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27 February 2017

Subject: Public Comments for inclusion in EIM Governing Body meetings on 02/28/17 and 03/01/17 in Las Vegas, Nevada regarding the regional "Energy Imbalance Market" (EIM)

Dear Jennifer: Per our recent email exchanges, Californians for Green Nuclear Power, Inc. (CGNP) is respectfully requesting the inclusion of our recently-released direct testimony and workpapers in CPUC proceeding A.16-08-006 in support of continued safe operation of PG&E's Diablo Canyon Power Plant (DCPP) far beyond PG&E's proposed abandonment date of 2025. Many of the components in the plant are robustly designed, consistent with a useful life of 100 years. Furthermore, PG&E has been an excellent steward of DCPP to date, earning the plant typical rankings in the top quartile among all U.S. nuclear power plants by the Institute of Nuclear Power Operations (INPO.) PG&E has been an industry leader in developing more robust and precise digital process control systems to replace various DCPP analog process control systems.

The more than 2 GW of DCPP generation was designed in conjunction with the more than 1 GW of PG&E's Helms Pumped Storage, (Helms) located in the Sierra foothills to the east of Fresno. There is a dedicated power pathway that has been running for over 3 decades between DCPP and Helms that allows Helms to be charged up at night with surplus DCPP power. Then during the afternoon and early evening demand peak, Helms discharges its power as one of the "world's largest storage batteries." Used 6 hours per day, Helms releases 2.67 Tera-Watt-hours (TWh) per year, and requires 3.54 TWh to "charge up" Helms, which is 75% efficient. DCPP produces abundant amounts of power, typically around 18 TWh/year (about 5 times the production of Hoover Dam or 14 times the production of Topaz Solar in eastern San Luis Obispo County. **Please note that both Helms and DCPP are emission-free power sources.** When a number of CGNP members visited CAISO headquarters on 20 May 2016, the guide made clear that CAISO appreciates the voltage and frequency stability that DCPP provides with a capacity factor in excess of 91%. On the other hand, solar and wind, (with much lower capacity factors) both subject to random and predictable generation capacity limitations require "spinning reserve generation" (typically fossil-fired) to operate in a "back off mode" to compensate for solar and wind's intermittencies. **The expensive California grid-scale storage battery projects are only in the megaWatt-hour (MWh) range, thereby limiting their use for such purposes as local voltage stability.**

Please print out sufficient copies of this two-page transmittal letter for Governing Body members and meeting participants. Given the extensive length and detail of the attached documents, CAISO might simply supply a single complete copy of our public comments on a display table (attached by some secure means to the display table) with a sign-up sheet so that interested meeting participants may receive a copy via a mailing or via a link from the CAISO website. CAISO's governing board might receive their copies electronically as well. Several annotated documents from the CAISO website are also attached. (As a consequence of its length, a second email will include CGNP's workpapers in CPUC Proceeding A.16-08-006)

CGNP has publicized its concerns about PacifiCorp, a Berkshire Hathaway Energy company, using the Regional Energy Imbalance Market as a means to market its ~6,000 MW of coal-fired generation and its ~3,000 MW of natural-gas-fired generation into the California energy market. Furthermore, CGNP is concerned that a CPUC A.16-08-006 Intervenor group CEERT may be serving as a proxy for commercial interests via the Chairman | Executive Committee, Jonathan M. Weisgall, who is also Berkshire Hathaway Energy's Vice President for Legislative and Regulatory Affairs and via CEERT's Affiliates who stand to benefit financially if DCPP is abandoned. (See relevant attached CEERT web pages.)

If efforts to shut down PG&E's Diablo Canyon Power Plant (DCPP) are successful, California will have no choice but to accept PacifiCorp's fossil-fired electricity, with attendant emission increases, to replace the annual production of approximately 18,000 GWh of DCPP's high capacity-factor reasonably-priced electricity. New solar and wind generation cannot make up for such a huge amount of power cost-effectively.

Sincerely, /s/ Gene A. Nelson, Ph.D.

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CGNP is an independent pro-environment non-profit educational organization advocating for the continued safe operation of Pacific Gas & Electric's Diablo Canyon Power Plant since 2013. We have been recognized by the IRS as a 501(c)(3) . We are also a CPUC Intervenor in Proceeding A.16-08-006, among others, supporting nuclear power in California..

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of the Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms (U39E).	Application 16-08-006 (Filed 08/11/2016*)*

WRITTEN DIRECT TESTIMONY OF CALIFORNIANS FOR GREEN NUCLEAR POWER

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January 27, 2017

Author's Verification

The authors below affirm under penalty of perjury that the information contained in this written testimony is true and correct, and is given in good faith to their best available knowledge,

subject to modifications resulting from new findings.

/s/ Alexander Cannara, Ph.D.

/s/ Michael (Marty) Marinak, Ph.D.

/s/ Gene Alan Nelson, Ph.D.

/s/ Abraham Weitzberg, Ph.D.

January 27, 2017

Table of Contents

CGNP Written Testimony Submission in Response to PG&E Application A16-08-006

The eight sections determined to be "within scope" in the 18 November 2016 CPUC scoping ruling are as follows:

In CGNP's view, the continued safe operation of DCPP beyond 2025 renders sections 2.4 and 2.7 moot. Thus, CGNP has not prepared responses to those sections.

Filed: 27 January 2017

Introduction

As our name suggests, we are a group of Californians who appreciate the advantages that that nuclear power offers for our environment. To set ourselves apart from other parties in this proceedings, many who obfuscate their goals and motivations, we disclose our predisposition freely and openly. But such disclosure should not distract from the facts, nor the inferences that must be drawn from them. Specifically:

- That we are a group of scientists, educated at top universities, considered to be elite specialists in our fields, and with decades of experience on the precise issues on which we offer testimony;
- That we have studied in great detail all the peer-reviewed materials available on these topics, and make the statements in our testimony based on those materials, our experience, and sound scientific methods;
- That we have come forward because we, as experts in this field, wish to help our home state of California (and our society) make wise decisions, for the benefit of future generations.

In what is increasingly an anti-science and "post-fact" world, it is all the more important to rely on individuals like us, and we hope that California policymakers, including of course the CPUC, buck the national trend and allow **the plain facts to guide sound policy**. Those facts, as explained in great detail below, will show, *inter alia*:

- That there is no way for California to meet its ambitious Greenhouse Gas (GHG)-reduction goals if it takes DCPP offline.
- In fact, a spike in GHG emissions is all-but-certain if the CPUC takes DCPP offline.
- That it will be difficult, if not impossible, for Californians to enjoy stable power if the CPUC takes DCPP offline.
- That for over thirty years, DCPP has been the backbone of PG&E's power generation, producing the

largest plurality of PG&E's power.

- DCPP has many useful years left. A thoughtful society wisely uses its resources, especially ones that it has already paid for and deployed. Decommissioning DCPP now would be a tremendous waste of a useful resource.
- Decommissioning DCPP would increase California's dependency on natural gas, which would tax our already burdened gas reservoirs, like Aliso Canyon.

In sum, there is simply no substitute for Diablo Canyon at this time or in the near future.

Californians need to know what we scientists are well aware of: that resources like solar and wind do not provide the entire mix of stable power needed at all times of the day and night. Unless nuclear power is part of the mix, California will become more dependent on fossil-fuel power from natural gas or even out-of-state coal.

Simply put, when a well-meaning Californian charges her Tesla upon coming home from work, right now there's a good chance the electricity comes from GHG-free Diablo Canyon. If the CPUC takes Diablo Canyon offline, that power will come from a much dirtier source, often one that negates the benefits of driving an electric vehicle. And here's the kicker: that power will come at a higher cost too.

We do not want these predictions to come true. We gain nothing for society by merely being on the right side of history. And we take no joy in making these statements. However, we, as concerned scientists, have come forward because we believe the truth must be told. After carefully evaluating all the relevant data, studies, and other published information, and after applying our combined (centuries of) experience in this field, we must relay the facts and inferences to which we testify in this document.

2.1

Abraham Weitzberg, Ph.D., Sponsor

Retirement of Diablo Canyon Power Plant

<u>2.1.0 Introduction</u>

My name is Abraham Weitzberg. I am a practicing nuclear engineer with over fifty-five years of experience in the industry. I earned a B. S. in Chemical Engineering, and a M.S. and Ph.D from MIT. My work experience particularly relevant to DCPP is the twelve years I spent at General Electric with technical and managerial responsibility for up to forty-three engineers in the area of Nuclear Engineering Methods and Core Development, supporting the design, licensing, construction, and operation of GE's Boiling Water Reactors. Additionally, I have been active in the American Nuclear Society standards development for over forty years, with a range of responsibilities including my present vice-Chairmanship of the Safety and Radiological Analyses Consensus Committee. I also have experience with regulatory oversight of Department of Energy research reactors and Nuclear Regulatory Commission licensing of commercial facilities.

CGNP supports the relicensing of DCPP and its continued operation, since it can be operated safely, reliably, and economically for the citizens and ratepayers of California for many years to come.

<u>2.1.1 DCPP can be relicensed and continue safe operation beyond the expiration of its current licenses</u>.

As described in Chapter 9 of PG&E's Prepared Testimony,[1] PG&E was pursuing Nuclear Regulatory Commission (NRC) license renewal (LR) of DCPP to 2045. To justify their expenditure of $53.2 million, the chapter provides a detailed description of the licensing activities. After the NRC staff completed their review of the license renewal application (LRA), they issued a Safety Evaluation Report (SER) in June 2011 documenting their review. The NRC concluded that the LRA met the standards for issuance of a renewed license. On 10 April 2011, PG&E requested that the LR process be delayed until after completion of additional seismic studies requested by the California Energy Commission. No seismic information has been developed that would show that the license renewal should not be approved, and all of the parties to the Joint Proposal, including the opponents of DCPP operation, have agreed that DCPP should continue operation until the end of their current licenses.

The LRA remains in the "under review" category by the NRC.[2] The NRC summary also shows that of the sixty-one applications received, four reactors were permanently shut down, fifty-one license renewals were issued, and six remain under review. From this, and the issuance of the DCPP SER, it may be reasonably concluded that the PG&E license renewal would be approved if the application were pursued, and that DCPP could continue operating at least through 2045.

The relicensing period through 2045 suggests a lower estimate for the lifetime of the plant. Many plant components were conservatively designed to last perhaps a century. As shown in the depreciation lifetime table[3] of the 2015 PG&E Annual Report to the CPUC, Account Number 321 Structures and Improvements has an Average Remaining Life of seventy-three years and Account number 322 Reactor

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1 PG&E Prepared Testimony

2 Status of License Renewal Activities as obtained from NRC website, December 2016.

3 2015 ANNUAL REPORT of Pacific Gas and Electric Company to the Public Utilities Commission of the State of California for the Year Ended December 31, 2015, p. 337.

Plant Equipment has thirty-nine years. The operational history of DCPP plant operations has shown that components even as complex and physically large as steam generators have been economically replaced so that DCPP was able to continue its safe operation.

On 27 October 2016, the NRC issued its sixth revision of its report for the Convention on Nuclear Safety.[4] In Chapter 14.1.4.3, captioned "Operating Beyond 60 Years," the report presents information on the efforts of the nuclear industry to extend the operation of nuclear power plants beyond the initial twenty-year license renewal. The NRC has already received letters of intent for a second license renewal for Peach Bottom Atomic Power Station, Units 2 and 3, in 2018 and for Surry Power Station, Units 1 and 2 in 2019. In August 2014, the NRC affirmed that the current regulatory framework for the first license renewal (*i.e.*, operation from forty years to sixty years) is sufficient to support the review of subsequent license renewal."

From this, I conclude that not only is license renewal for twenty years a reality, but that license renewal beyond twenty years is believed to be possible by the NRC and the industry. Based on independent evaluations of DCPP operating performance by the NRC and the Institute of Nuclear Power Operations (INPO), and generally accepted by nuclear professionals throughout the industry, DCPP has an exemplary safe and reliable operating history. This is reiterated in the PG&E Prepared Testimony of L. Jearl Strickland.[5] I see no evidence that DCPP could not be relicensed and continue to operate safely and reliably for another twenty years beyond its current license.

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4 The United States of America Seventh National Report for the Convention on Nuclear Safety, NUREG-1650, Revision 6, Nuclear Regulatory Commission Office of Nuclear Reactor Regulation, October 27, 2016. Available at: https://www.nrc.gov/docs/ML1629/ML16293A104.pdf

5 Strickland Testimony, Page 9-1, lines 25-30

2.1.2 DCPP can operate safely, reliably, and cost-effectively with the anticipated changes in the evolving mix of sources of electricity.

It is common knowledge that throughout its operating history DCPP has operated as a base-load plant, at full power for as much time as possible. This is advantageous from the perspectives of both the ratepayers and the PG&E shareholders. However, in its Application and Prepared Testimony[6] PG&E states:

> *"...However, California's electric grid is in the midst of a significant shift that creates challenges for the facility in the coming decades. Changes in state policies, the electric generation fleet, and market conditions combine to reduce the need for large, inflexible baseload power plants. These forces reduce the need for Diablo Canyon's output beyond the current license period."*
>
> and
>
> *"...PG&E will need less non-renewable baseload generation to supply its electricity customers. Hence the need for baseload power from Diablo Canyon will decrease after 2025."*

CGNP rejects PG&E's statement that DCPP is necessarily "inflexible." In its needs analysis, PG&E fails to consider the scenario wherein Diablo Canyon Power Plant (DCPP) operates flexibly, reliably, and cost effectively to meet future load demands. PG&E implies DCPP can only serve as a base-load generator of electricity: one which must operate at constant full power, and thus would be incompatible with the flexible operation required to balance generation from solar and wind resources increases in the future. To support the illusion of inflexibility, the word "baseload" occurs seven times in Application7 and 15 times

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Pacific Gas And Electric Company Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and Recovery of Associated Costs Through Proposed Ratemaking Mechanisms, Prepared Testimony, August 11, 2016, page 1-3, lines 2-7 and 27-30.

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PG&E Application 16-08-006

in the PG&E Prepared Testimony.[8] In fact, base-load operation is an economic choice, and not a physical constraint on DCPP operation.

Lack of flexibility is inconsistent with the fundamental design capabilities of Nuclear Power Plants (NPP) in general and DCPP in particular. DCPP is a four-loop PWR designed by Westinghouse. In Chapter 16 of the description of the "Westinghouse Pressurized Water Reactor Nuclear Power Plant"[9] it is stated that the control system is designed to automatically follow repetitive load changes throughout the range of 15% to 100% or rated power, consistent with the system load demand, automatically make step changes in load of 10% percent of rated power and ramp changes of 5% of rated power per minute, and follow a reference 12-3-6-3 daily load cycle consisting of 12 hours at full power, decreasing load to 50% power over a three-hour period, remaining at 50% power for six hours, and returning to full power over a three-hour period. It is recognized that these are general design bases, and that each power plant will have its own operating constraints specified in its Operating License, with its Technical Specifications and its Operating Limits.

There are numerous examples of PWRs flexibly operating to accommodate variable load demands, and indeed DCPP does practice flexible operation known as "curtailment." At the Diablo Canyon Independent Safety Committee meeting on October 20, 2016, Ken Johnston of PG&E[10] discussed Emergency Curtailment, Non-Emergency Curtailment, and Over-Generation Curtailment. During the PG&E presentation and the following committee discussions and public-comment periods, PG&E acknowledged that there are three modes of load-following or flexible operation, two of which have

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8 PG&E Prepared Testimony

9 The Westinghouse Pressurized Water Reactor Nuclear Power Plant, Westinghouse Electric Corporation Water Reactor Divisions, Pittsburgh, PA, 1984.

10 Ken Johnston, PG&E, "DCPP Curtailment Guidelines," selected slides from presentation to DCISC, October 20, 2016.

been safely performed as needed over the operating history of DCPP. They are plant-driven operational and maintenance power reductions and emergency curtailments requested by the California Independent System Operator (CAISO). The third mode is non-emergency curtailment, which might occur as a result of factors relating to economics and over-generation. Documentation of this issue is provided in the meeting transcript.[11]

The two reactors at Byron Nuclear Generating Station in Illinois are Westinghouse four-loop pressurized-water reactors (PWRs) similar in design to DCPP, and operate flexibly, and do so in daily operation.[12,13] On October 29, 2015, Byron 1 operated at 72% capacity and Byron 2 operated at 71%, with both units operating at reduced power for load following.

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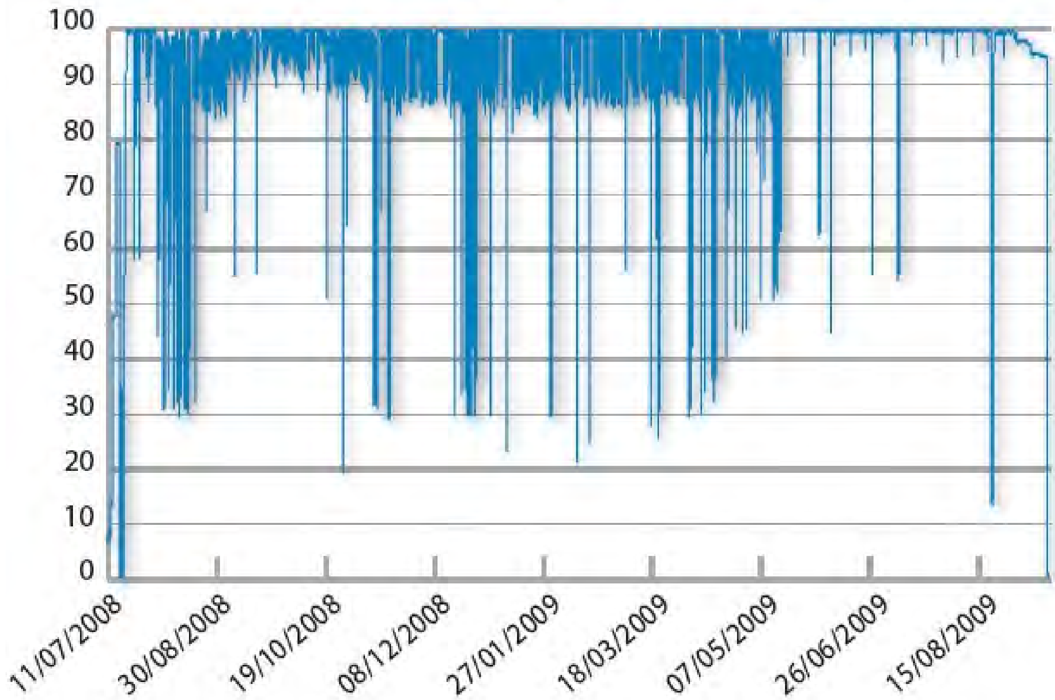
11 Transcript of the Eighty-Fifth Public Meeting of the Diablo Canyon Independent Safety Committee Held October 19 And 20, 2016 At Avila Beach, California, p. 374 et seq.

12 http://www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/2015/20151029ps.html

13 http://www.nrc.gov/reading-rm/doc-collections/event-status/reactor-status/2016/20160424ps.html

Similar powers were seen for the previous weeks. April 24, 2016 showed Byron 1 at 95% for load following (per load dispatcher) and Byron 2 at 0% for a refueling outage. In France and Germany flexible NPP operation is very common. Figures 1 and 2 are examples of actual power profiles from European reactors.[14]

Figure 1: Typical power history during an EDF reactor cycle (in % of rated power)



Courtesy of Électricité de France (EDF).

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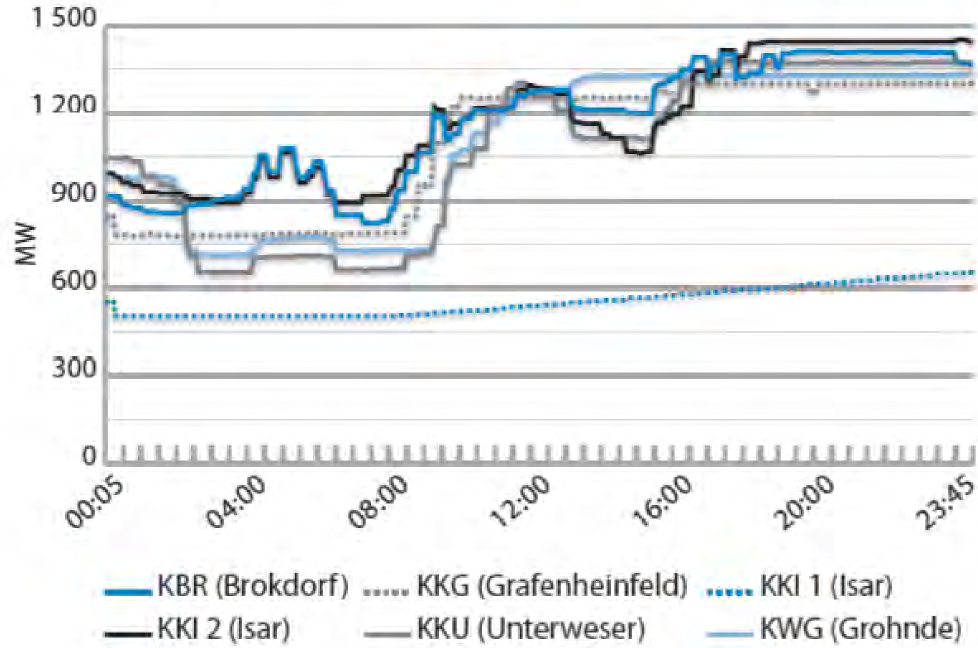
14 A. Lokhov, "Load-following with nuclear power plants," NEA Updates, Organisation for Economic Co-operation and Development (OECD) Nuclear Energy Agency (NEA), NEA News 2011 – No. 29.2.

Figure 2: Example of load-following during 24 hours at some German nuclear power plants



Courtesy of E.ON Kernkraft.

French and German nuclear power plants operate in load-following mode and contribute to grid stability. Load following is needed in France because it is a large part of the total electricity supply. In Germany, load following is important for the same reason as California, namely inherently intermittent generation from the non-dispatchable energy sources, solar and wind.

Utilities in the United States, including PG&E, are well aware of the need to analyze plant-specific issues and obtain NRC approval for operations beyond those authorized in their current Operating Licenses, including routine flexible operation. Flexible operation is the descriptor now used by industry rather than load-following, which has a specific meaning. Owners' groups meet regularly to address this issue because it is becoming a key economic factor as the contribution from solar and wind increases. Significant research continues to be performed in the U. S. and abroad in support of the transition of nuclear power plants to flexible operation rather than base-load. A 2014 report from the Electric Power Research Institute provides an excellent overview of the issues.[15]

The issue of DCPP flexible operation was discussed during the A.15-09-001 proceeding.[16] In his prepared testimony, Alliance for Nuclear Responsibility (A4NR) Attorney John Geesman attacks PG&E for indicating that it plans to operate DCPP as a flexible-capacity resource and curtail output when called upon to do so. Geesman bases this attack on a partially redacted PG&E memo of 29 September 2014 (Attachment 2 to his testimony) that describes in detail the technical issues specifically associated with flexible operation of DCPP. The issue of flexible operation of DCPP had also been discussed in 2014-2015 by the Diablo Canyon Independent Safety Committee (DCISC). It states in its annual report[17] that DCPP has expressed no intent to implement flexible power operation at this time, and has been examining the potential effects that could arise from such a change to its operating practices, safety, and reliability.

In its Prepared Testimony, PG&E neglects to mention that a portion of the $53 million in ratepayer compensation it is requesting were for technical studies devoted to the issue of flexible operation of DCPP in other than a base-load mode. In December 2013, the firm Areva completed a feasibility study on DCPP flexible power issues. PG&E then completed a draft report entitled “Facts, Discussions, Options and Recommendations on DCPP’s Ability to Implement Flexible Power Operations.” These documents are marked “Confidential” and their contents, which are certainly relevant to the possible future operation of DCPP, were curiously not made publicly available to be reviewed by stakeholders and the Diablo Canyon Independent Safety Committee (DCISC). In following its commitment to

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15 Program on Technology Innovation: Approach to Transition Nuclear Power Plants to Flexible Power Operations. EPRI, Palo Alto, CA: 2014. 3002002612.

16 Attorney John L. Geesman Testimony in Proceeding A 15-09-001, Exhibit No. A4NR-2, p 12, *et. seq.*

17 Twenty-fifth Annual Report on the Safety of Diablo Canyon Nuclear Power Plant Operations, July 1, 2014—June 30, 2015,” p 7.

continue to review the possible implications of flexible operation, DCISC requested these documents[18] and was rebuffed by PG&E,[19] citing attorney-client privilege. But PG&E did not deny the existence of the work product. It is significant that PG&E provided A4NR with the documentation of the flexibility issues but refused to provide similarly redacted documents describing how PG&E would possibly address the flexibility issues in their license application before the NRC.

The conclusions of the Need Analysis in PG&E's Prepared Testimony are similarly driven by the assumption that DCPP is a base-load resource and would not be able to reduce its generation to balance a surplus of electricity from renewable resources. There is ample documentation showing that nuclear power plants can operate in a flexible mode that is compatible with large and varying combinations of solar and wind resources. Absent evidence that flexible operation would pose an unacceptable safety risk at DCPP and based on flexible operations at other PWRs, and based on all of the materials I've studied and my fifty-five years of experience in the field, I conclude that DCPP can operate flexibly in an evolving mix of increasing solar and wind-powered generation. Moreover, the venue for such safety discussions is more appropriate to the NRC review of DCPP's license application rather than in a CPUC rate-setting Proceeding.

2.1.3 The citizens of California and the PG&E ratepayers would be better served if PG&E retained the option to continue to operate DCPP, instead of abandoning it now, based on current available information.

The closure of DCPP will profoundly affect PG&E ratepayers and the citizens of California in two

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[18] Letter, Robert R. Wellington to Cary Harbor, "Diablo Canyon Independent Safety Committee; Request for Copy of Reports on Flexible Power Issues, November 18, 2016.

[19] Letter, W. V. Manheim to R. Wellington, "Request for Copy of Reports on flexible Power Issues," December 12, 2016.

primary ways: increased power bills, and dirtier air, *i.e.*, failing to meet California's GHG emission-reduction goals.

<u>Future DCPP operating costs are uncertain.</u> The PG&E Application describes several speculative scenarios that might increase costs of operation of DCPP. PG&E's Application is factually, materially, and logically incomplete, however, in that it does not include a countervailing lists of items that could *decrease* costs of operation of DCPP, or ones that could diminish the estimated future supplies of solar or wind power or battery storage capability. Also, there is no discussion of scenarios where there might be *increased* demand for electricity supplied by DCPP.

PG&E's application fails to consider the possibility of California legislative or regulatory actions similar to those of New York State (Zero Emissions Credits) and the State of Illinois (Zero Emission Standard) to credit nuclear power plants for their emission-free generation. The New York Governor's office acknowledged that maintaining zero-emission nuclear power is a critical element for achieving New York's ambitious climate goals. Additionally, there is bipartisan support growing in the U.S. Congress and in some states across the nation to reexamine energy policy and level the playing field for all electricity generators that do not emit GHG. Significantly, California will elect a new Governor in 2018, and several of the candidates have expressed support for the abundant clean power that nuclear offers.

One possible large component of future DCPP operating costs would be the OTC mitigation measures. On November 18, 2014, the Subcommittee of the Review Committee for Nuclear Fueled Power Plants, consisting of representatives from the California Energy Commission, California Public Utilities Commission, the Center for Energy Efficiency and Renewable Technologies and the Alliance for

Nuclear Responsibility, issued a report[20] evaluating OTC mitigation measures. The report included cost and schedules prepared by Bechtel, and concludes: "At a minimum, the disparity in the different cost estimates is a good indicator of the high level of uncertainty about project costs."

A Party to this Proceeding, Environmental Progress, in its Protest of 15 September 2016, discussed the use of artificial reef mitigation at a one-time cost of $15 - $50 million to address the OTC compliance requirements.[21] PG&E, in its Reply to Responses and Protests, stated: "The potential future costs of compliance under the State Water Board's OTC policy are unknown. No decision has been made by the State Water Board."[22] It is clear that there is a very large uncertainty associated with OTC compliance cost estimates ranging from a high estimate of over $14 billion to a low estimate of $15 million. This and other uncertainties make any claim of future DCPP operating costs very unreliable *ab initio*. (OTC mitigation costs are discussed further in testimony addressing 2.6 Ratemaking and Cost Allocation.)

Another cost component that has not been considered in the PG&E estimates is potentially improved plant operational efficiencies. One example is the Westinghouse improved steam generator tube inspection method,[23] which shortens outage time by two days with an approximate $2 million savings for each outage, while reducing radioactive waste and worker dose.
Also, based on the PG&E notification of requested rate increase,[24] not only is the cost of electricity to ratepayers uncertain, it will certainly increase even before the proposed abandonment of DCPP in 2025, if

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20 "Subcommittee Comments on Bechtel's Assessment of Alternatives to Once-Through-Cooling for Diablo Canyon Power Plant," November 18, 2014.

21 Environmental Progress Protest, pp. 12-15.

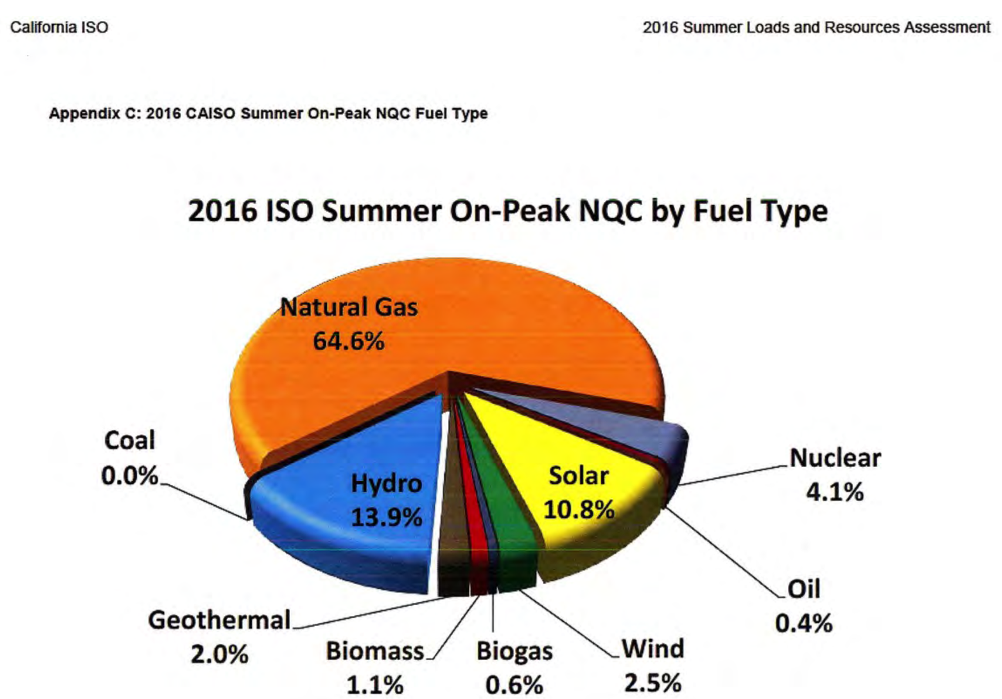
22 PG&E Reply to Responses and Protests, p. 8

23 Steam Generators, Improving Tube Inspections, *Nuclear News,* July 2016, www.ans.org/nn.

24 PACIFIC GAS AND ELECTRIC COMPANY'S (U 39 E) PROOF OF RULE 3.2(e) COMPLIANCE, October 3, 2016.

the PG&E Application is approved.

<u>The future demand for DCPP: electricity is also uncertain.</u> The following CAISO graphic[25] of Net Qualifying Capacity (NQC) clearly shows the large percentage of electricity that is now generated by the burning of natural gas even during the summer when solar production is at its highest. This percentage may decrease as additional California solar and wind are brought on line, but the burning of natural gas is certainly to continue being the predominant electricity generator for the foreseeable future. It is odd that the abandonment of non-GHG generating DCPP is being proposed at the same time California is making great efforts to reduce its production of greenhouse gases.



On September 16, 2016, the Los Angeles City Council amended and approved the report[26] of its Energy

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25 California ISO, 2016 Summer Loads and Resources Assessment, May, 18, 2016.

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And Environment Committee relative to a research partnership to determine what investments should be made to achieve a 100% renewable energy portfolio for the Los Angeles Department of Water and Power (LADWP).

In response to this resolution, LADWP issued a letter report[27] that contained the statement that its 100% Fossil-Free Scenario would include a combination of solar, wind, hydro, geothermal, nuclear, hydrogen turbine, fuel cell, ocean-wave energy, and other emerging clean technologies that will provide sufficient capacity to deliver 100% of LADWP's customer peak demand. Note that nuclear is included as a significant option, and thus DCPP could be considered as a source of emission-free electricity for Los Angeles.

Additional potential uses of hypothetical excess power from DCPP have been identified including desalination or responding to a large increase in the number of electric vehicles in California. Like many others, my experience tells me that the markets and demand are headed in that direction. One can also speculate about the projected new installations or replacements of rooftop PV solar if financial incentives are reduced or eliminated, particularly at the federal level, given the results of the 2016 election. The future effect of the cost of alternative sources of electricity on the potential demand for electricity from DCPP can only be hypothesized, and with great uncertainty.

<u>Experience has shown that the retirement of nuclear power plant invariably leads to an increase in GHG emissions.</u> In southern California, the closing of the San Onofre Nuclear Generating Station (SONGS) in 2012 contributed to a twenty-four percent increase in carbon emissions from the electricity sector,

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Los Angeles Council File 16-0243 "Research Partnership / 100 Percent Energy Portfolio / Department of Water and Power, September 16, 2016.

[27] Letter, David H. Wright to LA City Council, "16-0243_rpt_DWP_12-06-2016_DWP Report," 12-1-2016.

according to data from the California Environmental Protection Agency Air Resources Board.[28] Carbon emissions from the electricity sector in New England rose 2015, the first year-to-year increase since 2010, largely because of the closing of the Vermont Yankee Nuclear Power Station in December 2014. According to ISO New England, the region's grid operator, natural-gas-fired generation increased by about 12% from 2014 to 2015.[29] Similar increases in fossil generation were experienced in Europe after closure of nuclear plants. This concept is a universal truth wherever fossil generation is the predominant source of electricity. Simply stated, even under the best of circumstances, solar and wind require backup fossil-fired generation because they are incapable of operating 24/7/365, as nuclear power can. (This subject will be discussed further in testimony addressing 2.2 Proposed Replacement Procurement.)

2.1.4 Conclusion

Electricity costs in the years following the DCPP retirement would be more uncertain than those associated with its continued operation, because of the lack of knowledge about the sources of replacement power and lifetime, and total cost of any replacement power sources. Moreover, there are simply no 18,000 GWh/yr power alternatives that are GHG-free, like DCPP.

After evaluating all the factors, and applying everything I have learned in my fifty-five years in the field, I conclude that the citizens of California and PG&E ratepayers would be better served by continuing to operate DCPP as a provider of GHG-free electricity.

CALIFORNIANS FOR GREEN NUCLEAR POWER

28 2008 to 2013 Emissions Summary, Mandatory Reporting for Greenhouse Gas Emissions, California Air Resources Board, June 30, 2015

29 DRAFT 2015 ISO New England Electric Generator Air Emissions Report, November 2016, p. 14.

STATEMENT OF QUALIFICATIONS OF ABRAHAM WEITZBERG

Q 1 Please state your name and business address.

A 1 My name is Abraham Weitzberg, and I am self employed at 5711 Como Circle, Woodland Hills, California 91367.

Q 2 Briefly describe the nature of your business.

A 2 I am an independent consultant in the field of nuclear energy and am now providing services to the U. S. Department of Energy and Nuclear Regulatory Commission.

Q 3 Please summarize your educational and professional background.

A 3 I received three degrees from the Massachusetts Institute of Technology: a Bachelor's degree in Chemical Engineering in 1957, a Master's degree in Nuclear Engineering in 1958, and a Doctor of Philosophy degree in Nuclear Engineering in 1962. Since graduating, I have worked continuously in the nuclear field, for Atomics International, General Electric Company, Science Applications, NUS (aka Nuclear Utility Services), and Scientech. Much of this work was related to nuclear power reactors.

Q 4 Is any of your experience particularly relevant to the operation of the Diablo Canyon Power Plant?

A 4 Yes. My work experience particularly relevant to DCPP is the 12 years I spent at General Electric (GE) with increasing technical and managerial responsibility for up to 43 engineers in the area of Nuclear Engineering Methods and Core Development supporting the design, licensing, construction, and operation of GE's Boiling Water Reactors in the period up to the mid-1970s. Additionally, I have been active in the American Nuclear Society standards development for over 40 years, with a range of responsibilities up to my present vice-Chairmanship of the Safety and Radiological Analyses Consensus Committee. I also have experience with regulatory oversight of Department of Energy research reactors and Nuclear Regulatory Commission licensing of commercial facilities.

Q5 What is the purpose of your testimony?

A 5 I am sponsoring the following testimony in Californians for Green Nuclear Power's objections to PG&E's Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and

Recovery of Associated Costs through Proposed Ratemaking Mechanisms:

- Chapter 2.1 "Retirement of Diablo Canyon Power Plant,"
- Chapter 2.3, "Proposed Employee Retention Program."

Q 6 Does this conclude your statement of qualifications?

A 6 Yes, it does.

2.2

Proposed Replacement [Power] Procurement

Sponsor: Alexander Cannara, Ph.D.

My Testimony below (regarding A.16-08-006) addresses counter-factual statements made by PG&E and the Parties in their Joint Proposal (JP) and Testimony regarding Replacement [Power] Procurement "Tranches" should CPUC approve A.16-08-006 and allow DCPP to be closed without full replacement by equally emissions-free power. Imagine a machine on less than 100 acres, whose energy product over a year will run the entire world's electric demand for an hour, having generated no GHG emissions and yielding full power 90% of the time. No need to imagine, that's DCPP. Yet PG&E (plus Parties to the JP) place no environmental value on that machine, though at least some expect to reap great financial value, at the expense of the public interest.

Each section below addresses particular portions of the JP and PG&E Testimony that, despite only suggesting small, fractional replacements of DCPP's clean power and admitting that shortcoming, are counter-factual.

They are inadequate, uncertain and even damaging to California's legislated and administrative goals to reduce imported coal power (Fig. 1)[18] and to reduce GHG emissions "*40% Below 1990 Levels*"[1] <u>They fall by the weight of their scientifically and environmentally unsupportable assumptions</u>.

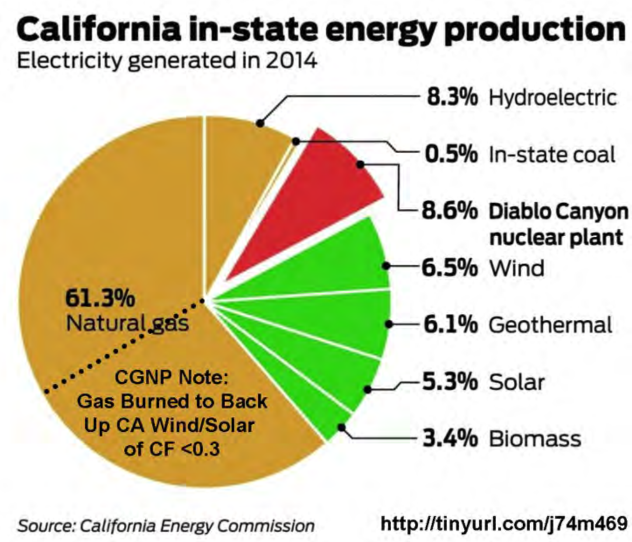
Their choice of "tranche" as an exotic substitute for "segment," "portion," or even "part" is intriguing. Tranched instruments were successfully used to fool raters of mortgage-backed securities (that contained both good and bad debts) to rate them by an average that disguised reality: just one or two failures of lower-tranche loans made the whole security worthless -- thus we experienced the world financial meltdown of 2008.

The proposed, fractional, tranched replacements for DCPP: Energy Efficiency (EE), GHG-Free RFOs (contracts and certificates), and 55-Percent RPS Commitment (JP, Section 2, pp. 4-8) are not credible, as explained below. Thus, A.16-08-006 is neither a factual representation **nor in the public interest** and should be rejected.

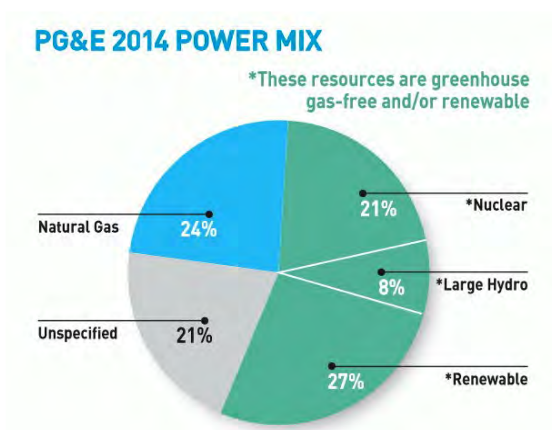
PG&E is voluntarily[2] proposing to retire DCPP, yet it cannot be retired. Retirement of DCPP means that meeting California's GHG-emissions goals ("*reducing carbon emissions in California to 40 percent below 1990 levels by 2030*") will be almost impossible.[1] CPUC can determine this from data, as discussed in paragraphs and conclusions below.

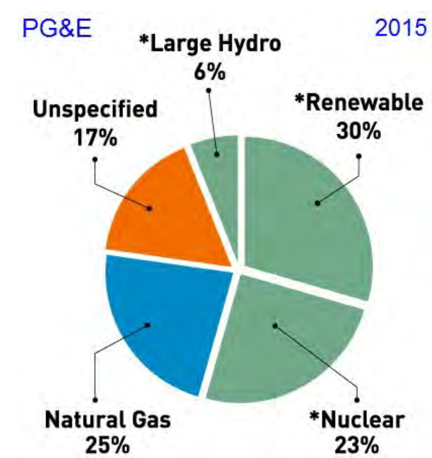
If PG&E no longer wishes to own and operate DCPP, then CPUC (and other state agencies) can facilitate DCPP ownership transfer to another competent nuclear operator. PG&E may even continue operating DCPP as contractor to the new owner, thus protecting both the local economy and a source of GHG-free energy. California can determine if the clean power from DCPP should be incorporated into a legislatively-revised, scientifically-correct California RPS (and Loading Order) for in-state service, or be delivered to out-of-state regions that already do include nuclear power in their clean-energy portfolios.[3]

PG&E's DCPP is providing about 8% of all California's electrical energy, and doing so without GHG emission – as illustrated by our CEC below, and in Section 2.1 of CGNP Testimony (our 2015/16 energy mix is similar).



<u>PG&E already meets and exceeds state-mandated[1] clean-power targets</u> because of Diablo Canyon. Diablo Canyon's nuclear power output remains superior in reliability and environmental impacts to any other California energy sources.[9] Other states[3] and countries (e.g., Canada, France, Switzerland) already recognize this in their nuclear-plant legislation.





http://tinyurl.com/jmvxhrj [4]

On <u>8 Dec. 2016, the CPUC held a Workshop</u>[5] at which PG&E (and other Parties) presented statements related to the JP and PG&E's Application to retire DCPP, especially with regard to possible sources of Replacement Power.

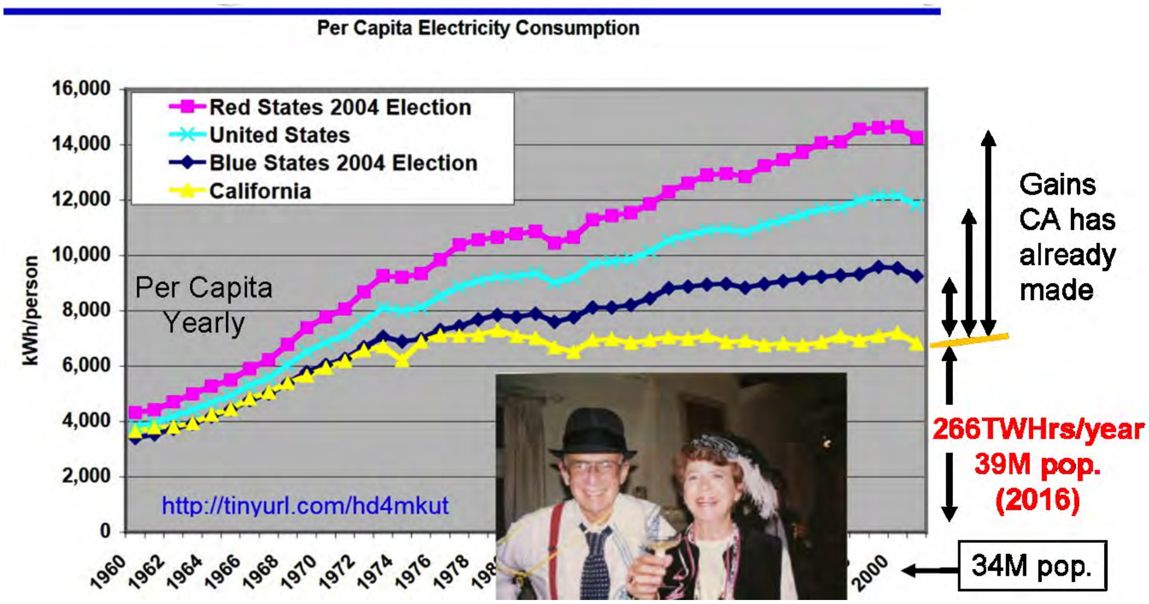
At the Workshop, PG&E staffers explained their estimations on the very modest proposed "replacements" of DCPP's clean power in three "tranches" that do not total more than a fraction (~20%) of DCPP's output: "*PG&E seeks Commission approval of its plan to replace a portion of DCPP with GHG-free energy resources procured in three tranches over a 12-year period*" (PG&E Testimony section B1).

The JP previously admitted this scenario's inadequacy: "*The Parties recognize that the three tranches of resource procurement proposed in this Joint Proposal are not intended to specify everything that will be needed to ensure the orderly replacement of Diablo Canyon with GHG free resources*" (JP Preamble section D, underline added).

Tranche 1 is Energy Efficiency (EE), which PG&E proposes to achieve by "*Adding 2,000 gross GWh of EE in PG&E's service territory in 2018-2024*" (PG&E Testimony section B1, pp. 1-7, lines 3-4). This **total, 6-year** "gross" commitment amounts to less than 1/8 of DCPP's emission-free energy output (~18,000 GWh/year). **In other words, PG&E's total EE commitment is less than 12% of what is needed to "replace" DCPP. It's therefore statistically almost meaningless, based on scientific standard.**

At the Workshop[5] near the 3pm closing, a PG&E analyst (Janice Berman?) was explaining how the "*2,000 gross GWh of EE*" might be achieved via their analyses of what "*other states*" are now implementing regarding EE. When asked if she had taken account of the fact that California has long achieved high per-capita efficiency and so cannot depend on applying what other, less efficient states do, she answered: "***No***" – she had not accounted for other states being able to make these gains with "low-hanging fruit," which has already been harvested in California. (*See* graphic below.)

The following graphic from a CEC presentation honoring its past Chair, Art Rosenfeld,* illustrates a basic problem with PG&E's available EE estimate – not only is California's growing population and product-variety increasing electrical load, but using other states' possible per-capita load reductions via EE is almost meaningless -- California has already done most of what others can do, under Rosenfeld's wise past leadership.



* Pictured, who spearheaded California's efficiency gains and legislation, including AB32, especially Title 24, regarding electrical efficiency: http://tinyurl.com/hd4mkut

Per the figure, even if all best (blue) states' "new" EE efforts brought them to California's 2004 curve, and if all those efforts had not yet been made by California, the most improvement in per-capita EE we could expect would be about 1/3 of present, per-capita electrical demand, leaving about 2/3 our demand untouched. The worst states' efforts must follow what we've already done, with little of novelty to our EE and no evidence that other states' EE choices are novel and unapplied to California.

Further note that the proposed "*2000 gross GWh*" EE target over the *"2018-2024"* years is less than 1% of present California demand (>260,000GWHr/Year) and about 1/40 of PG&E's "*service territory with* *an approximate system load of 80,000 GWh*" (PG&E Testimony, pp. 1-7, lines 16-17) per year. If the EE target is literally as stated (lines 3-4) "*2,000 gross GWh of EE in PG&E's service territory in 2018-2024*," then "*Tranche 1*" is worth only 1/6 of the above, or 1/240 of PG&E's service territory load (much less than 0.2% of state demand) and only 1/54 of DCPP's output. In other words, the EE tranche is just about meaningless.

At the Workshop[5], the same PG&E analyst was asked if EE losses inherent in alleged GHG-free replacements for DCPP, such as industrial-scale wind/solar, had been considered. She again said: "**No.**" This is independent of inherently low solar-PV and wind-generator input-to-output efficiency. Apparently, no consideration of electrical conversion and transmission losses inherent in necessarily-remote wind/solar (or other) installations has been made by PG&E with regard to A.16-08-006.

Note that losses in existing grid interconnections and switchyards, as well as in new, GHG-free installations' output-connections to them, increase as the square of the load current – at a given service voltage, so doubling currents quadruples energy losses. This adds inefficiency until all involved connections/substations are upgraded with lower resistance cabling and higher-current components (*e.g.*, transformers, breakers).

None of the above appear to have been considered by PG&E and its Parties in relation to imagined replacement of clean DCPP power via EE and new GHG-free sources.

Finally, California population is projected to increase 13% by 2030, more than nullifying any increases in EE.

Tranches 2 and 3 envision power-purchase strategies for PG&E to duplicate DCPP's GHG-free power via contract with other generation entities – (PG&E Testimony page i): "*ALL SOURCE GHG FREE*

ENERGY REQUEST FOR OFFERS & VOLUNTARY 55 PERCENT RENEWABLES PORTFOLIO STANDARD PROCUREMENT COMMITMENT."

