The adequacy and timeliness of the utilities completing the AB 1632 Report-recommended studies are critical to the CPUC's ability to make these decisions. However, the utilities' recent progress reports indicate they are not on schedule to complete the additional AB 1632 Report-recommended seismic hazard studies until 2013 (PG&E) and 2015 (SCE) at the earliest.

Recommendations

In light of the accidents and/or plant shutdowns following earthquakes at Fukushima Daiichi (2011), Kashiwazaki-Kariwa (2007), and at the North Anna nuclear plant (August 23, 2011) and other considerations, the Energy Commission, in consultation with the CPUC, recommends the following:

239 Nuclear Regulatory Commission, *Safety Evaluation Report Related to the License Renewal of Diablo Canyon Nuclear Power Plant, Units 1 and 2*, June 2, 2011, available at: pbadupws.nrc.gov/docs/ML1115/ML11153A103.pdf.

240 Southern California Edison is a member of STARS (Strategic Teaming and Resource Sharing), which has reported application submittal dates for late 2012 and fall 2013.

241 Letter to Senator Dianne Feinstein from NRC Chairman Gregory Jaczko, August 18, 2011.

242 Letter from CPUC to Alan Fohrer, CEO of Southern California Edison, June 25, 2009; Letter from CPUC to Peter Darbee, CEO of Pacific Gas and Electric, June 25, 2009.

Seismic Issues

- PG&E should provide in a timely manner to the Energy Commission, the CPUC, and the Independent Peer Review Panel (IPRP) the technical details and any significant updates of their proposed seismic hazard study plans and findings for Diablo Canyon.

- PG&E should submit to the Atomic Safety and Licensing Board (ASLB), as part of PG&E's final seismic report to the ASLB in the Diablo Canyon license renewal proceeding, the findings and recommendations from the California IPRP on PG&E's seismic studies. These studies include PG&E's onshore and offshore seismic studies funded by CPUC Decision 10-08-003.

- The CPUC should establish a SONGS IPRP, comparable to Diablo Canyon's IPRP, to review SONGS' seismic hazard study plans and findings as recommended in the *2008 IEPR Update*. SCE should provide in a timely manner to the Energy Commission, the CPUC, and the IPRP the technical details and any significant updates to their proposed seismic hazard study plans and findings for SONGS. SCE should include the IPRP's evaluations, findings, and recommendations in its seismic hazard analyses and submittals to the NRC. California's IPRPs for PG&E's and SCE's seismic studies for Diablo Canyon and SONGS should coordinate their seismic hazard evaluations.

- SCE should include greater representation on its SONGS' Seismic Advisory Board of independent seismic experts with no current or prior professional affiliation with utilities, including SCE or PG&E, or their consultants. The composition of SCE's SONGS' Seismic Advisory Board of independent seismic experts should include those with a continuing affiliation with SCE.

- PG&E and SCE should provide updates on their progress in completing the AB 1632 Report-recommended seismic studies to the Energy Commission as part of the *2012 IEPR Update*.

Spent Fuel Pool and Independent Spent Fuel Storage Installation

- PG&E and SCE should investigate adding safety-related instrumentation (capable of withstanding design basis natural phenomena) to monitor in the control room key spent fuel pool parameters, for example, water level, temperature, and radiation levels, during a severe accident in which radiation levels within the spent fuel pool building are unsafe.

- To reduce the volume of spent fuel packed into storage pools, and consequently the radioactive material available for dispersal in the event of an accident or sabotage, PG&E and SCE, as soon as practicable, should transfer spent fuel from pools into dry casks, while maintaining compliance with NRC spent fuel cask and pool storage requirements and report to the Energy Commission in the *2012 IEPR Update* on their progress.

- PG&E and SCE should evaluate, as part of the *2012 IEPR Update*, 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.

Station Blackout

- SCE and PG&E should report to the Energy Commission, as part of the *2012 IEPR Update*, on progress made in addressing the lessons learned from the station blackout at Fukushima and how well-equipped their plants are to withstand safely a station blackout lasting longer than seven days. This includes reporting on any significant changes, including estimated costs, associated with NRC requirements to address station blackout. It also includes arrangements for accessing emergency backup generation and fuel, responding to multiple unit events, seismically and flooding protected equipment, and addressing the lessons learned from Fukushima.

- PG&E and SCE should report to the Energy Commission on the adequacy of trained people, equipment, and external support, including written agreements, for providing emergency power equipment and fuel for handling an extended station blackout.

Nuclear Plant Liability Coverage

- Based on the Fukushima experiences, PG&E and SCE should provide a comprehensive study to the Energy Commission, as part of the *2012 IEPR Update*, on the adequacy of Price-Anderson Act liability coverage for a severe event at Diablo Canyon or SONGS resulting in large offsite releases of radioactive materials.

Replacement Power and Reliability

- To support long-term energy and contingency planning, the California ISO (with support from PG&E, SCE, and planning staff of the CPUC and CEC) should report to the Energy Commission as part of its *2012 IEPR* and the CPUC as part of its 2013 Long-Term Procurement Plan on what new generation and/or transmission facilities would be needed to maintain system and/or local reliability in the event of a long-term outage at Diablo Canyon, SONGS, or Palo Verde. The utilities should report to the CPUC on the estimated costs of these facilities.

- As a contingency in the event that Diablo Canyon and SONGS experience a long-term outage following a major seismic or other event, California ISO with input from the Energy Commission and CPUC, in cooperation with PG&E and SCE, should further evaluate: (1) the uncertainties of a long-term loss of electricity from these plants, (2) the extent to which existing resources have an energy supply capability beyond that used in normal market conditions, and (3) the need for new resources or different types of resources to satisfy any remaining energy gap. If necessary, the long-term planning and procurement process at the CPUC should be modified to ensure that any replacement resources found necessary through these studies are acquired in a timely manner.