At the 12/8/2016 Workshop,[5] near the lunch break, two analysts stated they could project neither future PG&E service-area nor California state power needs, nor could they predict confidently the ability of contracted GHG-free sources to meet RPS-equivalent needs without DCPP.

There is good reason to be skeptical of even the partial replacement procurements that tranches 2 and 3 might provide. The lead PG&E spokesperson at the 12/8/2016 Workshop (Todd Strauss?) mentioned under questioning by a Protesting Party, that PG&E would indeed purchase RECs ("Renewable" Energy Certificates) to complete its commitments in the JP and Application.

This is a serious defect in PG&E's Application and Proposal. It is well known that such Certificates are too often fraudulent – vendors selling power deliveries from producers who cover their combustion-power components. The term is "green-washing." The recently legislated CCA/CCE (Community-Choice) power retailers have the same issue that PG&E is creating for itself and all its customers – an inability to properly audit their true electric-power sources and corresponding GHG contents. For example:[6]

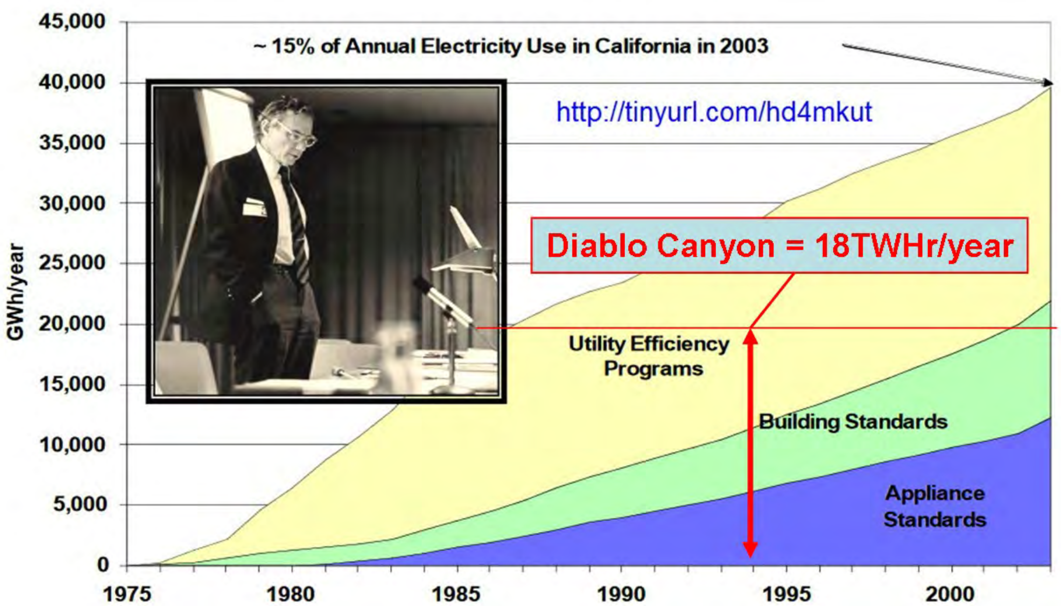
> *"California consumers have no way of distinguishing between renewable energy that is merely resold utility renewables and renewables that are at risk in the market. Fuel source labels required by California law will not differentiate between the two, nor does the private "Green-e" certification program recognize this critical difference among power products."*

> *"Most green products on the market have no positive impact on the environment because most marketers are merely reselling renewable energy that other consumers are already paying for and*

that would continue to operate regardless of any resale to green consumers."

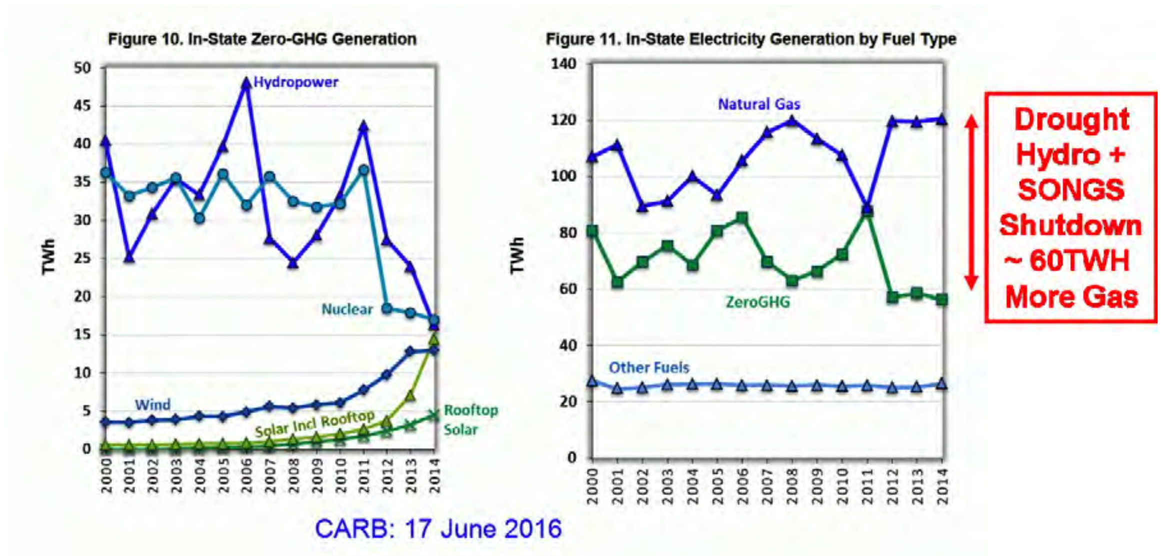
PG&E makes no mention of how it will audit/guarantee that Replacement Procurements and Renewable-Energy Certificates (RECs) will yield new power as clean as DCPP now produces, and do so for decades to come.

EE and Replacement Power Procurement Scale. The CEC's "*Rosenfeld Effect*" gave us the per-capita electrical efficiency gains illustrated above. How does DCPP support them?



Closure of DCPP would be equivalent to wiping away all 30+ years of the CEC's and Rosenfeld's progress on either utility efficiency or building and appliance standards. Closure of San Onofre (SONGS) already wiped away an equal amount of energy-efficiency progress, increasing California emissions (CO_2 and methane) and gas extraction/transport/storage and combustion to boot.

At the 12/8/2016 Workshop[5] PG&E's lead presenter (Todd Strauss?) intoned that PG&E wished to prevent the "*emissions spike*" that occurred when San Onofre was abruptly shut down.

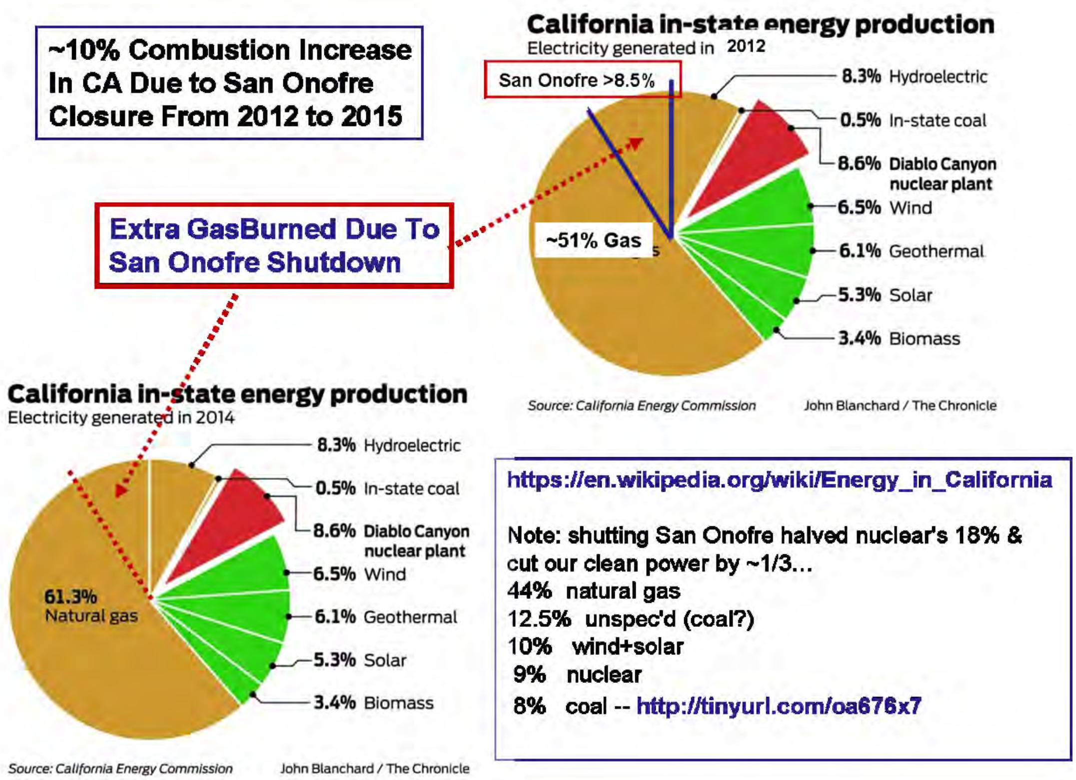


A "spike" is called such because it quickly rises and soon quickly falls. California did not experience a "spike" in emissions after San Onofre was shut down. California experienced, and is experiencing, a step-function increase in emissions[7] corresponding to what would have been emitted by gas power generation had the CEC never accomplished any efficiency heroics.

The >3-month Aliso Canyon natural-gas leak[8] (October 2015-February 2016) was estimated (via EDF and CPUC measurement) to have a GHG equivalent of about 8 million tons of CO_2. That leak, due to improper storage-well management, was equivalent to dumping about 800 million gallons (about 35,000 railroad tank cars) of gasoline/diesel fuel into a valley and igniting it. Much of that gas, of course, had been stored to make up for Southern California's loss of San Onofre's clean power. Some of it had been stored to make up for the low Capacity Factors of California's industrial-scale wind/solar installations. And, we later learned from California agency reports that the Aliso Canyon leak was far smaller than the "normal" oil/gas GHG leakages allowed across our state -- from well though transport, into storage, to distribution, to end use. Such regulator-allowed methane leakage in our state effectively wipes out all GHG-reduction benefits of our state's low-CF RPS sources, such as industrial-scale wind/solar power generation. Only geothermal, DCPP (and in the past, SONGS) provide natural-gas-free and leakage-free clean power.

As if to add insult to emissions injury, the CEC, on 10 February 2016 easily approved two, 300MW gas-plant expansions in San Diego County. CEC records show other such approvals subsequent to SONGS shutdown, despite the massive gas leak (~8 megatons CO_2 equivalent, per CA EPA) at Aliso Canyon.[8] At the time, gas dependence added the worry that loss of Aliso storage would jeopardize So. California power for summer air-conditioning loads.

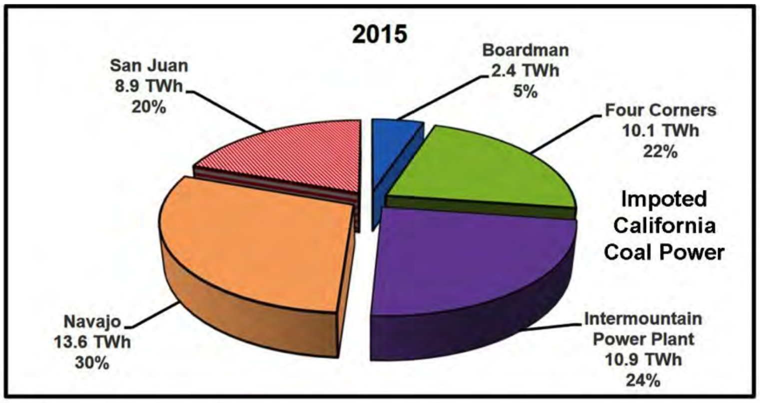
And the effect of gas substitution for SONGS is evident when plotted on the CEC's 2012 energy-source chart – SONGS closure plus drought-weakened hydro have wiped out about ½ the benefit of RPS sources. DCPP closure would wipe most of the remainder and gas combustion and emissions would fill the gap – again negating past energy use/sourcing progress.



Note that the graphic does not include out-of-state sources, such as LADWP's coal burning under contract with the Intermountain coal plant in Delta, Utah -- that plant is serving only Los Angeles. It also does not include injection into California of mixed incoming power, as from Pacificorp's assemblage of emitting and non-emitting sources.

California's dependence on coal combustion out-of-state is indicated in the following chart and table

(CEC: "*Total Electric system Power*", http://tinyurl.com/ze9xhdx).



Source: Electricity Supply Forms (S-2 and S-5) submitted by LSEs for the California Energy Commission's 2009, 2011, 2013, and 2015 *Integrated Energy Policy Reports (IEPR)* available at http://energyalmanac.ca.gov/electricity/.

Note: Directly imported means a power plant located out-of-state but has its first point of connection in a California balancing area. Intermountain Generating Station is the only coal-fired power plant in this category, being directly connected with the LADWP system.

Table values are in GWHrs.

Table 1: In-State and Imported Coal-Fired Generation With First Point of Connection Being a California Balancing Area

Used to Serve California Loads (2006–2015) Year	Total Generation to Serve California Loads	Coal-Fired Generation		
		In-State	Imported	Total
2006	298,316	4,190	28,622	32,812
		1.4%	9.6%	11.0%
2007	304,909	4,217	45,821	50,038
		1.4%	15.0%	16.4%
2008	307,450	3,977	51,852	55,829
		1.3%	16.9%	18.2%
2009	298,449	3,735	19,019	22,754
		1.3%	6.4%	7.6%
2010	291,184	3,406	19,019	22,425
		1.2%	6.5%	7.7%
2011	293,779	3,120	20,850	23,970
		1.1%	7.1%	8.2%
2012	302,320	1,580	21,106	22,686
		0.5%	7.0%	7.5%
2013	296,250	1,018	22,175	23,193
		0.3%	7.5%	7.8%
2014	297,062	1,011	17,877	18,888
		0.3%	6.0%	6.4%
2015	295,405	538	17,197	17,735
		0.2%	5.8%	6.0%

Note: Total may not equal in-state plus imported due to rounding.
Sources: California Energy Commission, California Electricity Data, Facts, & Statistics, Data, Facts, & Statistics, *Total Electric System Power*

Note that the total out-of-state coal generation delivered to California in 2015 equalled about 95% of

DCPP's (or SONGS') nominal output. If SONGS hadn't been shut down, all out-of-state coal power could have been eliminated. Maintaining DCPP in operation can eliminate coal in California's energy sourcing, as previously planned (Fig. 1).[18] Ironically, that's what all the Replacement Procurement strategies in the JP and PG&E's Testimony prove, perhaps unwittingly.

To illustrate the flexibility of DCPP's clean generation in relation to its ability to work actively with RPS variability: on 8 September, 2015 (before the Aliso leak), DCPP management was asked to delay a scheduled refueling operation so that possible, late-summer power shortfalls (especially from RPS components) could be avoided:[9]

> "*A planned maintenance outage scheduled to begin today on Unit 2 at ... [DCPP] has been postponed to make certain there is enough electricity to reliably meet California's energy needs during an upcoming heat wave.*
>
> *PG&E delayed the planned work ... at the request of [CAISO], ... that works to ensure there is enough to electricity to reliably meet state demands. PG&E will conduct the planned outage ... after CAISO determines there is enough backup generation available to meet state electricity demands.*
>
> *DCPP is a vital resource for California. It is a safe, clean, reliable and affordable energy resource for PG&E's customers statewide. We are absolutely committed to ensuring that our customers continue to receive a steady supply of reliable power, and we will continue to coordinate with the CAISO on an appropriate time to perform the planned outage*," (PG&E Senior Vice President and Chief Nuclear Officer Ed Halpin, 9/8/2015.)

That was done and clean-power shortfalls were avoided, thanks to a wise CAISO request and DCPP. This conclusively refutes PG&E's argument that DCPP's "*generation capacity is not needed*".

"Renewable" Energy Sources. PG&E's Application and Testimony hide some basic physics and engineering. There is no such thing as "renewable energy." Science and engineering remind us of "conservation of energy" – a harsh reality. There are no "perpetual-motion" machines. "Renewable" energy is a non-physical, misleading marketing term.

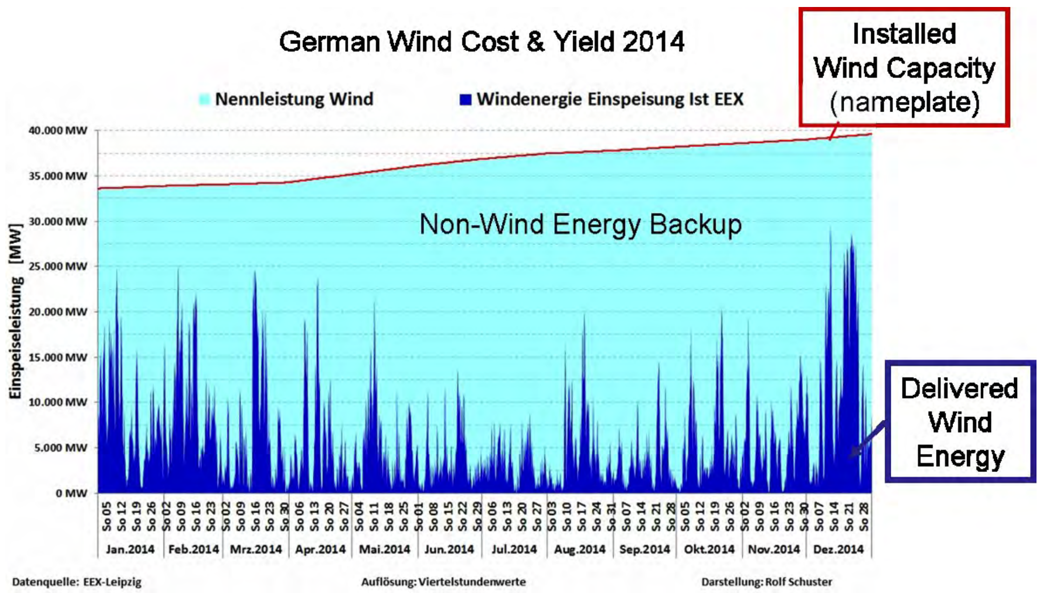
Not only are there unavoidable "conversion losses" in energy-production systems, some sources are also unpredictable in their outputs and even subject to climate change (*e.g.*, wind).[10] Solar-derived energy is more predictable in many locales, but inevitably fractional in its daily energy yield versus its design capability, simply due to Earth's rotation. This is also expressed by "Duty-Cycle" – sun is up, solar is on, sun is down 2/3 of a day, solar is off – solar-power Duty Cycle is about 1/3 (usually less).

The fractional production of energy in relation to a given source's design and materials capability ("nameplate" power) is that source's Capacity Factor (CF). Thus wind energy has a highly variable CF on a daily basis, yielding far less energy on average than could the resources (structural, electrical, *etc.*) designed into its wind-generator gear. Wind power's CF is typically near 1/3 in good locales, meaning about 3 times as many wind generators are needed to generate the rated (nameplate) power of any given group of them. Solar PV/CSP has an even lower CF of about ¼.

Atop the above realities are "missed opportunity" and "stranded asset" costs – if the sun's not out, or wind's too slow or too fast, or their power is not needed or storable, energy passes those systems by, never to be available to them again. These costs are particularly high for solar/wind systems (*see* CGNP Testimony for Scope 2.6), even if overbuilt by 1/CF and additional investment is made in energy-storage systems, assuming they will even exist, energetically and economically. In contrast, hydro, geothermal and nuclear have no such lapses – especially nuclear, where its energy is already stored internally, climate-independently and where un-fissioned atoms remain at the ready for millions of years -- truly flexible operation.[9, 17] There is no foundation for PG&E's overblown "over-generation concerns" in their

JP and Testimony.

Based on my research (and others'), Germany[11] has provides a clear example of the cost-versus-energy yield of "renewables" such as wind/solar PV, and how their over-reliance has increased annual emissions.



Note: The area of the ***blue*** *spikes divided by the area under the* ***red****, capacity-investment curve is the Capacity Factor-- far less than 0.3 in 2014. The graph of German solar for 2014 is worse.*

For 2014, German citizens paid for (through tariffs) the upper red line of nameplate wind power and received in return the lower blue spikes, despite there being "good wind" in their onshore and offshore wind-generator installation locales. The narrowness of the spikes indicates low Duty Cycle; the total spikes' area divided by the area under the red line yields German wind's very low C. The light blue area indicates the "rescue" energy needed to to maintain the country's economy (very expensively). Solar power in northern Europe has proven even less useful. The energy shortfall had to be made up by other sources, mainly combustion, nuclear (in and out of Germany) and other external energy purchases. Germany thus failed to meet its international GHG-reduction commitment.

These realities provide us all with a good lesson, in both energy choices and energy costs, including soaring management/stability costs. For Danes and Germans, costs have been clearly documented[11] and, since the graphing below, have accelerated past 39 cents/kWh.

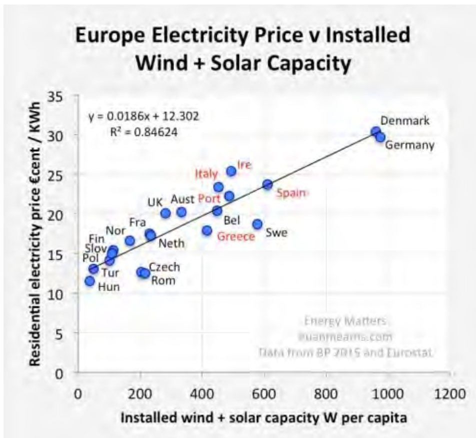
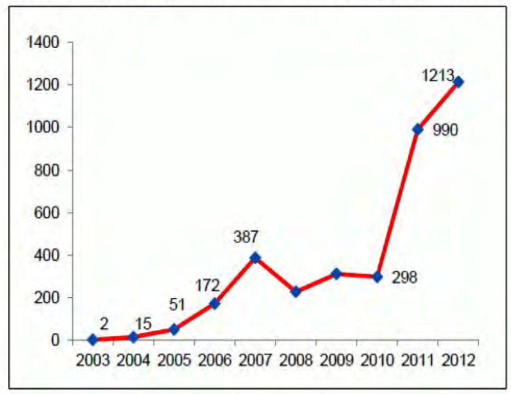


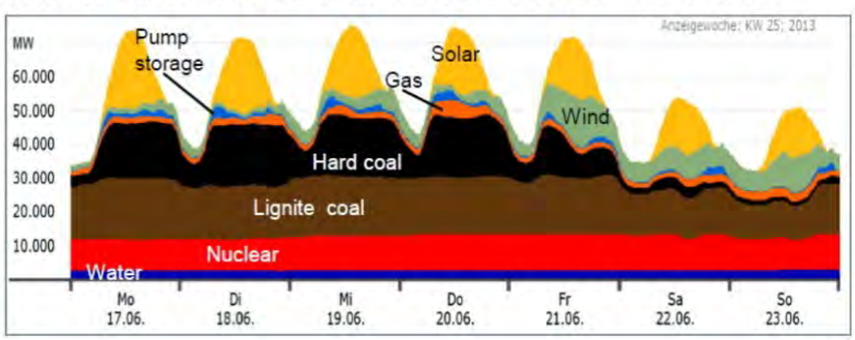
Figure 25. Grid interventions to stabilize the grid by grid operator



http://tinyurl.com/kyq6ddr

Countries with both lower emissions and lower electricity costs (above) are largely dependent on nuclear power. Even Germany, facing reality, has not greatly reduced its nuclear-power dependence, whether from its own plants or via external purchase.

Figure 26. SIEMENS: Weather-related fluctuation of renewable energy (solar and wind power) with significant influence on operation regime of conventional power plants



http://tinyurl.com/q7y6pfy In 2014: "*Germany's wind turbines as a whole ran at between 0 to 10% of their rated capacity 45.5% of the time (3986.75 hrs)! The* *turbines, which the German* *government says will become the "workhorse" of the German power industry, ran at over 50% of their rated capacity only for 461 hours, or just 5.2% of the time*."

As a result of various wind-generation "episodes," German grid-management costs have spiralled ("*Figure 25*" graph above) such that Germany has legislated destruction of 6GW (nameplate) of wind power by 2019.[15] In early 2016, their citizens were actually asked to turn on as many appliances as possible to combat a sudden wind-power surge that threatened to bring down the country's electrical system. German industry has also suffered -- $millions in equipment damage.

"Germany's wind and solar power systems have provided too much power at unpredictable times, which damaged the power grid and made the system vulnerable to blackouts. Grid operators paid companies $548 million to shutter turbines to fix the problem…Germany will get rid of 6,000 megawatts of wind power by 2019..."[30]

Over half a billion dollars were lost (plus raw materials and manufacturing embedded in thousands of wind generators).

Even South Australian wind power has been problematic for grid stability, power cost and reliability.[16] South Australia was blacked out on 9/28/2016, plunging 1.7 million residents into darkness. The country's utility blamed the blackout on violent fluctuations in output of a wind farm in Snowtown. The "farm" suddenly stopped providing 200 MW (with needed rotational inertia), causing grid instability. Then, a wind farm in Hallett experienced 70 MW fluctuations. All this induced other Australian power services to cut links to South Australia, causing its power grid to collapse entirely. The blackout is estimated to have cost businesses AUD$367 million.

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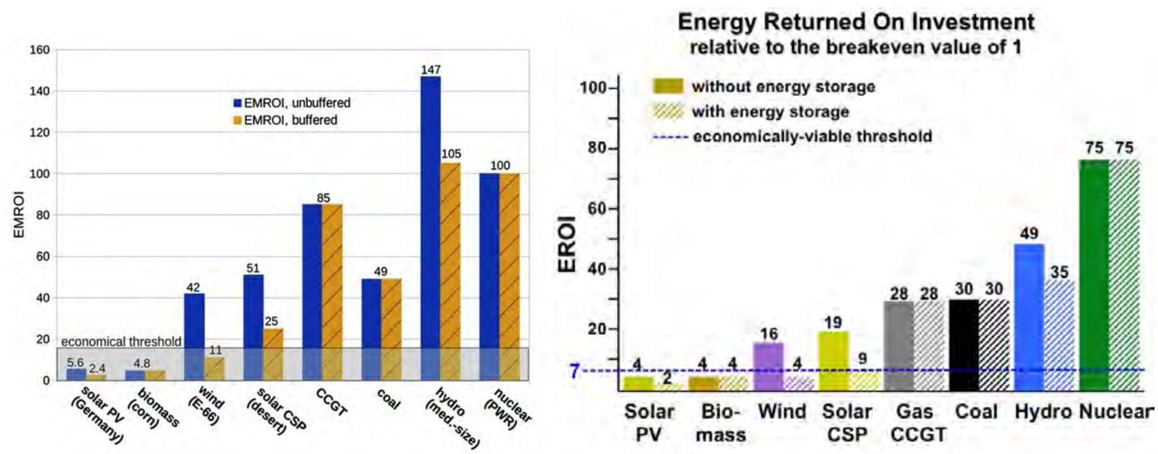
[30] http://dailycaller.com/2016/07/10/germany-votes-to-abandon-most-green-energy-subsidies/

The lesson from those who have invested greatly in wind/solar energy is that the investments (unless subsidized by rate/tax payers) do not pay off, in comparison with non-polluting, high CF sources, such as hydro, geothermal and nuclear.

> Warren Buffet (2014). "*...on wind energy, we get a tax credit if we build a lot of wind farms. That's the only reason to build them. They don't make sense without the tax credit.*" [31]



A study based upon data from two continents and a variety of sources suggests that as wind penetration increases, CO_2 reductions decrease, due to the cycling of the fossil-fuel plants that make up the balance of the grid. Several studies analyzed in this paper suggest that, when 20% of grid electricity is wind power, there is only a 4% reduction in GHG emissions.[32]

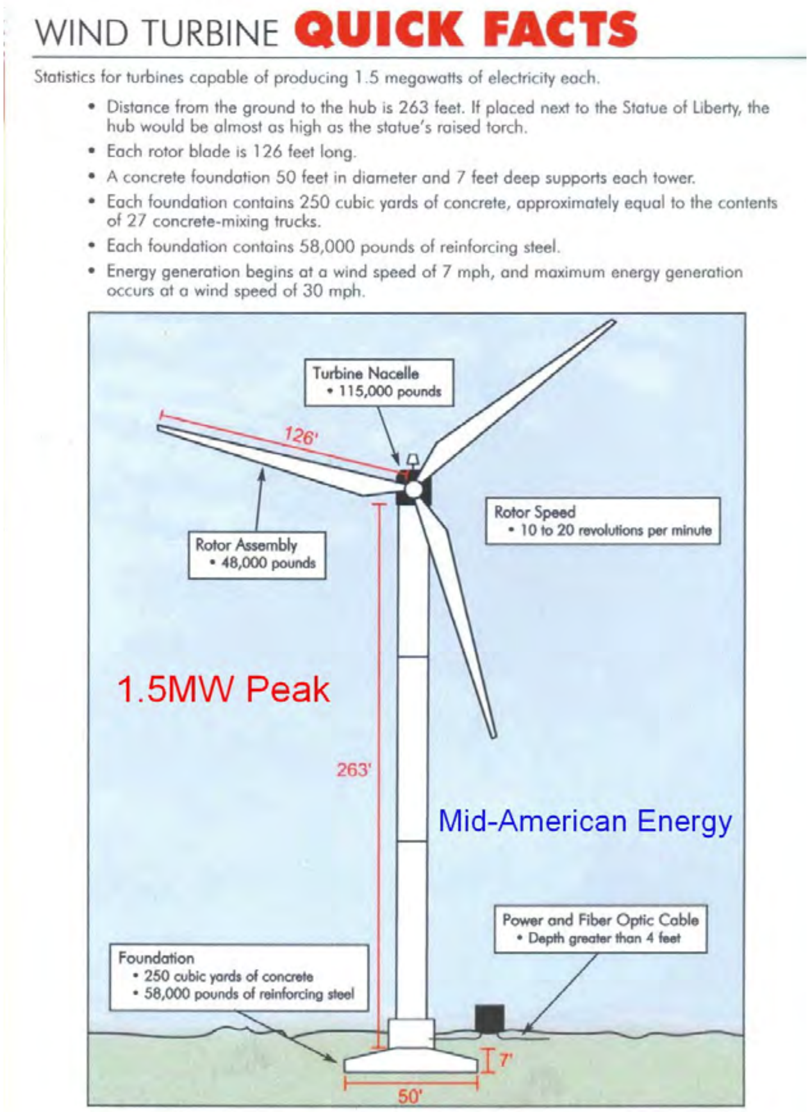
Wind/solar issues: resource and environmental.[23] PG&E and Parties to the JP appear to not grasp the implications of adding gigaWatts more dependence on intermittent wind and solar power in California – all necessary to their claims to be able replace (via "tranches") even their proposed, small fraction of DCPP's output.

[31] http://tinyurl.com/meule2r
[32] *Renewable and Sustainable Energy Reviews* 15, 2011, pp. 2557-2562.

CARB has already documented (above) California's increase in GHG emissions due to SONGS shutdown, and the CEC's in-state energy figures (above) and approved gas-plant expansions (*e.g.*, 600MW on 2/10/2016) document the need to rescue intermittent wind/solar generation with gas (in-state) and/or coal (out-of-state).

Moreover, a modern wind generator consumes about <u>2000 tons of raw materials per average MW</u> of electricity ever generated by the machine. This is partly due to the fact that designs only safely accept wind velocities from about 20 to 60mph. And, all of those <u>raw materials are mined, processed, fabricated, transported and installed via fossil fuels</u>. A ton of steel, for example, consumes more tons of coal, much in the form of coke, to produce proper carbon steel. Then, there are the tons of rock and limestone needed for the hundreds of tons of concrete supporting each wind generator – the limestone is kilned via fossil fuel and demands about 300kWHrs of equivalent energy to produce each ton of Portland Cement for a proper concrete mix.

A data sheet for a 1.5MW peak (nameplate) wind generator made by Mid-American Energy illustrates the massive resource consumption for just one modest machine, whose average yearly generation in the real world will at best be 1.5 x CF (~1/3), or about 500kW. The tower consumes ~150 tons of steel.



Few wind promoters clearly document such vast resource dependencies. But, Mid-American also provides a promotional video of an entire wind-generator's construction, from fertile prairie acres to a truly massive result whose resources still yield low-CF intermittent power:

https://www.youtube.com/embed/84BeVq2Jm88?feature=player_detailpage

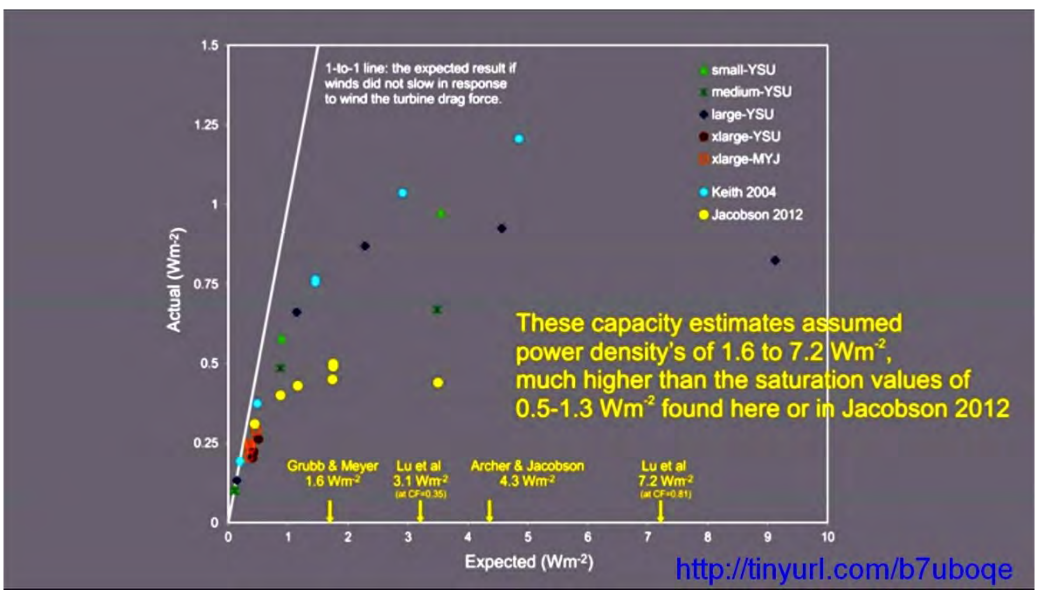
And the most advanced wind generators, as by Siemens, also consume huge quantities of rare-earth elements for magnet structures in their generators. A Siemens materials-engineering manager recently explained via video conference[24] from Germany that their 3MW peak (nameplate) wind generator consumes about 2 tons of Neodymium and related RE elements, the vast majority of which are only sourced by China.

The materials used by each modern wind generator are sufficient to fabricate the world's largest nuclear-reactor vessel.[26] The materials used in about 20 such wind generators build an entire nuclear power plant capable of generating, 24/7, about 500 times the energy of all those wind machines put together. A simulation of this reality appears here: https://www.youtube.com/watch?v=zc7rRPrA7rg

Wind-power's low CF is not only due to its weather and climate susceptibility, but to a scientific reality -- the Betz Limit, which simply reflects that a propeller is an inefficient means for capturing linear air motion (about 600W per square meter at 25mph) for rotational motion, as a generator needs. The best prop-generator conversion of wind to mechanical rotation is about 56% (Betz). Obviously, a propeller can't remove all the wind's energy, letting air molecules pile up infinitely behind it.

And, there's an even more basic reason for prop-generators' low energy density: downstream wake interference. Wind generators must be widely spaced to avoid one machine's disturbed air from interfering with the next one in the airflow. And, as wind direction changes (quarters), interrelationships among machines change. Thus wind generators must waste large amounts of land, while missing most of the energy embodied in the oncoming air's velocity – most wind "farm" wind never "sees" a propeller.

Wind-power assessments in general have been refined worldwide and indicate further over-optimism about their possible contributions to our growing clean-energy needs -- for example, careful analyses suggest we might at best gain less that 1.5W per square meter of land using wind (prop-generators).



The low CF of the result of all the above wind-resource investments is chastened further by relatively-short component lives, threats to species and the large amount of pollution currently produced by mining, processing, fabricating and transporting wind-generator materials. Because China currently dominates world markets for many raw materials and for inexpensive fabrication as well, poorly-regulated pollution in China from wind/solar materials and device production has raised world concern.[25]

Thus, approval of A.16-08-006 will not only reduce California's ability to meet our Legislature's and Governor's emissions targets, it will add some amount to unnecessary global pollution beyond GHGs.

Solar-power problems. On-structure (rooftop) solar PV/hot-water are useful environmentally and electrically because they confiscate no new lands, evict no species, add little extra to global warming, and gain efficiency by delivering power close to loads.

Industrial-scale solar, however, whether PV, thermal-conversion (CSP, etc.) share both the low CF of wind (typically much lower) and much of its fabrication pollution, as indicated above.

Present PV suffers a unique physical drawback – low conversion efficiency, with large heat waste. The best PV cells (and panels) today convert only about 20% of incoming solar energy (~1kW/square meter) to electrical energy output. Thus about 80% of incoming radiance ends up heating PV cells, panels and the air around them. This not only results in convective air heating (as glider pilots exploit over dark, plowed fields or parking lots), but creates unnatural infrared emissions from the panels upward into the air. This "black-body" radiation excites GHG molecules, coupling more heat into the air than if the PV wasn't present.

Scientists refer to such unnatural, human-structure-induced heating as contributing to the "*Heat Island Effect*" (table below). It's one reason why AB32 requires "cool roofs" on commercial structures and DoE has advised similarly for residences. Rosenfeld *et al.* expressed this with a table linking GHG emissions from cars to unnatural IR emitted from dark (hot) roofs.

	Solar Reflectivity Increase	CO_2 Offset by 100 m^2 (~120 sq yards)	CO_2 Offset Globally
White Roof	0.40	10 tons (~2 cars)	
Average Roof	0.25	6.3 tons	**24 Gt**
Cool Pavement	0.15	4 tons	20 Gt
Total Potential	--	--	**44 Gt**
Value of 44 Gt CO_2 at $25/t ~ $1 Trillion 100 gallons Gasoline/year => ~1 ton CO_2 **Global CO_2 emissions in 2009 ~24Gt** **(Akbari, Menon, Rosenfeld. *Climatic Change*, 2008)**			

Their analogy is that increasing reflectivity by 40% per home is equivalent to not driving 1 or 2 combustion-powered cars for a year or more. In other words, structural reflectivity makes the atmosphere appear to have fewer tons of GHG in it. It's a one-time benefit, of course, but reflectivity makes roofing last much longer too, with related manufacturing/installation energy and waste reductions. Even healthy plants avoid the Heat Island Effect.[23]

PV, on the other hand, is not regulated under AB32 and because of extreme economic competition, has no regulated reflectivity to reduce PV's own Heat Island Effect. If today's PV is installed on a poorly-reflective roof, then the GHG result is a wash. In other words, painting a roof white would accomplish the same effect. Thus PV cells, panels and fields get very hot, adding directly to local/global warming via convection and IR radiation. Touch a PV panel in the sun to see why the inverters on their back sides are designed to handle 85°C!

Present PV also suffers from ongoing degradation of about ½-1% of output loss per year, simply due to suffering UV damage to the innards of the PV junctions.

High temperature in semiconductor PV also reduces efficiency in generating electricity, due to quantum effects and simple electrical-resistance increase. So, an ideal PV installation is in the Arctic, as long as the Sun is visible above the horizon. Weather, of course, is crucial and though cold weather makes PV more efficient, it may come at a bigger even dangerous price.

An example of large, industrial-scale PV is the Topaz installation,[27] consuming over 9 square miles of open land, whose original reflectivity was that of a fair roof (pictures below), and is now near that of a tar roof. Topaz' yearly "generation is expected to be 1,100 GWh [~110MW], the capacity factor is 23%". PG&E has contracted to buy its intermittent power, which is about 6% of what DCPP produces, 24/7 – not exactly a reliable Replacement Procurement per PG&E's Application.

Note the bulldozed-earth approach, evicting most native species.


Topaz' cells are CdTe, of mediocre efficiency and dangerous if not recycled properly after degradation, which makes the project too inefficient when considering that better PV is available. The waste heat and IR from Topaz is about equivalent to about a 9-square-mile tar roof: more than 12GW while the sun is mostly overhead. Looked at per AB32 and the Heat Island Group's analyses, it corresponds to about 140,000 homes erected with tar roofs in the desert. Ironically, Topaz operators may have cut back on panel cleaning, allowing dust to both reduce output and improve reflectivity.

Combined with PV's heat generation, fabrication energy and pollution costs, degradation leads to an overall cost of present PV that makes its use at industrial scales even more expensive, because of necessarily long, lossy transmission to loads and grid interfaces, backup provisioning, natural land consumption, species threats, etc. These economic realities are discussed in detail in CGNP Testimony for Scope 2.6.

Solar thermal differs from PV in that it is essentially coupling solar radiance directly to a heat-engine, via a working-fluid tank onto which sunlight is reflected by mirror arrays. At Ivanpah, the fluid is molten salt. At other sites it may be an oil passing through plumbing at the focus of reflecting metal troughs. From those heat sources on, a plant is similar to a combustion or typical nuclear plant – the working fluid raises steam to drive a turbine and generator. These systems are all of about the same thermal-energy conversion efficiency: 33-40% -- better than PV on both output and waste heat.

The higher the working fluid's temperature, the higher the overall efficiency from sunlight in to power out. However, some choices are challenging for solar energy as input, since the sun is up but a fraction of a day (fractional Duty cycle), so heat storage overnight is essential for any solar-thermal (CSP) plant that wishes to deliver power beyond sunlit hours. It's even more essential for CSP like Ivanpah's, which must not let its salt cool below about 400C, whereupon it solidifies, with harsh consequences. Thus Ivanpah is rescued by gas – more gas than planned.

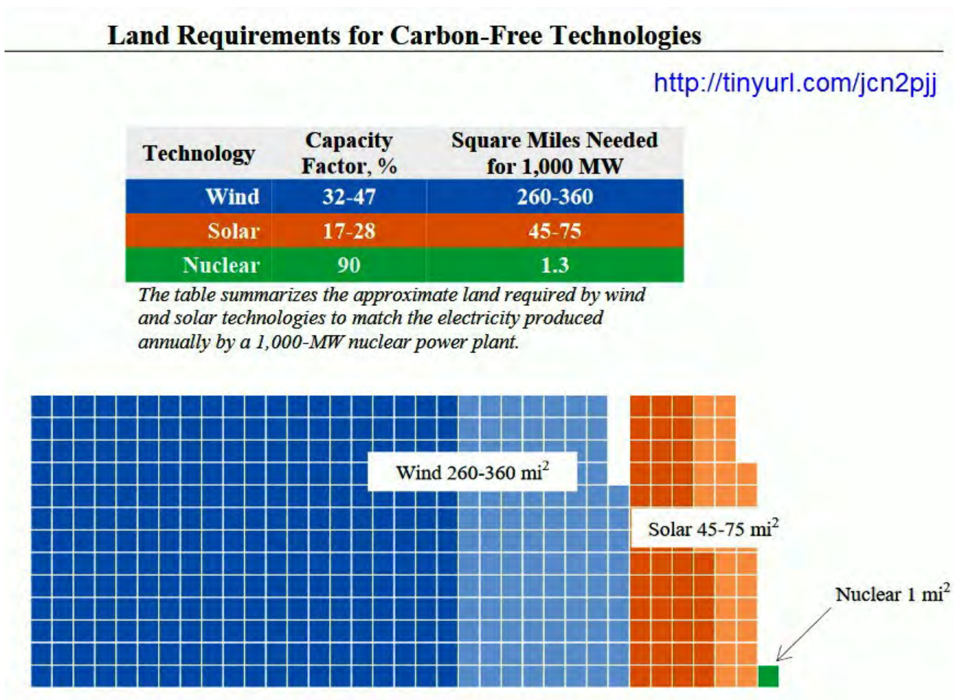
The problem for all solar generation is the firm natural limit of input solar energy: 1kW/square meter at noon. This is why CSP and PV systems consume vast land areas.

PG&E has even bought into the ongoing Ivanpah (left hand picture) saga,[28] despite its "Planned generation [of] 940 GWh" per year being just 940/18000 or about 5% of DCPP's. That's the CSP reality for Ivanpah's target "gross capacity of 392 megawatts" while the sun is up. So far, even that lowered target has been difficult to meet:

"*Performance improved considerably in 2015 — to about 650 GW·h, but ownership partner NRG Energy said in its November quarterly report that Ivanpah would likely not meet its contractual obligations to provide power to PG&E during the year, raising the risk of default on its Power Purchase Agreement… PG&E contracted to receive 640 GWh/year from Units 1 and 3, while SCE is supposed to receive 336 GWh from Unit 2… for which they pay about $200/MW·h (20¢/kW·h)* [about 5x DCPP's energy cost]. *In March 2016, PG&E agreed not to declare the plant in default for at least four months, in return for 'an undisclosed sum' from the owners*"[28]

This has resulted in both an energy and financial shortfall at Ivanpah, including possible forfeit of a $1.6B federal loan guarantee.

Thus, despite the thousands of acres of natural lands sacrificed to industrial-scale PV/CSP, environmental benefits are missing: Ivanpah cooks birds and bothers pilots; Topaz evicted desert tortoises and more, and wastes teraWatt-hours of heat and GHG excitation. And, their financial sagas have just begun.



<u>Local solar plus present and advanced nuclear</u> (geothermal included), plus environmentally-limited hydro, do the job just fine. They do it cleanly and as far into the future as we wish. Topaz and Ivanpah have consumed over 8000 natural acres – all for a small, low CF fraction of what DCPP delivers from a few tens of acres[27, 28] 24/7. And they charge over 10 times as much.

<u>Storage</u> is often <u>raised as the "solution" to low-CF</u> and low Duty-Cycle <u>energy sources</u>' difficulties to reliably meet our energy needs, yet it remains a technical and economic unknown. Storage advances are indeed coming, driven by the need for safe, low mass, high-capacity storage for EVs. <u>Electrified vehicles</u>

are an optimal target for storage developments, because they provide something combustion systems cannot – recovery of dynamic energy stored in a moving vehicle's mass. This recovery is realized via "dynamic" or "regenerative" braking, which applies the long-known electric-propulsion advantage of turning motors into generators, when braking, to charge batteries. For an EV, this amounts now to returning from a commute with 10-15% lower demand for recharge energy, if the on-board storage (battery) had sufficient capacity to accept all the commuter's braking energy.

Storage for low-CF energy sources, like solar/wind, must be far larger than what's needed for optimal EV behavior. The reason is simple: an energy source of capacity factor 1/3 can never fully charge one unit of storage to be more than 1/3 full. But the demand is one unit, all day every day. Larger storage would be overbuilt and un-economical for such a source.

In order to fully charge a one-unit energy-storage system, we thus must overbuild the low-CF generation system by a factor of 1/CF – more, in real life. And, rescue (backup) systems (typically gas turbine) must also be built, connected to the grid, managed and fuelled. Thus the cost of wind/solar 'renewables'-dependent energy systems with storage is be more than tripled, while emissions are greatly increased over those of higher-CF systems.

This raises another, perhaps untenable cost and engineering hurdle: to achieve full charge via tripled build-out of CF=1/3 generation, the storage system being charged (and ready for discharge of 1 – CF over each day) must be able to accept charging energy at an extraordinary 1/CF rate. In other words, electrical storage for low-CF sources is special – it must handle input currents 1/CF higher than it will ever be asked to deliver when the source is off (no sun/wind). It has to "make hay [1/CF more hay] while the sun shines" and wind blows, so to speak.

This is technically challenging, and expensive.[31] And, it directly affects system reliability, not just initial and operating cost. Low CF energy sources create far more problems, with costly implications and uncertain results, than do high-CF energy sources. The economics of 'renewables' overall is discussed in detail in CGNP Testimony for Scope 2.6.

Even the CEC's energy-storage target of "1,325 MW by 2020" is only about ½ of DCPP's 24/7 delivery and it's not clear what the CEC thinks the yearly energy competence of that storage hope is: http://www.energy.ca.gov/research/energystorage/tour/ .

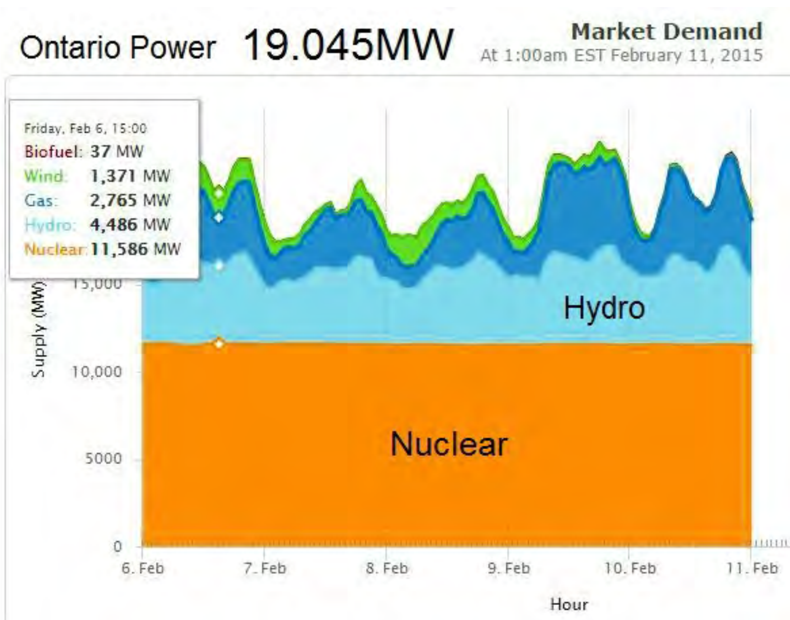
Of course, capable storage is already used in the CAISO region – the Helms pumped-storage facility is charged when demand lowers, as in the evening. Sources like DCPP deliver its "charging" power. And, the next day, Helms can return about 75% of that stored energy to our electric system. And, the complete system is not overbuilt, nor are the charging pumps at Helms 3-4 times the capacity of the generation turbines there. Inputs and outputs are balanced within about 25 percentage points, which has long reaped cost and reliability benefits. Finally, we know DCPP (and others like it) are quite capable of flexibly adjusting output[17] to meet the demands of grid stability in the face of "renewables" variability being illogically forced upon us by an unrealistic RPS and Loading Order.

Why waste resources, lands, species and energy trying to meet the 24/7, ~19GW CAISO "baseload" with 3x or 4x overbuilds of wind/solar "farms," plus make-up gas power, plus 2/3 or ¾ of 19GW-days of storage that doesn't even have an existence date or cost? This is a fatal, fundamental flaw in PG&E's and all JP Parties' proffering of Replacement Procurement "tranches" for even the small fraction of DCPP they unscientifically and unconvincingly put forth.

Approval of A.16-08-006 will not only reduce California's ability to meet our Legislature's and Governor's emissions targets, it will add some amount to unnecessary global pollution.

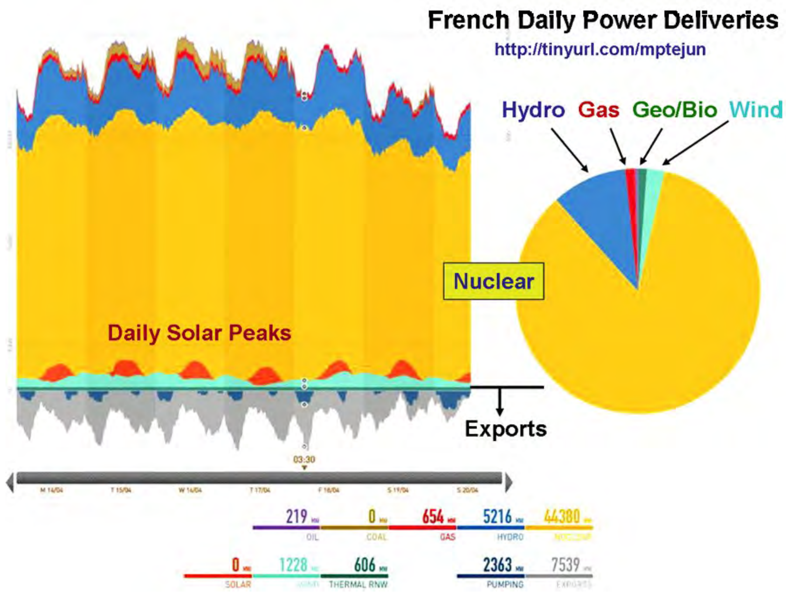
Worldwide, scientists like Sir David MacKay[12, 13, 31] have long explained the unfortunate physical realities of "renewables." In 1987, when DCPP was young, various nuclear-reactor designs were then classed as "renewable-energy" sources -- World Commission on Environment and Development report.[21]

Ontario, Canada provides an excellent example of wise energy sourcing (19.045 = 19,045):

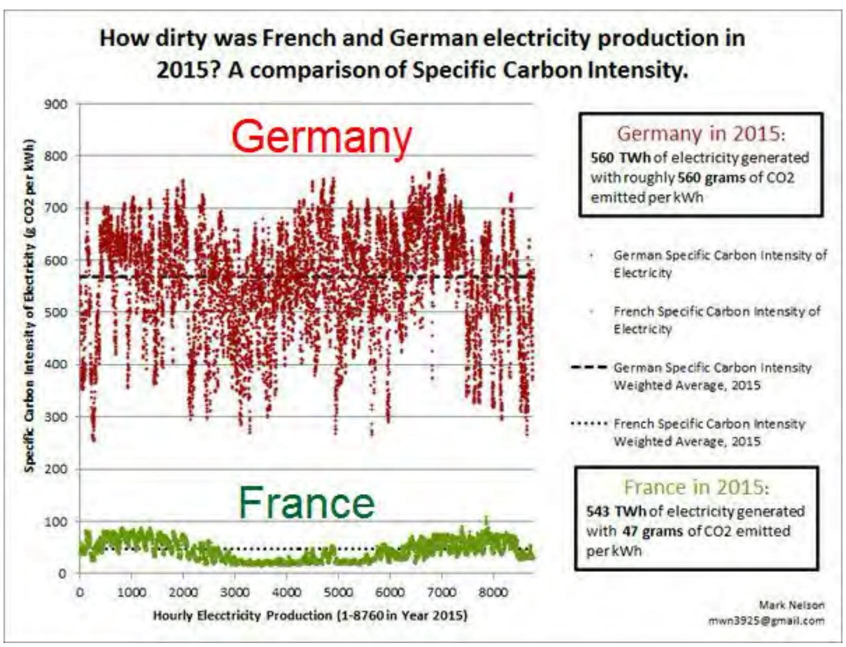


Ontario's total demand is about equal to CAISO's 24/7 demand (baseload) of about 20GW, indicated earlier. Its nuclear output is equivalent to about 5 DCPPs or SONGS. Its wind/solar sources do not cause much demand for combustion backup. Its emissions are superior to California's now and to our targets as well. http://tinyurl.com/zu8kt59

France, like Ontario, is similarly advanced and clean, even while balancing "renewables" output successfully with a grid that is highly dependent upon nuclear:



And the emission-reduction fruits are unmatched:



"*France emits around* <u>*40 grams of CO2 per kwh*</u>*. Germany, the US, Japan, and most other industrialized nations emit between 400 and 500 grams/kwh.*"

Scientifically, the most nearly renewable energy sources are solar and nuclear (geothermal is nuclear), since each derives from stellar fusion. Solar PV/CSP, *etc.* derive from radiance generated by the Sun's nuclear-fusion core. Nuclear-fission power derives from fusion energy stored in heavy elements (Actinides like Uranium) whose nuclei were fused from smaller elements in giant stellar shockwaves surrounding ancient exploding stars or massive young ones.

DCPP (like any Uranium reactor) simply discharges electro-mechanical energy stored billions of years ago in Uranium atoms. It (and all fission power plants) is an already-charged energy-storage system, with a very high CF (typically 90%) and operating Duty Cycle of 100%. DCPP is rechargeable via a climate-independent energy source (fissile Uranium atoms) whose energy density exceeds any other source by a factor far beyond 500,000 -- an extreme environmental benefit held by no other available energy source.

Capacity Factors and LCOE (comparable costs) for all US power sources are recorded by the EIA.[14] For 2013, EIA data did show extreme subsidization of 'renewables' with nuclear and natural-gas power being the least subsidized.

Table ES4. Fiscal Year 2013 electricity production subsidies and support

million 2013 dollars, unless otherwise specified

https://www.eia.gov/analysis/requests/subsidy/pdf/subsidy.pdf

Beneficiary	Direct Expenditures	Tax Expenditures	Research and Development	DOE Loan Guarantee Program	Federal and RUS Electricity[a]	Total	Share of Total Subsidies and Support
Coal	61	642	167	-	30	901	6%
Natural Gas and Petroleum Liquids	18	662	10	-	-	690	4%
Nuclear	37	1,109	406	-	109	1,660	10%
Renewables	**7,408**	**3,373**	**722**	-	**176**	**11,678**	**72%**
Biomass	62	9	47	-	-	118	1%
Geothermal	221	22	2	-	-	245	2%
Hydropower	194	17	10	-	171	392	2%
Solar	2,448	1,712	234	-	-	4,393	27%
Wind	4,274	1,614	49	-	-	5,936	37%
Other	209	-	380	-	5	594	4%
Subtotal Renewables Electric	**7,408**	**3,373**	**722**	-	**176**	**11,678**	**72%**
Biofuels	-	-	-	-	-	-	-
Electricity - Smart Grid and Transmission	**8**	**211**	**831**	-	**134**	**1,184**	**7%**
Total	**7,532**	**5,996**	**2,136**	-	**449**	**16,112**	**100%**

This contrast adds to the uncertainty of PG&E's Testimony and JP assertions about making any Replacement Procurements in ratepayer and public interest.

Plant Type	Capacity Factor (%)	Levelized Capital Cost	Transmission Investment	Total System LCOE	Subsidy[2]	LCOE including Subsidy
Dispatchable Technologies						
Conventional Coal	85	60.4	1.2	95.1		
Advanced Coal	85	76.9	1.2	115.7		
Advanced Coal with CCS	85	97.3	1.2	144.4		
Natural Gas-fired						
Conventional Combined Cycle	87	14.4	1.2	75.2		
Advanced Combined Cycle	87	15.9	1.2	72.6		
Advanced CC with CCS	87	30.1	1.2	100.2		
Conventional Combustion Turbine	30	40.7	3.5	141.5		
Advanced Combustion Turbine	30	27.8	3.5	113.5		
Advanced Nuclear	90	70.1	1.1	95.2		
Geothermal	92	34.1	1.4	47.8	-3.4	44.4
Biomass	83	47.1	1.2	100.5		
Non-Dispatchable Technologies						
Wind	36	57.7	3.1	73.6		
Wind – Offshore	38	168.6	5.8	196.9		
Solar PV[3]	25	109.8	4.1	125.3	-11.0	114.3
Solar Thermal	20	191.6	6.0	239.7	-19.2	220.6
Hydroelectric[4]	54	70.7	2.0	83.5		

Source: U.S.Energy Information Administration, *Annual Energy Outlook 2015* April 2015, DOE/EIA-0383(2015).

EIA Notes: 3 Costs are expressed in terms of net AC power available to the grid for the installed capacity.

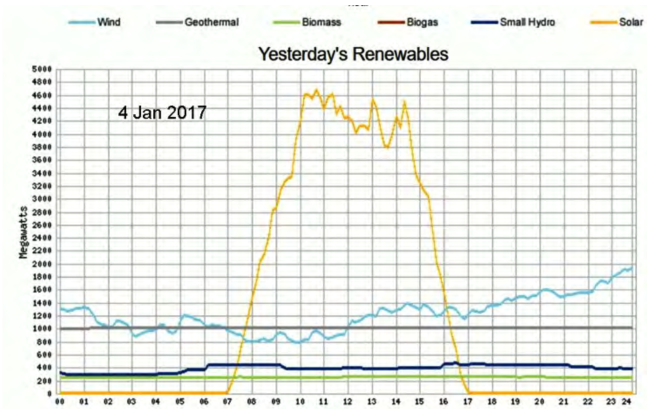
4 As modeled, hydro electric is assumed to have seasonal storage so that it can be dispatched within a season, but overall operation is limited by resources available by site and season.

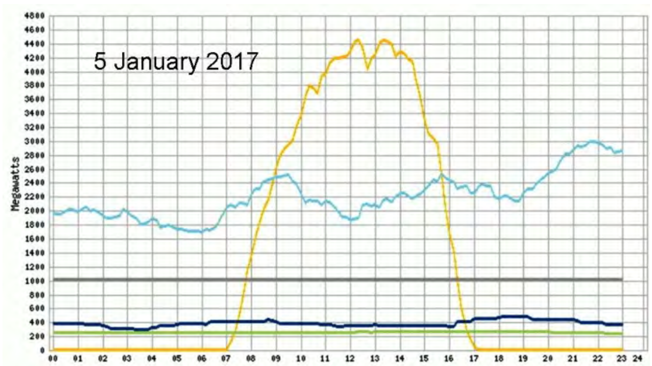
Current (advanced) <u>nuclear builds are superior in LCOE and CF</u> to nearly all "renewables" -- the two partial exceptions being hydro and geothermal -- each having one slightly better value.

Industrial-scale wind and solar generation have such poor Capacity Factors that they require more rescue (backup energy) from other sources than they themselves deliver – wind requires >60% of its nameplate power to be made up by other sources (primarily gas combustion in California), while solar (even in California sun), requires still more rescue generation and concomitant GHG production. DCPP is environmentally far superior to any such "replacements." Only a counterfactual RPS and Loading-Order force intermittent sources' occasional power to un-environmentally and un-economically displace reliable, clean sources, such as hydro, geothermal and nuclear. And, the expense of this is mammoth.[31]

In fact, DCPP's capacity was improved some years back by installation of two more efficient steam-turbine stages – no nuclear changes were made, yet more than 50,000 homes received clean power because of the upgrade. Similar, further turbine improvements have long been available, but not installed because of a California law that precludes DCPP from generating more power without threat of suit. Thus additional thousands of California homes have been denied DCPP's GHG-free power via counter-factual state artifice beyond our narrow RPS.

CAISO provides daily insight onto the variability inherent in "renewable" sources. The following two CAISO sequential daily summaries on the next page display both the "on-off" and choppy nature of California solar-energy sources and the poorly-predictable California wind-energy sources:

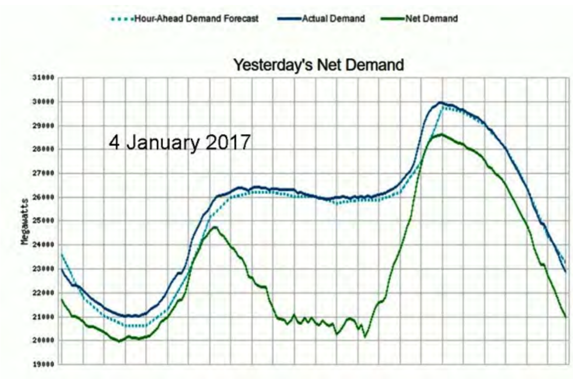


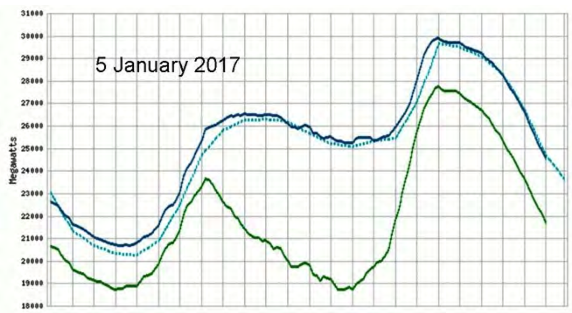


Note the constancy of geothermal power, which corresponds to almost the output of 1 DCPP reactor and turbine. Note also choppy, but somewhat predictable solar output and typical, nearly 2:1 variation in wind power between the two days.

The corresponding CAISO Net Demand (subtracting RPS-source outputs displayed above) shows the characteristic midday dip in Net Demand (green curve), which led to its whimsical shape characterization as the "duck curve."

And, note the **10x larger** vertical scale of Demand versus "Renewables" power:

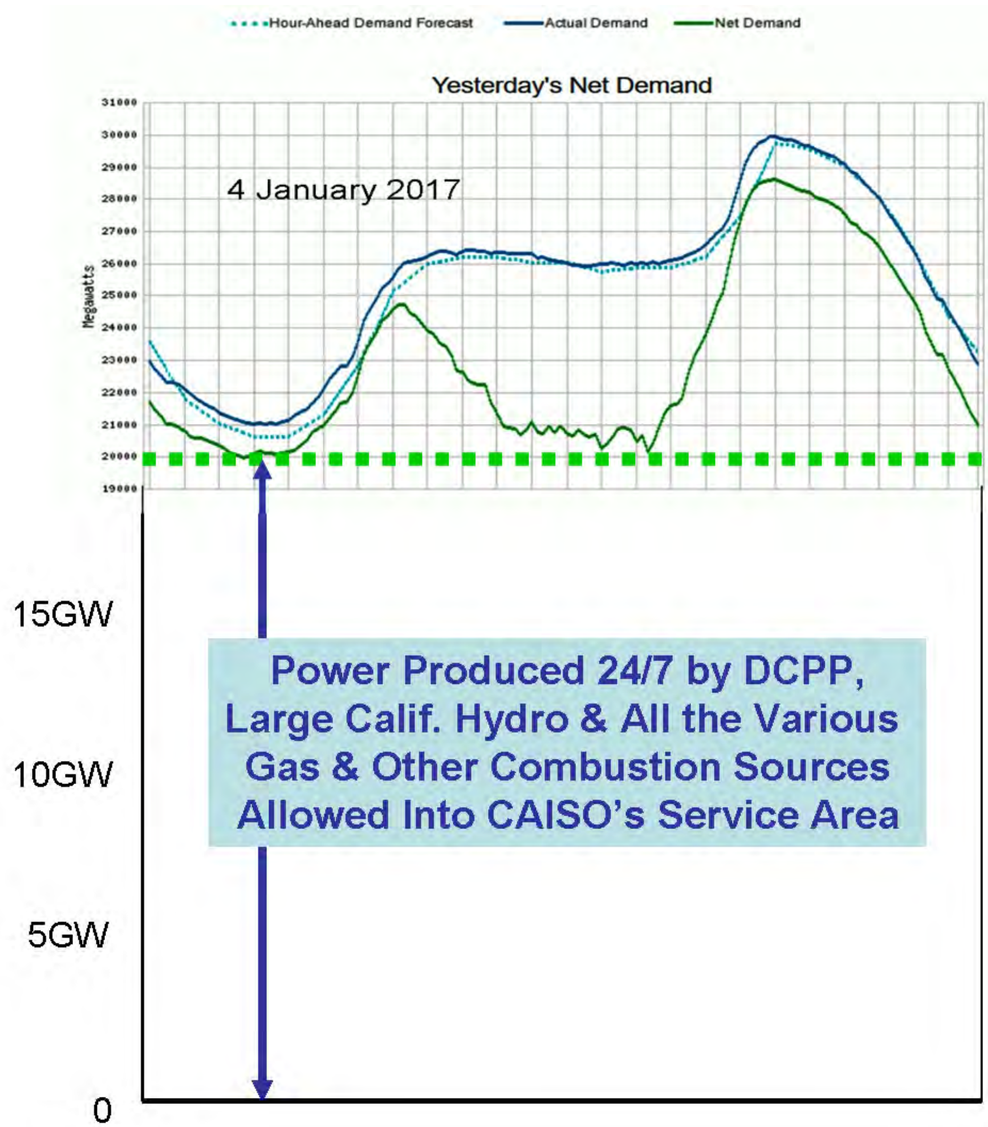




Note: never does net demanded power fall below 18GW, even when RPS sources are doing their best. California's citizens and economy never require 24/7 power delivery below about 9 DCPPs or about 18 times our total geothermal output.

In other words, nothing supports a belief that expansion of its comparatively weak, variable sources could physically and environmentally satisfy PG&E's DCPP Replacement-Procurement needs, as defined in its Application, JP and Testimony. Based on all my experience, I conclude that: "*reducing GHG emissions 40% below 1990 levels*" could not possibly be met without DCPP (and likely San Onofre and additional California nuclear power reactors) in full operation.

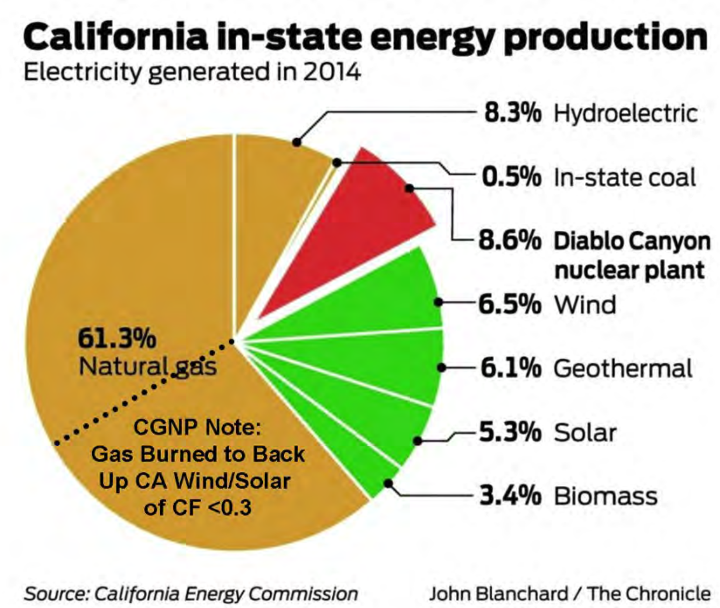
Graphing CAISO's Net Demand without bias shows the following:



This makes clear: a) present RPS sources are small (~1/8) in relation to 24/7 demand (baseload); and b) there's no factual support for removing DCPP from our power mix in vain hope of replacing its energy and environmental benefits via present RPS sourcing, while also decreasing state emissions far below their present values. PG&E ignores (CGNP Scope 2.1 Testimony) the reality that DCPP can run flexibly, accommodating most any RPS-source variations.[17] The graph also shows that forcing wind/solar output into the top of our Loading Order, at the expense of reliable clean sources achieves little but waste, in ratepayer and environmental costs, and emissions.

Every day, CAISO data points us to the scientific and environmentally-responsible path – expand geothermal and nuclear power in California[33].

Emissions consequences are also evident in daily CAISO reporting. The CEC's graphic below indicates that 2014 RPS energy production totaled 21.3% of all California energy production. Of that, 8.1% was rock steady (as in above graphics) geothermal. 3.4% was fairly steady biomass burning. Geothermal and biomass contributed little net GHG emissions, but what about the wind/solar total of 11.8%? Their low CF values mean what for emissions?



Based on my studies of all available scientific data accepted by authorities like myself and the CAISO, it is abundantly clear that increasing wind/solar sources commits California to more natural gas extraction, leaking and burning. That isn't a path to "…*reduce GHG emissions to 40% below 1990 levels.*"[1]

[33] See the 2011 *California Council on Science and Technology* report (sponsored by CEC) indicated in the **Conclusion** of this Testimony.

Again, the mean CF for California wind and solar total generation was (and is) below 30%. That means at least 70% of 2014's RPS-required California wind + solar (nameplate) power was supplied by other, flexible means. In California, that's primarily gas burning (the large, lower pie slice in the figure above). Outside California, as for the Los Angeles DWP, it's largely coal burning, as at LA's contracted Delta, Utah Intermountain coal mine and power plant, discussed earlier.[18]

Of gas's orange, 61.3% of the CEC's energy pie above, more than twice the total of wind/solar delivery of 11.8% was committed to rescue of wind/solar shortfalls due to their low CF. Of the ~210TWHr in 2014, gas-combustion delivered about 129TWHr. Solar/wind delivered about 25TWHr -- assume a generous CF of 0.3, then (1/.3 - 1) x 25 = 58TWHr -- a conservative estimate of the gas-burning energy that rescued California's 2014 wind/solar production. 58TWHrs is over 27% of total energy production for 2014. Or, it's 45% of the gas percentage arc and was only there to rescue poor wind/solar reliability/capacity.

For 2016, wind/solar gas backup amounts to about the same slice, which is larger in absolute energy. Not surprising that on 10 February 2016, our CEC easily approved 600MW of new gas generation, just in the San Diego region (see CEC hearing transcript). The extra CO_2 emissions, due to just wind/solar reliance in the California RPS, amounts to about 32 million metric tons of CO_2 (at 1.22lb/kWHr, per EIA FAQ). This is about 4 times the equivalent emissions of the US-record Aliso Canyon gas leak,[8] and about equal to the equivalent emissions from all California's allowed methane leakage. It is clear how California's wind/solar GHG benefits have been repeatedly wiped away by our state's gas dependence.

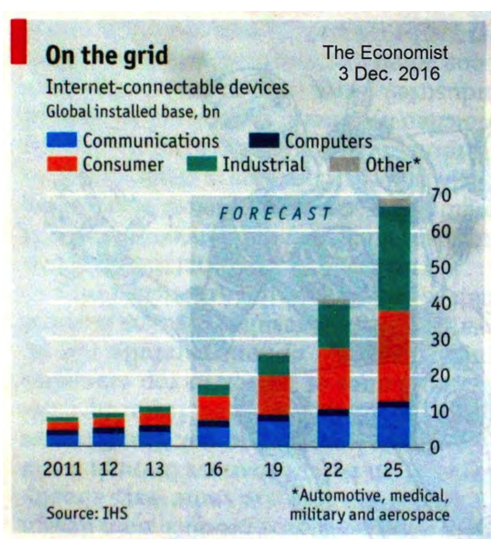
In stark contrast, DCPP produces about 18TWHr/year of energy (~9TWHr/reactor-year), with CF of about 0.9, no emissions, and DCPP at most is dependent on scheduled backup of 1.8TWHr (about 2MW), derived as desired, from non-combustion sources like hydro, geothermal, Helms Pumped Storage, *etc*.

This was exactly illustrated in September 2015, when CAISO requested a delay in DCPP's scheduled fuelling operation, so that unreliable wind/solar generation could be avoided in the face of forecasted high summer power demand.[9]

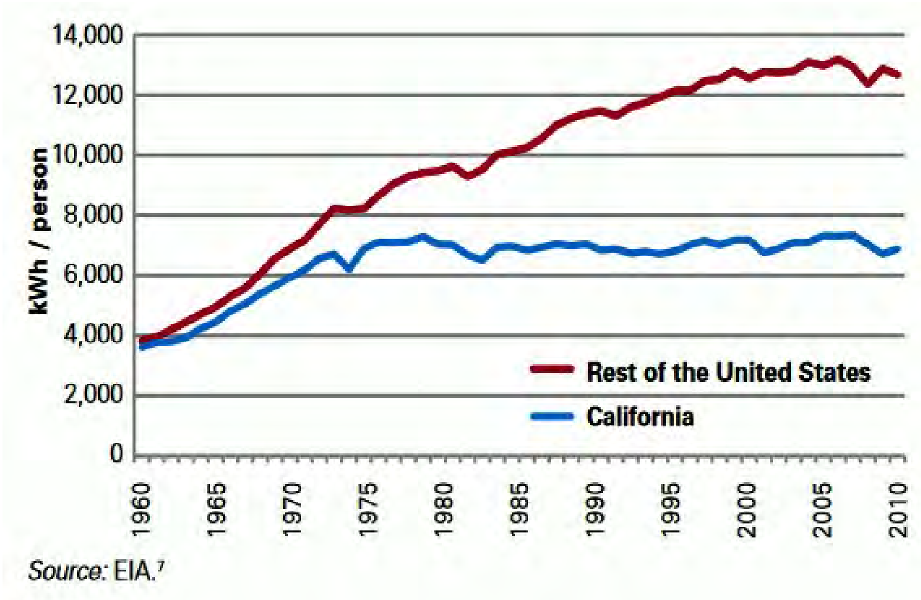
These are verifiable scientific facts. It appears to me that the materials PG&E submitted in this proceeding are not factual, and that this can be verified. CGNP Testimony to Scope 2.6 addresses the economic details of proposed alternative energy sources and related counter-factual PG&E statements in their Application, JP and Testimony.

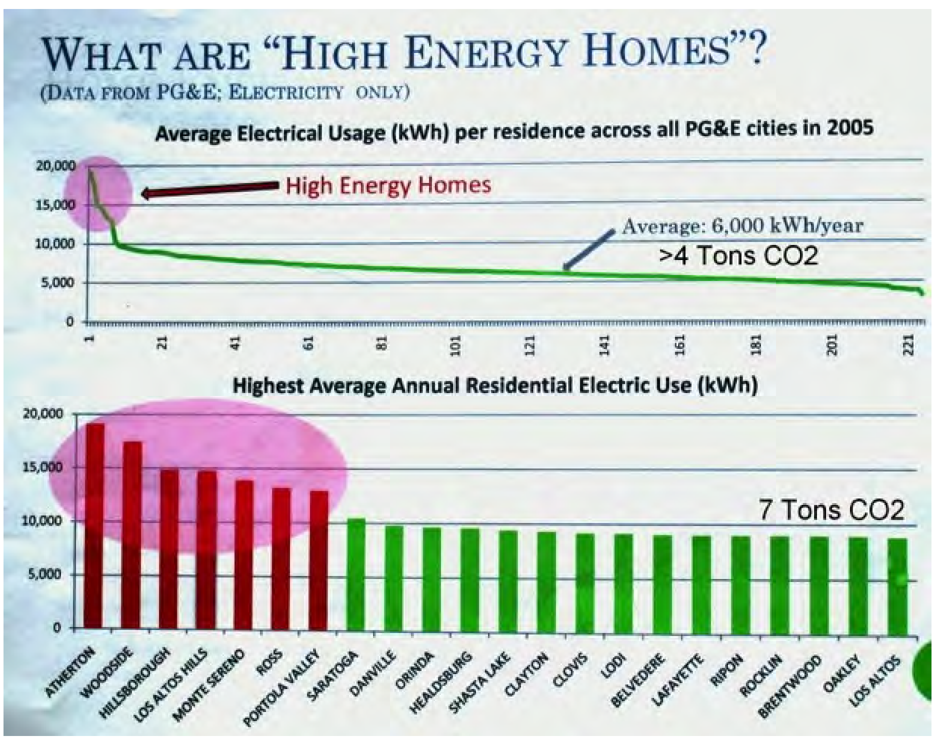
Demand Reduction is claimed to be a viable source of "Replacement" for a small bit of DCPP's clean power. But, measured from already-achieved efficiency gains (described earlier), there is no evidence of citizen or industrial demand reduction to date, and there are large additions to demand across the US, which Californians already engage in.

Burgeoning use of communications devices and systems of all types is now increasing power demands at accelerating rates. For example, just the "Internet of Things" growth is near exponential:



The stability of California's per-capita energy use up to 2010 did not comprehend added electrical devices of all sorts, and certainly didn't claim to model the impact of rechargeable EVs, which consume about 20kWHrs of electrical energy per commuting worker per day. That's the nominal consumption of a single-family home by itself – >6MWHrs/year:

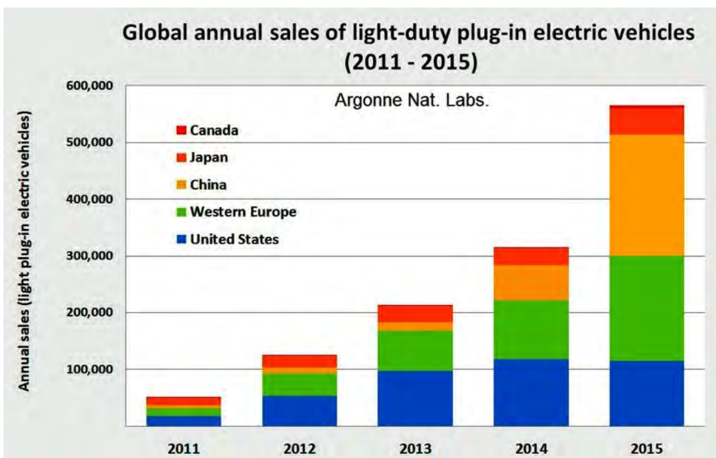




And note the uptick in Calif. electrical usage per capita near 2010.[19]

Just EV proliferation and use is on track to double the electrical load demanded by all California homes today (about 6MWHrs/year each).[20] And that ignores population growth, which from 2010 to 2015 increased over 1% (over 400,000 people). In terms of electrical usage, that's about 1 DCPP – and the device and EV explosion had barely begun.

Demand reduction may indeed occur in PG&E's service area, due to CCA/CCE activities, but that's unlikely to offset the demand increases above. There is no sensible reason to remove about 20% of California's clean-power when it soon will soon be needed even more than now.



Google itself provides a very clear example of why DCPP use must continue and even why SONGS should be repaired and re-operated. Google is the largest corporate consumer of electricity. Just their "renewables" purchases for 2015 delivered Google 5.7TWHrs – about 1/3 of DCPP. That number will increase greatly, with Internet expansions, as described above. Aware of this, Google is moving to higher CF sources. Marc Oman, EU energy lead at Google[22]:

"*Our founders are convinced climate change is a real, immediate threat, so we have to do our part. We want to do contracts with forms of renewable power that are more baseload-like, so low-impact* *hydro; it could be biomass if the fuel source is sustainable, it could be nuclear, God forbid, we're not averse. We're looking at all forms of low-carbon generation.*"

Those are important decisions. Internet/social-media companies create about 2% of global GHG emissions, rivaling airlines. Clean energy, as from DCPP, must be expanded, not shuttered for narrow corporate reasons, as PG&E intends in its Application.

Grid stability has long been essential to modern society and industry. A utility is defined by its services and their availability to customers. Such systems serve the public good 99.999% of every year. Advanced societies don't accept much more than 5 minutes a year of water, sewer, fire, police or power outages.

Yet, PG&E and its Parties, are asking that science and engineering fact be suspended so they can replace one of the most reliable power sources in their mix (DCPP, with ~90% reliability plus designed-in felxibility[17]) with the most unreliable (CF < 1/3) sources, and do that in unspecific ways, with unspecified, third-party products. CGNP Testimony for Scope 2.6 elaborates on this functional and economic unrealism. Some world examples illustrating "renewables" realities:

Sweden and Ireland: Recent studies[29] by the Max Planck Institute and the Royal Institute of Technology found that if Sweden's nuclear plants were replaced with wind power it would make the electrical grid unreliable. Conventional natural gas and coal power plants would be needed to compensate for the unreliability. That would double CO_2 emissions. The study was published in the *European Physical Journal Plus*. (Wagner et al. "*Study on a hypothetical replacement of nuclear electricity by wind power in Sweden*".)

Colorado: The Bentek Corporation measured emissions of CO_2, SO_2 and NO_X from coal plants in

Colorado and Texas.[30] They were cycling their outputs in response to fluctuations in the output of wind farms in those service areas. By correlating changes in coal-plant emissions with wind-power generation, the study concluded that cycling the coal plants produced a pronounced increase in emissions from those plants. The study concluded that those increases emissions largely cancelled reduction of GHG emissions via the wind generators. Actual GHG savings were minimal. The study also concluded that using natural gas turbines to back up the wind machines would result in a smaller increase in emissions. That, of course, depends on effective gas-leakage management.

Further German examples include unpredicted wind-power surges – see Voltage Surges[11] – some even damaging grid components and industrial machinery. As the references explain, Germany is now set to destroy thousands of wind generators simply because of the costs and instabilities they create.

California: The Wastern Area Power Authority (Sierra-Nevada Region https://www.wapa.gov/regions/sn/Pages/sn.aspx) is responsible for powering several US-government facilities, such as LLNL, LBL, SLAC (all DoE labs) and NASA Ames. Their power demands are typical for large research facilities, excepting NASA Ames. While the others do consume large amounts of power, their extreme loads are scheduled, as lengthy experiments run.

NASA Ames runs experiments too, often in the largest wind tunnel in the world. In an experiment, which must run for about one hour, or be a large financial waste, wind-tunnel motors will routinely throttle from 100MW to 300MW in about a minute, and do this repeatedly for the length of an experiment. The inductive nature of the large driving motors greatly challenges phase-stability on the grid. Ames contracts with WAPA to meet their demand fluctuations. Often, this is via hydro-output control, but the timing of their demand can also fit with DCPP's flexible-operation ability[17] and its ability to provide phase stability. Clearly, both lengthy, high-demand (*e.g.*, SLAC) loads and large, variable (*e.g.*, Ames) loads must be reliably served. DCPP can help do both, while unreliable wind/solar cannot – their shortfalls will trigger dynamic phase adjustments, gas combustion, thermal waste and emissions.

Again, PG&E and the JP Parties do not properly assess or explain how their self-admittedly modest "tranches" of Replacement [Power] Procurements can credibly allow even a reduction by half of DCPP's clean, stabilizing, 24/7 energy, while advancing our Legislature's and Governor's emissions-reduction goals. PG&E's Application should be rejected.

PG&E Testimony Analysis. The Application makes many projections and unsubstantiated assurances for what would be a truly unprecedented transformation of our electric grid. Therefore we must consider real-world experience with issues of cost and reliability actually being experienced with the proposed technologies proffered as DCPP replacements.

If DCPP were to be replaced by the 80:20 wind/solar mix proposed in the JP, it would likely be rescued by fossil-fuel plants, especially the least-efficient, more polluting, gas peaker plants. This is because of the very high costs and technical uncertainties associated with constructing required storage systems and 1/CF source overbuilds, as explained earlier. The JP and Testimony set no specific procedures and goals for constructing adequate storage systems, not to mention the wind/solar, etc. overbuilding and management of poor Capacity and Duty-Cycle sources.

Nor does PG&E's Testimony explain how it will guarantee that all its Replacement Procurement contracts, RECs and EE efforts will be verified via competent, continuous audit of the chosen energy sources. PG&E's Prepared Testimony makes the odd, unsupported claim:

> *"Given California's energy goals that require increasing reliance on renewables—at least 50 percent by 2030—the California electric system will need more flexible resources while the need for baseload electricity supply will decrease. PG&E will need less non-renewable baseload generation to*

supply its electricity customers. Hence the need for baseload power from Diablo Canyon will decrease 30 after 2025." (pp. 1-3 lines 24-30)

As explained earlier, backing up wind/solar generation with fossil-fueled plants will result in large net GHG- emissions and air-pollution increases, whether from combustion or leakage, as compared to the current, clean operation of DCPP. The expected outcome, after many billions of dollars in new costs, would be unacceptable emissions increases plus reductions in grid reliability.

PG&E (and Parties to the JP) Testimony ignores the scientific fact that "baseload" is not the only provisioning DCPP can deliver.[17] And they hide that CAISO's daily, 24-hour requirement is equal to about nine DCPPs running at full output. Closure of DCPP fails to be in the public interest, and fails our state government's needed reductions in GHG emissions and other environmental threats. I also noted the following factual inconsistencies in PG&E's testimony, for example:

"It is unclear what GHG-free resources, including RPS, EE and DG, will develop between now and then to help fill the gap; It is uncertain how much load growth there will be between now and 2025 and, as customer loads shift to CCA and other alternatives, it is equally unclear which LSE bears responsibility to meet customer needs in 2025; and There is also great uncertainty about the scope and timing of future compliance requirements that will apply in order to implement the State's GHG emission reduction target of 40 percent below 1990 levels by 2030 as stated in Public Utilities Code Section 454.52. In the face of this uncertainty, the natural reaction is to defer making any new GHG-free resource additions until a GHG emissions reduction compliance obligation is adopted by the Commission and, with the passage of time, there is sufficient clarity on the future resource mix and the size of its customer loads." (p.)

PG&E's Application has been made without proper acknowledgement of scientific/ engineering/environmental and business realities, and so without the public interest in mind.

We even have the prospect of creating mini-ENRONs, back from the past, as various holding companies, exploiting repeal of the 1935 PUHCA, gain footholds in the REC, CCA/CCE/DA power markets. They can thus exploit unwitting power purchasers who can't actually audit cleanliness of sources – PG&E itself makes no mention of how they'll protect their product quality, post DCPP, from such.

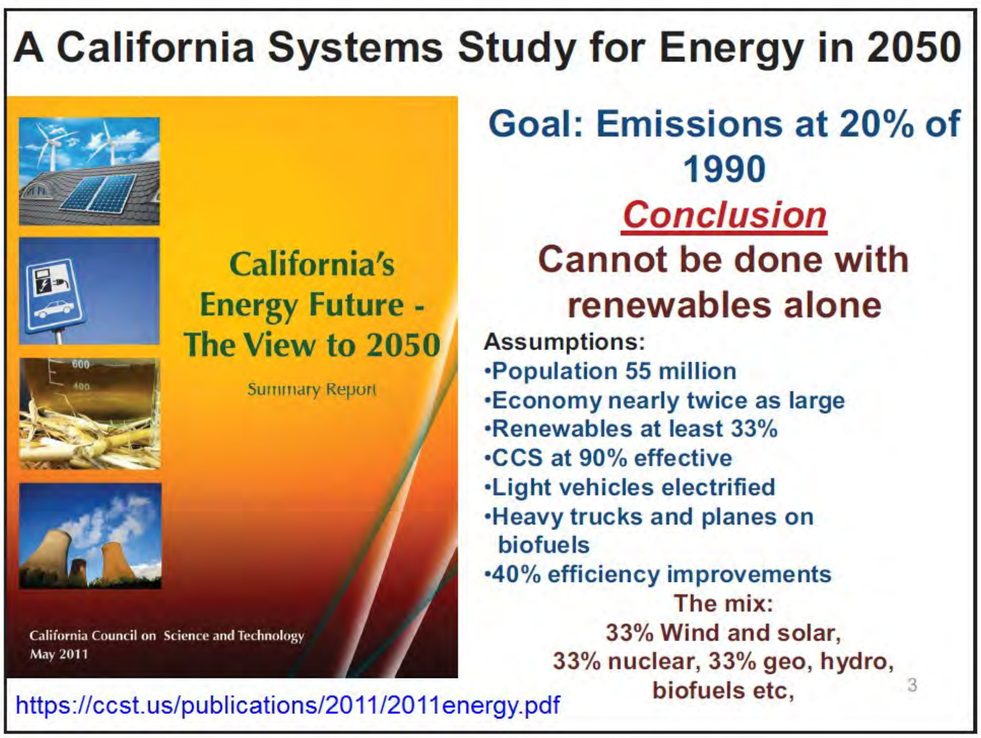
Moreover, if proposals on greater regional grid interconnection go through, they will provide opportunities in California to sell "greenwashed" power from remote wind/solar "farms" and gas/coal plants. LADWP doesn't even bother to mislead about its Intermountain coal plant, which supplies LA with coal power about equal to 95% of DCPP's output. Closing DCPP will make California even more dependent on out-of-state coal burning.

If PG&E does not want to operate DCPP as far into the future as NRC will allow, then it can demonstrate public interest by selling the plant to a competent nuclear operator and proceed to try to build reliable electric service without DCPP and within our malformed RPS definition. It could also contract with the new owner to operate DCPP profitably, and the new owner could sell actual clean power wherever markets with sensible clean-power definitions exist – Google[22] and similar are always looking for reliable, truly "green" energy.

Conclusion: The facts, and the scientific/engineering inferences I draw from them, lead me to believe that <u>CPUC must reject PG&E's Application</u> (A16-08-006) as not in the public interest. Even the fractional Replacement Procurements suggested by PG&E (and its JP Parties) have no surety or engineering or environmental benefit.

Other states[3] and countries have indeed set sound clean-power standards that include nuclear. Our power policy has even increased emissions, as the CARB data and graph shown earlier document when SONGS was shut down. No one wishes that California join Germany as an example of what not to do.

We've already been given a wise plan to follow -- our California Legislature, Governor, CEC and other state agencies have had expert guidance before, as by the California Council on Science and Technology report from 2011, one of whose authors is a Nobel physicist and retired Director of DoE's SLAC. Our descendants likely wish that we use it, in the public interest.



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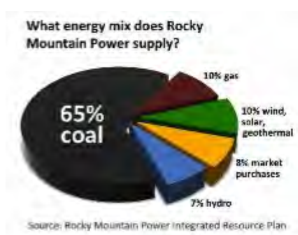

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http://www.pe.com/articles/plant-797333-ivanpah-solar.html http://ww2.kqed.org/news/2015/12/15/nrg-ivanpah-faces-chance-of-default-PGE-contract

29. Sweden and Ireland: *The European Physical Journal Plus,* 2016, DOI: 10.1140/epjp/i2016-16173-

8) http://tinyurl.com/gld8a3w http://tinyurl.com/3cl6f7p http://tinyurl.com/bfn8866

http://dailycaller.com/2016/06/14/study-replacing-nuclear-with-wind-would-double-co2-emissions/

http://www.forbes.com/2011/07/19/wind-energy-carbon.html

http://www.coalitionforenergysolutions.org/irish_wind_energycwk_wp.pdf (Irish example)

30. Colorado: http://tinyurl.com/j7pgjsl

https://www.wind-watch.org/documents/how-less-became-more/

31. Imperial College, London: **"***The Costs and Impacts of Intermittency - 2016 update***"** 21 February 2017, http://ow.ly/m6AL3087aB6

http://www.ukerc.ac.uk/events/the-costs-and-impacts-of-intermittency-2016-update.html

CALIFORNIANS FOR GREEN NUCLEAR POWER (CGNP.ORG)

STATEMENT OF QUALIFICATIONS OF ALEXANDER CANNARA, PH.D.

Q 1 Please state your name and business address.

A 1 My name is Alexander Cannara, 2043 Sterling Ave. Menlo Park, California 94025.

Q 2 Briefly describe the nature of your business.

A 2 I am an independent consultant in the field of energy, environmental science, electrical engineering and computer networking, plus related college and other educational instruction. I am now retired, but providing consulting support to the Thorium Energy Alliance, CGNP and a variety local environmental groups, such as the Palo Alto Waste-to-Energy Steering Committee. I also present energy/environmental papers/lectures at various international organizations' meetings, such as the National Conference on Science Education, the American Geophysical Union, the IEEE, the Association for Environmental

Studies & Sciences, the American Nuclear Society, the Association for Materials, the North Sea Council and others,

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science in Electrical Engineering (EE) from Lehigh University in 1961, a Masters and Degree of Engineer in (EE) Plasma Phtysics from Stanford University in 1965, a Masters Degree in Statistics from Stanford in 1974 and a Doctor of Philosophy (PhD) in Mathematical Methods & Computing Systems for Educational Research from Stanford in 1976. During those studies, I served as a Design Engineer in precision electronic measuring systems for Ballantine Labs & the Singer Company. Subsequently, I worked for a federal research contractor to design statistical analyses & interactive computer systems for federal research projects. I then moved into the Silicon Valley semiconductor industry, providing Applications Engineering consultation and training to customer engineers & managers at various companies, such as Zilog, AMD, 3Com, Vitesse & small startups. I also worked as a software consultant, providing software designs & products to meet specific customer needs. Over the last 15 years, I provided computer-networking consulting to many customers with regard to the design, security and performance of their networks – customers range from Citibank, Goldman Sachs, Wells Fargo, CBIC & CBOT to NASA & Duke Energy. I did similar work for small local firms and various medical organizations, such as Planned Parenthood, Florida Hospital & McKesson.

Q 4 What is the purpose of your testimony?

A 4 I am sponsoring the following testimony sections in CGNP's objections to PG&E's

Proposed Retirement of Diablo Canyon Power Plant (Application 16-08-006), Implementation of the Joint Proposal, and Recovery of Associated Costs through Proposed Ratemaking Mechanisms:

Section 2.1 "Retirement of Diablo Canyon Power Plant"

Section 2.2, "Proposed Replacement Procurement"

Section 2.5, "Recovery of License-Renewal Costs"

Section 2.8, "Additional Issues Not Discussed Above"

Q 5 Does this conclude your statement of qualifications?

A 5 Yes.

CALIFORNIANS FOR GREEN NUCLEAR POWER (CGNP.ORG)

STATEMENT OF QUALIFICATIONS OF RIPUDAMAN MALHOTRA, PH.D.

Q 1 Please state your name and business address.

A 1 My name is Ripudaman Malhotra, 17 Cedar Street, San Carlos, California 94070.

Q 2 Briefly describe the nature of your business.

A 2 I am an independent consultant in the field of energy, environmental science, chemical processing, and innovation. I am now retired, but continue to write on energy issues. I am the Associate Editor for the Journal of Sustainable Energy Engineering, and a Section Editor for The Encyclopedia of Sustainable Science and Technology. I provide consulting services to commercial government organizations, including the Thorium Energy Alliance and CGNP.

Q 3 Please summarize your educational and professional background.

A 3 I received a Bachelor of Science (Hons.) in Chemistry from Delhi University in 1971, and a Master of Science in Organic Chemistry in 1973 also from Delhi University. I earned my Ph.D. in Chemistry from the University of Southern California in 1979 and then joined SRI International where I worked until my retirement in 2015. At SRI most of my research focused mainly on the chemistry of hydrocarbons as they relate to energy conversions and environment. This work made me acutely aware of the twin challenges of supplying the world with adequate affordable energy and the climate change resulting from the use of fossil resources. With my colleagues I co-wrote a book, *A Cubic Mile of Oil*, wherein we described the global energy use from all sources using a common metric, a cubic mile of oil, which happens to be the annual global consumption of oil. We wrote the book with the objective of raising energy literacy in the public and I continue to write and give public lectures on the subject.

Q 4 What is the purpose of your testimony?

A 4 I am providing general testimony in support of CGNP's objections to PG&E's Proposed Retirement of Diablo Canyon Power Plant (Application 16-08-006).

Q 5 Does this conclude your statement of qualifications?

A 5 Yes.

2.3

Proposed Employee Program

Abraham Weitzberg, Ph.D., Sponsor

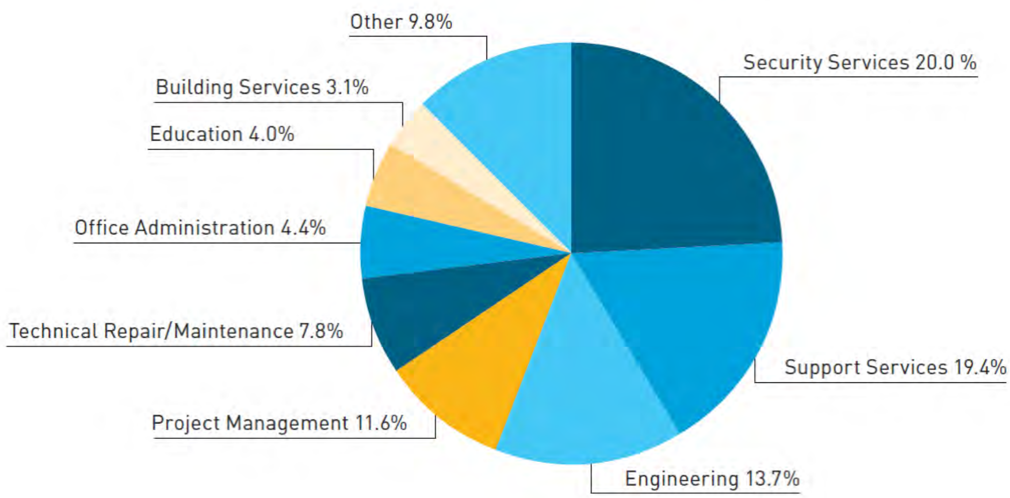
PG&E has requested the CPUC to approve an Employee Retention Program and associated cost estimate of $352.1 million; an Employee Retraining Program and associated cost estimate of $11.3 million; and an Employee Severance Program and associated estimate of $168 million.