Emergency Response Planning

- The CPUC should approve funding for Cal EMA[243] or the affected counties to evaluate the adequacy of current evacuation and emergency response plans, emergency planning zones, and training for Diablo Canyon and SONGS, given the Fukushima accident and NRC's recommended 50-mile evacuation zone for U.S. citizens in Japan. This review should include the adequacy of plans for dealing with prolonged station blackouts (for example, powering communications equipment), multiple or multiunit events at one site, increased population densities and traffic flow configurations near the plants, and the possible loss of access roads and evacuation routes in a major event, such as an earthquake or flooding.

- The California Department of Public Health should evaluate the adequacy of equipment, staffing, aerial plume monitoring, and models for dealing with two-unit events at the Diablo Canyon or SONGS sites involving radioactive releases.

243 Governor Brown's proposed 2012–2013 budget eliminates Cal EMA and makes it an office reporting directly to the Governor (www.ebudget.ca.gov/pdf/BudgetSummary/Making-Government-Work/...pdf).

Fukushima Lessons Learned

- PG&E and SCE should report to the Energy Commission, as part of the *2012 IEPR Update*, and the CPUC on their progress and estimated costs in carrying out the recommendations of the *NRC Near-Term Fukushima Task Force Report*.

- PG&E and SCE should report to the Energy Commission, as part of the *2012 IEPR Update*, on the adequacy of resources, training, and equipment to cope with severe plant events including a station blackout combined with natural or manmade events (earthquake, flooding, fires, or terrorist attack); for example, the availability of (1) seismically robust and flood protected essential safety systems and equipment, (2) suitably shielded, ventilated, and well-equipped facilities needed for the workers to manage the accident, (3) ability to respond to multiple events and multiple-unit events, and (4) trained onsite and offsite responders for a long-term station blackout or loss of all heat sinks.

- The NRC should expeditiously move forward on the Post-Fukushima Task Force recommendations, particularly the urgent recommendations.

Relicensing

- To help ensure plant reliability and minimize costs, PG&E and SCE should complete the remaining AB 1632 Report recommended seismic studies and make their findings available for consideration by the Energy Commission, CPUC, California Coastal Commission, and the NRC during their reviews of PG&E's (and SCE's, if they apply) license renewal application(s) and related certificates. SCE should not file a license renewal application with the NRC without prior approval from the CPUC.

- Since the regulatory changes and requirements recommended by the NRC Near-Term Task Force on Fukushima could result in higher costs, for example, seismic retrofits, PG&E and SCE should provide cost estimates to the CPUC for complying with NRC's requirements and the costs of potential replacement power in the event of an extended outage. The CPUC should consider these additional costs during its license renewal evaluations for Diablo Canyon (and SONGS, if SCE applies for license renewal).

- The NRC should delay its decisions on license renewal applications pending completion of the post-Fukushima lessons learned studies. NRC's license renewal review for Diablo Canyon and SONGS (if SCE applies for license renewal) should examine updated site-specific information on seismic and tsunami hazards, emergency preparedness and evacuation timeliness, lessons learned from Fukushima, spent fuel storage options, and plant security. NRC should delay license renewal reviews to allow for consideration of findings from Fukushima studies.

Plant Safety

- PG&E and SCE should report, as part of the *2012 IEPR Update*, on their efforts to improve the safety culture at Diablo Canyon and SONGS and on the NRC's evaluation of these efforts and overall plant performance.

- The CPUC should consider establishing a SONGS Independent Safety Committee, modeled after the Diablo Canyon Independent Safety Committee, to provide an independent review of SONGS' safety performance, and follow-up to the lessons learned from the Fukushima Daiichi plant accident.

Continuing Activities

- The Energy Commission will continue to monitor reviews of Diablo Canyon and SONGS by the NRC and the Institute of Nuclear Power Operations. In particular, the Energy Commission will monitor plant performance and safety culture at both plants.

- The Energy Commission will continue to monitor the federal waste management program and represent California in the Yucca Mountain licensing proceeding (in the event this proceeding resumes) to protect California's interests regarding potential groundwater and spent fuel transportation impacts to the state.

- The Energy Commission will continue to participate in United States Department of Energy and state-regional planning activities for nuclear waste transportation.

- The Energy Commission will continue to update information on the comprehensive, "cradle-to-grave" or life-cycle economic and environmental impacts of nuclear energy generation compared with alternatives. These include impacts from uranium mining, reactor construction, fuel fabrication, reactor operation, maintenance and repair, reactor component replacement and disposal, spent fuel storage, transport and disposal, decommissioning, and "beyond design basis" accidents including an extended station blackout lasting longer than assumed.