2.3.1 Employee Retention Program

The stated purpose of PG&E's request for the Employee Retention Program and associated cost estimate of $352.1 million was "to ensure the plant's continued safe and efficient operation through the end of each unit's license in 2024 and 2025." The information provided by PG&E in its Application and Prepared Testimony presents no details on the need for such a program or the potential consequences to the safe operation of the plant should such a program not be approved by the CPUC. PG&E simply states that "The technical experience needed by employees to work and operate the plant safely is not easily obtainable in the open job market" and "[t]he announcement of the plant's retirement will add even more time in DCPP's recruiting cycles."

The proposed Employee Retention Program will provide all management and bargaining unit employees a 25% retention bonus irrespective of the significance of their work relative to the safe operation of DCPP. Figure 10, below, from Section 8 of the PG&E Prepared Testimony, identifies the job classifications of 93.8% of the DCPP employees.

FIGURE 10: DCPP JOB CLASSIFICATIONS



Without delving into the specifics jobs performed by all of the labor categories, one can see there are many obvious categories that that are not safety-related and can be filled from the general labor pool. Additionally, there are the workers who may retire after the first four years (Tier 1) or after the seven year Tier 1 and Tier 2 periods and who could still receive their bonus while not working beyond their normal retirement age.

Even if there is a retention program, PG&E will have to maintain a routine hiring program to replace workers who leave for personal reasons or who are terminated or who die or who cannot work because of illness. No information is presented on the current rate of employee turnover and how PG&E continues to safely operate DCPP with this turnover, and how PG&E would effectively address future turnover prior to DCPP shutdown with or without the retention program. No rationale is provided explaining why a uniform 25% retention bonus is a preferred cost-effective method when compared with plausible alternatives such as offering significantly greater bonuses only to workers in difficult-to-replace safety-related positions.

As discussed in the 20 October 2016 afternoon session of Diablo Canyon Independent Safety

Committee(DCISC)[34] there are very few positions that are key to safely operating DCPP and for families with two wage owners, offering a bonus to one may be inadequate to motivate both wage earners to remain if another dual opportunity avails itself elsewhere. It was also stated that the high rate of acceptance of the proposed retention program by the DCPP workforce, in excess of 80%, should not be taken as support for the plant shutdown, but rather as a no-risk acceptance of the bonus with the worst case scenario being repayment if the worker chooses to leave before DCPP is retired.

Finally, the proposed Employee Retention Program is a very expensive way for PG&E to attempt to minimize its operational risk until the retirement of DCPP, all at the expense of its ratepayers. Because PG&E is voluntarily proposing to retire DCPP, it alone should bear any added costs of maintaining adequate staffing levels.

2.3.2 Employee Retraining Program

On this subsection, we submit no testimony.

2.3.3 Employee Severance Program

On this subsection, we submit no testimony.

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Transcript of the Eighty-Fifth Public Meeting of the Diablo Canyon Independent Safety Committee Held October 19 And 20, 2016 At Avila Beach, California, p. 270 et seq.

2.5

Recovery of License-Renewal Costs

Sponsor: Alexander Cannara, Ph.D

Background: PG&E has proposed (Scope 2.5) that it be granted rate recovery for approximately $53 million in costs relating to license-renewal activities, including the filing of a license renewal application with the Nuclear Regulatory Commission (NRC). Other Parties have questioned whether PG&E should get rate recovery for these costs.

CGNP takes the following position (on Application A16-08-006)**:**

CPUC Should Reject A16-08-006 and Any Recovery of License-Renewal Costs.

My testimony below addresses statements made by PG&E and its Parties in their Joint Proposal (JP) and Testimony regarding Recovery of Licensing Costs for DCPP's NRC-license renewal for operation past 2024-5.

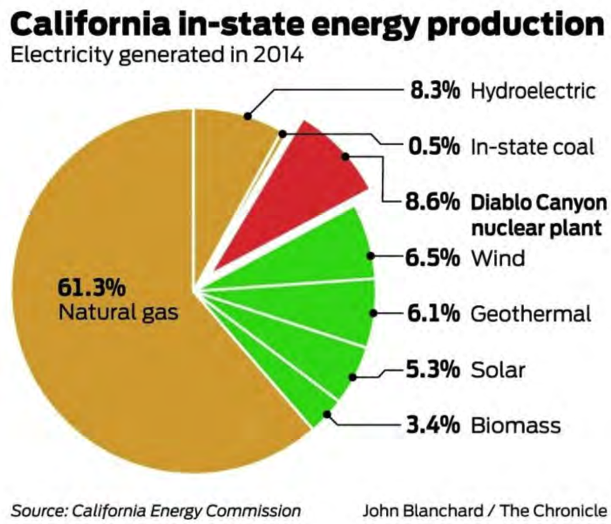
Because PG&E is voluntarily proposing to retire DCPP,[1] it alone should bear any added costs of maintaining adequate staffing levels, operational efficiency, safety and all other DCPP functions, just as they were prior to PG&E's initial decision to apply for DCPP retirement and related compensation.

The above decision by PG&E is not in the public interest. The Joint Proposal was the product of secret meetings among PG&E and special-interest groups (the other JP-signing Parties). The general public and ratepayers had no opportunity for input to the JP and meetings. Thus ratepayers should not be asked to pay for decisions resulting from special-interest negotiations where the public was excluded.

There is no possible benefit to PG&E ratepayers unless License-Renewal activities are concluded, by NRC decision, and DCPP continues in full operation, whether under PG&E ownership or other ownership.

DCPP closure has no possible benefit to the State of California and its citizens, because PG&E already meets and exceeds the state-mandated, future 55% clean-energy delivery target to its service area.[2] Closing DCPP would mean the loss of California's largest carbon-free energy source. That would severely set back efforts required by law to aggressively reduce GHG emissions 40% below 1990 levels. And, it would largely negate decades of our CEC's and Legislature's efforts to stave off powerplant construction and combustion-fuel emissions via energy efficiency (*see* CGNP EE Testimony for Scope 2.2).

PG&E entered NRC license-renewal on 11/24/09[3] with a clear intent to operate DCPP years beyond its present license expiry. To the date of PG&E's Application, no serious hurdles to renewal have been revealed. Nor has there been any evidence that DCPP does not, or would not, continue to operate in the public interest, providing about 8% of all California's electric power, and doing so without GHG emission (*see* CEC chart below, and Scope 2.1 of CGNP Testimony).



It is known that DCPP has a reactor design (pressurized-water) that can adjust output power quickly (about ±5%/minute) to facilitate load following, such as for unpredictable wind/solar-generation transient voltage and phase smoothing (CGNP Testimony for Scope 2.1 & 2.2). There is no validity to concerns of "overgeneration," as proposed by PG&E and Parties.

PG&E commissioned studies on such "flexible operation," and included them in license-renewal costs. The resulting PG&E documents are confidential and not available to the public. It is unreasonable to ask ratepayers to pay for hidden studies.

Further, PG&E should be directed to release any such "flexible operation" study results to DCISC (Diablo Canyon Independent Safety Committee) for its use in overseeing all future DCPP operations, whether A16-08-006 is rejected or not.

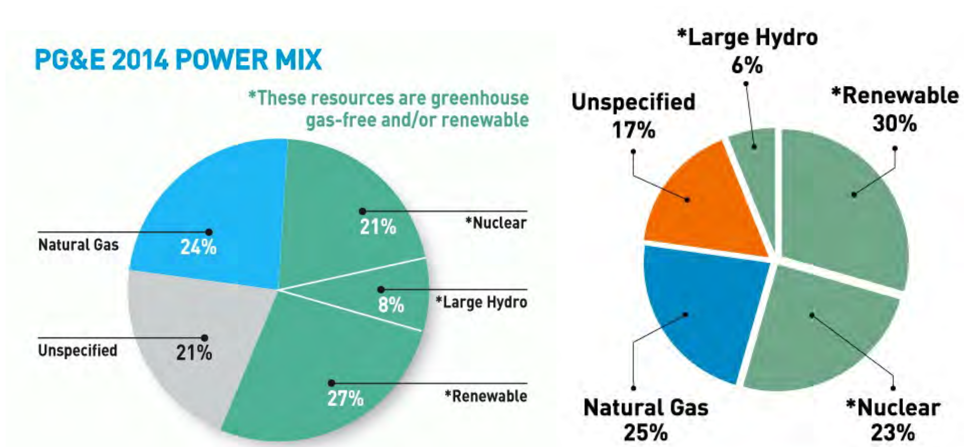
In conclusion, no recovery of PG&E's DCPP licensing or "flexible-operation" study costs should be approved. From 2009[3] until its decision to advance its Application, PG&E made no public CPUC request for NRC licensing-cost recovery, nor did PG&E have any expectation that it could do so, based on all re-licensing actions of all other US nuclear operators. PG&E made repeated re-licensing investment decisions over the years since 2009, under willful NRC direction, while accepting ratepayer money, and has no legitimate reason to ask anyone else to pay for its licensing decisions. Rejection of PG&E's

Application is in the public interest.

References:

1. PG&E Testimony and Joint Proposal (JP) filings: "*PG&E has joined with [the JP Parties] ... to imagine a different kind of energy future.phasing out nuclear power in California in 2024 and 2025. The proposal includes a PG&E commitment to a 55 percent renewable energy target in 2031 — an unprecedented **voluntary** commitment by a major U.S. energy company.*", (p1, lines 15-23, PG&E Testimony).

2. "*Diablo Canyon generates about 20 percent of the annual electricity production in PC&E's service territory and nine percent of California's annual production.*", (JP, p1 "Preamble A). "*More than half the electricity we [PG&E] provide to our customers comes from sources that are renewable and/or emit no greenhouse gases. In fact, PG&E's electricity creates only one-third as many greenhouse gas emissions per kilowatt-hour compared to the industry average.*" - http://tinyurl.com/jmvxhrj Zero-emissions deliveries for 2014 were 56% of PG&E's total electrical energy deliveries, (similarly for 2015 -- http://tinyurl.com/glsmrto **)**…



PG&E already meets & exceeds state clean-power targets because of Diablo Canyon. Diablo Canyon's nuclear-power output remains superior in reliability and environmental impacts to any other California electricity sources. Other states (including AZ, NY, WI; *see* Scope 2.2 of CGNP Testimony) already recognize this in their nuclear-plant legislation.

3. http://tinyurl.com/z6qgcl4   "*Receive license renewal application (LRA)…11/24/09*"

2.6

Proposed Ratemaking and Cost Allocation Issues - Part 1

Sponsor: Michael M. Marinak, Ph.D. [35]

Background: PG&E has requested a rate increase of $1.766 billion dollars in connection with the Joint Proposal's plan to abandon Diablo Canyon Power Plant (DCPP). It also requests that costs related to procurement of replacement power be passed on to customers in the form of a non-bypassable "Clean Energy Charge," regardless of how high those costs become.

CGNP takes the following position (on A16-08-006):

CPUC should reject the Application along with the proposed rate increase and request for a "Clean Energy Charge." CPUC should reject any request to use decommissioning funds to cover any additional expenses resulting from the Application.

The Application fails to justify the proposal to retire Diablo Canyon and replace it partially with wind and solar sources. It proposes to increase electric rates based upon incorrect, unreasonable and incomplete analysis. It fails to address adequately the overall impact upon rates resulting from the proposed action. As a first example, it makes no provision to replace the needed reliable generating capacity that would be lost and does not account for the associated costs of its replacement. Second, it presents no realistic plan to construct the needed storage systems, and fails to account for the substantial associated costs. Third, it makes no assessment of the effect of the proposed action on reliability, nor the potential costs to mitigate reliability problems resulting from its implementation, nor the potential damages to California businesses. Fourth, it fails to address the value of DCPP as a buffer against future increases in natural gas prices, or

[35] In preparing this testimony Dr. Marinak is not representing the views of Lawrence Livermore National Laboratory.

natural gas shortages. Fifth, it does not reconcile cost estimates with data showing nations having the highest dependencies upon the proposed wind and solar sources have among the highest electricity prices.

Utilities are required to assess these and other factors as part of long-term procurement planning and integrated resource planning, but the approach proposed in the Application ignores those processes and obligations. The proposal was drafted in private negotiations, with ratepayers completely excluded from participation. Yet the proposal places most of its very substantial risks upon them, and virtually none upon the parties of the Joint Proposal. These burdens are placed upon ratepayers in part through a non-bypassable "Clean Energy Charge," which is a significant departure from the historic approach to procurement and cost allocation established by the Commission. Benefits are claimed in the Application to justify placing the burden of these unprecedented risks upon ratepayers. Yet the benefits claimed are unsubstantiated. In particular, a realistic accounting would show that the cost of power obtained from continued operation of DCPP would be much less than costs of the proposed alternatives. Furthermore, implementing the proposal would cause substantial increases in emissions of greenhouse gases and air pollution.

The materials presented in the Application and PG&E Testimony are insufficient to establish the proposed action is cost-effective, prudent and in the public interest. The Application is unjustified and would impose upon ratepayers unnecessary and unreasonable rate increases.

The proposal would result in the loss of 2240 MW of needed reliable generation capacity and makes no provision for the costs of a reliable replacement.

For more than 30 years the Diablo Canyon Nuclear Power Plant has served as the backbone of PG&E electrical energy generation. It produces 2240 MW of electricity reliably, around the clock whenever it is needed, and supplies approximately 23% of overall PG&E electricity.[36] This ability to produce electricity on demand is integral to electricity's value proposition. The Joint Proposal suggests that the plant be abandoned in 2024/2025 and proposes that its output could be replaced by combination of new wind and solar photovoltaic (PV) sources, energy storage systems, energy conservation, and alternative suppliers. The proposal fails to account adequately for the fact that the solar and wind sources proposed as replacements are intermittent and unpredictable. This essential issue is referenced, in passing, in Section 2.5 of the Joint Proposal, where "the Joint Parties recognize that there will be significant challenges associated with renewable resource integration." Wind power relentlessly, continuously, destabilizes the balance between supply and demand, is highly variable and unresponsive, and provides no capacity value while inimical to demand cycles. Both wind and solar require effectively 100% backup by other sources. They are neither equivalent to nor interchangeable with the reliable sources such as DCPP. Solar and wind farms do not increase the capacity of the grid in any meaningful way, because they can never be counted on the produce energy at a particular time it is needed. Thus, adding *any* number of new solar or wind sources does not allow one to retire a *single* power plant from the grid.

Abandoning DCPP, PG&E's largest and most reliable power source, and replacing it with intermittent sources would reduce the reliable generating capacity available to PG&E by 2240 MW. This could well turn an abundant electricity resource into a scarce one. Under the scenario proposed in the Application, in which PG&E plans to accept bids for replacement sources of power, we cannot anticipate how high those future prices might go, when the supply of reasonably priced reliable electricity is substantially reduced — but all of my experience indicates that prices will rise. CGNP has prepared and filed with the CPUC studies in I.12-10-013 showing large electric power rate increases to San Diego Gas and Electric (SDG&E) customers when San Onofre Nuclear Generating Station (SONGS) was permanently shut down in 2013 by Southern California Edison (SCE) and Sempra. DCPP's abundant, reasonably priced power

[36] https://www.pge.com/en_US/about-pge/environment/what-we-are-doing/clean-energy-solutions/clean-energy-solutions.page

helps shield customers from rate increases associated with the historically volatile price of natural gas generation. This can be seen in PG&E's service territory, where electric power rates *decreased* from the 2009 reference, while SDG&E's customers have endured large rate hikes since 2012. The proposal has parallels to California's previous experiment with electricity deregulation, which also relied upon a market-based system, with suppliers bidding to supply electricity to the grid. Proponents of that new system confidently predicted that the market-based system would result in reduced electric rates.[37] The experiment in electricity deregulation culminated in the California power crisis of 2000-2001. During this time, when electricity became short in supply, electricity prices skyrocketed to unseen levels and rotating blackouts ensued. None of this was predicted by the proponents of the new deregulated system. This experience, from just a few years ago, illustrates how sharply and unpredictably electricity prices can skyrocket when electricity is in short supply.

The Application does not explain how the 2240 MW of firm electrical generating capacity lost if DCPP were closed would be replaced, what constructing that new generating capacity would cost, or who would be asked to pay for it. DCPP's capacity plays an essential role in helping PG&E and California meet its electrical generating capacity requirements, and keeping the lights on. For example, in September 2015 the California Independent System Operator requested that a regularly scheduled refueling outage at DCPP Unit 2 be "postponed to make certain there is enough electricity to reliably meet California's energy needs during an upcoming heat wave."[38] A utility does not reschedule a refueling outage without a compelling reason. Clearly Diablo Canyon's 2240 MW of reliable generating capacity is needed to ensure enough electricity is available.

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[37] Assembly OK's Bill to Deregulate Electricity, Los Angeles Times, August 31, 1996; http://articles.latimes.com/1996-08-31/news/mn-39301_1_electrical-deregulation

[38] http://web.archive.org/web/20150930001812/http://www.pge.com/en/safety/systemworks/dcpp/newsmedia/pressrelease/archive/planned_maintenance_at_diablo_canyon_unit2_delayed.page

The proposal presents no realistic plan to construct the needed storage systems, and fails to account for the substantial associated costs.

The Application makes vague references to construction of energy-storage systems for the wind and solar sources. It does not commit to any specific storage capacity goals, nor does it analyze the costs of constructing such truly unprecedented storage systems. Many technologies have been researched as potential methods of storing TWh of electrical energy over the last several decades. These include compressed air systems, flywheel systems, magnetic storage systems, chemical batteries and pumped hydro storage. After decades of research only pumped storage systems have proven technologically viable and economically feasible at the necessary TWh scale. This is why over 97% of all energy storage on the US electrical grid is accomplished with pumped hydro storage.[39]

CGNP has estimated the cost of replacing all of DCPP's 18 TWh per year of electricity with Topaz class photovoltaics, pumped hydro storage facilities to store 100% output and additional transmission lines to the remote locations where they would be sited. This analysis is presented in section 2.6.1. The estimated cost is an astronomical $73.6 billion. This is over thirteen times the original cost of DCPP. There are real doubts that necessary permits to site the many new large pumped storage plants required could be obtained. The Helms Creek pumped storage project operated by PG&E is approximately 75% efficient. That is, only 75% of the energy it stores is recoverable as electricity.[40] These losses add further to the costs of electricity sources whose output must be stored, and whose lack of capacity must be made available, such as intermittent wind and solar sources.

[39] https://www.energy.gov/eere/articles/get-pumped-about-pumped-storage
[40] **Helms at 30: Hydroelectric Plant Delivers Safe, Clean Affordable Energy**,
PG&E Currents August 1, 2014;
http://www.pgecurrents.com/2014/08/01/helms-at-30-hydroelectric-plant-delivers-safe-clean-affordable-energy/

As was explained in section 2.2, some analysts have expressed serious doubts about the ability to predict future PG&E service-area or California state electricity needs. They also doubted they could predict confidently the ability of contracted GHG-free sources to meet RPS needs without DCPP. There are serious doubts that the astronomical costs associated with the aforementioned procurements would actually be approved by regulators. In that case new fossil-fueled units would have to be constructed to regain the lost capacity from the DCPP abandonment. These would lock us into a long-term commitment to rely upon fossil fuels. They would increase emissions of greenhouse gasses and air pollution rather than reducing them, as is required by statute.

Whether the high expenses and permitting requirements to build the proposed wind and solar sources could be overcome is far from certain. We will nonetheless consider the costs and other issues associated with providing the required backup for them. Unless *bonafide* storage systems are constructed to cover 100% of the output of the wind and solar sources, then other dispatchable sources must be constructed or made available to provide backup. Without DCPP these new sources would be fossil-fueled, most likely in-state natural-gas plants, or out of state coal or gas plants. The net result is additional costs imposed upon these dispatchable sources, as we discuss below. In addition, as described in section 2.2, the necessity of continually ramping output of these fossil-fueled plants to adjust for the whimsical output of wind and solar farms results in increased fuel consumption, and substantially increased emissions of greenhouse gases and air pollution. These effects are of central importance, yet they not adequately accounted for in the Application.

Independent of whether the proposed wind and solar sources were actually constructed, new fossil-fueled units would have to be constructed to meet the federally imposed capacity reserve margin. The sources of capacity must be cost recovered, as they are the primary sources. Wind and solar are tag-along energy sources. They allow the capacity sources to reduce or "back down" their output part of the time, but without replacing the need for them. So the cost of replacing the lost firm capacity is higher with wind and solar than without. So much higher that the fuel cost savings associated with the wind and solar cannot come close to covering them over the wind and solar life spans. When the capacity sources are backed down their levelized fixed costs per unit energy are increased. This is a cost of wind and solar imposed upon dispatchable units.

Costs of replacement power from the proposed sources are much higher than the cost of power provided by continued operation of Diablo Canyon.

We consider how these additional costs are imposed when photovoltaics (PV) or wind turbines cause the underutilization of required natural gas plants. First we consider PV with natural gas backing down. As PV are added to the grid, the effect of the first few percent grid penetration is to reduce the net daytime peak load below loads occurring in the evening. This is the "effective capacity value" they add at the times they are able to generate electricity.

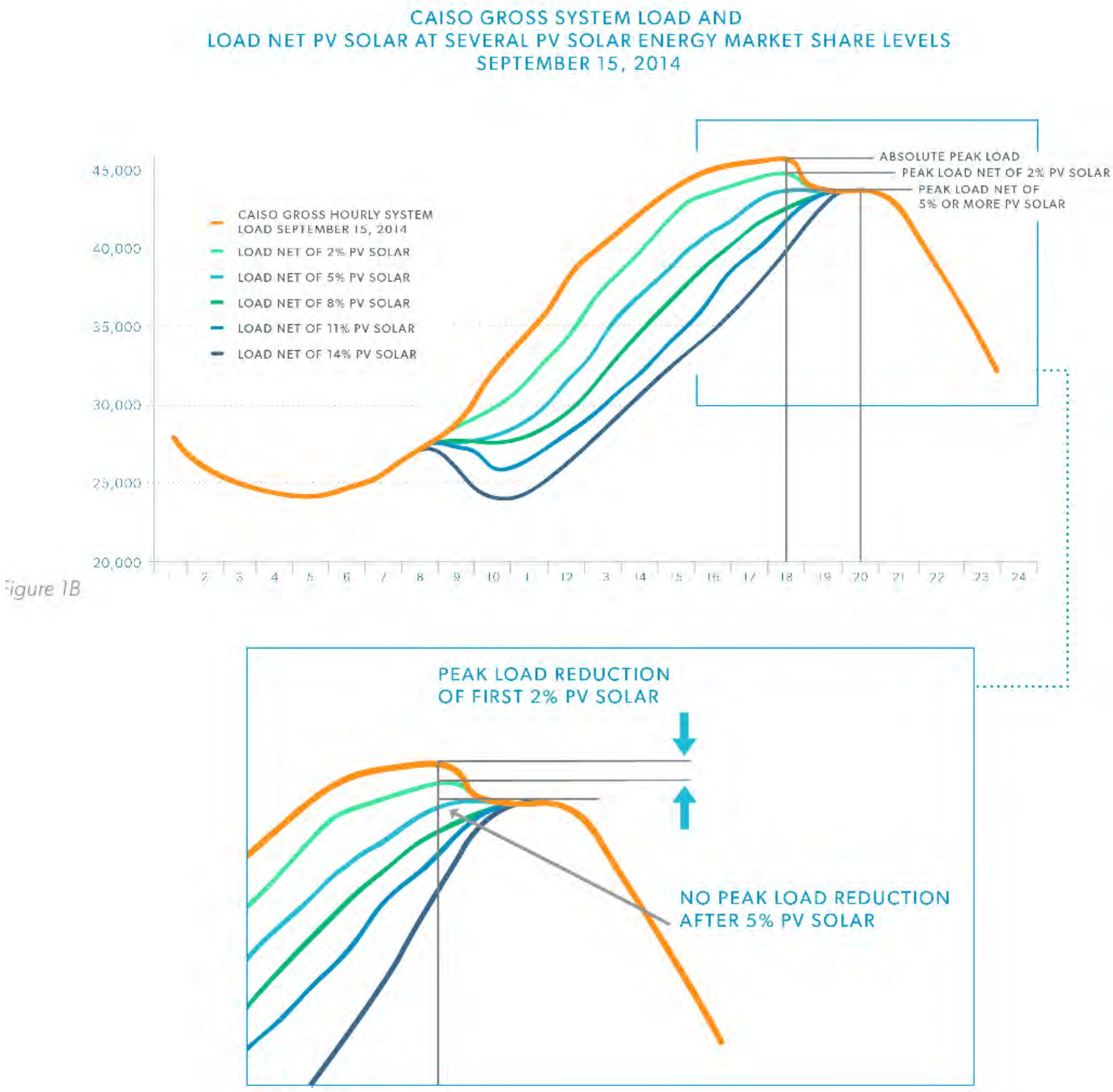

Fig 1. CAISO load net PV solar at several PV solar energy market share levels. (From The Levelized Costs of Electricity from Existing Generation Resources, Institute for Energy Research, July 2016)

As illustrated in Fig. 1, this shift has already occurred in California at just under 5% PV penetration of the grid. After that point additional PV adds no capacity value. Instead more generation resources must remain operational in the system to achieve the same system peak reserve margin. It is elementary then that on average generators must achieve a lower market share and utilization rate. At a lower capacity factor, the breakeven cost per MWh of the system generator fleet necessarily rises. In other words, the non-dispatchable resources impose costs on the dispatchable sources by causing them to run at a lower capacity factor without reducing the fixed portion of their costs. This is termed an imposed cost of PV energy on the capacity resources it displaces. These costs have been analyzed in a recent study by the Institute for Energy Research.[41] This study is based upon a compilation of data reported by the generators themselves by FERC and the US EIA. It includes an analysis of PV backed up by a combination of Conventional Combined Cycle (CC) gas and Conventional Combustion Turbine (CT) gas units. A detailed estimate of the levelized cost of electricity (LCOE) for the CAISO in 2020 has been prepared for PV as the fraction of PV increases in the 6th percent. (ibid, pp. 48) Using values for PV LCOE from the US Energy Information Agency 2020 California ISO this amounts to \$35.8 MWh at the 6th percent market share. When added to the region EIA LCOE 2020 estimate for PV (at 31% CF) of \$111.1 / MWh, this brings the total estimated cost of new PV to \$146.9 / MWh. The analysis shows the imposed cost per MWh increases as solar penetration increases market share.

As explained in the report "The US EIA forecasts new PV to have among the highest cost of electricity of any new resource in 2020." "With consideration of the imposed cost included LCOE for PV is estimated to be \$150 MWh both in California and the US. In regional systems such as the CAISO where incremental additions of PV capacity offer no reduction in system peak loads, the minimum installed capacity of dispatchable generators required to meet peak system load cannot be reduced at all, while additional PV generation continues to drive down their capacity factor while driving up their going-forward levelized costs. At 6% energy market share for CAISO the imposed costs alone rise above \$40 per MWh..." This imposed additional cost *by itself* is nearing the recent national average wholesale market clearing prices. These are real costs that would be borne by ratepayers.

We can compare this with the current costs for continued operation of DCPP. PG&E data on Diablo

[41] The Levelized Costs of Electricity from Existing Generation Resources, Institute for Energy Research, July 2016

submitted in its General Rate Case showed total operating and capital expenses of $627 million for the plant in 2015, about $36 per MWh, which is similar to industry averages. (Public Utilities Commission of the State of California,Pacific Gas and Electric Company 201 General Rate Case Exhibit (PG&E-1) Summary of PG&E's 2017 General Rate Case Supplemental Workpapers Supporting Chapter 1." pp. B5-1 to B5-6.) Adding an 11.8 percent return on the plant's $1.805 billion net value (**PG&E Testimony, p. 10-5)** would give a total revenue requirement of $840 million in 2015, for a unit electricity cost of $48 / MWh.

New PV comes at an astronomical price compared to the current operating and capital costs for continued operation of DCPP. New PV is more than 4 times as expensive as current operating costs for DCPP.

Analysis of the imposed costs resulting from backing up wind turbines with combined cycle gas plants were prepared using realistic capacity factors for wind in the aforementioned Institute for Energy Research study. Properly accounting the imposed costs resulting from utilizing a combination of CC and CT gas plants as backup, the overall cost of new wind turbines increases from $78.16 / MWh to $107.93 / MWh. (ibid, pp 39). New wind power is 3 times as expensive as current operating costs for DCPP.

The Joint Proposal establishes an estimated "upper bound" "proxy value" of $98 / MHh for a mix of 80% wind and 20% PV. As pointed out in the Joint Proposal "The actual costs of the three tranches of GHG-free procurement will not be known until the procurement is completed and the resources are delivering GHG-free energy or EE savings." The 80:20 mix is quite different from California's actual renewable energy mix, which has a much higher proportion of higher-cost solar than lower-cost wind. In 2015 the utility-scale intermittent energy mix in California was 45 percent wind to 55 percent solar, vastly different from the 80:20 wind to solar mix PG&E assumes, and solar power is growing much faster than wind power.[42] Using the more realistic mix and the aforementioned cost estimates that properly include imposed costs results in an estimated cost of replacement power of $131 / MWh. Note that this doesn't include the costs of lost fuel efficiency due to ramping and cycling the dispatchable sources or the higher maintenance costs associated with those more demanding operating dynamics. It doesn't include costs of transmission lines to remote sites of PV's and wind turbines. It also doesn't include the short life spans of PV and wind turbine systems compared to conventional generators. All of these factors will raise the relative costs of electricity from wind and solar sources. The potential costs of mitigating large numbers of bird deaths and injuries caused by wind turbines are also not included.

Another important observation is the JP estimate assumes the extension through 2030 of the production tax credit at 2016 levels for wind resources and continuation through 2030 of the investment tax credit for solar at 2016 levels. This assumption appears to be indefensible as under federal law the PTC is being gradually eliminated for new projects by 2020. The Investment tax credit for commercial solar PV of 30% drops to 10% by 2022. In previous comments President Trump has indicated he is not favorable to continued subsidies for wind and solar energy. At best such subsidies are highly uncertain over the 2024 time frame. Without them the overall costs of wind and solar rise substantially higher. If we consider that under the law the PTC and ITC will have expired by 2025, this has substantial impacts of the projected cost of new wind and solar sources. These replacement power cost are much higher than current costs for continuing to operate DCPP. They are also substantially higher than PG&E's inflated estimates of the cost of running DCPP in 2025 given in the Application.

Costs of energy from existing nuclear power plants are well known for being remarkably stable and predictable across the industry. This is true of both the fuel costs and overall operating costs over many

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[42] U. S. Energy Information Administration, Electricity Data Browser, http://www.eia.gov/electricity/data/browser/#/topic/0?agg=2,0,1&fuel=vtvv&geo=000000000004&sec=g&linechart=ELEC.GEN.ALL-CA-99.A&columnchart=ELEC.GEN.ALL-CA-99.A&map=ELEC.GEN.ALL-CA-99.A&freq=A&ctype=linechart&ltype=pin&rtype=s&pin=&rse=0&maptype=0

year periods.

U.S. Nuclear Plant Costs (2015 $):

Year	Fuel	Capital	Operating	Total
2002	5.73	3.92	18.61	28.27
2003	5.60	4.94	18.87	29.40
2004	5.29	5.66	18.56	29.50
2005	5.02	5.81	18.97	29.80
2006	5.05	5.56	19.23	29.85
2007	5.13	6.12	19.09	30.35
2008	5.36	6.77	19.53	31.66
2009	5.94	8.92	20.52	35.38
2010	6.77	9.17	20.66	36.59
2011	7.10	10.07	21.91	39.08
2012	7.47	10.77	21.50	39.75
2013	7.74	8.21	20.95	36.91
2014	7.22	8.19	20.95	36.35
2015	6.91	7.97	20.62	35.50
2002-2015 Increase	**21%**	**103%**	**11%**	**26%**
2010-2015 Increase	**2%**	**-13%**	**0%**	**-3%**

Table 1. US Nuclear Plant costs per year in \$/MWh[43]

As shown in table 1 overall costs for nuclear plants in the US rose by 2% annually in a thirteen-year period, equal roughly to inflation and thus not rising at all in real economic terms. This is a rather modest rate of increase in costs, even as the average age of the fleet has increased during this period. This is evidence of highly predictable costs for existing plants spanning more than a decade.

Figure 2. shows the ongoing capital and operating expenses US nuclear plants as a function of their age. There is a modest increase in overall operating expenses as the plants age and specific components are replaced. Note that the data extends to 40 years, the number of operating years the DCPP units will have served in 2024/2025. The plot shows predictable, economical operating costs extending out to the full extent of the database at 40 years.

[43] Nuclear Costs in Context, Nuclear Energy Institute, April 2016; http://www.nei.org/CorporateSite/media/filefolder/Policy/Papers/Nuclear-Costs-in-Context.pdf?ext=.pdf

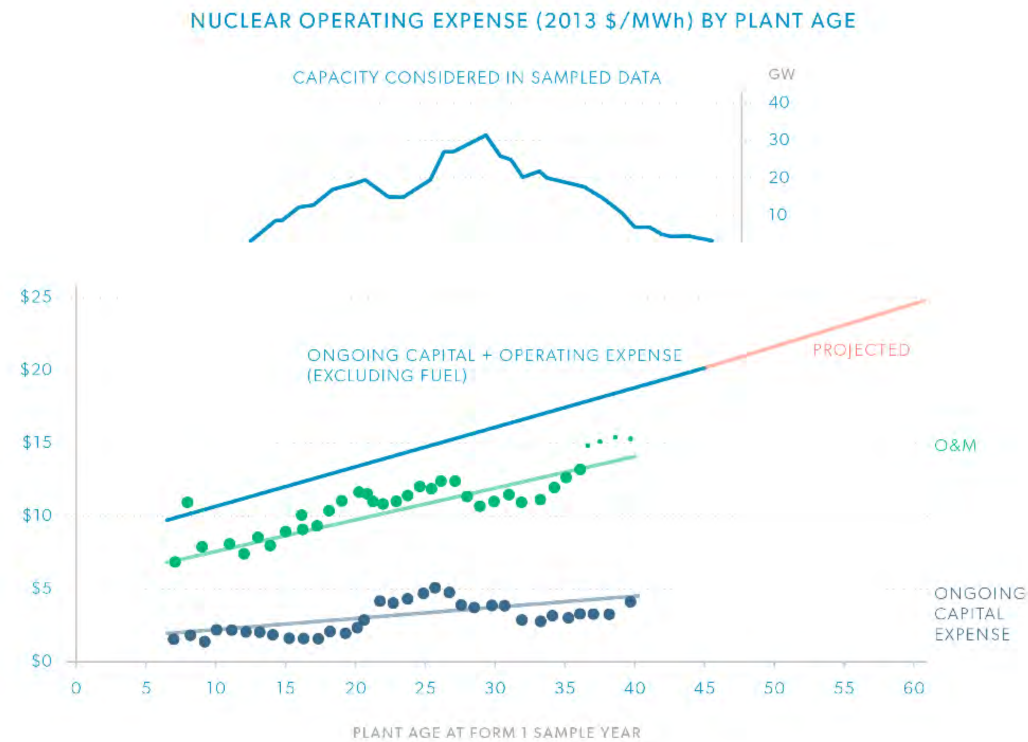

Figure 2. National average of nuclear plant operating expense (excluding fuel) versus plant age[44].

Because of these predictable, economical costs other utilities have obtained or applied for renewals of the operating licenses for their reactors extending out to 60 and 80 years.

The Joint Proposal lists an estimated revenue requirement for DCPP of $1.66 billion in 2025 and $1.74 billion in 2030. To reach these numbers DCPP's operating revenue requirement would have to double in the next 10 years. This is in stark contrast to the modest increases that have been experienced across the US nuclear fleet with time. Neither the Application nor its Testimony justify this huge, unexpected cost inflation. The Testimony claims this includes "post 2025 costs for OTC mitigation." (PG&E Testimony 2-22) But an economical solution to the OTC requirement in the form of an artificial reef has been discussed with the Regional Water Quality Board. The artificial reef was proposed at one-time cost of

[44] The Levelized Costs of Electricity from Existing Generation Resources, Institute for Energy Research, July 2016, pp. 32.

$15 - $50 million. According to Peter Raimondi's presentation to the State Water Board, and based on research with Steinbeck and Thomas, as quoted from the EP Protest,[45] "An artificial reef of sufficient size and with appropriate design and placement could compensate for the majority of impacts associated with entrainment at DCPP….The estimated cost for the construction of an artificial reef ranged from 15 million to 50 million dollars."[46] In fact there was precedent in southern California where for San Onofre Nuclear Generating Station (SONGS) a compensatory reef was built and is still operating.[47] [48]"The cost of the construction of the San Onofre artificial reef was $30 to $35 million, and that's close to the estimate from Diablo." The reef has demonstrated its ability to help increase the fish population. Construction of a compensatory reef represents an apparently viable solution to the OTC mitigation requirement, and it costs only a few million dollars per year, which is insignificant compared to DCPP's annual revenue. PG&E's estimates for future DCPP revenue requirements in the Application are far out of line with industry experience, DCPP cost data and other PG&E estimates. A 2013 report funded by PG&E estimated that DCPP revenue in 2027 would be about $1 billion.

PG&E makes an unsupported claim that DCPP would have to increase its refueling outage to 2 months as part of OTC mitigation. In its Testimony PG&E testimony states

> *"As part of its OTC mitigation compliance, it is assumed that DCPP would transition from the historical maintenance schedule to an annual two-month spring outage schedule with refueling occurring every other year. This two-month outage schedule in the spring would also help to mitigate over-generation events. Based on this two-month annual outage schedule, post-2025 generation from Diablo Canyon is projected to decline from historical levels to 16,300 GWh."*

[45] CPUC proceeding A1608006, conf #101848
[46] Peter Raimondi, "The Science of Mitigation: Based on work done with Michael Thomas, Greg Cailliet and John Steinbeck and many others," 2008. Submitted to the State Water Quality Board.
[47] San Onofre Nuclear Generating Station Mitigation Program, California Coastal Commission, November 2014; documents.coastal.ca.gov/reports/2012/F11-a-12-2012.pdf
[48] CPUC proceeding A1608006, conf #101848

But, as the Environmental Progress Protest states, “the longer outage was never included in mitigation framework proposed to the Regional Water Quality Board.” And as explained in section 2.1, DCPP is quite capable of adjusting its output in response to over generation events caused by unreliable wind and solar sources.

The Application’s cost estimates for operating DCPP past 2025 are unsubstantiated. When realistic overall cost estimates for continued operation of DCPP are compared with realistic estimates for new wind and solar, continued operation of DCPP is clearly much cheaper. By relicensing the plant and continuing to operate it through 2045 DCPP could continue producing reliable, emission free electricity for decades at a far lower cost than any of the potential new energy sources proposed in the Joint Proposal.

With an annual revenue requirement of $1 billion in 2025, the cost of electricity from DCPP would be approximately $57 / MWh. This is far less than the estimated net cost of $131 / MWh above for renewable sources. PG&E estimates that DCPP’s surplus power would sell on wholesale markets for roughly the same $57 / MWh price. This would enable PG&E’s bundled customers and other wholesale customers to enjoy the same economical prices, much less than the proposed wind and solar replacements.

The Application forecasts a substantial reduction in PG&E’s need for DCPP power, based upon its estimate that it will lose a large fraction of its bundled customers to alternative suppliers and Community Aggregation. But this estimate is subject to enormous uncertainty. The large cost advantage for DCPP’s power over the proposed solar and wind sources demonstrated above could reasonably be expected to enable PG&E to retain most of its current customers.

Even if some of DCPP's power exceeds the need of its bundled load, PG&E has no responsibility to close the plant, since it can sell surplus power to the larger grid. Minimizing the costs for its ratepayers is PG&E's fiduciary responsibility. An accurate estimate of costs would show that completing the relicensing process for DCPP and continuing its operation would meet that responsibility.

DCPP helps to protect PG&E ratepayers from volatile natural gas prices and fuel shortages.

The price of natural gas has historically undergone large unpredictable swings. Since the price of electricity generated with natural gas is strongly dependent upon fuel price, these large fluctuations translate into large variations in the cost for the ratepayer. With its stable fuel and operating costs, DCPP has served to shield PG&E ratepayers from these price swings over its 30 year history. And during much of that time the cost of electricity generated was natural gas was more expensive that DCPP energy. So DCPP has helped to reduce electricity costs.

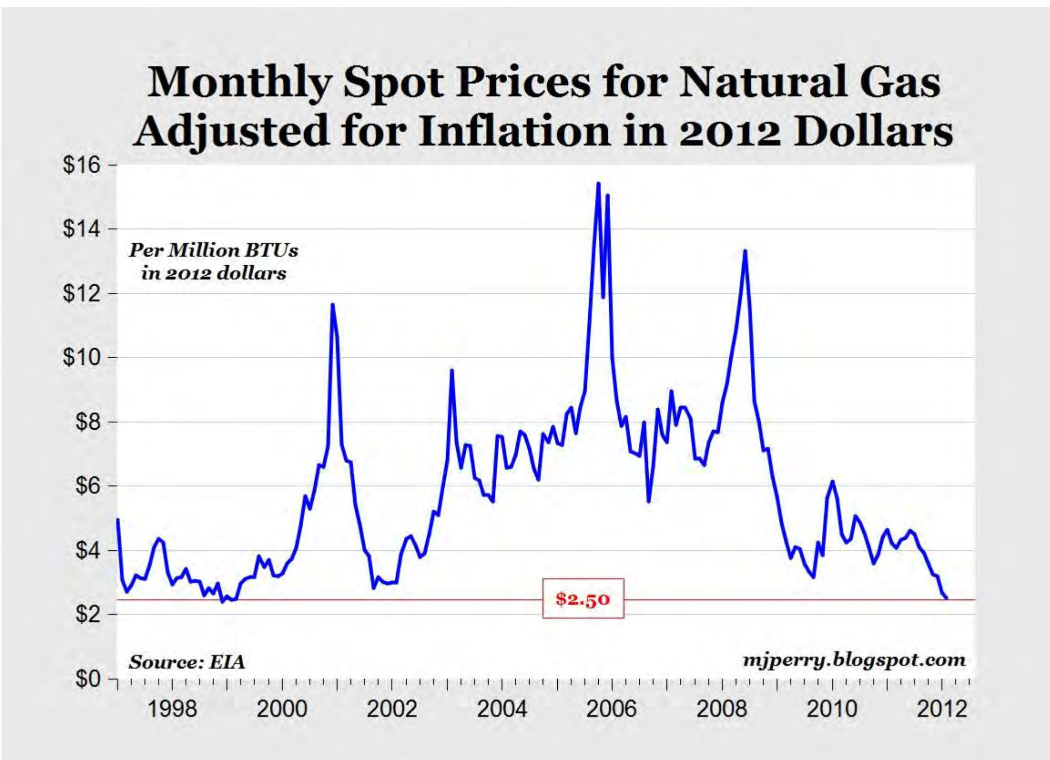

Figure 3. Monthly Spot Prices for Natural Gas Adjusted for Inflation in 2012 Dollars

Presently natural gas prices are near historic lows. Given the price history of any commodity, it would be unrealistic to expect this historic low to persist. According to the US EIA, natural gas prices are projected to double by 2025 in inflation-adjusted dollars (Fig. 4). So it is reasonable to expect DCPP will continue to help shield ratepayers from increasing natural-gas prices in the future.

Continued operation of Diablo Canyon also provides much needed diversity of reliable electricity generation for the California grid, which is already dangerously over dependent upon natural gas. According to a new report from the association of electric grid operators California suffers from a "single-fuel dependency" that could increase the state's vulnerabilities during "extreme weather conditions."[49] Diablo Canyon helps reduce the danger that a shortage of electricity could result from a shortage of available natural gas. As covered in section 2.2, since the closure of San Onofre, California's consumption of natural gas has increased beyond the ability of pipelines to deliver as needed. So it now must be stored. The association of electric grid operators report warns "Minimal dual-fuel capable units and immediate resource constraints from the outage at the Aliso Canyon underground natural gas storage facility increase the risks associated with single-fuel dependency." The unique value of DCPP to alleviate effects of natural gas price fluctuations and potential natural gas shortages should be considered when planning for the future mix of energy sources.

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[49] NERC 2026 Reliability Assessment:
http://www.nerc.com/pa/RAPA/ra/Reliability%20Assessments%20DL/2016%20Long-Term%20Reliability%20Assessment.pdf

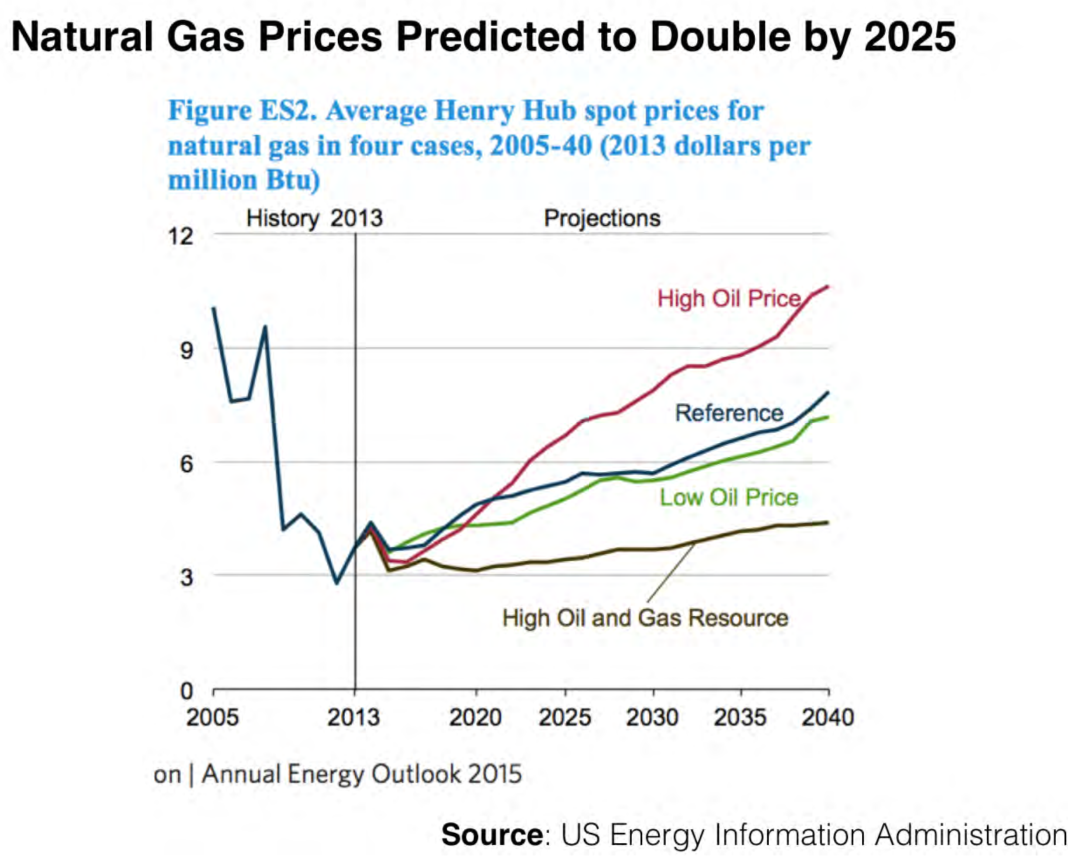

Figure 4. Projected natural gas prices adjusted to 2013 dollars

Nations having the highest dependencies upon wind and solar sources have among the highest electricity prices.

The Application includes specific yet incomplete estimates of the costs of constructing the proposed sources. But it does not reconcile these estimates with real-world data showing nations with the highest dependencies upon wind and solar sources have among the highest electricity prices.

Germany has adopted a policy of closing nuclear power plants and attempting to run its first-world economy on occasionally favorable breezes and sunshine. During this period, German residential electricity prices, which were previously unremarkable, have skyrocketed to nearly the highest rates in the world, $390 / MWh.[50] Now "energy poverty" is becoming a serious problem in Germany *as more than 800,000 households have disconnected their electrical service completely* because they can no longer afford to pay their electricity bills.[51]

Denmark, which leads the world in the fraction of electricity generated with wind power produced, is tied with Germany at this nearly highest rate of $390 / MWh.

Australia's aggressive program to increase wind power has caused electricity prices to skyrocket in recent years. For 2013/14 average household electricity prices are close to $300 / MWh according to government statistics.[52] A power crisis in South Australia, where dependence upon wind power is highest, has caused the price of electricity to spike to $2000 / MWh. Major businesses in South Australia have already threatened to suspend operations entirely until the price of power comes down.[53]

The request to use decommissioning funds to pay additional expenses generated by this Application is unjustified.

The Application proposes to use decommissioning funds to pay for some additional expenses that result from this proposal to retire DCPP. These are voluntarily incurred costs, not decommissioning costs, and

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[50] http://dailycaller.com/2016/05/01/these-maps-show-just-how-much-more-europeans-pay-for-electricity-than-americans/

[51] German Energy Policy: Man-Made Crisis Now Costing Billions, Institute for Energy Research, October 2012; http://instituteforenergyresearch.org/analysis/germanys-energy-policy-man-made-crisis-now-costing-billions/

[52] Electricity Prices In Australia: An International Comparison, CME, March 2012; http://www.aph.gov.au/DocumentStore.ashx?id=52040ade-8c93-4292-a50c-c8ce93c8236c

[53] http://dailycaller.com/2016/11/23/australia-has-serious-problems-with-green-energy-triggering-blackouts/

their proposed use is a thinly veiled attempt to hide the true impact of the closure on the ratepayers. **Since expenses are for abandonment and not for decommissioning, the use of decommissioning funds is inappropriate.** If the decommissioning funds eventually fall short then the ratepayers would be on the hook, not PG&E. So PG&E should pay all of the additional costs resulting from this proposal to retire DCPP, not the ratepayers.

The rationale given in the Application for subjecting ratepayers to a range of new expenses and risks is unjustified.

The Joint Proposal was the product of private meetings between PG&E, a set of special interest groups who have a bias against nuclear power plants, and a labor union. The ratepayers were completely excluded from participation in formulating the basic elements of the proposal. Yet ratepayers are being asked to shoulder the burden of its new increased costs, both specified and unspecified. Neither PG&E shareholders nor the aforementioned special interest groups behind the Joint Proposal are offering the pay the increased costs that would result from adopting their proposal.

At the time of the surprise announcement of the Joint Proposal PG&E assured us that it would not result in increased costs for ratepayers. Shortly thereafter PG&E modified this claim by filing a request with the CPUC for a $1.776 billion rate increase associated with the Application. The Application also requests authority to impose future non-bypassable charges upon customers in the form of a "Clean Energy Charge." Testimony supplied by PG&E repeatedly refers to "benefits" resulting from its proposal to justify the range of new expenses to which ratepayers would be subjected. For example:

> *"The Clean Energy Charge provides clear allocation of resource benefits and a transparent, market-based determination of net costs." (PG&E Testimony 5-15)*

"The Joint Proposal benefits PG&E customers and the state of California by reducing emissions, supporting a reliable and cost-effective electric system, and supporting PG&E employees and the community PG&E serves." (PG&E Testimony 1-4)

"The Joint Proposal reflects commitment from PG&E to procure GHG-free resources to serve bundled customer electricity needs, which will provide benefits to all customers across PG&E's service territory by helping to achieve California's climate change policies." (PG&E Testimony page 8)

As summarized below, the benefits claimed are not substantiated, and the justification for increased costs to ratepayers disintegrates.

Emissions of greenhouse gases and air pollution would increase.

As explained in section 2.2, PG&E already exceeds state mandated GHG-free power requirements because of Diablo Canyon. In 2015, 59% of PG&E's generation was GHG-free, with approximately 23% from Diablo Canyon alone. The decision to abandon DCPP would result in the loss of 39% of this GHG-free portion of generation, dealing a major setback to the state's efforts to *reduce* GHG emissions. As explained above it would also entail loss of 2240 MW of reliable generating capacity. The Application plans to replace only a small fraction of this GHG-free generation and makes no specific plan to replace this lost reliable generating capacity. Thus, there is no basis for an assurance that the 2240 MW of lost GHG-free generation would be replaced by GHG-free sources. As explained in section 2.2 in essentially every case that a nuclear plant has been closed, a sizeable increase in GHG emissions has resulted. Section 2.2 explained how a step function increase in GHG emissions occurred after the closure of San Onofre, and a large increase in electricity prices followed this action.

Even if enough wind and solar sources were somehow built to replace just the *average* output of DCPP, unless these were accompanied by enough new energy-storage systems, an increase in greenhouse gas emissions would result. But the Application establishes no specific targets for installing energy storage systems. As explained above building the large number of pumped-storage systems required would be prohibitively expensive. It also appears unlikely that such a number of large pumped-hydro storage systems could gain the necessary approvals due to environmental concerns. So the wind and solar sources that are proposed would most likely be backed up by in-state gas turbines, or out of state coal plants or gas turbines. As explained in section 2.2, when the outputs of these fossil-fueled sources are ramped up and down in the manner required to compensate for the erratic, whimsical output of wind turbines, there is a sizeable increase in their emissions of greenhouse gasses and air pollution.

This effect has been documented in numerous scientific studies, including a study that examined more than 300,000 hourly records of utilities in four regions of the country.[54] [55] [56] [57] [58] These increased emissions cancel out at least a substantial fraction of the claimed reduction in GHG emissions associated with the wind turbines. This is in stark contrast to the essentially emission free electricity generation of DCPP. So to the extent that the proposal causes DCPP output to be replaced with wind turbines backed up by fossil fuel plants, a large net increase in emissions of GHG and air pollution will occur. To the extent it causes DCPP to be replaced solely by natural gas or coal plants, a large net increase in emissions of GHG and air pollution will occur. These *increases* in emissions will move California farther away

[54]Study on a hypothetical replacement of nuclear electricity by wind power in Sweden, F. Wagner et al., The European Physical Journal Plus (2016). DOI: 10.1140/epjp/i2016-16173-8; http://dailycaller.com/2016/06/14/study-replacing-nuclear-with-wind-would-double-co2-emissions/

[55] How Less Became More: Wind, Power and Unintended Consequences in the Colorado Energy Market, Bentek Energy, April 2010;
http://docs.wind-watch.org/BENTEK-How-Less-Became-More.pdf

[56] Renewable and Sustainable energy Reviews 15 (2011) 2557-2562.

[57] Wind Energy Does Little To Reduce CO2 Emissions; W. Post, September 2011;
http://www.coalitionforenergysolutions.org/irish_wind_energycwk_wp.pdf

[58] Wind Energy In the Irish Power System, Fred Udo, October 2011;
http://www.clepair.net/IerlandUdo.html

from the legislated goals for *reduced* GHG emissions. Whether those increased emissions occur out of state does not matter to the overall balance of GHG emissions. The Application's claim that it will "help to achieve California's climate change policies" is demonstrably false.

Real world experience shows that countries that have the highest fractions of solar and wind power supplying their grids have among the highest electricity rates in the world. As explained in section 2.2, there have been serious difficulties in maintaining the reliability of electric grids, associated with sizeable dependence upon those sources, with important consequences. For example, Germany will destroy 6000 MW of installed wind capacity by 2019 to regain the stability of its electric grid. Yet the Application makes no assessment of how the unprecedented proposed changes to the grid would impact its reliability. This is a cause for serious concern, given how completely dependent our civilization, and its modern computer-reliant economy, are upon a reliable supply of electricity. These facts contradict the claim in the Joint Proposal that it "promotes a reliable and cost-effective electric system." Implementing the Joint Proposal would increase electricity costs and degrade the reliability of California's electric grid.

Historically the CPUC has assessed whether new power generation projects are reasonable and prudent individually based upon careful scrutiny of their overall costs and demonstrated record of reliable generation. The Application attempts to turn CPUC jurisprudence on its head by requesting a future non-bypassable "Clean Energy Charge" to the ratepayers for replacement power which could end up being for any cost amount. These approved charges would pay for projects yet to be proposed, whose ultimate costs are unknown, and bid in a future market potentially short of reliable generating capacity, whose prices would be consequently inflated. There would be additional large costs for storage systems that are not even estimated. And there could be sizable costs to mitigate reliability problems resulting from the proposed action. Therefore, preemptively granting PG&E carte blanche to place upon ratepayers the burden of *whatever it costs* to carry out this ill-considered, unprecedented proposal would be a dereliction of the fiduciary responsibilities of the Commission. The California power crisis of 2000-2001 reminds us of just how high and quickly electricity prices can skyrocket when an imbalance develops between supply and demand. The German misfortune of skyrocketing electricity prices, and nearly *one million* households that can no longer afford electricity service, demonstrates that preemptively approving unlimited mandatory charges to pay for a similar experiment here is neither reasonable nor prudent, and is not in the public interest.

Statement of Qualifications

Author

Michael M. Marinak, Ph.D.

My name is Michael M. Marinak. I received a Doctoral of Philosophy in Nuclear Engineering from the University of California at Berkeley in 1993. There I was a recipient of The Berkeley Fellowship for Graduate Study. Prior to this I obtained my Bachelor's Degree in Nuclear Engineering from UC Berkeley. I have been employed as a computational physicist at Lawrence Livermore National Laboratory full time since 1993. I am principal author on a number of articles in peer reviewed scientific journals, and co-author on many more.. In writing this testimony I am not representing the views of Lawrence Livermore National Laboratory. I previously provided input to the Final Environmental Impact Report for the Diablo Canyon Steam Generator Replacement Project (Application A04-01-009, August 2005.).

The following two gentlemen are expert witnesses regarding the Institute for Energy Research report, "The Levelized Cost of Electricity from Existing Sources," which is quoted in this section.

Travis Fisher

Institute for Energy Research

My name is Travis Fisher and I am an economist with over 10 years of experience in electricity policy. I hold a bachelor's and a master's degree in economics. I currently work for the Institute for Energy Research (IER), a nonprofit educational institution that focuses on free-market solutions to energy issues. My work has been featured in the Wall Street Journal and published in the journal of the U.S. Association for Energy Economics, of which I am a member. Prior to joining IER, I worked as an economist at the Federal Energy Regulatory Commission for seven years, focusing on wholesale electricity markets and rates. As it relates to IER's study on the levelized cost of electricity, I served on both iterations of that project (the 2015 and 2016 reports) as an editor and liaison between IER and the study's authors, Tom Stacy and George Taylor.

Tom Stacy

Institute for Energy Research

-My name is Tom Stacy. I have a Bachelor of Arts degree from Ohio State in Marketing with an industrial focus (some calculus/physics and chemistry), 1989. I have twenty years experience in primary capital machinery sales to the plastics industry and helped manage the firm 1989 – 2008. I have studied independently and engaged in electricity economics and market design for ten years, working closely with members of the Ohio legislature 2007 – 2016. I served on the ASME Energy Policy Committee for five years as a member at large.

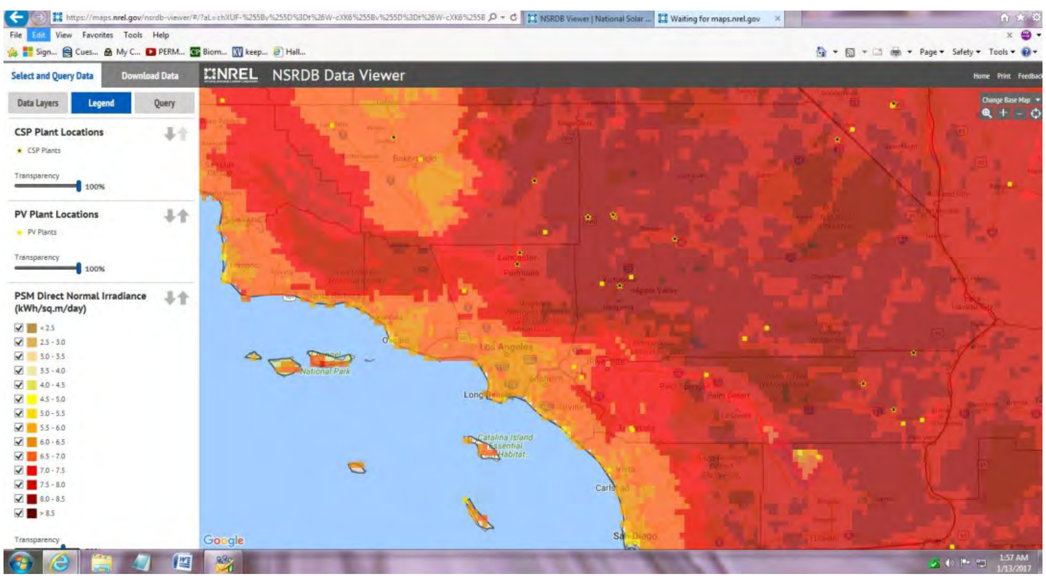
2.6

Proposed Ratemaking and Cost Allocation Issues - Part 2

Sponsored by Gene Nelson, Ph.D.

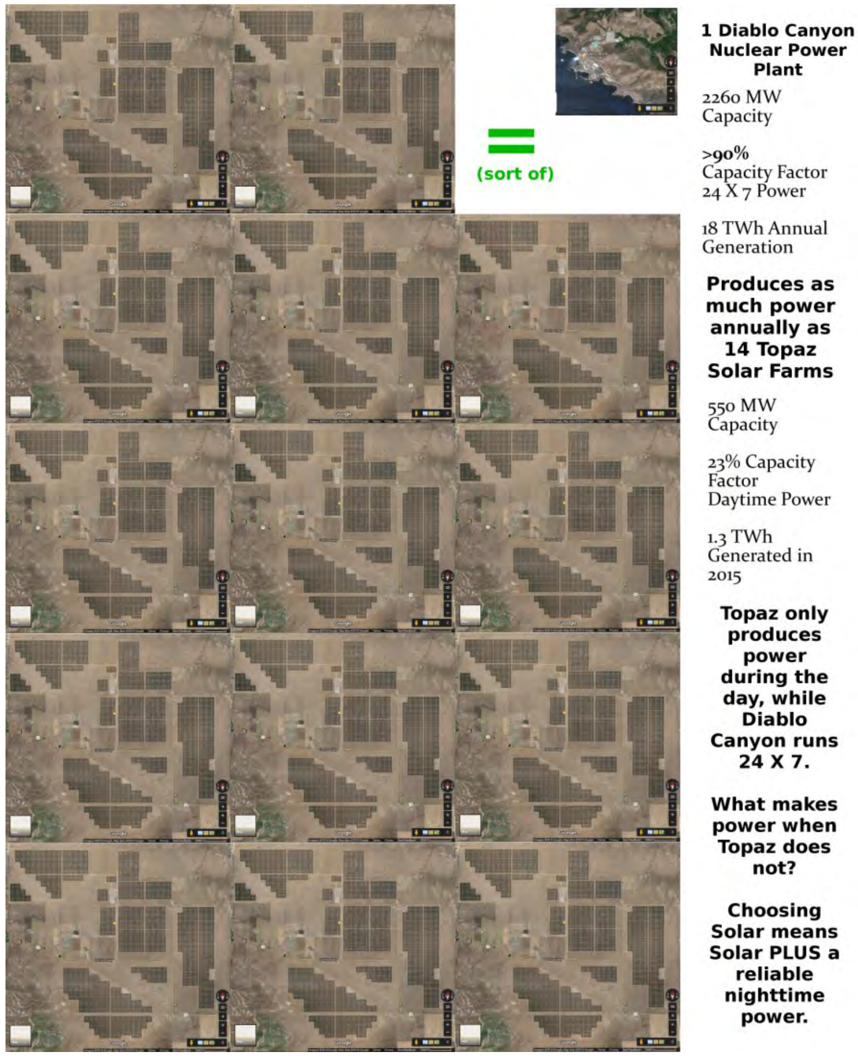
INTRODUCTION

This section's analysis will demonstrate that California large-scale solar power is *not* cost-effective at an estimated $73.6 billion to produce 18,000 GWh/year of dispatchable electric power. Contrast this bloated cost with the reliable and safe Diablo Canyon Power Plant, which began operation in 1984, with a construction cost of about $7.5 billion. Furthermore, the financial waste associated with premature DCPP abandonment is established. Finally, any shortfall in GHG-free replacement procurement if DCPP is abandoned should result in a substantial PG&E shareholder assessment for the social cost of carbon from any in-state or out-of-state fossil-fired generation.



Southern California's solar power generation ***potential*** is shown above by the National Renewable Energy Laboratory (NREL) NSRDB Data Viewer. Level terrain in the brick-red regions in southern California is ideal for solar power generation.

This photo-montage, recently developed by Billy Gogesch shows **two ways to generate about 18,000 gigaWatt-hours (GWh) per year.** Diablo Canyon Power Plant, (DCPP) completed in 1985 for a cost of about $7.5 billion, typically generates 18,000 GWh/year with a capacity factor greater than 91%. DCPP's power is dispatchable and cost-effective at about 4 cents/kiloWatt-hour (kWh.) DCPP's power is abundant, also equal to about five times the production of Hoover Dam. DCPP's power is emission-free. DCPP also



provides important voltage and frequency stabilization to the California power grid. DCPP is compact, at considerably less than a square mile in area. DCPP is well-guarded to prevent damage from vandalism. DCPP's robust construction protects it from the elements.

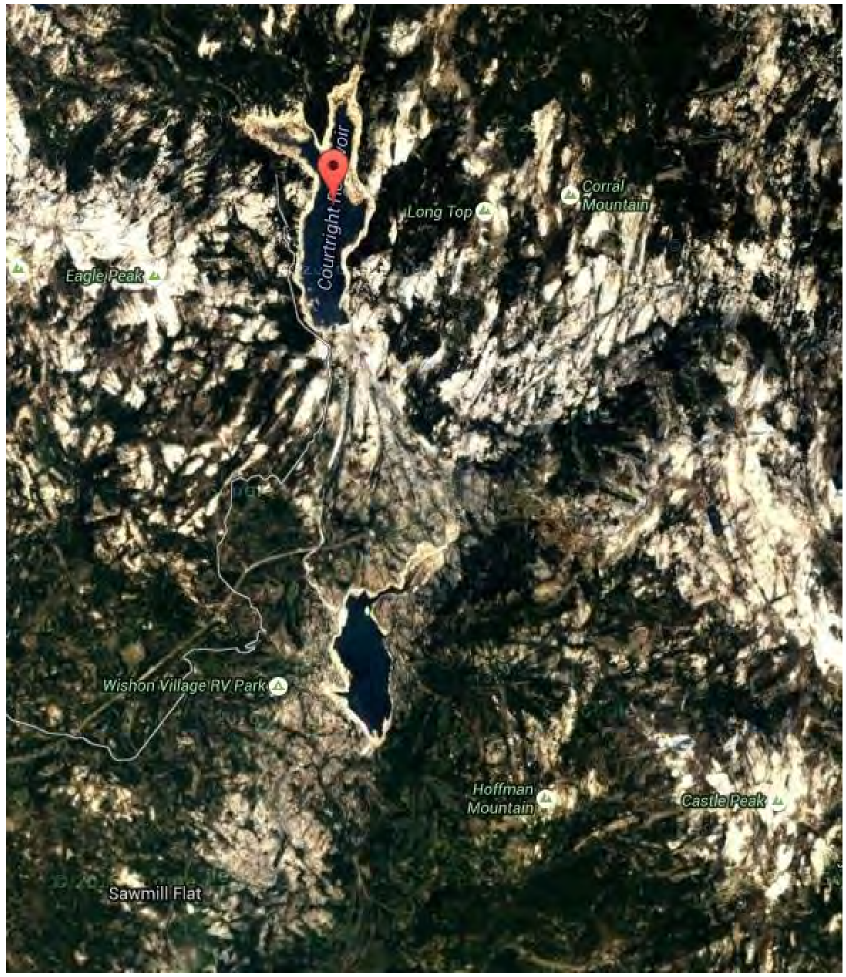
Topaz Solar's power is also emission-free. The energy source is cost-free. However, even the first iteration of a ***solar-super-plant*** is very capital-intensive. Topaz Solar cost $2.4 billion to complete in 2014. Topaz Solar covers 9.5 square miles. Thus, the cost of the first iteration ***super-solar plant*** would likely be 2.4 times 14, or **$33.6 billion.** The total land area would be 9.5 times 14, or **133 square miles.** This large land area is vulnerable to vandalism. Natural events such as sandstorms or hail could cause permanent damage to the solar collection panels. The solar collection panels will likely last 20-30 years before requiring replacement. Solar power is produced at Topaz during the approximately five hours centered around solar noon with a capacity factor of about 23%. The solar output peak is displaced from the California electricity demand peak at around sundown by about six hours. Topaz's power is subject to periodic interruptions (*e.g.*, night) and random interruptions from clouds passing over the plant. Topaz's power is not dispatchable. In fact, reliable, higher capacity factor generation must be operated in a "back-down" mode to accommodate the solar (or wind) output and a running reserve of higher capacity factor power generation must be running in standby mode to "fill in" for the random power interruptions inherent in solar and wind power installations. For this reason, solar and wind power destabilizes the California power grid, which further increases ratepayer costs.

DCPP's abundant power output may be used to "charge up" what PG&E described in 1984 as the "World's largest storage battery," namely Helms Pumped Storage (HPS) in the Sierra foothills to the east of Fresno. HPS was completed between June 1977 and June 30, 1984 with significant cost overruns. HPS cost $600 million in 1984. There is a dedicated power pathway between DCPP and HPS. HPS is used in a power arbitrage mode to supply the equivalent of about one DCPP power reactor of power during the six hours corresponding to the evening California demand peak without emissions.

Used in this mode, HPS releases 2,656 GWh per year.

To replace HPS would require at least $3 billion, projecting from a December 11, 2014 Stanford University student paper, "The cost of Pumped Hydroelectric Storage" by Oscar Galvez

An aerial view of the two lakes that are part of HPS is shown in this photograph , courtesy of Google maps.



While HPS has excellent power storage efficiency, it is only 75% efficient. That means that in order to "charge it up," **3,541 GWh per year are consumed**. A large complex of pumped storage facilities charged up by a ***solar-super-plant*** could be used to create a large, dispatchable power source equal to DCPP at much greater cost. To obtain 18,000 GWh/yr of output would require the equivalent of 6.8 HPS pumped storage facilities. For ease of calculation, rounding up to 7 HPS equivalents means that **only 6 more HPS equivalents would need to be constructed at an estimated cost of $18 billion.** The total input power needed to "charge up" this complex of 7 HPS equivalents with 75% storage efficiency would require 24,787 GWh per year. ***Thus, a total of 19 Topaz Solar plants are required. The cost of these***

solar plants balloons to $45.6 billion. The total square miles required climbs to 180.5 square miles.

Recalling the map of southern California power production potential that appears at the beginning of this section, there needs to be a means to move this massive amount of power at least 200 miles from the California desert to the Sierra foothills, and then to the California "power backbone" that includes the Gates and Buttonwillow substations. DCPP requires **three** 3-phase 500 kV alternating current lines, with each of the three conductors in a line carrying about 1,400 RMS Amperes. Since DCPP runs 24/7, 6,000 GWh flows over each of the 3-phase lines during a year. For the proposed ***solar-super-plant***, **zero line losses are assumed**. For the solar case, the power is generated over about 5.6 hours. About 4.25 times as many conductors as for DCPP would be required. Presuming 500 kV 3-phase lines, the number jumps from nine (9) conductors to 38.25, which will be rounded up to 39 conductors. Thus, this project would require thirteen (13) 500 kV 3-phase lines running parallel to each other. Two lines may be strung from the tall lattice towers required. Thus, there would be seven (7) lattice towers next to each on this power corridor that stretches at least 200 miles. A conservative estimate for this large construction project would be $10 billion. Unfortunately, this large solar power transmission system, like the solar generation system, would be in use **only about 23% of each day** - poor utilization of the capital-intensive infrastructure necessary to capture and transport the solar electric power.

In summary, the total project cost would include 19 Topaz Solar Plants at $45.6 billion.

The six new HPS energy storage facilities required would add $18 billion. The necessary power transmission system adds another $10 billion for a <u>total estimated cost of $73.6 billion</u>.

DISCUSSION:

It is very unlikely that the CPUC would force California ratepayers to pay an estimated $73.6 billion, just to equal the functionality of DCPP, which cost about $7.5 billion to construct by 1985.

In addition, such a large project would require an unprecedented number of environmental approvals, likely requiring until 2025 to just break ground on all three components. Based on past experience, this mega-project construction could require another decade to complete.

The second problem associated with PG&E's so-called "Joint Proposal" **is the wasteful plan to abandon an asset with a useful design life of approximately a century after *only 40 years of operation***. According to PG&E the current DCPP book value is **$1.8 billion** Note that as a consequence of deregulation, accelerated depreciation of DCPP started in the late 1990s.

> ... There is precedent for the type of transitional assistance proposed in the Community Plan. Reacting to **similarly rapid changes in DCPP's depreciation schedule** in the late 1990s due to **deregulation**, PG&E and the local community proposed, and the California Public Utilities Commission (CPUC or Commission) approved, $10 million to be paid to

the county and local jurisdictions over a four-year transition period.(3) .... Page 141 of 280, lines 15-20 [59]

While the accounting practice of accelerated depreciation was used to boost PG&E's profitability in this manner, **the useful lifetime of DCPP**, the underlying asset **is unaltered.** DCPP's long lifetime is a consequence of both its robust design and the excellent stewardship that PG&E has practiced to this point. As an example, PG&E began planning for the replacement of the four massive steam generators (RSGs) inside each reactor containment in April 2005, requiring two slightly extended refueling outages in 2008 and 2009. A *Power Engineering Magazine* article summarizes PG&E's engineering accomplishments during those routine maintenance outages. [60] PG&E has been an industry leader in replacing older analog measurement and control systems at DCPP with modern digital designs that provide robust redundancy and defense-in-depth.[61]

Here is a smoothed plot of DCPP's County of San Luis Obispo (SLO) California property taxes during the last decade, showing the **market value of the plant is essentially**

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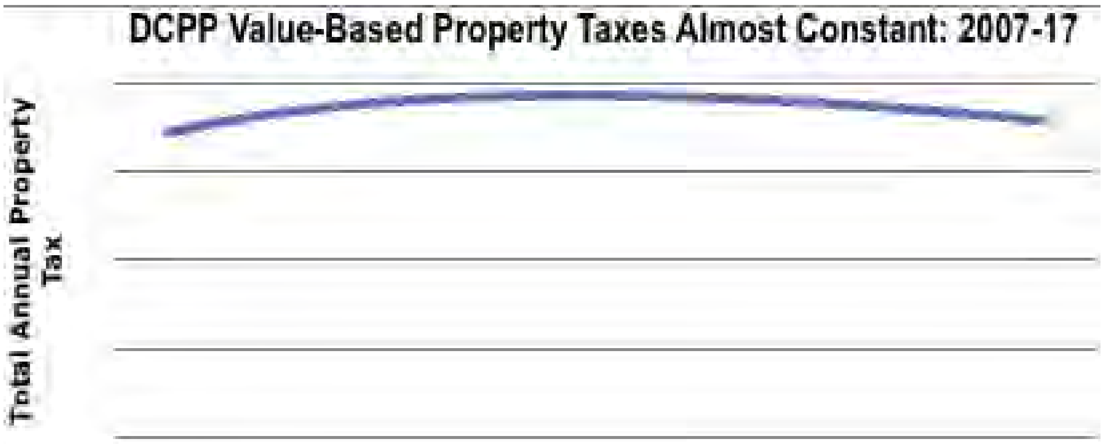
[59] PACIFIC GAS AND ELECTRIC COMPANY RETIREMENT OF DIABLO CANYON POWER PLANT, IMPLEMENTATION OF THE JOINT PROPOSAL, AND RECOVERY OF ASSOCIATED COSTS THROUGH PROPOSED RATEMAKING MECHANISMS - PREPARED TESTIMONY - Chapter 8 - Community Impacts Mitigation Program https://pgera.azurewebsites.net/Regulation/ValidateDocAccess?docID=381640

[60] Diablo Canyon Unit 1 Steam Generator Replacement Project, By Nancy Spring, Editor - *Power Engineering Magazine*, September 1, 2009 http://www.power-eng.com/articles/npi/print/volume-2/issue-3/nucleus/diablo-canyon-unit-1-steam-generator-replacement-project.html

[61] Diablo Canyon Power Plant Digital Process Protection System Replacement Diversity and Defense-in-Depth, By Scott B. Patteron, PE, PMP, John W. Hefler, PE, and Edward (Ted) L.Quinn (2011)
www.technology-resources.com/docs/5015.pdf

constant, since the SLO County Property Tax is likely proportional to the market value. The annual property tax range is between $20,487,204 - $22,742,363.



CGNP's understanding is that the SLO County property taxes are based on the *marketl value* of DCPP, akin to what a purchaser of the asset would pay, **not** its depreciated book value.

Here is the detailed spreadsheet supplied by PG&E in response to a CGNP data request: [62]

PG&E Data Request: CGNP_005-Q01
Sent: January 18, 2017
File: DiabloCanyonRetirementJointProposal_DR_CGNP_005-Q01Atch01.pdf

Fiscal Year	San Luis Obispo Property Tax*	DCPP - Plant Property Tax	DCPP - Land Property Tax	DCPP - Total Property Tax	Ratio
2007-2008	23,511,228	20,169,691	317,513	20,487,204	87%
2008-2009	25,161,572	21,693,961	319,930	22,013,891	87%
2009-2010	25,734,024	22,034,395	320,985	22,355,380	87%
2010-2011	26,225,628	22,343,573	331,220	22,674,793	86%
2011-2012	26,608,987	22,422,435	319,928	22,742,363	85%
2012-2013	27,409,842	22,897,553	280,550	23,178,102	85%
2013-2014	26,763,646	22,024,607	282,039	22,306,646	83%
2014-2015	27,030,280	22,264,433	287,137	22,551,570	83%
2015-2016	28,252,545	21,720,279	289,283	22,009,562	78%
2016-2017	28,398,490	21,084,122	306,427	21,390,549	75%

The property tax values are shown in dollars. **Property taxes are a proxy measure for the market value of an asset.** The SLO property tax is based on the sum of DCPP's value and the California Franchise Tax Board's apportionment of PG&E's Transmission and Distribution (T&D) assets to SLO County . Note how the DCPP value increased subsequent to the replacement of the steam generators in 2008 and 2009, despite a nationwide recession. The

[62] PG&E Data Request: CGNP_005-Q01
Sent: January 18, 2017
File: DiabloCanyonRetirementJointProposal_DR_CGNP_005-Q01Atch01.pdf

"ratio" column shows the ratio between the tax based on DCPP's total value as determined by PG&E's Capital Department and PG&E's total tax obligation for a given year. The spreadsheet below [63] shows the **strong divergence** between the **Market Value**, (with a current basis of about $8.5 billion) and the **Net Book Value** of $1.8 billion.

DCPP Direct Assigned Plant by FERC Account(s)		12/31/2015 - Recorded			12/31/2016 - Forecast		
		Plant	Accumulated Depreciation	Net Book Value	Plant	Accumulated Depreciation	Net Book Value
		in 000's			in 000's		
Nuclear Production:							
320		22,727	21,445	1,282	22,727	21,576	1,150
321		1,036,743	937,903	98,840	1,035,789	957,797	77,992
322		3,432,483	2,659,939	772,544	3,493,069	2,717,035	776,033
323		1,162,811	1,013,666	149,145	1,168,157	1,030,382	137,775
324		808,988	721,453	87,536	827,113	729,627	97,486
325		1,055,904	546,408	509,497	1,167,682	542,895	624,787
Subtotal		7,519,657	5,900,814	1,618,843	7,714,537	5,999,313	1,715,223
109	FAS109 Gross Up	468,499	468,499	0	468,499	468,499	0
303	Intangible (S/W)	85,027	47,859	37,168	94,905	62,541	32,365
352-356	Electric Transmission	96,074	64,318	31,757	96,023	67,045	28,978
389	Land Rights	10	10	(0)	10	10	(0)
Subtotal		181,111	112,186	68,925	190,938	129,595	61,343
390-399	Structures/General Plant	92,602	59,881	32,721	89,818	61,201	28,617
DCPP Direct Assigned Plant Total		**8,261,869**	6,541,380	1,720,489	**8,463,792**	6,658,609	1,805,183

Since PG&E's plan to abandon DCPP in 2025 is a voluntary plan, perhaps the most equitable solution would be for the CPUC to require that PG&E's shareholders absorb the entire cost of DCPP abandonment, since the ratepayers have already been paying for PG&E's Capital Cost Recovery (CCR) of DCPP since it was placed in service in 1984. Furthermore, PG&E's CCR of DCPP's book value of **$1.8 billion** should be disallowed.

[63] PG&E Response to CGNP_006-Q01Atch01.xls, Received 24 January 2017

Finally, the third problem is the **replacement procurèrent problem** that PG&E has admitted in its so-called "joint proposal" regarding DCPP abandonment. Even with the most optimistic reading of PG&E's plans, as of 2025, there will be a substantial gap between the 18,000 GWh/year that DCPP was generating and the replacement procurement. California, the world's 8th largest economy, will still require the power that DCPP supplied for business and residential uses - and a growing population. Since PG&E's plan is voluntary, PG&E should be required as a condition of the CPUC accepting their proposal to replace all of DCPP's power in 2025 with audited power sources that emit no greenhouse gases during generation (as DCPP operates.)

Otherwise, PG&E shareholders should be assessed with the **social cost** of any in-state or out-of-state **carbon emissions** necessary to equal 18,000 GWh/year, currently about $40.00 per metric ton of CO_2, until all of PG&E's audited replacement procurement is carbon-free. In the first pages of this section, CGNP demonstrated the folly of replacing DCPP with solar power. CGNP believes that this social cost of carbon assessment to PG&E's shareholders would make PG&E's so-called "joint proposal" more equitable for California ratepayers.

Current proposals suggest that out-of-state entities will replace DCPP (if abandoned) with fossil-fired generation

History of WSPP http://www.wspp.org/about_history.php

The Western Systems Power Pool (WSPP) began as an agreement among a group of utilities in the western states. The agreement, which was filed with the Federal Energy Regulatory Commission by **Pacific Gas and Electric Company** on behalf of the group, established a multi-state bulk power marketing experiment. The agreement was meant to test whether broader pricing flexibility for coordination and transmission services would promote increased efficiency, competition, and coordination.

The WSPP began operations in 1987 first as an experiment allowed by the Federal Energy Regulatory Commission (FERC) and then beginning in 1991 as a more permanent entity. Its initial purpose was to allow sales of power for short-term transactions to take place with a maximum of flexibility and minimum of regulatory filings and to test market efficiency and competition.

Comparison of Available Power of PG&E and PacifiCorp 03 27 07 to 01 17 17

The tool available at http://www.wspp.org/power.php shows that during the 3,584 days between these two dates that **Pacific Gas and Electric Company** (PG&E) had available power exactly **zero** days during this period.

WSPP

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Available Power

Post Generation

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Hide Search/Restore Original List

Date Posted▼	Available Date	Organization	Title
		Pacific Gas & Electric Company	

The table is empty or the filter you've selected is too restrictive.

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Thus, it can be inferred that PG&E is a power importer.

On the other hand, **PacifiCorp** had available power on **2,222 days**, or **62%** of the 3,584 days disclosed.

PacifiCorp Available Power October 7, 2016 to October 20, 2016

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Post Generation

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Date Posted▼	Available Date	Organization	Title
		PacifiCorp	
10/20/2016	10/22/2016	PacifiCorp	Estimated Excess Capacity
10/20/2016	10/21/2016	PacifiCorp	Estimated Excess Capacity
10/19/2016	10/19/2016	PacifiCorp	Estimated Excess Capacity
10/19/2016	10/20/2016	PacifiCorp	Estimated Excess Capacity
10/17/2016	10/18/2016	PacifiCorp	Estimated Excess Capacity
10/14/2016	10/17/2016	PacifiCorp	Estimated Excess Capacity
10/14/2016	10/16/2016	PacifiCorp	Estimated Excess Capacity
10/13/2016	10/15/2016	PacifiCorp	Estimated Excess Capacity
10/13/2016	10/14/2016	PacifiCorp	Estimated Excess Capacity
10/12/2016	10/13/2016	PacifiCorp	Estimated Excess Capacity
10/11/2016	10/12/2016	PacifiCorp	Estimated Excess Capacity
10/10/2016	10/11/2016	PacifiCorp	Estimated Excess Capacity
10/07/2016	10/10/2016	PacifiCorp	Estimated Excess Capacity
10/07/2016	10/09/2016	PacifiCorp	Estimated Excess Capacity
10/07/2016	10/08/2016	PacifiCorp	Estimated Excess Capacity

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PacifiCorp Available Power April 4, 2007 to April 25, 2007


WSPP
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Date Posted▼	Available Date	Organization	Title
		PacifiCorp	
04/25/2007	04/26/2007	PacifiCorp	Excess Capacity
04/24/2007	04/25/2007	PacifiCorp	Excess Capacity
04/23/2007	04/23/2007	PacifiCorp	Excess Capacity
04/20/2007	04/22/2007	PacifiCorp	Excess Capacity
04/19/2007	04/20/2007	PacifiCorp	Excess Capacity
04/18/2007	04/19/2007	PacifiCorp	Excess Capacity
04/17/2007	04/17/2007	PacifiCorp	Excess Capacity
04/16/2007	04/17/2007	PacifiCorp	avail Excess Gen
04/13/2007	04/14/2007	PacifiCorp	Avail Capacity
04/12/2007	04/13/2007	PacifiCorp	available excess gen
04/11/2007	04/12/2007	PacifiCorp	PacifiCorp Avail
04/10/2007	04/11/2007	PacifiCorp	Available Excess
04/09/2007	04/10/2007	PacifiCorp	Pacificorp Available
04/05/2007	04/05/2007	PacifiCorp	Available Excess Gen
04/04/2007	04/04/2007	PacifiCorp	Available Excess Gen

First Previous Next Last

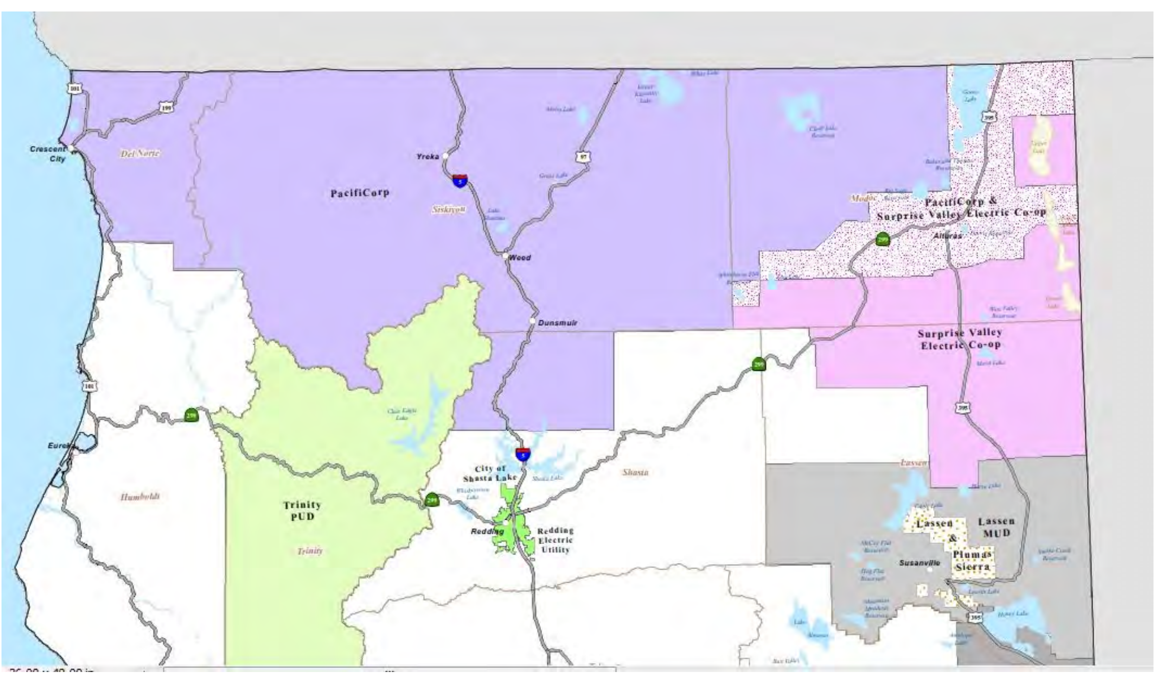
Thus, it can be seen that PacifiCorp is a significant WSPP power exporter.

Furthermore, per the California Energy Commission (CEC,) the PacifiCorp and the PG&E service territories share a **common border over 100 miles long**.

See the detailed version of the "California Electric Utility Service Areas Map" at

http://www.energy.ca.gov/maps/serviceareas/Electric_Utility_Service_Areas.html

(The PacifiCorp service territory is lavender and the PG&E service territory is white)



PacifiCorp has almost **6,000 GW of coal-fired generating** capacity and almost **3,000 GW of natural gas fired generating capacity.** [64] The WSPP trading data above establishes that PacifiCorp has surplus fossil-fired generating capacity available for export to PG&E. Per the CEC 2015 PacifiCorp Power Content Label, shown here, **none of PacifiCorp's power** is emission-free nuclear power.

PacifiCorp is constructing an "Energy Gateway" power transmission project that may be used, in conjunction with existing transmission facilities to move power from the firm's fossil-fired generators to prospective customers. The project includes more than 1,900 miles of new transmission lines. Per this two-page color brochure, "Construction on certain segments begins in 2008, with many major segments

2015 POWER CONTENT LABEL

ENERGY RESOURCES	Power Mix	2015 CA Total Mix**
Eligible Renewable	8.47%	22%
Biomass & Biowaste	0.30%	3%
Geothermal	0.44%	4%
Eligible hydroelectric	1.16%	1%
Solar electric	0.04%	6%
Wind	6.53%	8%
Coal	59.86%	6%
Large Hydro	3.24%	5%
Natural gas	14.31%	44%
Nuclear	0.00%	9%
Other	1.44%	0%
Unspecified sources of power*	12.68%	14%
TOTAL	100%	100%

* "Unspecified sources of power" means electricity from transactions that are not traceable to specific generation sources.

** Percentages are estimated annually by the California Energy Commission based on the electricity sold to California consumersuring the previous year.

For specific information about this electricity product, contact: Pacific Power 1-888-221-7070

For general information about the Power Content Label, consult: California Energy Commission 1-844-217-4925 http://www.energy.ca.gov/pcl/

http://www.energy.ca.gov/pcl/labels/2015_labels/Pacific_Power.pdf
Archived 01 18 17 by Gene A. Nelson, Ph.D.

PACIFIC POWER

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[64] PacifiCorp 2015 Integrated Resource Plan, Volume 1 pages 62-63 http://www.pacificorp.com/content/dam/pacificorp/doc/Energy_Sources/Integrated_Resource_Plan/2015IRP/PacifiCorp_2015IRP-Vol1-MainDocument.pdf

in service by 2014." Here are two key bullet points from the second page of the PacifiCorp brochure:

> • All new facilities – whether generation or transmission – are integrated into the existing system. **There is no way to physically distinguish one source of electrons from another source traveling along the transmission lines.** (emphasis added)
>
> • The region will need all types of resources to meet the growing demand for energy, and conventional resource types, particularly **natural gas,** will continue to play an important role in coming years. [65]

Furthermore, PacifiCorp has been lobbying many relevant regulatory and oversight bodies, and the government of the State of California to establish a "Regional Load Balancing Authority" (RLBA) or "Regional Grid Operator" (RGO) or an "Energy Imbalance Market (EIM.) Here is a passage found in a June 19, 2014 FERC decision involving both the California Independent System Operator and PacifiCorp.

> Page 3:
>
> 1. In this order, the Commission addresses proposed revisions filed by PacifiCorp to its Open Access Transmission Tariff (OATT) in order for PacifiCorp to participate in the Energy Imbalance Market (EIM) being created by the California Independent System Operator Corporation (CAISO). PacifiCorp's OATT revisions will work in parallel with tariff revisions proposed by CAISO, whose revisions will provide neighboring balancing authority areas (BAAs) the opportunity to participate in CAISO's real-time market for imbalance energy.
>
> **I. Background**
>
> 2. The Commission requires public utility transmission providers to offer energy imbalance service to transmission customers and generators as ancillary services under the pro forma OATT. PacifiCorp currently manages energy imbalances across two BAAs—PacifiCorp East and PacifiCorp West3 —by utilizing both automated and manual processes to provide imbalance

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[65] Energy Gateway and Renewable Resources
Major new regional transmission network supports renewable resource development, July 2008
http://www.pacificorp.com/content/dam/pacificorp/doc/Transmission/Transmission_Projects/Energy_Gateway_1.pdf

services from its resources under Schedule 4 (Energy Imbalance Service) and Schedule 9 (Generator Imbalance Service) of its OATT. On the other hand, CAISO manages its BAA through the operation of a bid-based real-time energy market that automatically dispatches the least-cost resource every five minutes to serve load while resolving transmission congestion through the use of a detailed network model.

Page 4:

3. **For several years, industry leaders in the West have examined the potential benefits of a regional energy imbalance market that could replace the energy imbalance services that utilities in the region, such as PacifiCorp, currently offer under their respective OATTs**. (emphasis added) CAISO and PacifiCorp studied the benefits of an energy imbalance market between their BAAs.

The EIM Benefits Study projected annual economic benefits to PacifiCorp of between $10.5 and $54.4 million (emphasis added) with benefits for customers resulting from dispatch savings, reduced flexibility reserves, and reduced renewable energy curtailment.

4. Following the EIM Benefits Study, CAISO and PacifiCorp executed a memorandum of understanding in February 2013 to begin development of a regional realtime energy imbalance market to commence operations by October 2014. On June 28, 2013, the Commission accepted an implementation agreement between CAISO and PacifiCorp to establish the scope and schedule of implementing the energy imbalance market and to account for PacifiCorp's upfront costs.[66]

Clearly, a "Regional Energy Imbalance Market" would benefit the profitability of PacifiCorp. Coupling the history during the past decade of a glut of PacifiCorp fossil-fired electric power to be wholesaled as documented by WSPP market data, the geographic proximity of PG&E and PacifiCorp service territories, the large PacifiCorp fossil-fired generating capacity and transmission network, with evidence of

[66] PacifiCorp Docket No. ER14-1578-000 ORDER CONDITIONALLY ACCEPTING IN PART AND REJECTING IN PART PROPOSED TARIFF REVISIONS TO IMPLEMENT ENERGY IMBALANCE MARKET (Issued June 19, 2014) www.FERC.gov/whats-new/comm-meet/2014/061914/E-5.pdf

PacifiCorp's lobbying to expand its market all support the contention that PacifiCorp is ready and able to replace the 18,000 GWh/yr that is generated by DCPP by exporting electricity that will be sourced by PacifiCorp fossil-fired generation.

On May 20, 2016, CGNP members learned about the RLBA plan while they toured the Folsom, California Independent System Operator (CAL-ISO) headquarters. Our guide claimed that power costs would decrease. Our guide admitted that California would relinquish its legislated authority to control emissions as the RLBA would have authority over what is now CAL-ISO.

Based on the history after the January, 2012 SONGS shut down in southern California, electric power prices are likely to sharply increase in the PG&E service territory should DCPP cease operation as a consequence of the economic law of supply and demand. While many of the most-harmful air pollutants such as the heavy metals arsenic, cadmium, and lead remain in the vicinity of a fossil-fired plant, a more accurate statement regarding the outcome when out-of-state fossil-fired generation replaces DCPP is that most of the air pollution would be **outsourced**, as it already is for out-of-state generation contracted by the Los Angeles Department of Water and Power (LADWP) several nearby cities. [67]

However, from a social-justice perspective, any plan to import fossil-fired electricity should be rejected as it disproportionately harms the respiratory health of very young and very old people

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[67] Intermountain Power Agency ANNUAL DISCLOSURE REPORT FOR FISCAL YEAR 2015-2016 dated December 30, 2016. Page 71 of 198 shows peak net production of 6,100,835 MWh from Coal-Fired Unit 1 and 6,233,084 MWh from Coal-Fired Unit 2 in FY 2014-15. Page 2 of 198 shows Purchasers of Intermountain's Power also include the Cities of Anaheim, Burbank, Glendale, Pasadena, and Riverside, California https://ipautah.com/wp-content/uploads/2016/12/2015-2016-Annual-Disclosure-Report-of-Intermountain-Power-Agency-with-Audited-Financial-Statements.pdf

with lower incomes living near the energy exporter's fossil-fired power plants. Whether those individuals live inside California or outside the state, it's simply wrong to subject them (and our earthly environment) to the harms of GHG-intensive power plants. In addition, any plan to import fossil-fired replacement power would dramatically increase U.S. carbon emissions, exacerbating anthropogenic global warming (AGW,) which is already harming the state of California in many ways.

CONCLUSION:

Instead of the likely alternative of importing even more fossil fired electricity into California, DCPP should be operated for its design lifetime of about 100 years, restraining the rate of increase of California electricity prices, which already burden ratepayers with some of the highest rates in the nation. Furthermore, operation of DCPP until about 2084 assists in the achievement of the aggressive emission reduction targets established in California A.B. 32 and S.B. 350, and in numerous California Executive Orders, such as B-30-15.

SPONSOR'S QUALIFICATION STATEMENT:

Q1: Please state your name and business address.

A1: My name is Gene Nelson. I serve in a volunteer capacity as the Central Coast Government Liaison for Californians for Green Nuclear Power Inc., whose address is 1375 East Grand Ave, Suite 103 #523, Arroyo Grande, CA 93420

Q2: Briefly describe the nature of your business.

A2: As a radiation biophysicist, I utilize a fact-based approach to evaluate the suitability of electric power resources for California's homes and businesses. As a result, I advocate for the continued use of clean nuclear power in California. My wife and I enjoy the clean air on the California Central Coast. We live about 10 miles from PG&E's Diablo Canyon Power Plant.

Q 3: Please summarize your educational and professional background

A 3: Gene A. Nelson, Ph.D. earned his bachelor's of science degree at Harvey Mudd College in 1973 and he earned his Ph.D. in radiation biophysics in 1984 from the State University of New York at Buffalo. Dr. Nelson has been employed by technology-intensive private sector employers including utilities. He has worked in the public sector, including appointments as a Professor in the fields of engineering, physical sciences, and biological sciences at three colleges and a university. In addition, he has been employed by nonprofits..

He has published many articles and has been involved in policy debates regarding science and public policy since 1979. In connection with those policy debates, he has twice delivered testimony in the U.S. House of Representatives and twice to the National Academy of Sciences.

He has advocated since 2007 for the continued safe operation of nuclear power plants in California before the California Public Utilities Commission (CPUC,) the California State Lands Commission (CSLC,) the California Energy Commission (CEC.) the California Coastal Commission (CCC,) the California State Water Resources Control Board (SWRCB,) the Diablo Canyon Independent Safety Committee (DCISC,) and the U.S. Nuclear Regulatory Commission (NRC).

Q 4: What is the purpose of your testimony?

A 4: I am sponsoring the following testimony in Californians for Green Nuclear Power's objections to PG&E's proposed Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, and Recovery of Associated Costs through Proposed Ratemaking Mechanisms: Section 2.6 Proposed Ratemaking and Cost Allocation Issues - Part 2.

Q 5: Does this conclude your statement of qualifications?

A 5: Yes, it does.