Acronyms

AB	Assembly Bill
AC	alternating current
AEO 2011	Annual Energy Outlook 2011
AFC	Application for Certification
AQIP	Air Quality Improvement Program
ARB	California Air Resources Board
ARFVT Program	Alternative and Renewable Fuel and Vehicle Technology Program
ARRA	American Recovery and Reinvestment Act
BEVs	battery electric vehicles
BLM	Bureau of Land Management
Cal/EPA	California Environmental Protection Agency
CAL FIRE	The Department of Forestry and Fire Protection
California ISO	California Independent System Operator
Caltrans	California Department of Transportation
CCCCO	California Community Colleges Chancellor's Office
CCEF	California Clean Energy Future
CED	California Energy Demand
CEERT	Center for Energy Efficiency and Renewable Technologies
CEQA	California Environmental Quality Act
CHP	combined heat and power
CNG	compressed natural gas
CO2e	carbon dioxide equivalent
CMUA	California Municipal Utilities Association
CPUC	California Public Utilities Commission
CPV	concentrating photovoltaic
CREZ	competitive renewable energy zones
CSI	California Solar Initiative
CLTC	California Lighting Technology Center
DG	distributed generation
DRECP	Desert Renewable Energy Conservation Plan
DSM	demand-side management
E10	10 percent ethanol
EDD	Employment Development Department
EJ	environmental justice
EME	Edison Mission Energy
EIA	Energy Information Administration
EM&V	evaluation, measurement, and verification
EPS	external power supplies
EPZs	emergency planning zones
ERP	Emerging Renewables Program

ETP	Employment Training Panel
EUR	estimated ultimate recovery
EV	electric vehicle
FCV	fuel cell vehicles
FFV	flexible-fuel vehicle
FTD	Fuels and Transportation Division
FTE	full-time equivalent
GGE	gasoline gallon equivalent
GHG	greenhouse gas
GPS	global positioning system
GWh	gigawatt hour(s)
HCICO	High Carbon Intensity Crude Oils
HVAC	heating, ventilation, and air conditioning
IEP	Independent Energy Producers
IEPR	*Integrated Energy Policy Report*
IOUs	investor-owned utilities
IPRP	Independent Peer Review Panel
LADWP	Los Angeles Department of Water and Power
LCFS	Low Carbon Fuel Standard
LCR	local capacity requirements
LED	light-emitting diode
LNG	liquefied natural gas
LSE	load-serving entity
LTPP	Long-Term Procurement Plan
MCF	1000 cubic feet of natural gas
MMBTU	million British thermal units
MMcf	million cubic feet
MMT	million metric tons
MPR	Market Price Referent
MW	megawatt(s)
NOx	nitrogen oxide
NGV	natural gas vehicles
NHSM	Non Hazardous Secondary Materials
NRC	Nuclear Regulatory Commission
NRDC	Natural Resources Defense Council
NRG	NRG Energy
NSHP	New Solar Home Partnership
NSR	New Source Review
OEMs	original equipment manufacturers
OIR	Order Instituting Rulemaking
OII	Order Instituting Informational
OTC	once-through cooling

PAB	Policy Advisory Board
PAG	Policy Advisory Groups
PGC	Public Goods Charge
PEV	plug-in electric vehicle
PG&E	Pacific Gas and Electric
PHEV	plug-in hybrid electric vehicle
PM10	particulate matter of ten micron diameter
PM2.5	particulate matter 2.5 micron diameter
PIER	Public Interest Energy Research
Phasor-RTDMS	Phasor Real-Time Dynamic Monitoring System
PPA	power purchase agreement
PSHA	probabilistic seismic hazard analysis
PV	photovoltaic
QF	qualifying facility
R&D	research and development
RD&D	research, development, and demonstration
REAT	Renewable Energy Action Team
RESCO	Renewable Energy Secure Community
RETI	Renewable Energy Transmission Initiative
RFS	Renewable Fuels Standard
RFS2	Renewable Fuels Standards II
RPS	Renewables Portfolio Standard
RWGTM	Rice World Gas Trade Model
SA	Staff Assessment
SB	Senate Bill
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric
SGIP	Self-Generation Incentive Program
SMUD	Sacramento Municipal Utility District
SONGS	San Onofre Nuclear Generating Station
SSCs	structures, systems, and components
SWRCB	State Water Resources Control Board
Tcf	trillion cubic feet
TDS	total dissolved solids
UCERF	Uniform California Earthquake Rupture Forecast-2
U.S. DOE	United States Department of Energy
U.S. EPA	United States Environmental Protection Agency
USGS	United States Geological Survey
VOC	volatile organic compounds
ZEV	Zero Emission Vehicle
ZNE	zero-net-energy

ATTACHMENT 3

Geothermal Resources

California has the largest geothermal production and technical potential of any state in the nation with an installed gross capacity of 1,870 megawatts (MW) and an estimated technical potential generation capacity of between 4,255 MW and 4,825 MW. Geothermal is a base load resource. Developing currently untapped geothermal resources can contribute significantly to the Renewable Portfolio Standard goals

Existing geothermal generation is conentrated in 7 Known Geothermal Resource Areas (KGRA) shown below. New technical potential generation capacity is predicted to occur in these and other KGRA's. All of Califorina's KGRA's are listed below the map with their existing estimated technical potential generating capacity. The exisiting, techincal potential, and predicted capacity in 2020 by county is available on the potential by county page.

Geothermal Resource Area	County	Existing Capacity (MW)	Most Likely Capacity (MW)	Predicted Capacity (MW) in 2020
The Geysers	Sonoma, Lake	1000	1400	1400
Salton Sea	Imperial	350	1750	1750
Coso Hot Springs	Inyo	300	355	300
Heber	Imperial	100	142	142
East Mesa	Imperial	73.2	148	73.2
Mono - Long Valley	Mono	40	111	40
Wendel - Amedee	Lassen	6.4	8.3	6.4
Glass Mountain - Medicine Lake	Siskiyou	0	304	175
North Brawley Geothermal Field	Imperial	0	135	135
East Brawley	Imperial	0	129	129
Sulphur Bank	Lake	0	43	43
Niland	Imperial	0	76	42
Mount Signal	Imperial	0	19	19

South Brawley	Imperial	0	62	0
Randsburg	San Bernardino	0	48	0
Lake City - Surprise Valley 1	Modoc	0	37	0
Calistoga	Napa	0	25	0
Dunes	Imperial	0	11	0
Superstition Mountain	Imperial	0	9.5	0
Glamis	Imperial	0	6.4	0
Sespe Hot Springs	Ventura	0	5.3	0
Bodie	Mono	0	0	0
Lake City - Surprise Valley 2	Modoc	0	0	0
Lassen	Tehema, Plumas	0	0	0
Saline Valley	Inyo	0	0	0
	Totals:	**1,870**	**4,825**	**4,255**

Click on a geothermal resource area's name to view it in on a map.