Dated: January 27, 2017

Respectfully submitted,

__/s/__Gene A. Nelson, Ph.D.

Gene Nelson, Ph.D.,
Government Liaison
Californians for Green Nuclear Power
1375 East Grand Ave, Suite 103 #523, Arroyo Grande, CA 93420
Tel: (805) 363 - 4697
E-mail: liaison@CGNP.org

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

Application of Pacific Gas and Electric Company for Approval of the Retirement of Diablo Canyon Power Plant, Implementation of the Joint Proposal, And Recovery of Associated Costs Through Proposed Ratemaking Mechanisms (U39E).	Application 16-08-006 (Filed 08/11/2016)

WORKPAPERS TO ACCOMPANY THE WRITTEN DIRECT TESTIMONY OF CALIFORNIANS FOR GREEN NUCLEAR POWER

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January 27, 2017

Californians for green nuclear power

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PG&E Data Request No.:	CGNP_001-Q01		
PG&E File Name:	DiabloCanyonRetirementJointProposal_DR_CGNP_001-Q01		
Request Date:	October 24, 2016	Requester DR No.:	001
Date Sent:	November 10, 2016	Requesting Party:	Californian's for Green Nuclear Power
PG&E Witness:	N/A	Requester:	Gene Nelson

SUBJECT: PG&E'S FERC FORM NO. 1

QUESTION 1

My question involves the column heading that I have marked with an oval, which indicates that the values in the column with that heading are thousands.

Based on that heading, I believe that the statement that DCPP's basis shown on line 40 would be $7.496 trillion is incorrect. It should be $7.496 billion.

Please confirm my understanding.

ANSWER 1

That is correct. Depreciable plant base for Nuclear Prod – Diablo as shown on line 41 should be $7.496 billon.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Retirement Joint Proposal
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Data Response

PG&E Data Request No.:	CGNP_002-Q01		
PG&E File Name:	DiabloCanyonRetirementJointProposal_DR_CGNP_002-Q01		
Request Date:	November 14, 2016	Requester DR No.:	002
Date Sent:	November 21, 2016	Requesting Party:	Californians for Green Nuclear Power
PG&E Witness:	Chuck Marre	Requester:	Gene Nelson

QUESTION 2

Given that about 71% of the value of DCPP is comprised of assets that have useful lives between 60 and 100 years per the table under discussion, how does PG&E justify artificially setting the value of DCPP to zero in 2025?

Utilizing the straight-line depreciation method, which I believe is the correct method to use for long--ived assets such as those under discussion, one may calculate that the plant basis was $4,620,584,094.00 in 2015. Furthermore the projected plant basis in 2025 is $3,546,261,341.00 . Please see my attached Appendix 1 spreadsheet for details.

An analogy may clarify my question. Imagine that I have a Rolls-Royce automobile. With proper maintenance and careful driving, that car will still be running well at 1,000,000 miles. Imagine that this automobile has a transmission that is warranted to last 400,000 miles. At 400,000 miles, the Rolls-Royce owner junks the car instead of replacing the transmission. This action would make just as much sense as PG&E abandoning DCPP after being an excellent steward of the plant for 40 years.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	New	% of plant base column added by Gene Nelson, Ph.D.	Date of Report (Mo, Da, Yr) 02/24/2016	Year/Period End of Report: 2015/Q4	Undeprec-iated Value (SL) in 2015	Undeprec-iated Value (SL) in 2025

APPENDIX 1 - DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands)	Percent of Plant Base	Estimated Avg. Service Life	Net Salvage (Percent)	Applied Depr. rates (Percent)	Mortality Curve Type	Average Remaining Life	New	New
12	Intangible Plant									
13	302	113,750,070		40.00		2.17	SQ	25.00		
14	303	2,482,275		3.00			SQ	--14.00		
15	Subtotal	116,232,345								
16										
17	Steam Prod - Fossil						0			
18	311	112,125,238		75.00		3.63	L0	69.00		
19	312	273,493,692		50.00		3.70	R1	44.00		
20	313									
21	314	248,783,088		40.00		3.58	R2.5	34.00		
22	315	50,697,111		30.00		3.51	R4	24.00		
23	316	28,295,579		40.00		3.76	L0.5	34.00		
24	Subtotal	713,394,708								
25										
26	**Hydraulic Production**									
27	331	428,450,107	11.98%	**100.00**	--1.00	0.97	S2.5	76.00		
28	332	1,943,104,867	54.34%	**100.00**	--2.00	1.28	S2.5	71.00		
29	333	789,278,656	22.07%	**51.00**	--6.00	2.19	R1.5	35.00		
30	334	253,646,444	7.09%	**50.00**	--9.00	3.21	R1.5	33.00		
31	335	87,261,944	2.44%	40.00	--14.00	3.93	R2	26.00		
32	336	73,960,001	2.07%	**65.00**	--3.00	2.52	R1.5	44.00		
33	Subtotal	**3,575,702,019**								
34										
35	**Nuclear Prod-Diablo**									
36	321	1,036,743,265	13.83%	**100.00**	--1.00	0.93	R1	73.00	756,822,583	653,148,257
37	322	3,432,483,225	45.79%	**60.00**	--1.00	2.50	R1	39.00	2,231,114,096	1,659,033,559
38	323	1,162,811,055	15.51%	40.00	--1.00	1.41	R3	14.00	406,983,869	116,281,106
39	324	808,988,441	10.79%	**75.00**	--1.00	1.14	R1.5	50.00	539,325,627	431,460,502
40	325	1,055,904,489	14.08%	40.00	--2.00	4.47	R4	26.00	686,337,918	686,337,918
41	Subtotal	**7,496,930,475**							**4,620,584,094**	**3,546,261,341**
42										
43	Other Production									
44	341	210,375,654		55.00		3.72	R5, R1	50.00		
45	342	11,264,118		50.00		3.73	R5,R1	45.00		
46	343	223,711,698		40.00		3.59	R5,R2.5	34.00		
47	344	353,570,942		27.00		4.27	R5, R2.5,	23.00		
48	345	210,675,563		35.00		3.76	R5,R2.5	30.00		
49	346	95,867,567		26.00		4.13	R5,S0.5,	20.00		
50	Subtotal	1,105,465,542								

Converted and 3 new columns added by Gene Nelson, Ph.D. 10 30 16. Source: PG&E FERC Form 1 – 2015 https://pgeregulation.blob.core.windows.net/pge-com-regulation-docs/FERCForm1.pdf

FERC FORM NO. 1 (REV. 12-03) Page 337 Confirmed in "**Uniform System of Accounts for Electric Utilities**"

http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18

Account Definitions from http://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=13021745 Public Service of New Mexico - FERC 1 - 07 03 12

Nuclear Production Plant - Palo Verde	
321	Structures and Improvements
322	Reactor Plant Equipment
323	Turbogenerator Equipment
324	Accessory Electric Equipment
325	Miscellaneous Power Plant Equipment

ANSWER 2

The purpose of the depreciation expense methodology is to distribute the original cost of the capital asset used in providing service and any net salvage, in a systematic and rational manner, over the useful life of the asset. This methodology ensures that the original cost of the plant and related net salvage are fairly distributed among both current and future customers who benefit from the plant. For the Diablo Canyon Power Plant (DCPP), the useful life is governed by the license life granted by the Nuclear Regulatory Commission (NRC), which terminates in 2024 and 2025 for DCPP Unit 1 and Unit 2, respectively. This is also the working assumption of the Joint Parties.

PG&E follows the remaining life method provided in CPUC Standard Practice U-4, Determination of Straight-Line Remaining Life Depreciation Accruals. The remaining life depreciation method is designed to ratably recover the cost of plant, less net salvage and less depreciation reserve, over the remaining life of the plant. This method provides for intergenerational equity, which means that the customers who benefit from the use of utility assets also pay for those assets over the expected life of those assets.

The information provided from the FERC Form 1 and presented in Attachment 1 of this request is not complete as it only looks at gross plant, not taking into consideration any deprecation already taken that is included in the depreciation reserve. More simply stated, the 2016 DCPP net plant balance as forecasted in the 2017 GRC Application is $1.805 billion.

The estimated average service lives provided in the FERC Form 1 of 60-100 years represent interim retirement lives and are not developed based on the retirement of Diablo Canyon Power Plant due to the regulatory license life.. For example, for a building the retirements of plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility would be interim retirements. The interim retirement lives are truncated (asset lives end) at the date of the expected retirement of the Diablo Canyon generation facility.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Retirement Joint Proposal
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Data Response

PG&E Data Request No.:	CGNP_003-Q01		
PG&E File Name:	DiabloCanyonRetirementJointProposal_DR_CGNP_003-Q01		
Request Date:	January 3, 2017	Requester DR No.:	003
Date Sent:	January 19, 2017	Requesting Party:	Californians for Green Nuclear Power
PG&E Witness:	N/A	Requester:	Gene Nelson

QUESTION 1

For CGNP's upcoming workpaper submissions to support our written testimony in CPUC Proceeding A.16-08-006, we are requesting to promptly receive directly from PG&E a copy of the following:

Pages 41-63 of Docket No. A.15-09-001 Exhibit No. A4NR-2 Date June ___ 2016

Attachment 2, "PG&E Response to Data Request A4NR 7.1

DCPP Non-Emergency Curtailment Scheduling Guidelines Basis Document (with redactions by PG&E)"

Pacific Gas and Electric Company

DCPP Non-Emergency Curtailment Scheduling Guidelines Basis Document

To: Senior Vice President - Energy Procurement, Vice President Energy Supply Management, Vice President - Transmission Operations

Dated September 29, 2014 from "Site Vice President - Diablo Canyon Power Plant"

Subject: Diablo Canyon Power Plant Scheduling Guidelines

GRC-2017-Ph1_DR_A4NR_007-Q01Atch01

Downloaded from http://a4nr.org/wp-content/uploads/2016/03/A1509001-A4NR-Geesman-Ratemaking.pdf 01 02 17

Since PG&E has already supplied this document in response to an interrogatory from the Party "Alliance for Nuclear Responsibility" (A4NR) in CPUC Proceeding A.15-09-001, there should be no difficulty in promptly emailing CGNP a copy of this document.

ANSWER 1

Please see Attachment: DiabloCanyonRetirementJointProposal_DR_CGNP_003-Q01Atch01.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Retirement Joint Proposal
Application 16-08-006
Data Response

PG&E Data Request No.:	CGNP_003-Q02		
PG&E File Name:	DiabloCanyonRetirementJointProposal_DR_CGNP_003-Q02		
Request Date:	January 3, 2017	Requester DR No.:	003
Date Sent:	January 19, 2017	Requesting Party:	Californians for Green Nuclear Power
PG&E Witness:	Jearl Strickland	Requester:	Gene Nelson

QUESTION 2

CGNP is also requesting any other PG&E documents available to Parties relating to the topic of "DCPP Non-Emergency Curtailment Scheduling."

ANSWER 2

PG&E objects to this question as overbroad, vague, and subject to privilege. Additionally, PG&E objects that any challenge to CPUC-approved operational curtailment protocols that may be responsive to this request are outside the scope of, and irrelevant to, this proceeding. Notwithstanding and without waiving these objections, PG&E responds as follows.

PG&E's law department requested the preparation of documents relating to this topic as part of its regulatory and legal assessment of future operating alternatives and strategies for Diablo Canyon. These documents are protected from disclosure as attorney-client communications and attorney work product. Please see PG&E's response to data request CGNP_004 for additional information.

PG&E filed a non-privileged operational curtailment protocol for Diablo Canyon as part of an update to its 2014 Bundled Procurement Plan ("BPP"). The purpose of the protocol is to facilitate back-down of Diablo Canyon during over-generation events declared by the California Independent System Operator. PG&E's 2014 BPP update was filed on October 3, 2014, in CPUC Rulemaking 13-12-010, and the operational curtailment protocol is found at Appendix L. The public version of the BPP can be accessed at the following link:
http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=119019259.
A portion of the protocols that apply to Diablo Canyon were designated confidential in that proceeding (Confidential Attachment 1 to Appendix L). PG&E's Diablo Canyon operational curtailment protocol was approved by the CPUC as part of its decision resolving the 2014 BPP update filing.[1]

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[1] *See* D.15-10-031, p. 16.

Memorandum

Date: September 29, 2014

To: **SENIOR VICE PRESIDENT - ENERGY PROCUREMENT**
VICE PRESIDENT - ENERGY SUPPLY MANAGEMENT
VICE PRESIDENT - TRANSMISSION OPERATIONS

From: **SITE VICE PRESIDENT – DIABLO CANYON POWER PLANT**

Subject: Diablo Canyon Power Plant Scheduling Guidelines

Pacific Gas and Electric Company®

FONG WAN
ROY M. KUGA
GREGG LEMLER

This supersedes Diablo Canyon Power Plant (DCPP) memorandum dated March 1, 2013, regarding the DCPP backdown capability. DCPP will notify the Senior Vice President, Energy Procurement, the Vice President, Energy Supply Management, and the Vice President, Transmission Operations of any changes in DCPP operating conditions affecting DCPP backdown capability. If any changes unexpectedly occur during non-business hours, the DCPP Shift Manager (SM) will notify the Grid Control Center (GCC) via tie-line and Energy Trading (ET) at Company number 8.223.5789.

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

[redacted]

DCPP NON-EMERGENCY CURTAILMENT SCHEDULING GUIDELINES BASIS DOCUMENT

Several parameters govern the ability of Diablo Canyon Power Plant, a Westinghouse pressurized water reactor (PWR), to reduce power in non-emergency conditions, including: (1) regulations and guidance of the Nuclear Regulatory Commission (NRC); (2) vendor (Westinghouse) recommendations and guidance regarding use of its equipment; (3) recommendations and guidance of the Institute of Nuclear Power Operations (INPO); (4) the chemistry/science of nuclear operations; and (5) operational safety-based limitations and considerations. Each of these parameters supports the plant's safe, efficient and cost-effective operation.

NRC regulations and guidance and INPO and Westinghouse recommendations and guidance govern the total amount of output DCPP can reduce per fuel cycle and how much notice DCPP needs prior to reducing output. The chemistry/science of nuclear operations governs how long it takes to reduce output, the optimal duration of curtailment, how long it takes to come back up to full power, and how often and when it is feasible to curtail power output. Operational and safety-based limitations and considerations govern decisions to be made at the time DCPP receives a request from Short Term Energy Supply (STES) to curtail DCPP.

PG&E has evaluated whether other, similarly-designed nuclear power plants operating in the United States operate in load-following mode. PG&E learned that there are no other PWR plants in the United States that operate in this manner. Columbia Generating Station (CGS), a boiling water reactor (BWR) is the only nuclear plant in the United States that regularly follows load. In doing so, CGS follows similar parameters and imposes similar requirements on non-emergency power curtailment as those PG&E implements through the Diablo Canyon Power Plant Scheduling Guidelines supported by this document. Benchmarking information is summarized at the end of this basis document.

[redacted]

A nuclear power plant may only operate in analyzed conditions. In June of 2006, Westinghouse notified licensees of their Nuclear Steam Supply Systems (NSSS) (InfoGram IG 06-03) that the Loss of Coolant Accident (LOCA) blowdown loads analyses have always been performed only at full power initial conditions. This decision by Westinghouse to perform these analyses only at full power was based on the following:

- The industry practice of performing LOCA blowdown loads analyses only for full power initial conditions is based on the assumption that plants would operate at full power most of the time.
- The probability of a large break LOCA at zero power is reasonably expected to be lower than that at full power for the Westinghouse plant fleets as a result of less challenging plant conditions at zero power and the shorter amount of time spent at zero power compared to full power.
- Definitive regulatory guidance regarding initial conditions for LOCA blowdown loads analyses does not appear to exist.
- The Nuclear Regulatory Commission (NRC) has not explicitly required performing LOCA blowdown loads analyses at reduced power levels.
- In Generic Letter GL-84-21, "Long Term Low Power Operation in Pressurized Water Reactors" (October 16, 1984), the NRC expressed concern about the effects of extended reduced power operation on core physics parameters. Although the Generic Letter does not specifically address LOCA blowdown loads analyses, it indicates NRC concern about extended operation outside analyzed conditions.
- Performing LOCA blowdown loads analyses at full power initial conditions is consistent with the assumptions required by 10 CFR 50.46 for analyzing the LOCA that produces the highest peak cladding temperatures and oxidation percentages.

[redacted]

[redacted]

[redacted]

The NRC and INPO have established performance metrics that strongly encourage operation at full power. These metrics support nuclear safety by minimizing the potential for initiating events that might challenge nuclear safety. The NRC's regulatory oversight process for inspection, assessment and enforcement of commercial nuclear power reactors utilizes performance indicators, including Unplanned Power Changes per 7,000 Critical Hours. This indicator monitors unplanned power changes that could challenge safety functions of the plant. [redacted] This indicator supports NRC Safety Cornerstone #1, Initiating Events.

INPO evaluates, monitors, and sets agreed upon standards for all U.S. nuclear power plants. INPO's evaluation of plants includes metrics on performance. INPO performance metrics include:

Forced Loss Events - The number of forced power reduction events > 20% not scheduled or planned > 10 days prior to the event. PG&E has received feedback from INPO that if a power reduction was ordered by the system operator, it will not be accounted for as a forced loss event.

Unit Capacity Factor - The ratio of available energy generation over a given period to the reference energy generation over that period.

Unplanned power changes per 7000 Critical Hours (IE05) - The objective of this cornerstone is to limit the frequency of those events that upset plant stability and challenge critical safety functions.

Number of unplanned power changes - The number of unplanned power changes that are initiated less than 72 hours following the discovery of an off-normal condition and that result in or require a change in power level.

[redacted]

An additional factor [redacted] is the efficient management of nuclear fuel. The number of effective full power days the unit is expected to complete during the upcoming operating cycle is an important factor in reactor core design. The statistic of concern here is the energy removed from the core during the cycle. If the reactor does not produce a predetermined amount of energy (i.e., does not achieve a specific burn-up), the design of the subsequent core is affected. If the energy difference is small, the task is to reanalyze the proposed design and demonstrate that the new core design would still be acceptable. A large energy difference can potentially require a physical core redesign and substantially delay restart of the unit. It could require restarting with a fresh design, a complete new analysis, and (in the worst case) require a different initial enrichment and replacing the fabricated assemblies with other new assemblies. Also, if the core is designed to operate at full power for the cycle but operates at reduced power for a significant duration, the unburned nuclear fuel energy will be wasted. This loss is unavoidable due to the fixed refueling outage dates, which are laid out years in advance. Operation contrary to the core design results in unused energy being placed in the spent fuel pool and eventually dry cask storage.

B. OPERATIONAL/CHEMISTRY BASIS

The power output of a nuclear reactor is adjusted by controlling how many neutrons are able to create more fissions. Control rods made of a neutron poison are used to absorb neutrons. Absorbing more neutrons in a control rod means that there are fewer neutrons available to cause fission, so pushing the control rod deeper into the reactor will reduce its power output, and extracting the control rod will increase it. At the first level of control in all nuclear reactors, a process of delayed neutron emission by a number of neutron-rich fission isotopes is an important physical process. These delayed neutrons account for about 0.65% of the total neutrons produced in fission, with the remainder (termed "prompt neutrons") released immediately upon fission. The fission products which produce delayed neutrons have half-lives for their decay by neutron emission that range from milliseconds to as long as several minutes. Keeping the reactor in the zone of chain-reactivity where delayed neutrons are *necessary* to achieve a critical mass state, allows time for mechanical devices or human operators to have time to control a chain reaction in "real time"; otherwise the time between achievement of criticality and nuclear meltdown as a result of an exponential power surge from the normal nuclear chain reaction, would be too short to allow for intervention.

In some reactors, the coolant also acts as a neutron moderator. A moderator increases the power of the reactor by causing the fast neutrons that are released from fission to lose energy and become thermal neutrons. Thermal neutrons are more likely than fast neutrons to cause fission. If the coolant is a moderator, then temperature changes can affect the density of the coolant/moderator and therefore change power output. A higher temperature coolant would be less dense, and therefore a less effective moderator.

In other reactors the coolant acts as a poison by absorbing neutrons in the same way that the control rods do. In these reactors power output can be increased by heating the coolant, which makes it a less dense poison. Nuclear reactors generally have automatic and manual systems to scram the reactor in an emergency shutdown. These systems insert large amounts of poison (often boron in the form of boric acid) into the reactor to shut the fission reaction down if unsafe conditions are detected or anticipated.

Most types of reactors are sensitive to a process variously known as xenon poisoning, or the iodine pit. Xenon-135 produced in the fission process acts as a "neutron poison" that absorbs neutrons and therefore tends to shut the reactor down. Xenon-135 accumulation can be controlled by keeping power levels high enough to destroy it as fast as it is produced. Fission also produces iodine-135, which in turn decays (with a half-life of under seven hours) to new xenon-135. When the reactor is shut down, iodine-135 continues to decay to xenon-135, making restarting the reactor more difficult for a day or two. This temporary state is the "iodine pit." If the reactor has sufficient extra reactivity capacity, it can be restarted. As the extra xenon-135 is transmuted to xenon-136 which is not a neutron poison, within a few hours the reactor experiences a "xenon burnoff (power) transient". Control rods must be further inserted to replace the neutron absorption of the lost xenon-135.

[redacted]

[redacted] Late in core life, boric acid, the neutron poison used to control the reactor, has become diluted. The boric acid changes required during power changes can challenge the ability of the installed equipment to dilute the boric acid concentration. A typical power reduction will require adding boron to start the ramp downward. As xenon concentrations start to increase in the down power, the boric acid concentration can be held reasonably constant. Once power starts to stabilize at the lower power level, a dilution will be required to stop the power change and to compensate for the increase in xenon concentration. As the xenon concentration peaks and starts to drop, the dilution will stop and boration will be required to compensate for the decreasing xenon concentration. This process is reversed for increases in power.

The amount of water required to reduce boric acid concentrations in the reactor coolant system is a function of the initial boric acid concentration. When the boric acid concentration is high (beginning and middle of fuel cycle), boric acid concentration changes are straightforward and readily achievable. At the low boric acid concentrations typical of late cycle, large amounts of water are required to reduce boric acid concentration. A power ramp can require dilutions in excess of 10,000 gallons of water. This requires that any power changes associated with reducing boron concentrations (associated with increasing xenon concentrations) be conducted at a rate that the chemical processing capability of the plant can sustain. As an example, a recent contingency ramp to reduce Unit 1 power late in core life predicted that the reduction would have required approximately 14,000 gallons of water to reduce and stabilize reactor power at 80%. A return to full power would likely have required an additional similar quantity of water.

Radioactive waste water must be processed and discharged into the ocean. Large radioactive waste volumes due to end-of-life power changes could overwhelm plant water treatment capacity if performed on multiple consecutive days. The plant also needs to consider other routine and periodic sources that contribute to the liquid radioactive waste holdup tanks. Increasing the volume of liquid radioactive waste will decrease the available capacity for gaseous radioactive waste. Also, increasing the throughput to the system will decrease the holdup (decay) time, and therefore increase the curies of activity disposed of or discharged. If failed fuel is present, thermal cycling of the fuel can increase the damage, thus aggravating the leak. [redacted]

Following a refueling outage, the nuclear fuel core must be conditioned in accordance with vendor recommendations. A substantial portion of the core has been replaced with new, unconditioned fuel, and the remainder of the core (the fuel on its second or third burn) has been moved to locations with different power distributions. Thus, the fuel in the core needs to be conditioned for operation in the new core, new set points established and other operating parameters for normal power operation established. [redacted] This limit prevents damage to the fuel due to physical stresses from thermal growth and associated conditioning of the fuel. [redacted]

3. Backdown Duration Varies with the Amount of Power Reduction

Xenon is a fission product poison produced during and immediately following operation of a critical core. The amount of xenon in the core is controlled while the reactor is critical and at a stable power level. When the reactor power decreases, xenon concentration will change and adjust to a new equilibrium value (rises and then drops to a new lower value). [redacted] During ramp up, the opposite effect (xenon concentration drops and then builds up) occurs. To compensate for the effects of xenon concentration changes, operators are required to change the boron concentration in the reactor coolant system in conjunction with moving control rods. Large power changes result in potentially large xenon oscillation, which can translate into large and undesirable power distribution oscillations. The effects of these xenon oscillations should be evaluated in advance to assess the impacts of the power change on power distribution and to plan for the required reactivity manipulations to ensure that the reactor continues to operate within analyzed limits.

[redacted]

[redacted]

As described in section 3, when reactor power is changed, core physics and parameters change and can potentially result in an unstable power oscillation. [redacted]

[redacted]

Chemistry-related work associated with non-emergency power reductions is the same, regardless of the number of MW reduced. Current core design limits control rod movement for reactivity control. As such, curtailing load in non-emergency conditions will require frequent Reactor Coolant System (RCS) boration and dilution. These adjustments will impact chemistry parameters, including boric acid required for reactivity control, and chemistry control parameters, including lithium hydroxide and dissolved hydrogen, in addition to other important diagnostic parameters. Changes in power and flow through the core will increase corrosion product transport and activation, leading to increased coolant activity and potentially to increased plant radiation fields and personnel exposure. Increased Chemical and Volume Control System (CVCS) cleanup flow for the purpose of reducing RCS corrosion products will contribute to increased filter changes and activity loading on CVCS demineralizer resin. Nitrogen blanked boric acid storage tanks (BAST) and primary water storage tanks (PWST) will increase nitrogen feed to the RCS and increase RCS non-condensable gases, leading to a decrease in the hydrogen concentration and requiring increased Pressurizer venting and Volume Control Tank (VCT) degassing, all of which increases gaseous radwaste. Each boration and dilution event will divert flow to the Liquid Hold Up Tanks (LHUT) and decrease the LHUTs' freeboard, decreasing gaseous radwaste storage capacity. The increased liquid volume routed to the LHUTs also will increase resin and filter consumption (to treat the liquid before discharge), which in turn potentially increases radioactive effluents to the environment due to decreased decay time from challenging the systems' installed capacity.

Changes to the secondary system will impact feedwater iron concentrations and Condensate Polisher (CP) operation and regeneration. Chemical feed will need to be more frequently adjusted to maintain secondary chemistry within specification. Furthermore, changes in secondary flow and temperatures have the potential to impact flow-accelerated corrosion (FAC) in locations not previously observed when operating continuously at 100% power.

Each of the following tasks must be performed to effectively and safely manage and control DCPP operation at less than full power.

(a) Primary Systems

- Boration of the Reactor Cooling System (RCS) by adding boric acid for reactivity control; dilution of boron from the RCS by adding primary water for reactivity control.
  - Sample/analyze RCS for boron with each boration and dilution
  - Increased boric acid usage
  - Sample/analyze the BASTs with increased boric acid usage

  - Increased primary water usage
- Increased lithium hydroxide feed to the RCS (for pH control) with borations and dilution
  - Sample/analyze the RCS for lithium hydroxide with each boration and dilution
  - Increased lithium hydroxide usage
- Increased monitoring of RCS dissolved hydrogen due to borations and dilution
  - Increased hydrogen gas usage
- Increased activated corrosion product generation in the RCS with changes in flow and chemistry
  - Potential for increased plant radiation fields and personnel radiation exposure
- Increased CVCS flow from 75 gpm to 120 gpm
  - Increased CVCS filter dose rates
  - Increased CVCS filter replacements
  - Increased personnel radiation exposure
  - Increased CVCS pumps run time; two pumps required to achieve 120 gpm
- Increased depleted zinc acetate feed to the RCS with borations and dilutions
  - Increased depleted zinc usage
- Increased argon-40 gas feed to the RCS with borations and dilutions
  - Decreased accuracy for detecting primary-to-secondary leakage, if present
- Increased volume of liquid generated due to borations and dilutions
  - Increased CVCS letdown demineralizer resin and CVCS evaporative feed resin usage
  - Decreased decay time for liquid and gaseous radwaste
  - Decreased gaseous radwaste system capacity
  - Challenge the capacity of liquid radwaste system discharge
  - Potential increase in radioactive effluents to the environment
- Increased Pressurizer venting and VCT degassing
  - Increased non-condensable gases in the system with borations and dilutions

- o Increased gaseous radwaste volume generated from venting and degassing

(b) Secondary Systems

- Adjust the number of CP vessels in service based on power (e.g., 6-7 vessels at 100% power; 5-6 vessels at 82% power; 4-5 vessels at 50% power)
  - o Revise CP regeneration frequency
  - o Increased iron transport may impact CP regenerations
  - o Increased resin regenerations (chemical usage) or resin replacement is possible
  - o Adjust hydrazine and ethanolamine chemical feed rate based on power
  - o Adjust air injection for oxygen control and increased monitoring

Given all of the tasks involved and impacts of performing these tasks (all of which are subject to human performance), it is not reasonable from the perspective of safe and efficient operations to undertake the effort required to reduce power by a nominal amount. [redacted]

When reactor power is changed more than 15% in an hour, DCPP's license requires additional chemistry sampling for radioiodine be taken and evaluated. When fuel defects are present, additional sampling may be required. [redacted]

C. U.S. BENCHMARK INFORMATION

1. United States Nuclear Power Plants

PG&E contacted INPO to identify U.S. nuclear plants that could be benchmarked concerning reduced power operations. INPO advised that Columbia Generating Station (GS) in

Washington is the only nuclear plant in the U.S. conducting any type of load following. PG&E contacted the Columbia GS operations manager during the week of December 10, 2012 and learned the following:

- Columbia GS load follows in the spring and summer due to hydro abundance.
- Columbia GS is a Boiling Water Reactor (BWR) with a net output of approximately 1180 MW.
- When dispatched to load follow, the unit curtails between 10 and 15% of rated output (up to approximately 180 MW).
- The change in power stays below the NRC Unplanned Power Change and the INPO Forced Loss Event 20% triggers.
- When changing power, no ramp plan is provided. This is due to the relatively "small" change in power.
- Curtailment durations average about three days. Nominal notice prior to initiating the power change is 24 - 48 hours.
- Core design does not plan for these curtailments. The resulting unburned fuel is moved to the Spent Fuel Pool and eventually to dry cask storage. This impacts capacity factor less than 10% per cycle.
- Columbia GS is dispatched and owned by the same entity, Bonneville Power Administration.
- Because there is no reactor temperature change with these small power reductions, no LOCA load issue similar to that experienced by Pressurized Water Reactors (PWR) arises. Refer to Westinghouse InfoGram 06-3.
- The Columbia GS operations manager was not aware of any other nuclear unit in the U.S. that follows load.
- BWR designs inherently allow reactor power changes more easily than PWR designs. Columbia GS is a BWR, while DCPP is a PWR.

2. AREVA- French Nuclear Power Plants

AREVA categorizes its nuclear power plants as either 'A mode' reactors, which are similar in design to DCPP, and gray mode reactors, which are designed more specifically to follow load. Once installed, this design feature cannot be altered due to Reactor Pressure Vessel head design and upper reactor vessel internal components.

According to AREVA personnel, the control modes depend upon the design of the rod cluster control assemblies (RCCAs). If the RCCAs are fabricated with a strong ("black") neutron absorber such as silver-indium-cadmium (AIC) (*DCPP RCCAs are AIC*) or boron carbide (B4C), then operating the reactor with the RCCAs inserted into the core for long periods may cause adverse burn-up effects on the adjacent fuel rods ("shadowing"). If the control rods are later withdrawn, the shadowed fuel will undergo an unacceptably large increase in power peaking factors, or local linear heat generation rates. Therefore, plants that operate with RCCAs that use AIC or B4C absorber have to follow load using the A Mode methods in which the control rods are not allowed to be inserted for long periods. Since the control rods cannot be inserted very far into the core for long periods, load follow maneuvers have to rely more heavily on changes in the reactor coolant boron concentration to control the transient xenon reactivity. Although it is possible to conduct load follow operations using A Mode methods, feed and bleed volumes would have to be managed. The plant design is more suited for long periods of base load operation than for frequent or extensive load following.

However, if some of the RCCAs are fabricated with a weaker neutron absorber material such as Inconel ("gray" rods), then the core can operate with the control rods inserted for longer periods because the shadowing effect is reduced. Then the plant can be operated using the G Mode ("gray" mode) methods. To operate in G Mode, the control rods may have to be re-patched so that they are configured and controlled in groups or banks that are different from the typical patching that would be used for A Mode operation. The advantage of operating with the gray RCCAs is that the control rods can be used more extensively to control *both* the thermal power and xenon reactivity changes, with a significant reduction in feed and bleed volumes.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Retirement Joint Proposal
Application 16-08-006
Data Response

PG&E Data Request No.:	CGNP_004-Q01		
PG&E File Name:	DiabloCanyonRetirementJointProposal_DR_CGNP_004-Q01		
Request Date:	January 3, 2017	Requester DR No.:	004
Date Sent:	January 18, 2017	Requesting Party:	Californians for Green Nuclear Power
PG&E Witness:	N/A	Requester:	Gene Nelson

QUESTION 1

For Californians for Green Nuclear Power's (CGNP's) upcoming workpaper submissions to support our written testimony in CPUC Proceeding A.16-08-006, we are requesting to promptly receive directly from PG&E a copy of the two documents referenced in this 18 November 2016 letter to PG&E from the Diablo Canyon Independent Safety Committee (DCISC,) specifically

1) The feasibility study on flexible power issues prepared by Areva in December 2013; and
2) The PG&E draft report entitled "Facts, Discussions, and Recommendations on DCPP's Ability to Implement Flexible Power Operations"

- In the event that these documents are not already being supplied to CGNP in response to CGNP_003-Q02.

ANSWER 1

PG&E objects to this data request on the basis of legal privilege. The requested materials are privileged from disclosure as attorney-client communications and attorney work product. These documents were prepared under the direction of counsel. The documents address potential future operating alternatives and strategies that PG&E considered as it evaluated its regulatory and legal strategy with respect to Diablo Canyon. The materials were prepared at the request of counsel to assist and inform counsel in the preparation of a legal/regulatory risk assessment for DCPP. Provision of these documents, even subject to a non-disclosure agreement, would result in a waiver of the privilege.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Retirement Joint Proposal
Application 16-08-006
Data Response

PG&E Data Request No.:	CGNP_005-Q01		
PG&E File Name:	DiabloCanyonRetirementJointProposal_DR_CGNP_005-Q01		
Request Date:	January 3, 2017	Requester DR No.:	005
Date Sent:	January 18, 2017	Requesting Party:	Californians for Green Nuclear Power
PG&E Witness:	Tom Jones	Requester:	Gene Nelson

SUBJECT: REQUEST FOR TABULATION OF SUMMARY DCPP TAX INFORMATION

QUESTION 1

For Californians for Green Nuclear Power's (CGNP's) upcoming workpaper submissions to support our written testimony in CPUC Proceeding A.16-08-006, we are requesting to promptly receive directly from PG&E a tabulation of summary Diablo Canyon Power Plant (DCPP) tax payment information to assist in the preparation of our organization's economic analysis of DCPP.

We are requesting a year-by-year tabulation of the following information for the years from 1985-2016, inclusive.

The requested entries for each year are:

1. The annual unitary tax payment (or its equivalent) for each year to San Luis Obispo County, California associated with the operation of DCPP.
2. The annual DCPP depreciation claimed on PG&E's United States Corporate tax return for each year.
3. The marginal tax rate for PG&E's United States Corporate tax return for each year.
4. The annual DCPP depreciation claimed on PG&E's State of California Corporate tax return for each year.
5. The marginal tax rate for PG&E's United States State of California tax return for each year.

ANSWER 1

Following a teleconference between PG&E and CGNP on January 5, 2016, CGNP agreed to withdraw parts 2-5 to this data request.

With regard to Question 1, the parties discussed the relative inaccessibility of tax calculations prior to 2007 due to changes in technology; accordingly, PG&E is limiting its response to tax records from 2007-2016. PG&E’s response to Question 1 is attached as: DiabloCanyonRetirementJointProposal_DR_CGNP_005-Q01Atch01.

PACIFIC GAS AND ELECTRIC COMPANY
Diablo Canyon Retirement Joint Proposal
Application 16-08-006
Data Response

PG&E Data Request No.:	CGNP_006-Q01		
PG&E File Name:	DiabloCanyonRetirementJointProposal_DR_CGNP_006-Q01		
Request Date:	January 9, 2017	Requester DR No.:	006
Date Sent:	January 24, 2017	Requesting Party:	Californians for Green Nuclear Power
PG&E Witness:	Chuck Marre	Requester:	Gene Nelson

SUBJECT: CGNP_006-Q01 - 2.6 PROPOSED RATEMAKING AND COST ALLOCATION ISSUES

QUESTION 1

CGNP is requesting information from PG&E's Capital Department regarding determination of the current "Full Book Value of Diablo Canyon Units 1 and 2" and the projected "Full Book Value of Diablo Canyon Units 1 and 2 on PG&E's proposed retirement dates in 2024 and 2025 as applicable.

CGNP has prepared an estimate aggregating both units for 2015 of $4.62 billion and an estimate of $3.55 billion in 2025, based on the projected useful life of the assets using straight-line depreciation as tabulated in PG&E's recent CPUC filing that includes the 2015 FERC Form 1. The attached spreadsheet shows the level of detail that CGNP is seeking regarding the current year 2017 and year 2025 DCPP Full Book Values - namely an analysis using the Uniform System of Accounts for Electric Utilities, asset classes 321-325, as are shown on the spreadsheet.

ANSWER 1

PG&E is providing DCPP's recorded net book value as of December 31, 2015 by FERC account. Neither year end 2016 nor current year 2017 data is yet available. Please refer to DiabloCanyonRetirementJointProposal_DR_CGNP_006-Q01_Atch01 which provides DCPP's plant, accumulated depreciation, and net book value as of 12/31/15. PG&E has provided the nuclear production accounts 321-325 requested. Since DCPP's net book value also includes direct assigned non-nuclear plant FERC accounts as well as the nuclear production land account 320, DiabloCanyonRetirementJointProposal_DR_CGNP_006-Q01_Atch01 includes these accounts in the net book value total amount.

As a reference tool, DiabloCanyonRetirementJointProposal_DR_CGNP_006-Q01_Atch01 also provides the DCPP forecast plant, accumulated depreciation, and net book value amounts as of December 31, 2016 that comprise the $1.805 billion 2016 direct assigned net plant forecast amount discussed on p.10-5 of testimony.

PG&E's December 31, 2015 net book value of $1.720 billion is lower than CGNP's estimate of $4.621 billion, mainly because PG&E"s amount includes the associated accumulated depreciation of $6.541 billion as of 12/31/15, which CGNP has not incorporated in their undepreciated value calculation (the FERC Form 1 does not provide accumulated depreciation by FERC account).

In this application PG&E has proposed to amortize the 2016 DCPP net book value over the remaining life of DCPP – 8.5 years, assuming Unit 2 operates until 2025. Any plant additions subsequent to 2016 will be amortized through 2025, using a life that decreases with each year subsequent to 2016. As such, the forecast 2025 net book value is zero.

It should be noted that the estimated average service lives and curve type included in PG&E's FERC Form 1 are for interim retirements, and not the final retirement of PG&E's Diablo Canyon Power Plant. As discussed in PG&E's 2017 GRC direct testimony (Exhibit PG&E-10, Chapter 11), the life span method is used to estimate the lives of generation plant for which concurrent retirement of the entire facility is anticipated. The interim survivor curve describes the rate of retirement related to the placement of elements of the facility that will not survive to the final retirement of the entire facility. For example, for a building the retirements of plumbing, heating, doors, windows, roofs, etc. that occur during the life of the facility would be interim retirements and would be estimated by an interim survivor curve. The life of those facility elements, however, would be truncated when the entire facility is retired. For DCPP, those dates are 2024 and 2025 for Units 1 and 2, respectively.

Name of Respondent PACIFIC GAS AND ELECTRIC COMPANY	New	% of plant base column added by Gene Nelson, Ph.D.	Date of Report (Mo, Da, Yr) 02/24/2016	Year/Period End of of Report: 2015/Q4	Undeprec-iated Value (SL) in 2015	Undeprec-iated Value (SL) in 2025

APPENDIX 1 - DEPRECIATION AND AMORTIZATION OF ELECTRIC PLANT (Continued)

C. Factors Used in Estimating Depreciation Charges

Line No.	Account No. (a)	Depreciable Plant Base (In Thousands)	Percent of Plant Base	Estimated Avg. Service Life	Net Salvage (Percent)	Applied Depr. rates (Percent)	Mortality Curve Type	Average Remaining Life	New	New
12	Intangible Plant									
13	302	113,750,070		40.00		2.17	SQ	25.00		
14	303	2,482,275		3.00			SQ	--14.00		
15	Subtotal	116,232,345								
16										
17	Steam Prod - Fossil						0			
18	311	112,125,238		75.00		3.63	L0	69.00		
19	312	273,493,692		50.00		3.70	R1	44.00		
20	313									
21	314	248,783,088		40.00		3.58	R2.5	34.00		
22	315	50,697,111		30.00		3.51	R4	24.00		
23	316	28,295,579		40.00		3.76	L0.5	34.00		
24	Subtotal	713,394,708								
25										
26	**Hydraulic Production**									
27	331	428,450,107	11.98%	**100.00**	--1.00	0.97	S2.5	76.00		
28	332	1,943,104,867	54.34%	**100.00**	--2.00	1.28	S2.5	71.00		
29	333	789,278,656	22.07%	**51.00**	--6.00	2.19	R1.5	35.00		
30	334	253,646,444	7.09%	**50.00**	--9.00	3.21	R1.5	33.00		
31	335	87,261,944	2.44%	40.00	--14.00	3.93	R2	26.00		
32	336	73,960,001	2.07%	**65.00**	--3.00	2.52	R1.5	44.00		
33	Subtotal	**3,575,702,019**								
34										
35	**Nuclear Prod-Diablo**									
36	321	1,036,743,265	13.83%	**100.00**	--1.00	0.93	R1	73.00	756,822,583	653,148,257
37	322	3,432,483,225	45.79%	**60.00**	--1.00	2.50	R1	39.00	2,231,114,096	1,659,033,559
38	323	1,162,811,055	15.51%	40.00	--1.00	1.41	R3	14.00	406,983,869	116,281,106
39	324	808,988,441	10.79%	**75.00**	--1.00	1.14	R1.5	50.00	539,325,627	431,460,502
40	325	1,055,904,489	14.08%	40.00	--2.00	4.47	R4	26.00	686,337,918	686,337,918
41	Subtotal	**7,496,930,475**							**4,620,584,094**	**3,546,261,341**
42										
43	Other Production									
44	341	210,375,654		55.00		3.72	R5, R1	50.00		
45	342	11,264,118		50.00		3.73	R5,R1	45.00		
46	343	223,711,698		40.00		3.59	R5,R2.5	34.00		
47	344	353,570,942		27.00		4.27	R5, R2.5,	23.00		
48	345	210,675,563		35.00		3.76	R5,R2.5	30.00		
49	346	95,867,567		26.00		4.13	R5,S0.5,	20.00		
50	Subtotal	1,105,465,542								

Converted and 3 new columns added by Gene Nelson, Ph.D. 10 30 16. Source: PG&E FERC Form 1 - 2015
https://pgeregulation.blob.core.windows.net/pge-com-regulation-docs/FERCForm1.pdf

Confirmed in "**Uniform System of Accounts for Electric Utilities**"

http://www.ecfr.gov/cgi-bin/text-idx?c=ecfr&SID=054f2bfd518f9926aac4b73489f11c67&rgn=div5&view=text&node=18:1.0.1.3.34&idno=18

Account Definitions from http://elibrary.ferc.gov/IDMWS/common/OpenNat.asp?fileID=13021745 Public Service of New Mexico - FERC 1 - 07 03 12

Nuclear Production Plant - Palo Verde	
321	Structures and Improvements
322	Reactor Plant Equipment
323	Turbogenerator Equipment
324	Accessory Electric Equipment
325	Miscellaneous Power Plant Equipment

DCPP Direct Assigned Plant by FERC Account(s)	12/31/2015 - Recorded			12/31/2016 - Forecast		
	Plant	Accumulated Depreciation	Net Book Value	Plant	Accumulated Depreciation	Net Book Value
	in 000's			in 000's		
Nuclear Production:						
320	22,727	21,445	1,282	22,727	21,576	1,150
321	1,036,743	937,903	98,840	1,035,789	957,797	77,992
322	3,432,483	2,659,939	772,544	3,493,069	2,717,035	776,033
323	1,162,811	1,013,666	149,145	1,168,157	1,030,382	137,775
324	808,988	721,453	87,536	827,113	729,627	97,486
325	1,055,904	546,408	509,497	1,167,682	542,895	624,787
Subtotal	7,519,657	5,900,814	1,618,843	7,714,537	5,999,313	1,715,223
109 FAS109 Gross Up	468,499	468,499	0	468,499	468,499	0
303 Intangible (S/W)	85,027	47,859	37,168	94,905	62,541	32,365
352-356 Electric Transmission	96,074	64,318	31,757	96,023	67,045	28,978
389 Land Rights	10	10	(0)	10	10	(0)
Subtotal	181,111	112,186	68,925	190,938	129,595	61,343
390-399 Structures/General Plant	92,602	59,881	32,721	89,818	61,201	28,617
DCPP Direct Assigned Plant Total	8,261,869	6,541,380	1,720,489	8,463,792	6,658,609	1,805,183

http://www.power-eng.com/articles/npi/print/volume-2/issue-3/nucleus/diablo-canyon-unit-1-steam-generator-replacement-project.html

Diablo Canyon Unit 1 Steam Generator Replacement Project

09/01/2009

By Nancy Spring, Editor

All photos, courtesy PG&E

SGT West (SGT), a URS Washington Division/AREVA NP joint venture company, provided services for replacing four steam generators at Unit 1 of the Diablo Canyon Nuclear Power Plant (DCPP) in California. Replacement occurred during a planned refueling outage that began in January 2009.

Old steam generator moving out of the protected area on a self-propelled modular transporter. Diablo Canyon's challenging configuration required handling all components three times versus the usual two.

Pacific Gas and Electric Co.'s Diablo Canyon nuclear power plant in San Luis Obispo County, Calif., is a dual unit Westinghouse pressurized water reactor. Each of its two units produces 1,150 MW of electrical power and was designed with four steam generators.

Steam generator on a barge in the Diablo Canyon Power Plant intake cove. The generators were manufactured in Spain and shipped to California, where they were transferred to barges in Port Hueneme and delivered to the intake cove.

Completing the meticulous welding on the large components. At its peak, almost 1,200 SGT personnel worked at Diablo Canyon on alternating 12-hour shifts 24 hours per day.

Steam generators are replaced as part of a nuclear plant's long-term maintenance program. The pre-planning for Diablo Canyon began in April 2005—45 months before the January 2009 Unit 1 outage began. The defuel, replacement of four steam generators, refuel and successful start-up at Diablo Canyon Unit 1 was performed in 58 days "breaker to breaker."

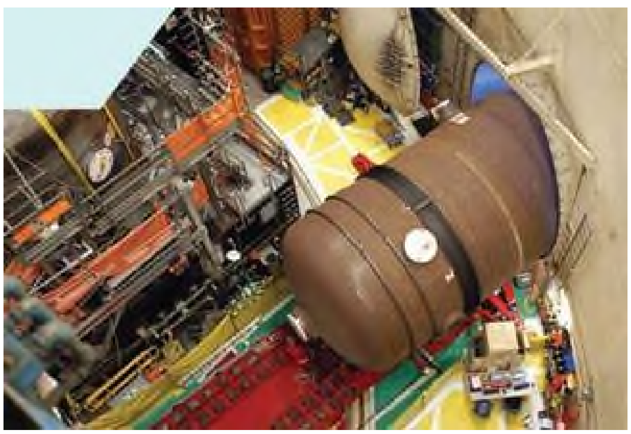
Old steam generator being lowered with polar cranes onto the hatch transfer system before removal from containment. A completely customized rigging system and an innovative assembly process were required to move the steam generators.

The major work scope included, but was not limited to, cutting, rigging and removal of the old steam generators and transporting them to the concrete storage facility.

Old steam generator being transported to the storage facility, a 1.5 mile trip. To store the old steam generators coming out of containment, SGT built a large concrete structure that could house eight steam generators and two reactor vessel heads.

Replacement steam generator on the outside lifting system. Each generator is 70 feet long and weighs 350 tons.

The new replacement steam generators were transported, rigged, set and welded. Using photogrametry and computer modeling, SGT positioned the 70-foot long, 350-ton replacement steam generators to tolerances within 1/16 inch of the optimal location, an accomplishment recognized industry-wide.



Replacement steam generator moving through the containment hatch. The containment building's configuration and the original installation of the steam generators were not designed for easy replacement.

The SGT Team had successfully replaced the steam generators in Unit 2 during a scheduled refueling outage in 2008. The installation of all eight generators was the largest project in the history of the Diablo Canyon Nuclear Power Plant since its construction completion in the mid-1980s.

Diablo Canyon Power Plant
Digital Process Protection System Replacement
Diversity and Defense-in-Depth

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ABSTRACT

Diablo Canyon Power Plant (DCPP) is replacing the existing digital Westinghouse Eagle 21 Process Protection System (PPS) to address maintenance and obsolescence issues. Eagle 21 was installed in 1994 to replace the original analog Westinghouse 7100 PPS. The License Amendment for replacement of the Eagle 21 PPS was submitted to NRC on October 26, 2011. Key to submittal of the PPS replacement LAR was resolution of the need for Diversity and Defense-in-Depth (D3) in the replacement design to mitigate the potential for a common design error to disable redundant channels of the protection systems through common-cause failure (CCF).

The D3 evaluation reviewed the Diablo Canyon Final Safety Analysis Report Update (FSARU) to determine the events that required the PPS for primary or backup protection to identify available automatic means to prevent PPS software CCF from adversely affecting the mitigation of FSARU Chapter 15 accidents or events. PG&E developed a replacement PPS design based on DI&C ISG-02 diversity guidance that is Class 1E, nuclear safety-related and that automatically performs all the protection functions credited in the FSARU with automatic operation. Further, the replacement PPS provides safety-related automatic mitigation functions for the events where the Eagle 21 Safety Analysis credited manual operator action given a postulated concurrent CCF to the PPS.

PG&E submitted the PPS Replacement Project D3 Assessment Topical Report to NRC in April, 2010, and revised it in September, 2010 to incorporate responses to Requests for Additional Information (RAI). PG&E received NRC approval of the D3 Topical Report in April, 2011.

This paper discusses the methodology by which PG&E assessed the diversity requirements of the Diablo Canyon Power Plant (DCPP) digital PPS relative to current regulations and guidance, and the coping strategy that provides sufficient built-in diversity to meet USNRC DI&C ISG-02 Staff Positions 1-3 without a Diverse Actuation System (DAS).

Key Words: Digital, RPS, RTS, ESFAS, CCF, Diversity, Defense-in-Depth

1 INTRODUCTION

Diablo Canyon Power Plant (DCPP) is replacing the existing digital Westinghouse Eagle 21 Process Protection System (PPS) to address maintenance and obsolescence issues. The Eagle 21 PPS was installed in 1994 to replace the original analog Westinghouse 7100 PPS. The analog PPS possessed design depth and diversity such that two or more diverse protective actions would terminate an accident before consequences adverse to public health and safety could occur [1]. Existing diverse RPS functions, including the ATWS Mitigation System Actuation Circuitry (AMSAC) that was installed to meet 10CFR50.62 [2] are not affected by the PPS replacement. The Eagle 21 PPS met the requirements for D3 that existed at the time it was licensed; however, manual operator action was credited for several mitigation scenarios where both primary and backup protection functions were performed in the Eagle 21 PPS.

The current USNRC staff position regarding manual operator action credited in D3 evaluations is set forth in Interim Staff Guidance (ISG)-02 [4] as follows:

"(1) When an independent and diverse method is needed as backup to an automated system used to accomplish a required safety function, the backup function can be accomplished via either an automated system, or manual operator actions performed in the main control room. The preferred independent and diverse backup method is generally an automated system. The use of automation for protective actions is considered to provide a high-level of licensing certainty.…

"(2) If automation is used as the backup, it should be provided by equipment that is not affected by the postulated RPS CCF and should be sufficient to maintain plant conditions within BTP 7-19 recommended acceptance criteria for the particular anticipated operational occurrence or design basis accident…

"(3) If manual operator actions are used as backup, a suitable human factors engineering (HFE) analysis should be performed to demonstrate that plant conditions can be maintained within BTP 7-19 recommended acceptance criteria for the particular anticipated operational occurrence or design basis accident...

Using the guidance of DI&C ISG-02, PG&E reviewed the DCPP Final Safety Analysis Report (FSAR) [3] Chapter 15 licensing basis accident analyses and the Nuclear Regulatory Commission (NRC) Eagle 21 Safety Evaluation Report (SER) [5] in accordance with USNRC Branch Technical Position (BTP) 7-19 [6]. The review considered the CCF to cause failure of the entire Process Protection System (PPS) concurrent with each Chapter 15 event and accident for which primary or backup mitigative action by the PPS was credited in the analysis. The goals of the review were to identify available automatic means to prevent concurrent PPS software CCF from adversely affecting the mitigation of FSARU Chapter 15 accident or events; and to develop a coping strategy without crediting manual operator actions to mitigate events where diverse automation sufficient to meet above Positions (1) and (2) did not exist outside the existing PPS. PG&E considered that the Human Factors Evaluation (HFE) study to demonstrate adequate operator response per above Position (3) presented an unacceptable degree of project risk with respect to the additional Staff review time that would be required for evaluation and the potential uncertainty of the outcome.

PG&E submitted the PPS Replacement Project D3 Assessment Topical Report to NRC in April, 2010 [7], and revised it in September, 2010 [8] to incorporate responses to Requests for Additional Information (RAI). PG&E received NRC approval of the D3 Topical Report in April, 2011 [9]. The License Amendment for replacement of the Eagle 21 PPS was submitted to NRC on October 26, 2011. Approval is anticipated in May, 2013.

1.1 Method

The DCPP digital PPS replacement D3 assessment describes the integrated digital PPS system design proposed for the replacement. The assessment describes the diversity between the PPS software and the plant control systems, indications, alarms and readouts, and manual circuitry. The assessment evaluated design-basis transients and accidents with the assumed concurrent CCF to demonstrate that plant responses to these transients and accidents can successfully comply with the defined acceptance criteria. Diverse systems and/or operator actions required to meet acceptance criteria were noted.

The evaluation comprised three basic tasks:

1. Identification of the set of transients and accidents to be considered in combination with the assumed CCF of the digital PPS.
2. An evaluation of these transients and accidents which could challenge BTP 7-19 acceptance criteria given a CCF of the PPS; that is, where primary and backup protection functions resided in the PPS, thus potentially susceptible to the postulated CCF.
3. Determination of a coping strategy to address the events where BTP 7-19 acceptance criteria could be challenged given a design basis accident or event with a concurrent CCF to the PPS.

The first two tasks identify the FSAR Chapter 15 design basis events to be considered. Each design basis accident or event in the existing FSAR analyses was then screened for one of the following four categories based on the assumption of PPS failure due to CCF:

Category 1: Events that do not require the PPS for primary or backup protection

Category 2: Events that do not require the PPS for primary but require the PPS for backup protection

Category 3: Events that require the PPS for primary protection but also receive automatic backup protection from systems other than the PPS

Category 4: Events that assume the PPS for primary and backup protection signals for some aspect of the automatic protection

The events of the first three categories required no further analysis because the postulated concurrent CCF will not adversely affect event mitigation. The remaining Category 4 events are potentially challenging to BTP 7-19 acceptance criteria and require further analysis with respect to the coping strategy.

1.2 Architecture of the Replacement PPS

The PPS Replacement Project replaces in its entirety the Westinghouse Eagle 21 PPS hardware as illustrated in the shaded portion of Figure 1. Equipment in the unshaded portion of Figure 1 is not being replaced or modified by this project. Thus, the PPS Replacement Project maintains the Westinghouse 4-channel, 2-train architecture without affecting existing diverse systems (Nuclear Instrumentation System, ATWS Mitigation System, and Solid State Protection System).

Figure 2 illustrates a typical allocation of the specific signals used to implement Reactor Trip System (RTS) and Engineered Safety Feature (ESF) functions between the Tricon and the ALS for one of the four (4) redundant replacement Protection Sets. The ALS provides Class IE signal conditioning for the Pressurizer Vapor Space temperature, RCS wide range temperature and narrow range RTD inputs to the OPDT and OTDT thermal trip functions. These temperature signals are passed from the ALS to the Tricon for processing by the Tricon portion of the PPS replacement. Figure 2 further illustrates the diverse systems not subject to CCF (i.e, NIS, direct contacts, and AMSAC) that are not affected by the PPS replacement.

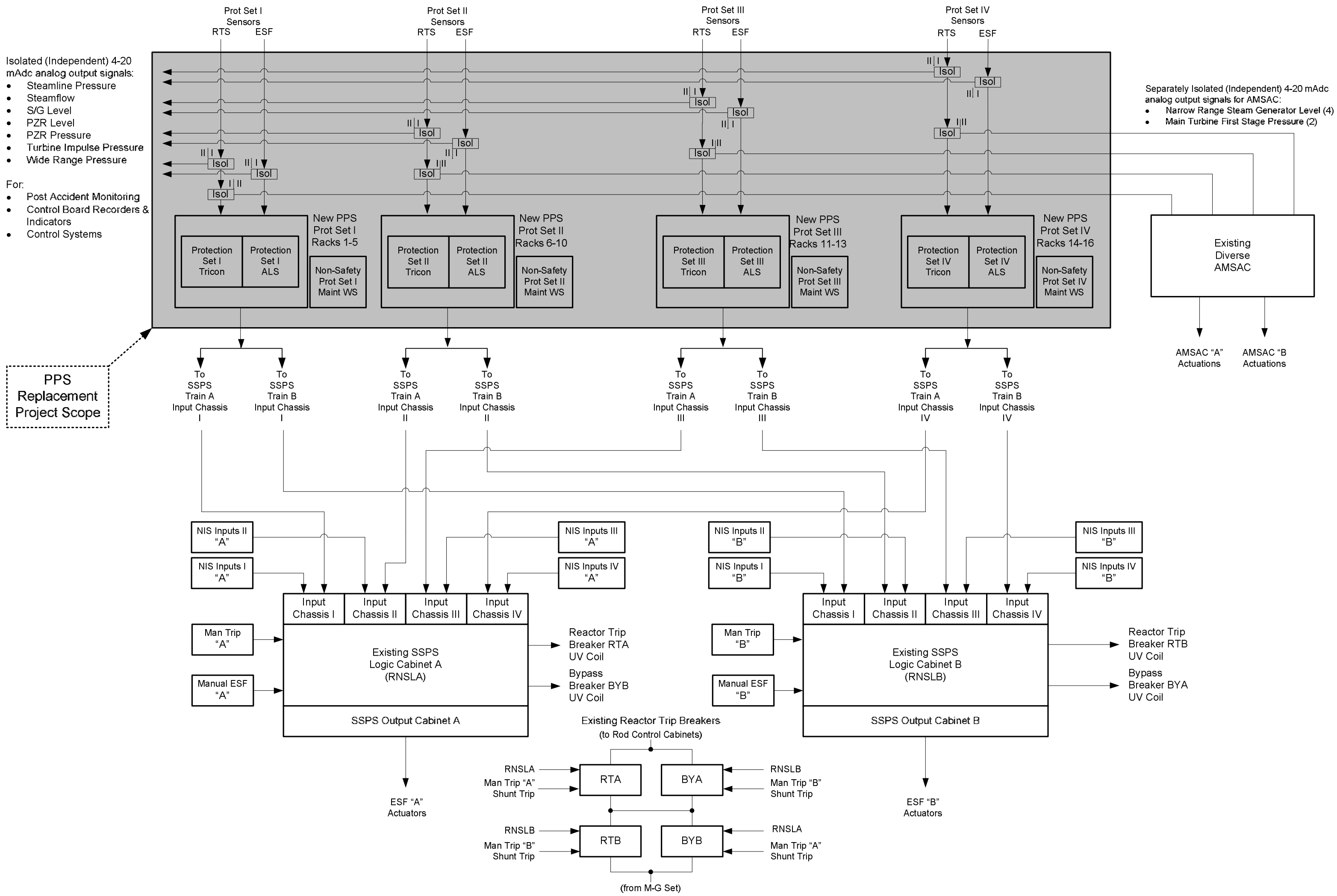

Figure 1: Simplified Diablo Canyon Process Protection System Replacement

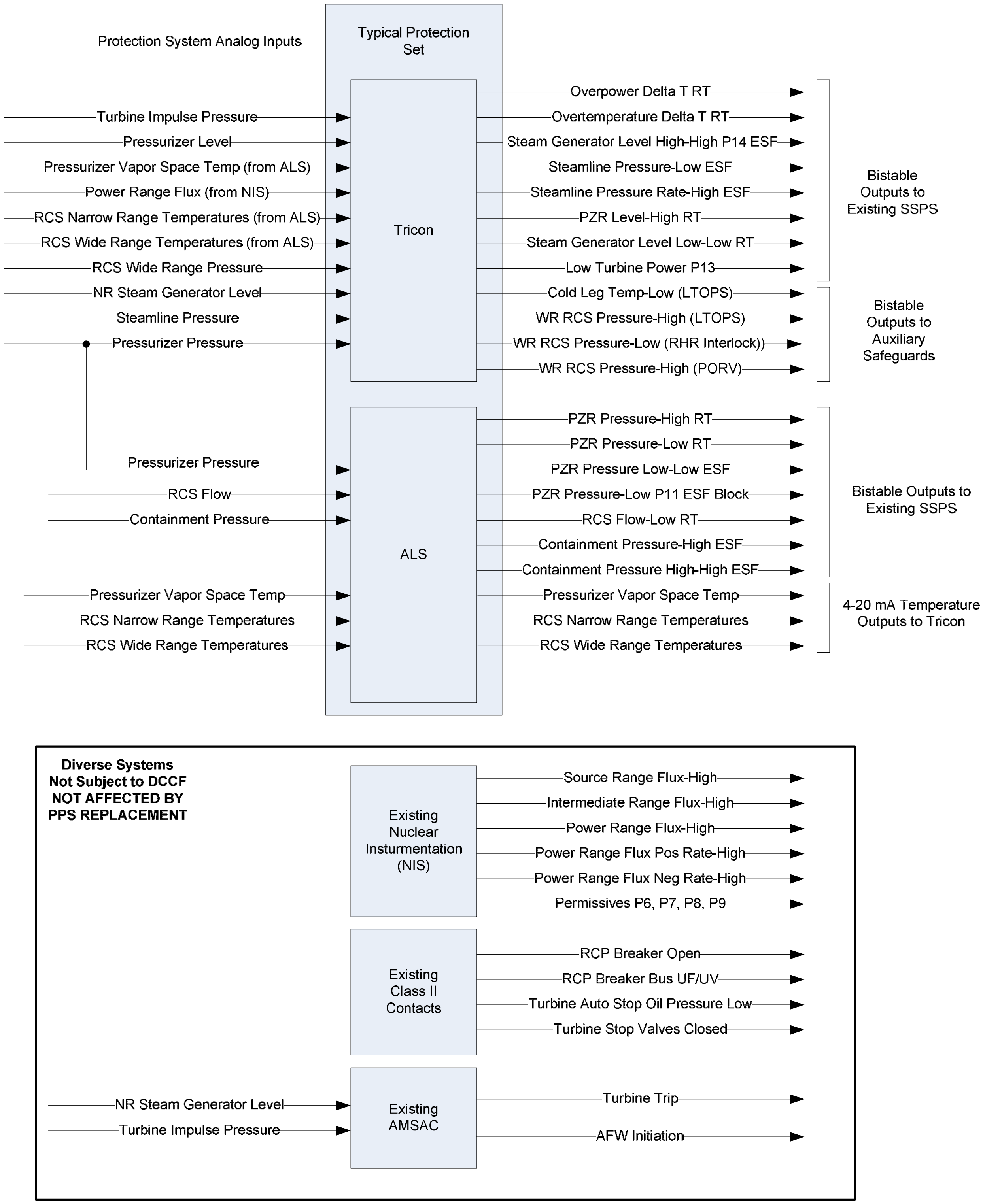

Figure 2. Typical Replacement Process Protection Set

PPS replacement functions are implemented in the same four (4) redundant Protection Sets as the existing Eagle 21 PPS. Each Protection Set uses a software-based Triconex Tricon processor described in Tricon V10 Topical Report Submittal [10] to mitigate events automatically where the PPS Replacement D3 Assessment determined that existing diverse and independent automatic mitigating functions are available to mitigate the effects of postulated CCF concurrent with FSAR [3] Chapter 15 events that were credited with automatic mitigation . For the events where this assessment determined that additional diversity measures were necessary to preclude manual mitigative action, automatic protective functions are performed in the diverse safety-related CSI ALS shown in the shaded portion of Figure 1. The ALS is described in the ALS Topical Report Submittal [11].

The Tricon is Triple Modular Redundant (TMR) from input terminal to output terminal, each input and output module includes three separate and independent input or output circuits or legs. These legs communicate independently with the three Main Processor modules. Standard firmware is resident on the Main Processor modules for all three microprocessors as well as on the input and output modules and communication modules, which are not shown in the figure. The TMR architecture allows continued system operation in the presence of any single or multiple faults within the system. The TMR architecture also allows the Tricon to detect and correct individual faults on-line, without interruption of monitoring, control, and protection capabilities. In the presence of a fault, the Tricon alarms the condition, removes the affected portion of the faulted module from operation, and continues to function normally in a dual redundant mode. The system returns to the fully triple redundant mode of operation when the affected module is replaced.

The diverse ALS portion of the PPS replacement platform utilizes Field Programmable Gate Array (FPGA) hardware logic rather than a microprocessor and has no software component required for operation of the system. Concern for ALS software CCF is minimized through incorporating additional design diversity in the FPGA-based hardware system and using qualified design practices and methodologies to develop and implement the hardware. The ALS subsystem provides two complete and diverse execution paths “A” and “B” with independent design and V&V teams for the Core Logic Boards (CLB), input boards and output boards as shown in Figure 3. Appropriate V&V activities ensure that the output from each development team is indeed diverse from the other. Each CLB has its own set of input and output boards (“A” for CLB “A” and “B” for CLB “B”). The diverse execution path outputs are combined in hardwired logic to ensure that the protective action is taken if directed by either path. A single failed path cannot prevent a protective action.

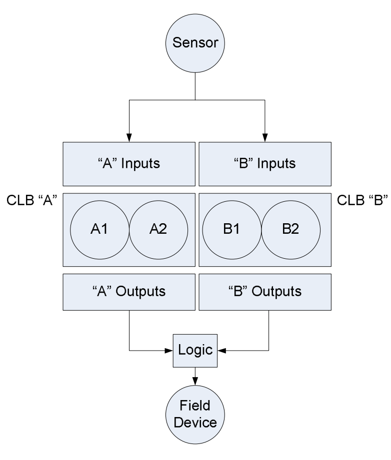

Figure 3. ALS Diversity Architecture for DCPP PPS Replacement

Each FPGA in an execution path contains two sets of redundant hardware logic (“A1” & “A2”; “B1” & “B2”), which perform the application-specific functions independently and in parallel. Diversity between the two sets of logic within a CLB is achieved by changing the logic implementation during the synthesis process. A CLB that detects a mismatch between its logic core outputs identifies itself as failed and sets its outputs to a fail-safe state before halting operation.

Safety-related information (i.e., Pressurizer vapor space temperature and RCS narrow and wide range temperatures) is transmitted from the FPGA logic-based ALS to the software-based Tricon via analog signals. There is no digital communication of safety-related information from the software-based Tricon to the logic-based ALS. There is no software-based communication between or among redundant or diverse Protection Sets. No database information or equipment that uses software is shared between the Tricon and the diverse ALS or between redundant Protection Sets within Tricon or ALS portions of the replacement PPS, except for the analog temperature signals discussed above.

The built-in diversity of the ALS subsystem ensures that the PPS replacement will perform the required safety functions automatically in the presence of a postulated Tricon CCF without an adverse impact on the operator's ability to diagnose the event or perform previously credited manual actuation activities. A Tricon CCF cannot affect ALS safety function.

In other words, a CCF may be assumed that causes the “A” ALS subsystem to fail, but the “B” ALS subsystem will remain functional because the built-in diversity provided by the “A” and “B” execution paths prevents both “A” and “B” paths from being disabled by the same CCF. Conversely, a CCF may be assumed that causes the “B” ALS subsystem to fail, but the “B” ALS subsystem will remain operational.

1.3 Results of the Evaluation

The DCPP D3 assessment assumed that a worst-case CCF results in a total failure of the Tricon portion of the PPS system, similar to the Eagle 21 D3 evaluation. The Eagle 21 diversity assessment assumed a postulated CCF caused all automatic protection functions generated in the Eagle 21 PPS to fail to perform the protection functions described in DCPP FSAR Chapter 15.

Category 1 protection functions are processed through systems other than the PPS. The FSAR Chapter analysis of the events crediting these independent and diverse protective functions either: (1) takes credit for independent primary mitigating functions; or (2) does not require a primary mitigating function. Mitigation of these D3 Assessment Category 1 events is unaffected by CCF of the PPS.

Process Variable	D3 Assessment Category 1 Protection Functions
Neutron Flux	Power Range High-Flux (Low Setting) Reactor Trip
	Power Range High-Flux (High Setting) Reactor Trip
	Power Range Positive Flux Rate Reactor Trip
	Power Range Flux Control Rod Stop
	Intermediate Range High-Flux Reactor Trip
	Source Range High-Flux Reactor Trip
	Input to Over Power Delta Reactor Trip
	Input to Over Temperature Delta T Reactor Trip
AMSAC(Steam Generator Low Level)	Turbine Trip Above C-20 Permissive
Main Turbine Stop Valve Position	Turbine Trip Reactor Trip
Turbine Auto Stop Oil Pressure Low	
RCP Bus Undervoltage	Reactor Trip
RCP Bus Underfrequency	Reactor Trip
RCP Circuit Breaker Open	Reactor Trip

Category 2 and 3 protection functions either: (1) do not require the PPS for primary protection but assume PPS for backup protection (Category 2); or (2) require the PPS for primary protection but receive automatic backup protection from systems other than the PPS (Category3). These protection functions are performed in the software - based Tricon subsystem of the replacement PPS. Independent and diverse primary or backup protection is available for these functions. Mitigation of these Category 2 and 3 events is not adversely affected by CCF of the PPS Tricon subsystem.

Process Variable	**D3 Assessment Category 2 and 3 Protection Functions**
Pressurizer Level	Pressurizer High-Level Reactor Trip
RCS Narrow-Range Temperature	Input to Over Temperature Delta T Reactor Trip
	Input to Over Power Delta T Reactor Trip
	Input to SG Low-Low Level Trip Time Delay
Steam Generator Level	Steam Generator Low-Low Level Reactor Trip
	Hi-Hi Level Feedwater Isolation
	Hi-Hi Level Turbine Trip
	Hi-Hi Level MFW Pump Trip
	Low-Low Level AFW Actuation (Process Sense performed by RTS; AMSAC utilizes independently isolated level signals and independent turbine impulse pressure channels to provide diverse function)
Steam Line Pressure	High-Negative Pressure Rate SLI
	Low-Pressure SI
	Low-Pressure SLI
Turbine Impulse Pressure	Permissive 13 Low Turbine Power Permissive (Input to P-7 Low Power Reactor Trip Permissive)

Category 4 protection functions require the PPS for both primary protection and backup protection. Manual operator action is credited in the existing Eagle 21 SER to mitigate these events given a concurrent CCF in the PPS. In the replacement PPS, these protection functions are performed in the logic based ALS subsystem of the replacement PPS where built-in diversity ensures continued automatic protection given a concurrent CCF. Mitigation of Category 4 events is not affected by CCF of the PPS Tricon or ALS subsystem. The ALS is not affected by a Tricon CCF. The ALS “A” and “B” execution paths are not disabled by the same CCF.

Table 1 shows how the PPS functions performed by the diverse ALS subsystem preclude the manual operator actions otherwise required to mitigate events in the presence of a concurrent CCF. Each of the Category 4 events listed in the left hand column of the table required manual operator action for accident mitigation in the presence of a CCF in the Eagle 21 PPS SER [5]. The "X" in the associated PPS function column identifies the ALS functions that will remain operational due to the built-in diversity characteristics of the ALS system.

The need for manual operator action is eliminated by the diversity built into the replacement PPS design and plant safety is improved without the need for a DAS.

Accident Analysis/Event		Primary Protection System Functions Performed by Diverse ALS Sub-System							
FSAR Section	**D3 Topical Report Category 4 Events**	**PZR Pressure Low SI (Note 1)**	**PZR Pressure High RT**	**PZR Pressure Low RT**	**Cont. Pressure High SI**	**Cont. Isolation Phase A**	**Cont. Isolation Phase B**	**Cont. Pressure High Containment Spray**	**RCS Flow Low RT**
15.2.5	Loss of Forced RCS Flow								X
15.2.13	RCS Depressurization			X					
15.3.1 15.4.1	SBLOCA / LBLOCA	X		X	X	X	X	X	
15.4.2.1	Steam Line Break	X				X	X	X	
15.4.2.2	Main Feed Pipe Rupture		X		X	X			
15.4.3	SG Tube Rupture	X		X					

Note 1: Automatic reactor trip occurs on safety injection due to low pressurizer pressure or high containment pressure.

Table 1. Diverse ALS Protection Functions

2 CONCLUSIONS

Diablo Canyon Units 1 and 2 FSARU Chapter 15 licensing basis accident analyses were reviewed to determine which events required the Eagle 21 Process Protection System for primary or backup protection. Those transients identified as requiring the Process Protection System for primary protection system response were reviewed to determine if diverse means of automatically mitigating the transient are available, or annunciators and indicators are available to allow the operator to diagnose the event and bring the plant to a safe shutdown condition in a timely manner. For most transients no operator action is required since sufficient non-PPS-based automatic functions exist; i.e., the Nuclear Instrumentation System (NIS), Solid State Protection System (SSPS) and the AMSAC. For several events, however, some operator action was necessary. In these cases, backup protection system functions, alarms, and indicators processed independently of Eagle 21, along with existing Diablo Canyon operating procedures and Emergency Operating Procedures, were credited to bring the plant to a safe shutdown condition.

Each of the eight Category 4 functions shown in Table 1would be rendered inoperable due to the effects of a postulated CCF under the existing Eagle 21diversity scheme [5], because both primary and backup protection functions are performed by the Eagle 21 PPS. The replacement PPS design, which incorporates the safety-related ALS subsystem with built-in system diversity, will ensure that these functions will be performed automatically without adverse impact to the operator's ability to diagnose or perform previously credited manual actuation activities.

In their SER, NRC Staff determined [8] that the Class IE, nuclear safety-related DCPP replacement PPS design provides reasonable assurance that appropriate diverse means of actuation exist to mitigate DCPP Chapter 15 event events automatically, should a CCF occur in either the Tricon or ALS subsystems of the PPS system concurrent with the events for which automatic mitigation by the PPS is credited. Therefore, the replacement PPS design addresses the ISG-02 Staff Positions adequately and will meet BTP 7-19 acceptance criteria without a Diverse Actuation System (DAS).

3 REFERENCES

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Planned Maintenance at Diablo Canyon Unit 2 Delayed to Meet State Energy Needs During Heat Wave

California Independent System Operator Requests Both Units Operate at Full Power

September 8, 2015

Avila Beach, Calif.— A planned maintenance outage scheduled to begin today on Unit 2 at Pacific Gas and Electric Company's (PG&E) Diablo Canyon Power Plant (DCPP) has been postponed to make certain there is enough electricity to reliably meet California's energy needs during an upcoming heat wave.

PG&E delayed the planned work and power curtailment at the request of California Independent System Operator (CAISO), an entity that works to ensure there is enough to electricity to reliably meet state demands. PG&E will conduct the planned outage, which includes a tunnel cleaning, after CAISO determines there is enough backup generation available to meet state electricity demands.

"DCPP is a vital resource for California. It is a safe, clean, reliable and affordable energy resource for PG&E's customers statewide. We are absolutely committed to ensuring that our customers continue to receive a steady supply of reliable power, and we will continue to coordinate with the CAISO on an appropriate time to perform the planned outage," said PG&E Senior Vice President and Chief Nuclear Officer Ed Halpin.

There are no safety impacts associated with postponing the planned work on Unit 2. In the past, PG&E has performed similar delays at the request of the CAISO.

Both Unit 1 and Unit 2 at DCPP continue to safely operate at full power.

About Diablo Canyon Power Plant

Diablo Canyon Power Plant is a nuclear power facility owned and operated by PG&E. Its two units together produce approximately 2,300 net megawatts of carbon-free power. It provides nearly 10 percent of all electricity generated in California, and enough energy to meet the needs of more than three million Northern and Central Californians. Diablo Canyon has a $920 million annual local economic impact and is the largest private employer in San Luis Obispo County.

About PG&E

Pacific Gas and Electric Company, a subsidiary of PG&E Corporation (NYSE:PCG), is one of the largest combined natural gas and electric utilities in the United States. Based in San Francisco, with more than 20,000 employees, the company delivers some of the nation's cleanest energy to nearly 16 million people in Northern and Central California. For more information, visit www.pge.com/ and www.pge.com/en/about/newsroom/index.page.

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Posted on August 1, 2014 http://www.pgecurrents.com/2014/08/01/helms-at-30-hydroelectric-plant-delivers-safe-clean-affordable-energy/

Helms at 30: Hydroelectric Plant Delivers Safe, Clean Affordable Energy

By Denny Boyles

FRESNO — PG&E marks 30 years of commercial operation at Helms Pumped Storage Project this month. The hydroelectric facility was considered an engineering marvel when it was built and came online in 1984, and continues to play a vital role today as well in California's clean energy future.

This month marks the 30th anniversary of the Helms Pumped Storage Project, which produces enough electricity to power the cities of Fresno and Oakland.

Helms operators can take the plant from an idle state to full generation in eight minutes. That ability to quickly ramp up and down plays a key role in integrating intermittent renewable resources such as wind and solar onto the power grid, said John Conway, PG&E senior vice president for Energy Supply.

"Helms and our Diablo Canyon Power Plant give us the unique capability to fully integrate a significant amount of clean energy into the power supply while still ensuring that we can meet the energy demands of our customers," Conway said. "When it began delivering power 30 years ago, Helms played a key role for California and our customers. That role has only grown as our electric grid has evolved."

Nestled high in the Sierra Nevada Mountains about 50 miles east of Fresno, Helms features two reservoirs and three hydro pump-generators. The generators can produce a total of 1,212 megawatts of electricity or enough to power the cities of Fresno and Oakland. Nearly four miles of 28-foot diameter tunnels connect the powerhouse and two reservoirs. (At 6 hours/day of power production, Helms annually produces 2,656, 098 MWh of power [2.67 TWh/year output with 3.54 TWh/year input]) - GN

[See a video tour of Helms.]

During times of high electric demand, water flows downhill from Courtright Lake at the higher elevation (8,200 feet) through the powerhouse. When there is excess generation online, the pumps can be reversed, pushing the water uphill from Lake Wishon at the lower elevation (6,500 feet) to recharge the upper reservoir.

With nearly 4,000 megawatts of generation, PG&E has the largest privately owned hydroelectric system in the nation, stretching from the Southern Cascade Mountain Range south along the Sierra-Nevada Mountains to Bakersfield. PG&E's hydroelectric system produces enough energy to power almost 4 million average homes.

Email Currents at Currents@pge.com.

http://www.wapa.gov/sn/ops/transmission/path15/factSheet.pdf Verified 05 07 15 by Gene A. Nelson, Ph.D.

Path 15 Upgrade Project

Path 15 UPGRADE

Los Banos

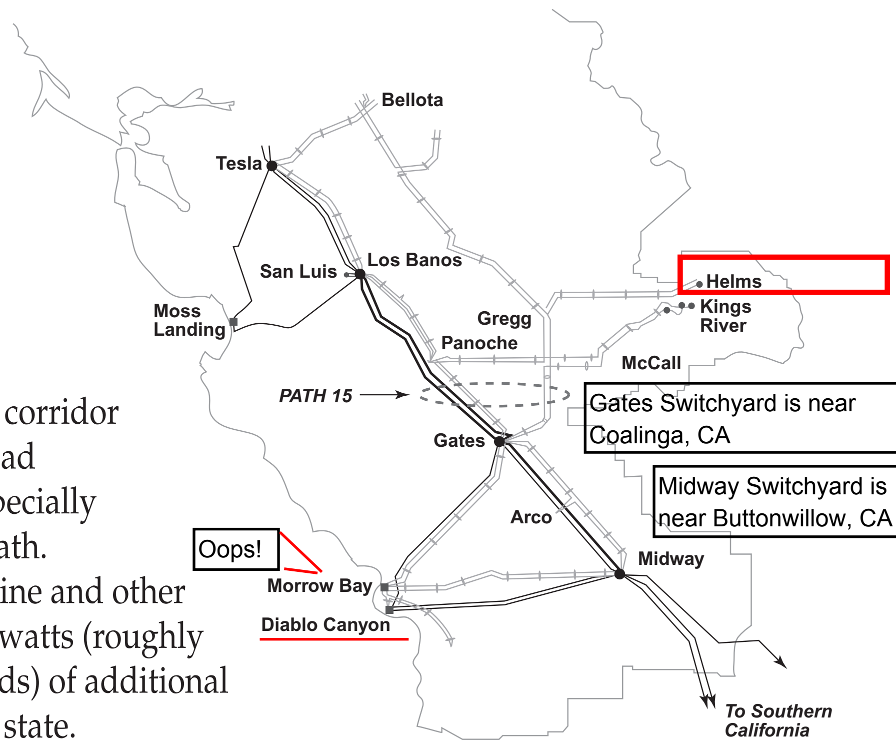
Gates

WAPA is the Western Area Power Administration

Current facilities

Path 15 is located in the southern portion of Pacific Gas and Electric Company's service area and in the middle of the California Independent System Operator's Control Area. Path 15 is rated at 3,900 MW and consists of these lines:

- Los Banos-Gates 500 kV
- Los Banos-Midway 500 kV
- Gates-Panoche No. 1 230 kV
- Gates-Panoche No. 2 230 kV
- Gates-Gregg 230 kV
- Gates-McCall 230 kV



Capacity through this transmission corridor is insufficient to carry the electricity load needed to maintain grid reliability, especially during periods of high usage on the path. Building a third 500-kV transmission line and other upgrades will allow about 1,500 megawatts (roughly enough to power 1.5 million households) of additional electricity to be transmitted across the state.

Third 500-kV transmission line conducts ~3,000 RMS Amperes. - GAN

Upgrade plan

The path upgrade will relieve constraints on the existing north-south transmission lines. The plan to increase the path rating is to:

- Construct a new 84-mile-long, 500-kV transmission line between PG&E's Los Banos and Gates substations.
- Modify the existing Los Banos and Gates substations to accommodate new equipment.
- Establish a second 230-kV circuit between Gates and Midway.

This plan will increase the nonsimultaneous south-to-north path rating to 5,400 MW from the existing 3,900 rating.

Western Electricity Coordinating Council approved the south-to-north rating increase in February 2003.

The project could become a model for relieving other transmission constraints throughout the country.

Project financing

The project will be financed substantially with non-Federal funds. Project participants are Western Area Power Administration, a Federal agency, Pacific Gas and Electric Company and Trans-Elect New Transmission Development, under this public-private partnership.

PG&E will perform the substation and 115- and 230-kV system work and receive about 18 percent of the new transmission capacity. On Feb. 12, 2002, the U.S. Bankruptcy Court approved up to $75 million for PG&E to do the work.

Western will complete all planning work, acquire land rights and manage the construction project. Western will retain a 10-percent share. Congress appropriated $1.328 million in FY 2001 to fund project startup.

Trans-Elect will provide the remaining funding for the transmission line and own the remaining transmission rights (about 72 percent).

Estimated project cost is $306 million.

In early August 2003, Moody's Investors Service assigned a Ba1 bond rating to $95 million of senior secured bonds and a Ba3 rating to $56 million of senior secured bonds. Moody's assigned stable ratings outlooks to each company.

On Sept. 15, 2003 Trans-Elect's New Transmission Development Company, which is responsible for funding the transmission line, provided Western with $76 million to start work on the transmission line.

System benefits

Upgrading Path 15 to remove transmission constraints is crucial to the reliability of California's power system. In early 2001, Path 15 constraints limited the amount of power that could be shipped from Southern California and the Southwest to Northern California, resulting in rotating power outages in Northern California. Eliminating the potential for such outages is expected to benefit the state's economy.

In addition to enhancing reliability, the Path 15 upgrade will create a more robust electricity market in the West by permitting greater power transfers between southern and northern California, increasing the ability to use the least-cost power source.

On Sept. 25, 2001, the ISO filed testimony with the California Public Utilities Commission supporting the need for the Path 15 Upgrade. The testimony stated it is "economically justified to reduce the risk of high prices associated primarily with the exercise of market power by strategically located generation and the existence of drought hydro conditions but also other factors such as the risk of a low level of new generation development in Northern California. An examination of historical congestion costs and studies undertaken by the ISO show that:

1) between September 1, 1999 and December 31, 2000, congestion on Path 15 cost California electricity consumers up to $221.7 million; and

2) using reasonable assumptions, the $300 million cost of upgrading Path 15 could potentially be recovered within one drought year, plus three normal years. Further, upgrading Path 15 is consistent with a broader strategy to put into place a robust high-voltage transmission system that supports cost-effective and reliable electric service in California and a broader and deeper regional electricity market."

ISO to assume operational control

PG&E and Trans-Elect will turn over the operational control of their entitlement in the project to the California Independent System Operator. Western intends to turn over the operational control of its share to the ISO.

The project will be operated following accepted utility practice as a transmission facility within the ISO control area.

Project status

Western released a solicitation for an Engineering, Procurement and Construction Contract for the transmission line work on Jan. 31, 2003.

Maslonka & Associates Inc., Mesa, Ariz., was selected in May 2003 for the $87 million contract to construct the 84-mile, high-voltage transmission line.

PG&E awarded two contracts to Burns & McDonnell in June 2003 for the 500-kV substation modifications and the 230-kV shunt capacitor work. PG&E will perform all other work. Work began on the PG&E portion of the project in summer 2003.

The Coordinated Operations and Interconnection Agreement outlining coordination and interconnection of the Path 15 Upgrade with the existing PG&E electric system was filed at the Federal Energy Regulatory Commission on April 1, 2004. PG&E and Trans-Elect have completed the Transmission Control Agreements and Transmission Owner Tariffs necessary to turn over the operational control of these facilities to the ISO. Western is in the process of finalizing the necessary agreements.

The project participants negotiated a Programmatic Agreement with the Native American tribes and state and Federal agencies spelling out consultation procedures and methods to protect historical and cultural resources and Native American cultural sites, including burial sites.

Western has acquired the necessary easements to construct the project.

The U.S. Fish and Wildlife Service issued a Biological Opinion for the project in June 2003 and Western obtained other necessary permits.

Western issued the construction notice to proceed on Sept. 15, 2003.

Project timeline

Fall 2003—Construction began

Late 2004—Line energized

Western's role as project manager

Western will:

- own the transmission line and 10 percent of the transmission rights in recognition of funding ($1.328 million appropriated in FY 01) provided to date and other contributions as project manager.
- ensure the necessary negotiated project agreements are executed; that participants are actively involved in the process; and that participants cooperate to move the project forward. Western performed lead Federal agency efforts for the National Environmental Policy Act process and has acquired necessary land rights.

Project history

Utilities in the 1980s recognized the potential for constrained power flows over Path 15 under certain conditions. Western, the Transmission Agency of Northern California and PG&E studied possible additions to relieve constraints in 1988 as part of the planning for the California-Oregon Transmission Project. Western and others prepared an Environmental Impact Statement on a proposed Path 15 upgrade as part of COTP planning. The EIS concluded that Path 15 upgrades would produce no significant adverse environmental impacts. But for a variety of reasons, the Los Banos-Gates Transmission Project was not built.

The National Energy Policy, released in May 2001, recommended the Department of Energy take action to explore relieving the constraints on Path 15.

On May 28, 2001, U. S. Energy Secretary Spencer Abraham directed Western to complete the planning needed to relieve Path 15 constraints and determine whether investors would be interested in financing the upgrades.

Western received 13 responses to a Federal Register notice by the July 13, 2001, deadline and recommended nine interested parties as project participants.

The Path 15 Partnership; Kinder Morgan Power Co.; Mirant Americas Development Inc.; PG&E National Energy Group; Williams Energy Marketing and Trading Co.; and the Transmission Agency of Northern California withdrew at various times in the process.

Western issued a Supplement Analysis to the 1988 Environmental Impact Statement on Dec. 20, 2001, and a second Supplement Analysis addressing subsequent issues, such as transmission line realignment, in May 2003.

The CPUC issued a Final Environmental Impact Review on March 5 that found the proposed transmission corridor west of Interstate 5 is the environmentally superior alternative.

Participants signed a Letter Agreement and filed it at the Federal Energy Regulatory Commission on April 30, 2002. The agreement provided $1.5 million in initial funding and outlined the overall terms and conditions for the project. FERC accepted the terms of the letter on June 12, 2002.

The California Independent System Operator's Board of Directors approved a Path 15 upgrade on June 23, 2002.

Trans-Elect provided $1.5 million in initial funding on July 3, 2002, to finance preliminary work.

On Dec. 30, 2002, the project participants executed the Construction and Coordination Agreement. This document spelled out the project terms and conditions in more detail than previous documents and provided an additional $8.5 million to Western in initial funding.

On May 22, 2003, the California Public Utilities Commission granted PG&E's motion to withdraw its Application for a Certificate of Public Convenience and Necessity for Path 15 and found that the Final Supplemental Environmental Impact Report on the project can be used as the Environmental Impact Report, allowing PG&E to proceed with the project under Federal authority with the principal project partners.

On Oct. 23, 2003, the Western Electricity Coordinating Council released the north-to-south path rating of 3,265 MW for the Path 15 Upgrade Project.

Project participants

Western is a Federal agency within the Department of Energy. It markets electricity from Federal water projects in a 15-state region of the West and manages more than 17,000 miles of transmission lines.

Pacific Gas and Electric Company is one of three California-based investor-owned utilities. PG&E delivers electricity and natural gas to 13 million consumers in northern and central California.

Trans-Elect, Inc., based in Reston, VA is the first independent transmission company in North

America. It holds interest in and serves as general partner for assets totaling nearly $1 billion, which represents 12,600 miles of transmission lines in the U.S. and Canada. Trans-Elect's New Transmission Development Co. was launched in Fall 2002. NTD's singular focus is to develop and construct new electric transmission lines.

Updated: June 1, 2004

Posted on August 1, 2014 http://www.pgecurrents.com/2014/08/01/helms-at-30-hydroelectric-plant-delivers-safe-clean-affordable-energy/

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Email Currents at Currents@pge.com.

SoCalGas
A Sempra Energy utility®

January 24, 2017
FOR IMMEDIATE RELEASE

SoCalGas Statement on Natural Gas Withdrawal at Aliso Canyon

Earlier today, in order to address increased system demand driven by current weather conditions, SoCalGas began withdrawing natural gas from its Aliso Canyon storage facility to support reliability of the region's natural gas and electricity systems. The withdrawal is being executed in accordance with the Aliso Canyon Winter Withdrawal Protocol established by the California Public Utilities Commission (CPUC). The company issued the following statement:

"Today's withdrawal at Aliso Canyon, the first since January 2016, utilizes only those wells that have been approved for use by the Division of Oil, Gas and Geothermal Resources. These wells have passed all of the tests required by the State's Comprehensive Safety Review. Withdrawal is consistent with the California Public Utilities Commission's June 2, 2016 authorization for SoCalGas to utilize the remaining 15 billion cubic feet of natural gas to help prevent service curtailments.

"Also to support system reliability, SoCalGas issued a "SoCalGas Advisory" at 7 a.m. on Monday, January 23, 2017 that will remain in effect until further notice. A SoCalGas Advisory asks all customers to immediately reduce their natural gas use to help lower the risk of possible natural gas and electricity shortages. In addition, SoCalGas issued a system-wide curtailment watch for noncore customers (large commercial and industrial customers, including electric generation plants), effective yesterday at 7 a.m. and continuing until further notice. These customers are advised that they may receive a notice to curtail service.

"SoCalGas urges all customers to immediately reduce their natural gas use by:

- Lowering their thermostats to 68 degrees or below;
- Delaying the use of natural gas appliances; and
- Washing clothes in cold water when possible."

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Media Contact: SoCalGas | 24-Hour Media Line: 213-244-2442 | socalgas.com/newsroom

January 24, 2017
FOR IMMEDIATE RELEASE

SoCalGas Statement on Gas Withdrawal at Aliso Canyon Stopped

Earlier today, at approximately 11:30 a.m., SoCalGas ceased natural gas withdrawal operations at its Aliso Canyon storage facility. The company issued the following statement:

"Cold weather is expected in the greater Los Angeles region tonight and into tomorrow, which could impact demand for natural gas. Additionally, low temperatures forecasted east of California for this week could impact the availability of natural gas supply to the Southern California region. SoCalGas will continue to monitor weather regionally and nationally and its potential impact on system conditions, including any need for additional withdrawals from Aliso to maintain the reliability of natural gas and electricity services.

"Both the 'SoCalGas Advisory' and the 'curtailment watch' issued yesterday, January 23, remain in effect until further notice. A SoCalGas Advisory asks all customers to immediately reduce their natural gas use to help lower the risk of possible natural gas and electricity shortages. The system-wide curtailment watch for noncore customers (large commercial and industrial customers, including electric generation plants) advises these customers that they may receive a notice to curtail service."

###

Media Contact: SoCalGas | 24-Hour Media Line: 213-244-2442 | socalgas.com/newsroom

January 25, 2017
FOR IMMEDIATE RELEASE

SoCalGas Statement on Natural Gas Withdrawals at Aliso Canyon

In order to address increased system demand driven by current weather conditions, SoCalGas began withdrawing natural gas from its Aliso Canyon storage facility today at approximately 7:00am. The withdrawal is being executed in accordance with the Aliso Canyon Winter Withdrawal Protocol established by the California Public Utilities Commission (CPUC). The company issued the following statement:

"Cold weather conditions this morning continue to put pressure on our natural gas system. In order to avoid curtailments or service interruption for large customers, including electric generators, refineries, and other critical service providers such as hospitals, airports and transit systems, this morning we began withdrawing natural gas from Aliso Canyon in accordance with the Aliso Canyon Winter Withdrawal Protocol established by the California Public Utilities Commission (CPUC).

"Throughout the day, hourly peaks in demand can result in sudden stresses on our system. Withdrawals from storage allow us to address those sudden peaks in demand and help prevent curtailments or service interruptions. Demand on our system this morning has been higher than we experienced yesterday.

"The SoCalGas Advisory issued for all customers remains in effect until further notice. All customers are urged to immediately reduce their natural gas use to help lower the risk of possible natural gas and electricity shortages. The system-wide curtailment watch for non-core customers issued Monday also remains in effect until further notice. Non-core customers may receive a notice to curtail service."

"SoCalGas will continue to monitor weather regionally and nationally and its potential impact on system conditions. All efforts will be made to avoid curtailments and service interruptions."

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Media Contact: SoCalGas | 24-Hour Media Line: 213-244-2442 | socalgas.com/newsroom

January 25, 2017
FOR IMMEDIATE RELEASE

SoCalGas Statement: Withdrawals at Aliso Canyon Stopped

At approximately 9:00 am today withdrawals from Aliso Canyon were stopped. Earlier today, to address increased system demand driven by weather conditions, SoCalGas began withdrawing natural gas from its Aliso Canyon storage facility at approximately 7:00am. Today's withdrawal was executed in accordance with the Aliso Canyon Winter Withdrawal Protocol established by the California Public Utilities Commission (CPUC). The company issued the following statement:

"This morning, as a result of the cold weather, hourly customer demand on our system significantly exceeded gas supplies being delivered through interstate pipelines and our other storage facilities. Withdrawals from Aliso Canyon played a critical role in helping us meet that peak demand. Over the last hour, demand on our system dropped and we were able to suspend withdrawals from Aliso Canyon.

"This morning's customer demand illustrates the sudden peaks we regularly experience with changes in the weather. We work with the California Independent System Operator and our customers to manage these changes in demand on an hourly basis to help prevent curtailments or service interruptions.

"Cold weather conditions are forecast to continue to put pressure on our natural gas system. In order to avoid curtailments or service interruption for large customers, including electric generators, refineries, and other critical service providers such as hospitals, airports and transit systems, additional natural gas withdrawals from Aliso Canyon may be necessary. Any withdrawals will be made in accordance with the Aliso Canyon Winter Withdrawal Protocol established by the California Public Utilities Commission (CPUC).

"The SoCalGas Advisory issued for all customers remains in effect until further notice. All customers are urged to immediately reduce their natural gas use to help lower the risk of possible natural gas and electricity shortages. The system-wide curtailment watch for non-core customers issued Monday also remains in effect until further notice. Non-core customers may receive a notice to curtail service."

"SoCalGas will continue to monitor weather regionally and nationally and its potential impact on system conditions. All efforts will be made to avoid curtailments and service interruptions."

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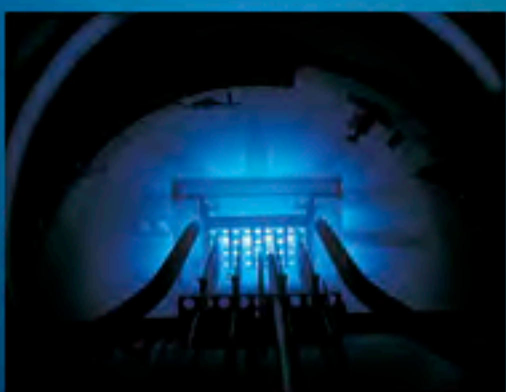

California's Energy Future - Powering California with Nuclear Energy

California Council on Science and Technology
Burton Richter, Robert Budnitz, Jane Long, Per Peterson, and Jan Schori
July 2011

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 CCST is a non-profit organization established in 1988 at the request of the California State Government and sponsored by the major public and private postsecondary institutions of California and affiliate federal laboratories in conjunction with leading private-sector firms. CCST's mission is to improve science and technology policy and application in California by proposing programs, conducting analyses, and recommending public policies and initiatives that will maintain California's technological leadership and a vigorous economy.

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Letter from CCST

CCST is pleased to present the results of an analysis of the future of nuclear power in California. This study is part of the California's Energy Future (CEF) project, which was undertaken to help inform California state and local governments of the scale and timing of decisions that must be made in order to achieve the state's goals of significantly reducing total greenhouse gas emissions over the next four decades.

California's Global Warming Solutions Act of 2006 (AB32) and Executive Order S-3-05 set strict standards for the state to meet. In order to comply, California needs to reduce its greenhouse gas emissions to 80% below 1990 levels by 2050 while accommodating projected growth in its economy and population. This will likely require a doubling of electricity production with nearly zero emissions. Nuclear power could be an important component in strategies for meeting these standards. This report is a summary of the realistic potential of nuclear power for California and presents an analysis of technological readiness, safety, fuel supply, costs, and siting.

As this report was nearing completion, the nuclear power accidents that resulted from an earthquake and tsunami in Fukushima, Japan were unfolding. Consequently, this report also includes some preliminary observations about Fukushima relevant to California. As the Fukushima events unfold and we learn more about exactly what happened and why, it will be worth revisiting the meaning of Fukushima for California in more depth.