The resource potential figures shown here are based on data described in Geothermal Strategic Value Analysis CEC-500-2005-105-SD and Intermittency Analysis Project: Appendix A, Intermittency Impacts of Wind and Solar Resources on Transmission Reliability CEC-500-2007-081-APA

ATTACHMENT 4

California Energy Maps

List of All Energy Maps

Map of Geothermal Resources in California

Updated: 2005

You can also download an **Adobe Acrobat PDF Version of this map** (1 page, 440 kilobytes)

ATTACHMENT 5

CALIFORNIA GEOTHERMAL RESOURCES

IN SUPPORT OF
THE 2005 INTEGRATED ENERGY POLICY REPORT

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Research and Development Office
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Staff Paper

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Abstract

California has the largest geothermal production and potential of any state in the nation with an installed gross capacity of 1,870 Megawatts (MW) and an estimated potential generation capacity of 4,732 MW. Even though geothermal electricity generation has declined in the past decade, an estimated 2,862 MW of generating capacity from geothermal may be available for development. Certain drivers have emerged to encourage the development of geothermal resources. The California Legislature adopted the Renewable Portfolio Standard (RPS); the federal government has made a production tax credit (PTC) available to new geothermal generation facilities. Geothermal is a base load resource, and developing currently untapped geothermal resources can contribute significantly to the goals of the RPS.

Keywords

Geothermal; dry steam resource, liquid dominated resource

Introduction

California has a tremendous supply of renewable resources that can be harnessed to provide clean and naturally replenishing electricity supplies for the state. Currently, renewable resources provide approximately eleven percent of the state's electricity mix.[1] California's Renewable Portfolio Standard (RPS) established in 2002 by Senate Bill 1078 (SB1078, Sher, Chapter 516, Statutes of 2002) requires electricity providers to procure at least one percent of their electricity supplies from renewable resources so as to achieve a twenty percent renewable mix by no later than 2017. More recently, the California Energy Commission, the California Public Utilities Commission and the California Power Authority approved the Energy Action Plan (EAP), accelerating the twenty-percent target date to 2010.[2]

The purpose of this white paper is to provide estimates of the geothermal resources located within California and potentially available for use in meeting the RPS and EAP goals. Estimates are provided on the "technical" potential (i.e., unconstrained by economic or environmental requirements). This information updates and expands upon resource information provided in the Renewable Resources Development Report of 2003.[3]

Short History Of Geothermal Development In California

Currently, California's geothermal generating capacity is approximately 1,870 MW from both dry steam and liquid dominated resources (see Table 1). In the state, 46 geothermal power plants are widely dispersed from north to south (see Figure 2). While most development has occurred in The Geysers, the Salton Sea and Coso Known Geothermal Resource Areas (KGRA) both have considerable installed capacity.

Over the past decade, geothermal resource use stagnated considerably and the geothermal industry has retrenched. As illustrated in Figure 1, installed or nameplate capacity peaked in 1989 at 2,686 MW. Since then, both installed and operating capacity have declined due to plant retirement, and more importantly, operating capacity has declined due to the reduction in steam flow at The Geysers. This decline, over 1,300 MW in 1998 at the nadir and approximately 640 MW in 2002, has had serious ramifications both to the geothermal community as well as stable power supplies to Californians. In the following sections the discussion focuses on the individual fields and status.

Figure 1
California Installed and Operating Geothermal Capacity[4]
(1960-2003)

A Dry Resource-The Geysers

In the late 1950's, companies such as Union Oil Company of California (Unocal), Magma Energy Company and Thermal Power Company initiated full scale commercial development of vapor dominated geothermal at The Geysers. These companies produced steam to the Pacific Gas and Electric Company (PG&E) electrical power generation grid. Since then, The Geysers has developed into the world's largest dry steam resource with almost 2,000 MW (1989) of installed electrical generating capacity and is the only dry steam field that is commercially developed in the nation. The Geysers geothermal field reached maximum steam production of 1,866 MW in 1988 and today, The Geysers retains a peak capability of nearly 1,000 MW.

Since the mid 1980s, The Geysers reservoir has exhibited the effects of heavy steam withdrawal. Steam pressure, particularly in the central part of the reservoir, has dropped much faster than was originally expected. In many existing wells, steam pressure has declined from the initial 500 pounds per square inch (psi) in 1960 to less than 200 psi, shortening the wells' useful life and hastening the need

for make up wells. This condition is due to cumulative over production. In many instances, the additional supply of steam by new make up wells has proven to be insufficient to maintain the original steam output. Also, many of the steam developers are encountering production interference. That is, steam that would otherwise be produced from an existing well is diverted to a new well.

The steam production decline demonstrates the importance of increased water injection to maintain reservoir pressure. While continuing research is helping to determine the best methods for water injection, mitigation efforts such as the Santa Rosa and Southeast Geysers pipeline projects to augment fluid injection to offset production declines have been implemented. Other activities implemented include modifications to plant operations for increasing efficiency. In addition, the older, less efficient power plants have been suspended, and steam rerouted to newer and more efficient plants. Plant operators have installed new turbines designed to operate at lower turbine inlet pressures and modified the design and operations of existing turbines, condensers, and gas handling systems for low-load and cycling. These changes may extend the life of the resource, but come at a higher cost.

Geothermal resources developments are now planned with more caution than before, to avoid a scenario similar to The Geysers. The competition between steam producers and plant operators has eased as ownership of The Geysers has been consolidated and auction strategies have changed. Reservoir management activities are being implemented such as further spacing of production and injection wells, as well as monitoring water resources for flow, quantity, chemistry, and tendencies toward brine and scaling. As a result, binary and liquid dominated flash extraction systems are the only ones installed today.

Liquid Dominated Geothermal Resources

Geothermal exploration of liquid dominated resources in California began in 1967, when both Unocal and Morton Salt Company deployed small, experimental geothermal turbines operating at the Salton Sea field. However, problems with silica scaling and high salt concentrations prevented the commercial development of the resource then. In developing liquid dominated resources during the 1970's, developers had to consider the degree of risk, greater capital costs, an adverse regulatory climate, and the relative immaturity of the exploration, drilling, and production technology, which impeded the development of liquid dominated resources. These impediments were mitigated significantly when the federal and state government responded to the oil crisis of 1973.

The development of liquid dominated resources was further facilitated in 1975, when the U.S. Geological Survey (USGS) concluded a nation-wide geothermal resource assessment.[5] The USGS assessment document was instrumental in expanding interest in developing liquid dominated resources in the Southwestern states.

A liquid dominated geothermal resource was developed in November 1979 for a power generation plant, at the East Mesa field in Imperial County, which consisted of a binary application using isobutane as the secondary working fluid to turn out 13.4 MW of electrical power.

In June 1980, Southern California Edison (SCE) began operating a 10 MW experimental power plant at the Brawley geothermal field with steam produced by Unocal. However, after a few years of operation, SCE and Unocal ceased further development of the field due to corrosion, reservoir uncertainties, and the high salinity brines.

In June 1982, Unocal initiated electrical power generation at the Salton Sea geothermal resource from its 12 MW plant. In 1982, Unocal added two additional generation units for a total gross electrical generation of 83 MW.

In late 1985, Magma Power Company (Magma) began continuous production from their first 40 MW power plant at the Salton Sea field. Within a couple years, Magma added 3 more generating units that brought their total to 145 MW. CalEnergy Corporation (CalEnergy) bought out Unocal's and Magma's operations at the Salton Sea. Today, the entire Salton Sea field operation consists of 8 power plants with 288 MW capacity.

CalEnergy and Calpine Corporation (Calpine) planned developments in the Glass Mountain KGRA but were initially halted due to permitting issues related to destruction/disturbance of habitat and conflicts with Native American spiritual beliefs. Both projects eventually received permitting approval from the Bureau of Land Management (BLM) to proceed to the development stage.

The California Energy Commission awarded Calpine $1,108,000 in June 2001 to drill an exploration well in the Fourmile Hill area of the Glass Mountain KGRA. The project was completed as of June 2003, but Calpine encountered a geothermal resource at a temperature of 411°Farhenheit (F) at a depth of 6,360 feet with low permeability. The well can only produce 22 kilo pound per hour (kph) steam and 105 kph total mass flow at a wellhead pressure of 14 pounds per square inch gage (psig) which is insufficient to justify developing the 49 MW project. In addition, legal action against this project has been filed by the Earthjustice Environmental Law Clinic (Earthjustice) at Stanford.[6] The status of this project is uncertain.

In October 2001, Calpine acquired all of CalEnergy's interests in Glass Mountain KGRA, including Telephone Flat. In May 2003, the Department of the Interior issued a site license authorizing the operation of a 48 MW geothermal power plant in Telephone Flat. Calpine has all major permits to develop a geothermal power plant at the Telephone Flat Prospect. However, current legal action by Earthjustice and the Save Medicine Lake Coalition leaves the status of this project uncertain.[7]

Figure 2 Known Geothermal Resource Areas

Source: California Energy Commission

Table 1 Location of California Geothermal Power Plants and Capacity

Geothermal Resource Area	County	Existing Gross MW
East Mesa	Imperial	73.2
Heber	Imperial	100
Salton Sea (including Westmoreland)	Imperial	350
	Imperial Total	523.2
Coso Hot Springs	Inyo	300
Geysers (Lake & Sonoma Counties)	Sonoma/Lake	1000
	The Geysers Total:	1000
Honey Lake (Wendel-Amedee)	Lassen	6.4
Long Valley (mono- Long Valley) Mammoth Pacific Plants	Mono	40
Total:		**1870**

Source: "*New Geothermal Site Identification and Quantification*" by GeothermEx Corporation

Geothermal Resource Assessment

In July 2002, the Energy Commission executed a Public Interest Energy Research Program (PIER) contract with Hetch Hetchy Water and the Power Division of the San Francisco Public Utilities Commission (Hetch Hetchy/SFPUC) to fund studies and projects related to renewable energy. GeothermEx, Inc (GeothermEx) was retained by Hetch Hetchy/SFPUC to provide a geothermal resource assessment for California and western Nevada. This section summarizes the findings of GeothermEx on the resource assessment for California[8].

GeothermEx used prior research, exploration, and development results that are available in the public domain. They also used data and information released by some developers into the public domain for this study. Three baseline conditions were used to determine the geothermal resource areas included in this assessment: geographic location, resource temperature, and evidence of a discrete resource. In California, 22 geothermal resource areas were included in the assessment.

Among the various geothermal resource areas, the amount and quality of technical data are extremely variable. Because of this, a uniform set of required resource criteria needed to be quantified to determine commercial feasibility for each resource area. For each selected reservoir, values for the following criteria were obtained or reasonably estimated: temperature, area, thickness, porosity, and resource recovery factor.

To better capture the uncertainty of each resource, minimum, most likely and maximum values were used for each criterion. These values were then used in probabilistic simulation, based on Monte Carlo random-number sampling, to calculate estimated generation capacity based on the accessible heat in place at the resource area. Because the generation capacity is estimated based on calculated heat in place, there is no guarantee that sufficient permeability exists to allow commercial production for those resources where little or no drilling has occurred.

For the 22 California resource areas, the total estimated most-likely generation capacity was calculated to be approximately 4,732 MW. The total generation capacity, minus the installed gross capacity of existing generation, was 2,862 MW. Table 2 reflects the estimated generation capacity for each resource area, grouped by geographical area and county.

Despite the steam production decline mentioned earlier, The Geysers has potentially 400 MW of most-likely generation capacity available. The total proven reservoir at The Geysers is nearly 40 square miles, as determined by the extensive shallow and deep drilling in the region. For this area, there is a portion of approximately 10 square miles, which has never been developed for continuous steam supply. Lying between the Aidlin project area to the northwest and the areas of units 5-6, 7-8 and 11 to the southeast, these 10 square miles comprises about 25% of the 40 square miles total proven area. In addition, about 2 square miles in the northeastern of the field (within the proven reservoir area) remained untapped at the former Bottle Rock project and contiguous area to the southeast. In these areas, a reasonable estimate of average installed capacity is 33 MW per square mile. Therefore, the unutilized 12 square miles should be able to support about 400 MW under the right economic conditions.

Recent Geothermal Development Trends And Future Direction

This section focuses on trends currently observed in the geothermal industry; these trends are differentiated by: (1) technology, (2) environmental, (3) institutional, and (4) economic considerations.

Table 2: Most-Likely (MLK) Geothermal Resource Capacity

Geothermal Resource Area	County	MLK MW	Existing Gross MW	MLK-Existing MW
Brawley (North)	Imperial	135	0	135
Brawley (East)	Imperial	129	0	129
Brawley (South)	Imperial	62	0	62
Dunes	Imperial	11	0	11
East Mesa	Imperial	148	73.2	74.8
Glamis	Imperial	6.4	0	6.4
Heber	Imperial	142	100	42
Mount Signal	Imperial	19	0	19
Niland	Imperial	76	0	76
Salton Sea (including Westmoreland)	Imperial	1750	350	1400
Superstition Mountain	Imperial	9.5	0	9.5
	Imperial Total	2487.9	523.2	1964.7
Coso Hot Springs	Inyo	355	300	55
Sulfur Bank Field, Clear Lake Area	Lake	43	0	43
Geysers [Lake & Sonoma Counties]	Sonoma	1400	1000	400
Calistoga	Napa	25	0	25
	The Geysers Total:	1468	1000	468
Honey Lake (Wendel-Amedee)	Lassen	8.3	6.4	1.9
Lake City/ Surprise Valley	Modoc	37	0	37
Long Valley (mono- Long Valley) Mammoth Pacific Plants	Mono	111	40	71
Randsburg	San Bernardino/ Kern	48	0	48
Medicine Lake (Fourmile Hill)	Siskiyou	36	0	36
Medicine Lake (Telephone Flat)	Siskiyou	175	0	175
Sespe Hot Springs	Ventura	5.3	0	5.3
Total:		**4732**	**1870**	**2862**

Source: "*New Geothermal Site Identification and Quantification*" by GeothermEx Corporation

Technology

Recent and forecasted trends for geothermal technology development may be characterized within the following four classifications: (1) resource exploration, (2) resource development and completion, (3) drilling, and (4) power generation technology.

Resource Exploration

In 2004, the USGS began to categorize new geothermal resources, principally in the Great Basin of the western United States. This work will update the existing resource assessment completed in the 1980's. Because of the inherent difficulty in assessing geothermal potential, this work is likely to be important to further define the possibilities for new geothermal development.

Initiated in 2000, Geothermal Resource Exploration and Definition (GRED) Program is a cooperative Department of Energy (DOE)/industry effort to find, evaluate, and define additional geothermal resources throughout the western United States. To help mitigate a portion of the initial risk associated with the exploration and definition of geothermal resources, DOE provides up to 50% cost sharing. The DOE and its laboratories also provide technical oversight and monitoring.

Improvements and trends in resource exploration can be grouped as follows:

- Continue to develop of geophysical survey methods to identify those with the most robust signatures.
- Identify the advantages and limitations of imaging technologies (e.g., infra-red, SAR, ground penetrating radar) for exploration.
- Identify naturally occurring tracers that provide information on the time scale of interest (1,000's years).
- Integrate reservoir simulation with geophysical methods to predict the exploration signature of geothermal fields.
- Develop techniques to locate subsurface fracture zones.

Progress continues in applying micro earthquake seismology to identify active fractures. Seismic reflection and refraction techniques are now capable of providing sharper structural resolution, especially in rocks with the chaotic, non-bedded, and poorly bedded characteristics typical of geothermal reservoirs. These improvements have helped to reduce exploration time and costs, and the drilling risk.[9]

Resource Development and Completion

This element addresses the need to better understand subsurface conditions and develop techniques to modify the subsurface to recover energy from reservoirs lacking sufficient natural flow for economic development. Economically viable geothermal systems have both sufficient heat and permeability. Engineered geothermal systems (EGS) are transformed geothermal resources which had sufficient heat, but lacked adequate rock matrix permeability and/or natural reservoir fluids to transport the heat to the surface in economic quantities. The U.S. was an early leader in developing technology for engineered geothermal systems (i.e. the Hot Dry Rock effort at Los Alamos / Fenton Hill). During the 1990s, the Japanese program made significant advances, while the European community continues to develop their hot dry rock project located in France.

Progress continues to be made in the following reservoir development areas:

- Increase fundamental understanding of geothermal fields,
- Develop improved understanding of how to sustain production from hydrothermal systems and enhanced and engineered geothermal systems, and
- Demonstrate tools for designing and predicting the performance of engineered geothermal systems.

Reservoir simulators are being coupled with geophysical models to assist in developing geothermal system models used to frame exploration for new geothermal systems. Integrating reservoir simulators to geochemical and geomechanical models will enable future design and operation of engineered geothermal systems.

Drilling

Geothermal drilling is difficult because rocks are hard, abrasive, fractured, and, by definition, hot. Formation fluids are often highly corrosive and usually underpressured (i.e., pore pressure is less than an equivalent column of water). These harsh conditions mean that many of the tools used to reduce cost in oil and gas drilling cannot be used in geothermal reservoirs. Also, the requirement for geothermal wells to produce large volumes of fluid means that geothermal wells are larger in diameter than equivalent oil and gas wells of the same depth. All of these factors drive the cost of typical geothermal wells much higher than oil and gas wells of comparable depth.

For the near term, the development of geothermal drilling technology will continue to address the following elements:

- High temperature electronics. Batteries, components, printed circuit boards and monitoring technology with fiber optics and high temperature tools will continue to be developed for the harsh geothermal environment. This "segment" will benefit from concurrent development of instrumentation for jet engines.
- Rock reduction. Considerable advances have been made in cutter technology, bit and drillstring dynamics, and bit hydraulics. New computer simulation techniques and advanced materials are likely to foster greater development in this area.
- Diagnostics-while-drilling. The advances in electronics, sensors, and data management continue to flow into the geothermal drilling industry. Continued improvements in diagnostics will foster greater penetration rates and shorter downtimes.
- Wellbore integrity. Lost circulation zones, cross-flow control, cementing and well completion continue to present challenges to drillers. Improved twin-streaming sodium silicate and cement plugs will see increased utilization. R&D efforts on trimie pipe and reverse circulation primary cementing will foster "trouble free" drilling and cementing.

Power Generation Technology

Over the past decade, few geothermal plants have been built. However, discernible trends exist that are affecting electricity production including the following:

- The advent of low-temperature power plants has spurred a new interest in developing more efficient cycles such as the Kalina cycle.[10]
- The most severe challenge to improving the cycle efficiency for either a steam or a binary cycle is on the low-temperature side – the rejection of heat to the ambient environment. This requires improvements in heat exchangers used as condensers. The challenge is to use fluid flow to take advantage of opportunities to disrupt and renew boundary layers to enhance transfer rates with no additional parasitic energy losses.
- Some brines are quite corrosive, particularly higher temperature brines. These present a challenge for innovative coatings and linings that have sufficient protection to allow the use of inexpensive base materials such as carbon steel while providing the benefits of low initial cost and long service life.
- Many geothermal source locations tend to be in arid areas, necessitating the use of air-cooled heat exchangers for heat rejection. This means an extreme sensitivity to ambient air temperature, especially in the summer.

This may require innovative design and operating techniques for hybrid condensers.

- Geothermal operators will continue to adopt monitoring technology from other power plants to increase efficiency of operations.
- The costs and performance of geothermal plants is poorly documented and not universally understood as only a small number of significant plants have been built within the U.S. for the last decade. This makes it difficult to compare alternatives.

Environmental Effects From Geothermal Developments

While geothermal is generally considered among the most environmentally preferred energy sources, power plants can emit trace amounts of heavy metals. Over the next several years, plant operators are likely to install activated carbon systems to remove metals emissions such as mercury.

A majority of flashed steam plants in California have been built in the Imperial Valley, where the problems associated with waste disposal can be reduced by recovering various minerals from the spent geothermal brine before the fluid is injected into the ground. Studies by CalEnergy have shown that mineral (i.e. zinc, silica and manganese) recovery to be economical. CalEnergy has made substantial progress in reducing waste disposal cost and more importantly been able to turn a waste product into a revenue-enhancing venture through the extraction of zinc. If silica and manganese can also be extracted, CalEnergy estimates that these combined waste reduction operations may reduce the amount of wastes generated by 95%.

Because of the strict sitting regulations, developer's typically plan to minimize habit disturbance. Directional drilling will continue to be a preferred technology because of the lessened impact associated with well pad siting. Drillers will incorporate advanced monitoring systems to minimize fluid leakage during drilling.

Institutional[11]

Federal legislation has been proposed to "streamline" the often time consuming and duplicative processes for geothermal power plant siting, development, and operation. Specifically, federal and state agencies are now developing administrative procedures for processing geothermal lease applications, including lines of authority, steps in application processing, and timeframes for application processing.

Specific to the US National Forests, efforts are underway to better define and classify the known geothermal resources on USFS lands as well as to develop plans for leasing the land for geothermal production. Further, web-enabled data

retrieval systems are being implemented to track lease and permit applications and requests.

Because of the vast nature of military land jurisdiction, coupled with the Federal requirement for 2.5% of electricity purchases to come from renewable sources, it is likely there will be increased exploration and development of geothermal resources on military lands. Coupling the development of military resources to the Geothermal Steam Act provisions will allow for common regulatory or siting considerations for developers.

In 2002, the Governor signed the Renewable Portfolio Standard (RPS) (SB 1078, Sher, Chapter 516, Statues of 2002. This standard requires an annual increase in renewable generation equivalent to at least 1% of sales, with an aggregate goal of 20% by 2017. In the second quarter of 2003, the California Energy Commission, the Public Utilities Commission (CPUC), and the Consumer Power and Conservation Financing Authority (called the CPA - which is now defunct) adopted the Energy Action Plan (EAP) that identified specific goals and actions to eliminated energy outages and excessive price spikes in electricity or natural gas. The EAP recommends aggressively implementing the RPS, with the intent of achieving the 20% goal by 2010[11].

Economic

The Energy Policy Act of 1992 created a PTC to produce electricity from renewable energy sources. Codified as Section 45 of the Internal Revenue Code, certain renewable facilities (mostly wind technologies) qualify for a production tax credit that initially provided 1.5 centers per kilowatt-hour.

In October 22, 2204, H.R. 4520, the "American Jobs Creation Act of 2004", was signed into law, expanding the availability of the PTC include geothermal and other renewable resources. Under the terms of this new law, the PTC is 1.8¢/kWh (1.5¢/kWh adjusted for inflation) for a new facility's first five years of operation. The credit will also be allowed against a company's alternative minimum tax. However, to qualify for the credit, new plants must be up and running by the end of 2005. Efforts are currently undertaken by the geothermal industry to have this deadline extended.

Presently, the calculation and payment of royalties on leased Federal lands is a complex process. Recently proposed Federal legislation seeks to reduce the complexity of the royalty payment process and return the funds to the state and county. As of late 2004, the US Department of Interior (DOI) is planning a new initiative to simplify and improve the geothermal royalty system. The DOI has put together a Geothermal Royalty Review Committee to examine alternative approaches to geothermal royalties. This committee held a public meeting in late January 2005 to get input from interested parties.

Summary

Geothermal energy provides significant benefits in terms of improved air quality, increased diversity in electric energy sources, local and state revenues, and employment. California has the largest geothermal installed capacity in the country with approximately 1,900 MW. In addition, California has the potential to produce an estimated additional 2,862 MW from resource areas such as Coso Hot Springs, Imperial Valley, Glass Mountain, and Mono/Long Valley. Imperial County has 11 KGRAs including Brawley, Salton Sea, and East Mesa, and has the largest potential resource base within the state at over 2,400 MW. Cal Energy applied and received a permit to construct a 185 MW power plant in the Salton Sea KGRA. They anticipate completing construction, at the earliest, in 2006. With the RPS and the PTC in place, geothermal development is poised to increase dramatically within the next decade.

Endnotes

[1] California Energy Commission, April 2005, *2004 Net System Power Calculation*, Sacramento, CA. CEC-300-2005-004SF

[2] California Energy Commission, May 8, 2003, *Energy Action Plan*, www.energy.ca.gov/energy_action_plan

[3] California Energy Commission, November 19, 2003, *Renewable Resources Development Report*, Sacramento, CA 500-03-080F

[4] California Energy Commission, data provided by Valentino Tiangco, PhD.

[5] U. S. Geological Survey, Circular 726, *Assessment of geothermal resources of the United States, 1975*. http://pubs.er.usgs.gov/pubs/circ/circ726

[6] Personal Communication with Sean Hagerty, U.S. Department of Interior, BLM-California State Office on April 14 2005

[7] Personal Communication with Sean Hagerty, U.S. Department of Interior, BLM-California State Office on April 14, 2005.

[8] Material from this section was adapted from the Energy Commission Consultant Report written by GeothermEx, *New Geothermal Site Identification and Quantification*.

[9] http://www.agiweb.org/geotimes/july02/high_geothermal.html

[10] http://www.eere.energy.gov/consumerinfo/factsheets/ba9.html

[11] California Energy Commission, May 8, 2003, *Energy Action Plan*, http://www.energy.ca.gov/energy_action_plan/index.html

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ATTACHMENT 6

The California ENERGY COMMISSION

Background About Geothermal Energy in California

Geothermal energy is produced by the heat of the earth and is often associated with volcanic and seismically active regions. California, with its location on the Pacific "Ring of Fire," has 25 known geothermal resource areas, 14 of which have temperatures of 300 degrees Fahrenheit or greater.

Forty-six of California's 58 counties have lower temperature resources for direct-use geothermal. In fact, the City of San Bernardino developed the largest geothermal direct-use projects in North America, heating 37 buildings – including a 15-story high-rise and government facilities – with fluids distributed through 15 miles of pipelines. Environmentally benign fluids are discharged to surface water channels after heat is used.

When added together, California's geothermal power plants produce about 4.5 percent of the California's total electricity.

The most developed of the high-temperature resource areas of the state is the Geysers *(a photo of a Geysers' power plant's Unit # 18 is shown to the right).*

Located north of San Francisco, the Geysers was first tapped as a geothermal resource to generate electricity in 1960. It is one of only two locations in the world where a high-temperature, dry steam is found that can be directly used to turn turbines and generate electricity (the other being Larderello, Italy).

Other major geothermal locations in the state include the Imperial Valley area east of San Diego and the Coso Hot Springs area near Bakersfield. It is estimated that the state has a **potential** of more than 4,000 megawatts of additional power from geothermal energy, using current technologies.

Additionally, two forms of geothermal energy – Hot Dry Rock and Magma – have the potential to provide thousands of megawatts in California. Investigations in Hot Dry Rock were done in the Clear Lake area of Lake County; Magma research occurred in the Long Valley Caldera of Mono County.