We believe that the CEF nuclear power report presents valuable insights into the possibilities and realities of meeting California's electricity needs and emissions standards over the decades to come, and hope that you will find it useful.

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

Miriam John
California's Energy Future
Committee, Co-chair

Burton Richter
California's Energy Future
Committee

I. Introduction and Conclusions

This report is aimed at examining the potential of nuclear energy to meet California's electricity demand in the year 2050. The main focus of our analysis is on the CCST Realistic Model (described in detail elsewhere) which assumes that total electricity demand in California in the year 2050 amounts to 510 terawatt-hours per year (TWh/y). Since nuclear electricity is capital intensive, it is most economically used as baseload power where the plants run at their maximum output all of the time and that is what we assume here. We also assume that nuclear plants have a 90% capacity factor and that baseload power represents 67% of total electricity demand (adjusting the baseload fraction up or down does not affect the conclusions reached herein), the rest being supplied by renewables as mandated by California's law AB32. This requires about 44 gigawatts (GW) of nuclear electricity capacity. This scenario and one scenario where nuclear electricity is deployed on a much larger scale (call the Stress Test) are described in section III. We also assume that a large scale growth in nuclear energy in California will be part of a large scale growth worldwide which affects infrastructure and work force requirements as discussed below. Consequently, our analysis assumes that California only gets its fair share of resources needed to scale up, but an expanding nuclear industry results in economies-of-scale which makes nuclear power less expensive for California.[1]

Some of the scenarios used in the full report include use of hydrogen as a fuel. Hydrogen can be produced using nuclear reactors though doing so efficiently requires a new generation of nuclear plants.[2] Requirements for hydrogen production are also briefly discussed in Section III.

While reactor technology is certain to evolve over the period of interest, we are assuming for this study that for electricity production these future reactors will have characteristics similar to the new generation of large, advanced, light-water reactors (LWR), known as GEN III+ that are now under review by the U.S. Nuclear Regulatory Commission for deployment in the next decade. This allows us to say something about costs since these are under construction in Asia and Europe, and a larger number of similar systems have been built in Asia recently. We comment later on the potential of new and improved designs. Our main conclusions on technical issues are as follows:

- There are no technical barriers to large-scale deployment of nuclear power in California. There are, however, legislative barriers and public acceptance barriers that have to be overcome to implement a scenario that includes a large number of new nuclear reactors.
- The cost of electricity from new nuclear power plants is uncertain. No new ones have been built in decades, though 104 generating plants are operating in the U.S. today. Thus, operations, maintenance and fuel costs are known well, but the dominant cost, the amortization of construction costs, is uncertain. Estimates of electricity costs from new plants range from 6 to 8¢ per kilowatt hour (KW-hr) up to 18¢ per KW-hr with most estimates at the lower end of the range. Our conclusion is that 6 to 8¢ per KW-hr is the best estimate today. This is discussed in more detail in section II.

1 The scale-up of nuclear power in California could occur whether or not the world develops an expanded role for nuclear power. Although there are no non-proliferation issues with expanding nuclear power in California, we note that nuclear nonproliferation will be an issue for global scale up and if nuclear power is to fulfill its potential as a global carbon-free energy resource, expansion must be accompanied by dramatic increases in cooperation among national governments to strengthen the Nuclear Nonproliferation Treaty, the IAEA system of safeguards against diversion of civilian nuclear programs to any military purpose, and the physical security of nuclear fuel cycle facilities against attack by terrorist groups and theft of weapon-grade materials by terrorist or other criminal groups.

2 The favored method of hydrogen production requires reactors that operate at much higher temperatures than occur in the present generation of power reactors in order to achieve reasonably high efficiency. These high temperatures raise new materials problems and a major R&D effort will be required to solve them. R&D has begun, but it is not possible as yet to say how long it will take to solve the problems.

- Loan guarantees for nuclear power will be required until the financial sector is convinced that the days of large delays and construction cost overruns are over. Continuation of the Price-Anderson act is assumed.
- Nuclear electricity costs will be much lower than solar for some time. There is insufficient information on wind costs yet to allow a comparison, particularly when costs to back up wind power are included.
- Cooling water availability in California is not a problem. Reactors can be cooled with reclaimed water or with forced air, though air cooling is less efficient and would increase nuclear electricity prices by 5% to 10%.
- There should be no problem with uranium availability for the foreseeable future and even large increases in uranium costs have only a small effect on nuclear power costs. There may be shortages of natural uranium in the long term, but there are ways to get around them.
- While there are manufacturing bottlenecks now, these should disappear over the next 10 to 15 years if nuclear power facilities world-wide grow as expected.
- There are benefits to the localities where nuclear plants are sited. Tax rates in California are set by the State Board of Equalization, typically at 1% of the cost of the plant, and collected locally. By current estimates this would amount to $50 million per year per gigawatt of electrical capacity (GWe). In addition, about 500 permanent jobs are created per GWe.
- The events at Fukushima, Japan where a number of boiling water reactors (BWR) were damaged in a major earthquake and tsunami will trigger review and evalution of safety in design, operation and mangement. The information gained during the Fukushima review and any recommendations made should be factored into decisions about the potential future use of nuclear reactor technologies in California.

Section II of this report looks at costs; section III focuses on the realistic and extreme scenarios; section IV examines fuel availability; section V looks at site issues; section VI discusses the spent fuel problem; and section VII briefly touches on weapons proliferation. Section VIII is a story line; what has to be done on the State, Federal, and industrial levels to make this kind of nuclear expansion possible. Section IX gives some preliminary comments on the nuclear accidents at Fukushima nuclear power plants in Japan which were triggered by a massive earthquake and tsunami. Appendices 1-3 go further into fuel availability, waste disposal, and future options (including fusion).

II. Nuclear Technology and Costs

We focus on reactor types that can be deployed now (none of the new generation has as yet been licensed by the U.S. Nuclear Regulatory Commission, but license approvals are expected soon). Cost estimates for nuclear electricity have been made recently by an MIT group in an update to its 2003 report on nuclear energy,[3] the National Academy of Sciences,[4] and the Energy Information Administration of the DOE.[5] These reports give prices for nuclear electricity in the range from 6¢ to 8¢ per KW-hr in 2007 dollars. These estimates are based on the assumption that loan guarantees are given at the start of construction and that first-of-a-kind costs of a particular reactor type have been recovered in the first few models to be deployed. Without loan guarantees the MIT and NAS reports estimate that higher interest rates on construction loans would lead to an electricity price about 2 to 3¢ per KW-hr higher. The EIA report does not specifically mention the issue (in keeping with the methodology of the California's Energy Futures study, all costs given here are in today's dollars and exclude inflation from now to the year 2050).

The International Energy Agency (IEA) of the Organization of Economic Cooperation and Development (OECD) estimates nuclear electricity costs of 5¢ to 6¢ per KW-hr depending on interest rates.[6] The IEA estimate is based on world costs and is dominated by experience in Asia where many reactors have been built in the last decade in Japan and South Korea.

Seven reactors have been built and put into operation in Japan and South Korea in the period from 1994 to 2005. The average overnight cost of these was $2,100 per KW, and during the period the cost per KW declined by about 30%. Inflating these costs at a rate of 3% per year, leads to a cost of $2,800 per KW in today's dollars. Costs for the first few reactors of any given type will likely be higher in the U.S. because of the lack of recent experience in construction of such facilities.

The Keystone Center in 2007 published a report called "Nuclear Power Joint Fact-Finding"[7] that was produced by a group including members from industry, universities, national laboratories, former government officials, environmental groups, finance experts, etc. Their analysis leads to a levelized cost of electricity of 8.3¢ to 11.1¢ per kilowatt hour without loan guarantees, not inconsistent with the lower estimates above that were made with loan guarantees.

A particularly interesting report commissioned by the German government is "The World Nuclear Industry Status Report 2009".[8] It reviews reactor costs worldwide including the relatively low costs in Japan and Korea, the cost overruns of the AREVA EPR projects in Europe, and summarizes what is known about the costs of reactors proposed for the U.S. Their estimates for U.S. overnight costs range from $2,500 to $4,900 per KW including first of a kind costs. They do not predict the cost of power.

The outlier in electricity costs comes from a report by Energy and Environmental Economics, Inc.[9] Their estimate of electricity costs is about 18¢ per KW-hr of which 6¢ is operations, maintenance,

3 http://web.mit.edu/mitei/docs/nuclearpower-update2009.pdf
4 America's energy Future, National Academy of Sciences, 2009
5 EIA Report #:DOE/EIA-0554(2008)
6 OECD/IEA, World Energy Outlook 2006
7 http://keystone.org/files/file/SPP/energy/NJFF-Final-Report-6_2007.pdf
8 http://www.bmu.de/english/nuclear_safety/downloads/doc/44832.php
9 Energy and environmental Economics, Inc, Meeting California's Long-Term Greenhouse Gas Reduction Goals, November 2009

and fuel; and 12¢ is the levelized capital cost of the plant. There is not much information on how these estimates were arrived at.

Our analysis of all this data leads us to the conclusion that the most reasonable estimate that can be made today of nuclear electricity cost is in the range of 6¢ to 8¢ per KW-hr, with loan guarantees and after first of a kind costs have been recovered. The reader has to choose what to believe. We won't really know what costs are until several reactors have been built. The preponderance of the evidence favors something toward the low end of the estimates.

We expect 20% cost reduction after about ten reactors of a given type have been constructed in the U.S., a further 10% after 30, and, if a large number are built in the U.S., costs should decline by a further 20% by the year 2050. Our assumptions on the learning curve apply separately to reactors from Westinghouse, General Electric and AREVA, among others, and exclude inflation.

Small, modular nuclear reactors are being developed by industry. For example, a Babcock and Wilcox design operates at 125 MWe, a NuScale design at 45 MWe, and others are in the works. Costs of these reactors are claimed by their proponents to be about $4,000 per KW, comparable on a per KW basis with the costs of large LWRs. Small reactors are suited to electrical generation but also may have other applications, for example, desalinization and industrial process heat. We have not included these applications in our estimate of demand though we note that locating reactors near a sea-water supply would allow the waste heat of the reactor to be used for desalinization at little or no cost.

New types of reactors are being studied in the International Generation IV (GEN IV) program and some may turn out to be significantly less costly than the present GEN III+ reactors, and use uranium more efficiently. Considerable time is required to complete the necessary R&D, produce a prototype, and obtain design certification from the Nuclear Regulatory Commission. We expect the earliest possible date for first-of-a-kind deployment of these new reactors could be 2030. We note that one of them, the very-high-temperature gas reactor, is particularly well suited for hydrogen and process heat production (see note 1). If hydrogen and process heat become important, this may increase the demand for nuclear energy. The hydrogen option adds greatly to demand as discussed in Section III.

Studies of uranium availability foresee no problems until the second half of this century at the earliest, even with increased demand. Current estimates of uranium availability at today's prices are enough to fuel 1,300 1-GWe reactors for their full 60 year lifetime (discussed further in Section IV). Uranium prices have been volatile in the past and will probably continue to be volatile in the future. However, the most costly part of reactor fuel fabrication is enrichment, and new players are entering this field while existing enrichment service providers are expanding their facilities. We do not expect enrichment to be a bottleneck. Present fuel contribution to the cost of nuclear generated electricity is only about 0.5¢ per KW-hr[10] so even large increases in uranium costs will have little effect on the price of nuclear electricity. Reference 1 indicates that doubling raw uranium prices would increase nuclear electricity costs by only 0.13¢ per KW-hr. Spent fuel management costs are not likely to increase significantly beyond today's 0.1¢ per KW-hr. Both of these issues are discussed in more detail in section IV and appendix 1.

10 http://www.world-nuclear.org/info/inf02.html

III. Matching Supply with Demand

Introduction

The CCST exercise has several scenarios. Here we look at two including the Realistic Model which has a balanced mix of very low emission energy sources, and an alternate extreme variation (the Stress Test) where nuclear energy supplies nearly all the demand expected in 2050 in a business as usual scenario where total demand is much larger than in the realistic case. The 2050 situation will certainly not be like the extreme version and may not be exactly like the realistic one either but the result presented here can be scaled to whatever realistic scenario is eventually realized based on the mix of supply that is most cost and environmentally effective. Note that in all cases below it is assumed that 33% of electricity is produced from renewables as mandated in state law by 2020.

Balanced Portfolio

As mentioned earlier, the main focus of our analysis is on the CCST Realistic Model which assumes that total electricity demand in California in the year 2050 amounts to 510 terawatt-hours per year (TWh/y). Our assumptions for this case are that nuclear electricity is used as baseload power where the plants run at their maximum output all of the time; that nuclear plants have a 90% capacity factor (it was 92% in 2009) and that baseload power represents 67% of total electricity demand. This requires about 44 Gigawatts (GWe) of nuclear electricity capacity.

California currently has a total of 4.5 GWe of nuclear electricity capacity installed at San Onofre and Diablo Canyon. Even with 20-year life extensions for reactors at both sites, all will have passed 60 years by 2050 so that absent further life extensions the entire 44 GWe will have to come from new reactors.[11] This requires 28 of the AREVA EPR plants or 31 of the Westinghouse AP-1000 plants.

Maximum Electricity

The Stress Test scenario assumes a demand for 1,160 TWh/y and asks that nuclear plants supply it 67% of it. This requires an average output of 99 GWe, but much more in practice because nuclear plants may have to supply the peak demand, not just the base load. This might require a maximum output nearly twice as high as the average requirement giving a total nuclear capacity of as much as 200 GWe. Given the high capital cost of nuclear plants, this would not seem to make much sense and we discuss it no further.

Hydrogen

In the Realistic scenario the hydrogen variant lowers electricity demand to 460 TWh/y requiring 39 GWe of electricity capacity, and adds a requirement for 910 trillion Btus of energy to be supplied in the form of hydrogen. The preferred way today to make hydrogen on a large scale with nuclear electricity relies on high temperature electrolysis which has an efficiency of roughly 50% at temperatures of 800˚C to 900˚. This requires a new type of nuclear reactor which in now being con-

11 Possible life extensions to 80 years are being studied for existing reactors. Since California's nuclear base is small, this would make only a 2% reduction in new nuclear power if it were to come about.

sidered, but is not yet beyond the R&D phase. Even with aggressive promotion such a reactor could not be ready before the year 2030. However, we give the numbers here for completeness. If such a reactor was available, the total nuclear electricity requirement would approximately double.

In the Stress Test case electricity demand is reduced from 1,160 TWh/y to 800 TWh/y while the hydrogen requirement jumps to 2,600 TBtu/y. The total nuclear electricity component would be more than four times the 39 GWe given above.

Infrastructure Issues

At present there is a world-wide infrastructure bottleneck for large reactor construction. The main problem is the forgings required for reactor vessels. We assume that this bottleneck will have been removed by 2025 if world-wide demand is large. There is also a skilled-worker bottleneck in the U.S. and we assume that this too will have gone by 2025 if new reactor demand is as large as expected (enrollment in nuclear engineering majors at colleges is already starting to increase). Operators will also have to be trained.

According to the IEA, the peak of reactor construction world wide occurred in the 1984 when 34 new reactors began operation.[12] Back then, many fewer countries had the industrial capability to build nuclear reactors, and each reactor tended to be different from what had been built before. Today, more countries can and do build nuclear power plants, and the manufacturers are producing more modular designs that have many components factory built and assembled at the site. This simplifies the production and installation of new facilities. We believe that there should be little difficulty in raising this production rate to 70 to 100 per year world-wide if the demand was there.

It will take a while to get up to speed and we assume that from 2020 to 2050, 2,000 to 3,000 new GEN III+ reactors could be turned on world-wide producing from 2,400 to 3,600 GWe if they were the size of the Westinghouse AP-1000 or to 3,200 to 4,800 GWe if they were the size of the AREVA EPR. The U.S. has nearly one-quarter of the world's nuclear power and if that continues there would be no barriers in principle in California having 44 GWe of nuclear power out of a U.S. total that might be as much as ten times larger.

Small, Modular Reactors

The small reactors that might begin to be deployed by 2015 to 2020 offer another road to large scale nuclear power that, because of their lower capital cost per unit, might be more attractive than the large reactors that are now the work-horses of nuclear energy if they also prove to have acceptable costs per kilowatt-hour. For example, the proposed Babcock and Wilcox reactors are to be factory-built and delivered to the site ready for installation. Plans now are for factories capable of producing two to four 125 MWe modules per month which corresponds to 75 to 150 GWe per factory over the 2025 to 2050 period. If this program works out, one such factory could satisfy California's needs. Reactor availability would seem to be of little concern in this scenario.

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12 http://www.iaea.org/programmes/a2/index.html

IV. Fuel

The present generation of nuclear power reactors runs on uranium enriched in the fissionable isotope U-235. Natural uranium contains 0.7% U-235, and the enrichment process increases this to something in the range of 4% to 5% for power plant use. It takes about 200 tonnes (1,000 kilograms per tonne) per year of natural uranium fuel for each 1,000 megawatt-years of electricity produced by a reactor. The U.S. fleet of 104 reactors requires about 20,000 tonnes of natural uranium per year, and the entire world collection of power reactors requires 80,000 tonnes per year.

The current estimate of available uranium including both proven and estimated reserves is about 16 million tonnes, a 200 year supply at the current rate of consumption. If nuclear power does expand greatly in the next decades, some worry that a shortage of uranium may develop. However, in contrast to oil and gas, there has been little exploration for new uranium deposits in the last two decades because of relatively low prices. Even so, the world inventory seems to be growing. Many geologists think there is much more available, though perhaps at a higher price.

There are ways to use the 99% of natural uranium that is in the isotope U-238; non-fissionable in today's LWRs. All reactors consume fissile isotopes but also produce new fissile isotopes at the same time by neutron capture in U-238 (or in Th-232 for thorium cycle reactors). The ratio of the amount of fissile material produced to that consumed is called the conversion ratio. It is possible to increase the conversion ratio to values above 1.0 in reactors designed for the purpose, thereby producing more fissionable material than is consumed, by transforming the non-fissionable isotopes into fissionable ones (discussed in detail in appendix 3). Note that the cost estimates given earlier are for the present generation of power reactors that do not use this technology.

Fuel availability for the next 50 to 100 years is discussed further in appendix 1.

V. Sites

At present there are only two sites in California with operating reactors, Diablo Canyon and San Onofre, each with two reactors. Expansion at either of these sites is possible technically, but neither could accommodate a large enough number of additional units to make a major difference in the context of the number needed to achieve the scenarios outlined here. We are not able to offer an opinion on the potential for more coastal sites which would be important for desalinization applications as this involves political and environmental decisions that are beyond the scope of this report.

There are many potential inland sites, and the only technical barrier for these may be the availability of water for cooling. Reactors have no problem using reclaimed water for cooling and, if there is not enough of that, can be air cooled. Air cooling increases the cost of electricity by 5% to 10% because of the need to power the fans in the cooling towers from electricity produced by the plant which decreases the amount of electricity that can be delivered to the grid by the same 5% to 10%.

Because California is "earthquake country", reactors to be deployed in California would, of course, require special design features in order to assure that they are safe in earthquakes. This engineering problem has been solved successfully already. Both the Diablo Canyon and San Onofre reactor plants that are now operating are designed to withstand the ground motion from very large earthquakes, and meet all of the stringent NRC regulatory criteria with adequate margin. There is no reason to believe that earthquake issues should be a barrier to deploying additional reactors in California. In addition, there are potential inland sites with lower seismicity.

The simplest system for California would be a small number of energy parks, each with a large number of reactors. For example, 5 to 10 sites each with 5 to 10 GWe plus the existing coastal sites would be enough to meet the electrical output needs assumed here in the realistic nuclear case. Such reactor parks could each generate over $250 million in local taxes annually and more than 2,500 jobs. We note that California today imports a significant percentage of its power needs and new nuclear plants can be located in other states as well as here. If so, the impact on the grid needs analysis which is beyond the scope of this report.

VI. The Spent Fuel Problem

Appendix 2 discusses the spent fuel issue from both national and California perspectives. We summarize the situation here.

At present, California law requires the licensing of a national repository for spent fuel before any new reactors are built in the state. The Obama administration has said that it will not use Yucca Mountain in Nevada as a geological long-term repository, though it is designated as such by Federal law. It has appointed a "Blue Ribbon Commission" to analyze the issue and recommend alternatives.

The Blue Ribbon Commission is to issue an interim report early in 2011. Any alternative to Yucca Mountain would require that Congress change existing law, a new site be selected, the necessary R&D be conducted to validate the site's technical acceptability, and an NRC license be obtained. It is very unlikely that a new site could be opened to accept fuel in less than 25 years.

What to do with spent reactor fuel in the meantime is an issue of importance. A recent study by the American Physical Society[13] and an older one by a Harvard, University of Tokyo joint group[14] show that storing all of the spent fuel produced over a reactor's lifetime in dry casks at the reactor site is an effective interim solution and is being implemented at all U.S. reactor sites. Centralized interim storage may also be developed. Some experts recommend that it be used to consolidate spent fuel from decommissioned reactor sites, of which two exist in California, while on-site storage be continued for operating reactors.

If California pursues a future with many new reactor sites, state permitting and public acceptance will be issues that could cause major delays in implementing a nuclear route to the state's greenhouse gas reduction goals. As far as land use is concerned, nuclear energy is much more economical than any of the renewables. For example, the entire San Onofe 34 hectare site delivers 2.2 GWe while covering all of it with 10% efficient solar cells would only deliver about 1.5% of that at noon on a bright summer day.

13 "Consolidated Interim Storage of Spent Nuclear Reactor Fuel", February 2007, http://www.aps.org/policy/reports/popa-reports/upload/Energy-2007-Report-InterimStorage.pdf

14 "Interim Storage of Spent Nuclear Fuel", M. Bunn et. al., Harvard University & University of Tokyo (2001); IAEA, http://www.iaea.org/OurWork/ST/NE/NEFW/nfcms_spentfuel_conf2003_res.html

VII. Proliferation of Nuclear Weapons

This is a national, indeed a world issue, rather than a California issue. Yet it is a concern to many that expansion of nuclear energy use will increase the risk of weapons proliferation. The U.S. is a nuclear weapons state so expansion here does not increase proliferation risk. The issue arises with states that use nuclear energy as a road to procuring the material required for weapons. The states that have developed weapons clandestinely include India, Israel, North Korea, and Pakistan. It is worth noting that among these only Pakistan used the enrichment technology required for power reactors to produce the material for their bombs. There is concern about Iran's intentions.

There is an ongoing effort to internationalize the nuclear fuel cycle so that enrichment of uranium and the treatment of spent fuel can be better monitored and controlled. This is a political problem, not a technical one. It is still early in the discussion, but progress is being made. Abu Dhabi which has just contracted with South Korea for the construction of four large reactors has said it will not do its own enrichment or spent fuel treatment. This issue is getting lots of attention and progress is being made, though slowly.

VIII. Story Line

This section outlines what has to happen on the state and national scenes to make a large expansion of nuclear power practical.

- The Nuclear Regulatory Commission has to license more than one new reactor design. Closest is the Westinghouse AP-1000. Next are likely to be the GE ESBWR and the Toshiba ABWR. The AREVA EPR, though under construction in Europe, has to be licensed in the U.S. which will take at least 2 years. The small reactor builders have not yet submitted applications for design certification to the NRC, though the NRC has promised an expedited review when they do arrive.
- Loan guarantees for six to eight new starts nationally will have to be available. DOE now has about $18 Billion for such guarantees, which will only be enough for two to three large facilities. New funding for guarantees will have to be provided, and Secretary of Energy Chu has said that this is an administration priority. These first new builds have to be completed on time and at cost for a large scale nuclear build up to occur. If all goes well, this buildup could start in 2020.
- For small reactors, it is unlikely that design and licensing can be completed in less than 5 years. These too will require loan guarantees and possible federal subsides for the first-of-a-kind plants.
- The interim report of the Blue Ribbon Commission on waste disposal is due in early 2011. This report, and the final report due six months later, will begin a process of review that will determine the road ahead for spent fuel disposition. If it recommends going back to Yucca Mountain (considered a low probability) it will take about 10 more years before the repository could be opened. If it recommends something new, existing law that mandates Yucca Mountain as the repository site will have to be changed, and it will be 25 to 30 years before the cycle of legislation, site selection and characterization, design, licensing, and construction can be completed.
- Interim dry cask storage of spent fuel at reactor sites is the present default system. The courts have determined that the federal government has to pay the reactor owners for it because of present contracts. Since new reactors will have new contracts, the terms and conditions will be different. Recent new contracts require the federal government to take title to spent fuel within 25 years after a new reactor ceases operation.
- By 2020 California will have to repeal its limitation on new nuclear starts which is now based on the licensing of a permanent repository.
- By 2020 California's regulations that now mandate that the large amounts of emission free energy required in the future can only come from wind, solar, geothermal and small hydroelectric systems should be changed to allow all low or zero emission sources to contribute.
- The DOE needs to develop a long term strategic plan for nuclear R&D that supports present reactors, supports advanced fuel cycle R&D that might lead to breeder reactors for the future or fast spectrum burner reactors to ease the waste disposal problem, continue its international collaborations on GEN IV reactors, etc. Such a strategic plan has now been submitted to Congress.[15]

15 http://www.nuclear.gov/pdfFiles/NuclearEnergy_Roadmap_Final.pdf

- Future administrations need to continue what is a long range program and Congress needs to supply the necessary funding.
- Public acceptance needs to continue to grow. Such growth might come about because of relatively low energy costs, efficient land use, etc.

IX. Preliminary Comments on the Nuclear Accidents at Fukushima

On March 11, 2011 a giant earthquake and tsunami struck Japan, severely damaging the cities and towns along the coast near the epicenter of the quake and leading to a still uncertain, but large loss of life, mostly from the effects of the huge tsunami. Four of the six nuclear reactors at the Fukushima nuclear power complex were seriously damaged, along with several of the used-fuel pools, and there is worldwide concern about the effects from the radiation release that is still ongoing.

Damage to the reactors and used fuel storage pools at the complex is heavy though many of the key details are still unclear. While the giant earthquake knocked out all power coming to the nuclear station from the outside the site, all emergency systems started properly, shutting down the nuclear reactions and starting the emergency power and cooling systems. The emergency systems were overwhelmed by the tsunami, now estimated to have exceeded 45 feet in height, which struck the site 55 minutes later. The protective barriers, designed for a maximum tsunami height of 18 feet, were too low to keep water out, and the resultant flooding knocked out the emergency power, destroyed external electrical switch gear, and destroyed infrastructure for delivering fresh water to the site. Subsequently when battery power supplies were exhausted, the backup emergency cooling systems failed. It took two weeks to get electric power back on at the plant.

There was major fuel melting in three of the reactors before fire trucks were used to begin injecting sea water into the reactors to restore cooling, as well as in one of the water filled pools used to store spent fuel. The reactor containment systems retained a large fraction of the radioactive materials released from the damaged fuel, but sufficient radioactive material was released to cause off-site contamination of land. There was also a period of a few hours when workers had to leave the site. Emergency response actions included evacuation of people residing up to 20 kilometers from the plant. At this time the accident has resulted in no cases of radiation illness or fatalities to plant workers, and exposures to the public have remained low. Cleanup will take considerable time, and it is certain that most of the reactors will never operate again. While injuries, deaths, and damage from the radioactive releases will be small compared to the direct effects of the quake and tsunami, they must be taken seriously and are triggering a worldwide review of safety systems at nuclear plants.

In the United States, the Nuclear Regulatory Commission (NRC) has begun a review of nuclear reactor safety which will be comprehensive. Existing power plants utilize what is known in the industry as Generation II technology. In the light of problems at Fukushima the review will certainly include at a minimum the capability of these U.S. plants to function under a prolonged station black out, to rapidly connect external sources of water injection and backup power, to supply water to spent fuel pools from locations remote from the pools, and to control hydrogen accumulation effectively even under station black-out conditions. It will also include reviewing inspection frequency, as well as the ability of plants to come through multiple disasters.

The new generation of nuclear plants now being considered for licensing and construction here in the United States and elsewhere is called Generation III+. While all of the Gen III+ designs being advanced have extensive passive safety systems which require little operator intervention and little or no external power for operation in the event of an emergency, the same questions will be asked. These new designs will also be reviewed by the NRC and others in light of lessons learned from the Fukushima accident. The information gained during the Fukushima review and any recommendations made should be factored into decisions about the potential future use of these Gen III+ nuclear reactor technologies in California.

Appendix 1: Reactor Fuel

Introduction

The standard reference on uranium production and reserves is published every two years as a joint effort of the OECD Nuclear Energy Agency and the International Atomic Energy Agency. The latest volume, "Uranium 2007: Resources Production and Demand" (known as the Red Book), was published in 2008. The estimate of proven reserves is given as 5.5 million metric tonnes, with additional undiscovered reserves an additional 10.5 million tonnes; all at a cost of less than U.S. $130 per kilogram (kg). Reserves have increased from the estimate in the previous volume because of increased exploration induced by rising uranium prices.

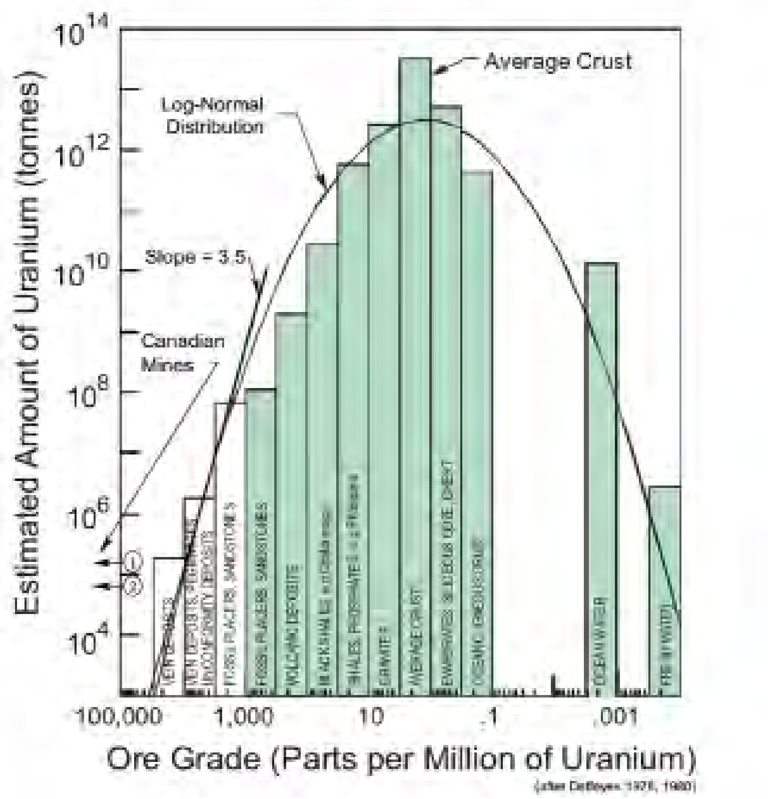
Only the isotope U-235 which makes up 0.7% of natural uranium is fissionable. Fuel for the standard LWR is enriched to 4.5% U-235, mainly in gas centrifuge plants which typically extract about 65% of the natural U-235. A 1-GWe power plant uses about 20 tonnes of enriched fuel per year derived from 200 tonnes of natural uranium. In the U.S., operating licenses for 60 years are becoming the standard, so each new 1 GWe of nuclear power will need 12,000 tonnes of natural uranium to fuel it over its entire 60 year lifetime. The 16 million tonnes given in the Red Book corresponds to lifetime fuel for about 1,300 GWe of new nuclear plants. The current world installed capacity is about 365 GWe

The "Nuclear California" scenario is done in the context of a world that also goes heavily nuclear. Since the 16 million tonnes picture in the Red Book would only be enough lifetime fuel for about 1,300 GWe of new reactors operating in 2050, a faster world-wide expansion would commit the 16 million tonne estimated supply long before 2050. There are three options for solving this problem.

- Find more natural uranium,
- Make reactors operate at higher electrical efficiency so that there is more output for the same amount of fuel,
- Deploy breeder reactors that can turn non-fissionable U-238 and thorium (Th-232) into fissionable fuel, thereby increasing the available amount of potential fissionable material more than 100 fold.

Uranium Availability

There is far more uranium in the earth's crust than the Red Book estimate of what can be recovered at a cost of less than $130 per kg. Figure 1 shows the estimated amount as a function of concentration. The amount of uranium is huge and the issue is extraction from lower concentration ores at a reasonable cost.



Distribution of Uranium in the Earth's Crust (Deffeyes and Macgregor, Scientific American, 1980)

Fuel is a small part of the cost of nuclear electricity and raw uranium is a small part of the cost of fuel. The World Nuclear Associations gives the cost of reactor fuel as of January 2007 in the table below.

Uranium:	8.9 kg U_3O_8 x $53	US$ 472
Conversion:	7.5 kg U x $12	US$ 90
Enrichment:	7.3 SWU x $135	US$ 985
Fuel fabrication:	per kg	US$ 240
Total per kg, approx:		**US$ 1787**

U.S. dollar cost to get 1 kg of 4.5% enriched uranium as UO_2 reactor fuel at likely contract prices: At 45,000 MWd/t (megawatt days per tonne) burn-up this gives 360,000 kWh electrical per kg, hence fuel cost: 0.50 c/kWh.

The cost of uranium is only a small fraction of the cost of fuel and a 5-fold increase in uranium cost would only add another 0.5¢ per KW-h to the cost of nuclear electricity. If other ores are any example, much more uranium will be found when demand rises.

One particular low concentration source deserves special mention. In Japan work has been going on to develop techniques to extract uranium from sea water. In their technology, natural ocean currents move sea water through an absorber that extracts the uranium. Costs now are said to be about $900 per kg with costs at commercial scale estimated to come down to about $250 per kg. If this works at the necessary large scale, the supply of uranium becomes effectively unlimited.

Appendix 2: Spent Fuel Disposal

Introduction and Background

The issue of how ultimately to dispose of the high-level radioactive wastes generated by the use of nuclear power, and also generated during the manufacture of nuclear weapons, has been a contentious one for decades. The related issue of how to store this dangerous material in the interim before its ultimate disposal has also been contentious, especially because with no ultimate disposition path on the immediate horizon, interim means at least a decade or two from now, and perhaps longer.

There is very broad agreement that the material at issue should not be disposed of permanently near the surface, such as in shallow land burial, or even in engineered facilities at or near the surface. A large number of careful studies and reviews, both domestically and internationally, and going back a half century or more, have all concluded that for the very long term (meaning for millennia or even millions of years) the only management approach that can provide adequate safety is deep underground disposal. The material simply poses too great a hazard to human health and to the broader environment, to be disposed of on or near the surface, even in the best engineered facility that anyone can imagine deploying today or anytime soon.

The material at issue is mostly used nuclear reactor fuel from LWRs, containing radioactive fission products and actinides. By weight it is about 95% unburned uranium, about 4% fission products, and about 1% long lived actinides, mostly plutonium. There is about 60,000 tons of this used fuel already stored in the U.S., and about 2,000 tons arise annually from the 104 operating reactors. It is mainly still located at the sites where it was generated by the reactors. Its composition varies only slightly from reactor to reactor.

Most of the used reactor fuel comes from commercial power plants (all in the U.S. today are LWRs), but there is also used fuel from naval-propulsion reactors and various research, test, and isotope-production reactors. There is also the waste from the U.S. nuclear-weapons program, much of it still in waste tanks (although much of the tank waste has now been dried out) and other defense waste in various other forms such as glass that have been prepared for ultimate disposal. The only material in California is LWR-generated waste at the two operating reactor sites, San Onofre in San Diego County and Diablo Canyon in San Luis Obispo County, and at two sites where commercial reactors no longer operate, Rancho Seco in Sacramento County and Humboldt Bay in Humboldt County.

Safety and Security During Interim Storage

California nuclear wastes are all stored at the sites where they were generated in storage facilities licensed by the U.S. NRC. When used fuel is initially discharged from a power reactor, it generates so much (thermal) heat that, if not cooled well and continually, the heat would soon melt the fuel rod cladding, thereby releasing the enclosed radioactivity. Therefore, this fuel must be kept in a fuel pool (under water) for three to four years with active cooling to remove the heat from the water, after which the heat generation has decreased enough to allow the used fuel to be removed from pool storage, and to be placed in so-called dry-cask storage. However, this transfer to dry-cask need not take place until later, and some used fuel has remained in pool storage 3 decades.

This fuel storage is controversial with the public, many of whom have strong concerns about whether the storage, especially storage in the pools, is safe and secure. This is in part because a loss of pool cooling, or of pool integrity, would result in loss of the cooling water, and a significant radioactive release could ensue. Thus the integrity and reliability of pool cooling is justifiably a genuine concern. Also, the pools are more vulnerable to sabotage or a terrorist-type attack than if the waste is in dry casks, although the experts believe that such acts would be very difficult to execute.

There is much less safety or security concern with the dry-cask storage, because these are passive systems, they require no active working parts nor active personal intervention to maintain the used fuel intact, and the cask designs are highly resistant to attack.

Despite continuing public concern, the general conclusion of the engineering community is that, if NRC regulations are met, the integrity of the power-reactor pools against radiological releases is very strong. The NRC, for its part, has recently reexamined its regulations and concluded that they are adequate. A number of independent evaluations have confirmed this. This conclusion is even more robust for the dry-cask storage configuration where the consensus is that waste can be kept in these casks for the better part of a century. The total cost of storage for all U.S. power reactors is estimated to be about $500 million annually.

The Current Federal Disposal Scheme

The current scheme in the U.S., embodied in Federal law, policies, and regulations, is to dispose of this used fuel directly, as it is, in an engineered repository located in a volcanic tuff formation deep under Yucca Mountain in southern Nevada. (The current legal framework provides for using Yucca Mountain for disposing of only about half of the reactor fuel ultimately created by our current LWR commercial reactor fleet, after which either a second deep repository site would need to be developed, or the Federal law changed to allow the rest to be disposed of in Nevada too.)

The scheme described above, while embedded in current Federal law and regulation, is not endorsed by the new Obama Administration, which has announced that it wishes to abandon the Yucca Mountain repository and seek an alternative solution for the management of commercial reactor spent fuel. However, the administration has not yet settled on any new policy to replace what is now in law, and has appointed a presidential Blue Ribbon Commission to develop options and advice on this vital matter. This is a situation that is in flux as this is being written in mid-2010.

By current law the site for disposal of the high-level waste will also be used for left over material from the Federal nuclear-weapons program. This waste is composed of materials with generally shorter half lives than spent power reactor fuel. The total amount of the waste in Federal hands requiring disposal, from the nuclear-weapons program, the naval propulsion program, and other sources, is about 10% of the amount of used commercial reactor fuel destined for disposal.

The Federal waste disposal program is financed through a fee, levied on each commercial nuclear power plant, of $1.00 for each thousand kilowatt-hours generated. This "waste fund", which now totals over $20 billion, is judged adequate for the purpose of ultimate disposal at Yucca Mountain. The Federal government assumed responsibility for the disposal of the commercial used fuel in exchange for collecting this fee, and agreed in 1987 to take the used fuel off of the hands of the commercial utilities in 1998, when it was anticipated that the repository would be ready to begin accepting fuel. This 1998 deadline has of course been missed, leading to legal wrangling now in Federal courts about who should pay for the storage costs since then. The current Federal obligation from missing this deadline is judged to be perhaps $10 billion or more, and is increasing at about $500 million annually. Meanwhile, all of the waste is being stored "temporarily" at the reactor sites, and the waste from the Federal government's programs is sitting at Federal reservations too, awaiting resolution of the issues.

There has been controversy about the requirements for safe and secure disposal of spent reactor fuel from the start, but this has been settled by the adoption of an EPA standard and an NRC regulation that a repository design must meet. The basic radiation safety standard is an individual dose standard, under which the repository can obtain an NRC license only if no individual residing in the vicinity receives an annual dose exceeding 15 millirems per year for the first 10,000 years, or 100 millirems per year from then to 1,000,000 years in the future.

The burden of proof is on the repository developer, DOE, to demonstrate the adequacy of the repository design, which can only be done by analysis. The form of the analysis is prescribed by NRC regulations. DOE spent almost two decades and over $12 billion on site characterization, experiments, and analysis, and in mid-2008 it finally submitted a License Application to the NRC, containing its analysis. The DOE analysis, as submitted, seems to demonstrate that the NRC's regulatory criteria are met, and with substantial margin.

The NRC is currently reviewing the application, and in the most optimistic scenario, if sufficient funding is made available by the Congress, could issue its ruling by 2011, or more realistically 2012 or 2013. However, the Obama Administration has notified the NRC that it is withdrawing the application, but several states have said they will sue to prevent this, since U.S. law now designates Yucca Mountain as the repository site. In addition, the State of Nevada has hired a group of consultant experts to challenge the application, and based on their work Nevada has submitted hundreds of individual technical challenges that DOE is studying and that the NRC is now considering too. Today, there is no way to know how this NRC process will play out, but it is fair to say that there is a broad consensus among the community of technical experts in repository science that the DOE work has strong technical quality, is thorough, and will likely stand up well to NRC scrutiny if it ever gets that scrutiny.

Cost of Spent Fuel Management and Disposal

The costs involved in used reactor fuel management and ultimate disposal are not great in the overall scheme of things. While the overall cost of the Yucca Mountain. repository, as now designed, runs to around $100 billion, estimates by DOE and the industry of the total cost to any individual electric utility to dispose of its used nuclear fuel at Yucca Mountain come to between 1% and 2% of the value of the electricity generated. The costs for surface storage, even for decades, are much smaller than this.

If one puts these costs in perspective, one is driven to conclude that while considerable controversy continues about how to manage these radioactive wastes, the cost side of the argument should not be determinative, nor has it been very influential so far.

Chemical Processing of Spent Fuel

It is, of course, feasible to use chemical techniques to treat the spent fuel that is now destined by law for direct disposal at Yucca Mountain, and separate it into components that can be treated differently according to their potential use and potential hazard. This is called reprocessing. Indeed, much of the reactor fuel used to create the material for the U.S. nuclear weapons arsenal has already been reprocessed and put into special waste forms for disposal, and some of the rest will be. Overseas some countries (notably France and Russia) have been reprocessing commercial-reactor fuel for some time, and the Japanese have a plant under construction now to do so too. The purpose of reprocessing as part of nuclear weapons production was to extract the plutonium made in the reactor core for weapons use. The current reprocessing of commercial fuel also seeks to extract the plutonium for re-use as a fuel to be recycled into LWR reactors, which with only modest changes can use such plutonium-laden fuel instead of the more common uranium-laden LWR fuel, and thereby extract about 30% more energy from the original uranium.

If the LWR fuel of today that is destined for disposal at Yucca Mountain were to be reprocessed, the resulting waste material requiring geological disposal would have less radioactive material because of the extraction of the plutonium and other actinides. It would then contain much less of the most dangerous species with very long half-lives, and would also be put into a better physical and chemical form prior to deep disposal. Those who favor such LWR-fuel reprocessing offer several different rationales, which are given different weight by different advocates. Some see reprocessing mainly as a means for reducing the radioactivity and radiotoxicity of the material requiring deep disposal, hence lowering the "burden" on the deep repository. Some mainly wish to extract the plutonium for use as a reactor fuel in today's LWR reactors. Some advocate reprocessing to obtain a stockpile of plutonium and other actinides for use to start up a fleet of reactors of a different design, namely fast-spectrum reactors that can provide both electricity and the destruction of many of the actinides that would otherwise be disposed of deep underground.

Fast-Spectrum Reactors

These reactors operate with neutrons of much higher energy that the LWR power reactors in use today. In some designs, they can actually "breed" more fuel than they consume through neutron capture on the non-fissile uranium isotope U-238, whose latent nuclear energy is otherwise mostly not used to make energy in today's LWRs. Three or four decades ago, the general expectation among advocates of nuclear energy was that the fast-spectrum "breeder" reactors would soon displace LWRs as the major component of nuclear power generation worldwide. This did not happen – there have been a few large reactors of this kind built and run, but none is commercially viable. The reasons are both technical and non-technical. First, the use of such fast-spectrum reactors requires reprocessing to make the scheme attractive, but the costs of the fast-spectrum reactors plus the costs of the reprocessing technology as of now do not allow the scheme to compete economically with LWRs that use direct disposal. (In fact, the reprocessing now underway in France and Russia and planned in Japan, in which LWR fuel is reprocessed for re-use in other LWRs, is also more expensive than the once-through approach, although the cost penalties for this scheme are modest.)

Proliferation concerns are the major reason why some organizations oppose reprocessing. The extraction of plutonium, and its recycle into new reactor fuel, could create vast stores of separated plutonium that might be diverted by a government or stolen by terrorists for use in fabricating nuclear weapons. This concern led the U.S. to change its policy in 1977 to forbid nuclear-fuel reprocessing at home and to try to discourage other nations from moving in that direction (the formal prohibition was dropped in the Reagan Administration, but the policy was never officially repudiated). Opposition is strong among that sector of the public who oppose any use of nuclear power, but it is also present among some who favor expanded use of nuclear power but not expanded reprocessing.

The debate over fast-reactors and reprocessing has been going on for decades, and has been re-energized in recent years by the Bush Administration's proposed Global Nuclear Energy Partnership (GNEP). GNEP was to separate the components of spent reactor fuel that required isolation for hundreds of thousands of years and destroy them in fast spectrum reactors thus solving two problems. Repositories would only require isolation for a thousand years or so, much easier than a million years, and the stocks of weaponizable plutonium would be destroyed as well. The reactors could stretch the world's uranium resources by breeding new fuel, and the proliferation concerns were to be coped with by developing and deploying advanced safeguards technologies for both the reactors and the reprocessing plants. This Bush-era policy is now under reconsideration, and where the US policy will come out in the end cannot be known now.

Nuclear-Waste Policy Status

Nuclear-waste policy is currently is disarray. The President's Blue Ribbon Commission will report in 2011. It is not clear if using Yucca Mountain will be an allowable option in their deliberations. Even if it were to be included, it could not accept spent fuel until 2020 at the earliest. A new repository in a different area and in different geological conditions will require years of R&D and design before it could be opened. Spent fuel will be kept for decades at the sites where it was generated or perhaps at a few consolidated interim-storage sites. This would require Federal legislation. How this will come out is now unknowable.

For California, there are so many options and parameters that no simple conclusion is obvious. However, a few salient points are worth making:

a) The status quo, in which the used fuel at Diablo Canyon and San Onofre is being managed today in pools and ultimately in dry cast storage will continue for many years in any event. This is also true of the fuel at the "orphaned" nuclear-reactor sites in California, Rancho Seco and Humboldt Bay.
b) Even if the Yucca Mountain repository goes ahead on the fastest schedule it could, nothing will change in California vis-à-vis in-state used fuel storage for 10 or 15 years, and probably longer.
c) If a change in Federal policy leads to the search for a new repository instead of Yucca

Mountain, the status quo would be extended another 15-20 years, or more.

d) If Federal policy moves toward significant R&D that ultimately successfully demonstrates that reprocessing technology for LWR fuel to make other LWR fuel makes sense, this technology could be deployed at the earliest in about 20 years. [Here "makes sense" operationally means "is deployed in a commercial marketplace environment", even if not in California.]
e) If Federal policy moves toward significant R&D that ultimately successfully demonstrates that fast-reactor technology and the associated fuel-reprocessing and recycling technologies make sense, this could be deployed at the earliest in 25-30 years.
f) If Federal policy changes leading to the establishment of one or more sites for consolidating all U.S. used nuclear fuel, then California's used fuel could move there. But even if such a decision were taken today, it is unlikely that California's used fuel could move earlier than say a decade or so hence. Since the decision could not be taken today, one must add on whatever extra delay is associated with the timing of such a decision.

Appendix 3: Advanced Systems

Advanced Fission Reactors

In nuclear reactors, neutrons are absorbed in fissile material to cause fission reactions. Each neutron absorbed by a fissile isotope generates an average of 2.1 to 2.9 new neutrons, with the specific value for a given isotope and neutron energy being called *eta*. To sustain criticality, one of these neutrons must go on to be absorbed by another fissile isotope, leaving 1.1 to 1.9 excess neutrons. Some of these neutrons are absorbed by fertile isotopes like U-238 or Th-232 and produce new fissile isotopes. The remaining neutrons are absorbed in materials that do not produce fissile isotopes, or leak from the reactor core.

The number of new fissile atoms created, per fissile atom consumed, is referred to as the reactor *conversion ratio*. Conventional light water reactors (LWRs), which operate with thermal neutrons (neutrons that have been slowed down) and are fueled with low-enriched uranium (LEU), have conversion ratios around 0.6, and are net consumers of fissile material, requiring an external source of fissile material to operate, such as LEU or recycled plutonium or U-233.

Several routes exist to increase reactor conversion ratios, and thus use uranium resources more efficiently. These include measures to reduce neutron leakage (larger cores, use of fertile blankets) and parasitic neutron capture (through careful selection of coolant, structural, and moderating materials, as well as by adjusting the average energy level of neutrons). They also include measures to increase eta.

For U-235, the principal fissionable part of the fuel in thermal-neutron-spectrum LWRs, the number of neutrons released per fission (eta) has a low value of 2.1. Eta takes substantially higher values for high-energy, fast neutrons, typically around 2.9 for Pu-239. Thus, uranium-fueled, fast-spectrum reactors can be readily designed to reach conversion ratios of 1.0 or greater. Above 1.0 more fissionable material is produced in the reactor than is consumed in its operation, hence the name breeder.

Alternatively, when thorium-232 is used in thermal-spectrum reactors, the U-233 produced from Th-232 has an eta of 2.4. This is lower than the fast-spectrum eta for Pu-239, but a variety of approaches exist to use thorium in thermal spectrum reactors that can increase the conversion ratio compared to conventional LEU-fueled LWRs, with some designs achieving a conversion ratio of 1.0 or slightly greater.

In considering how reactor technology might evolve to use uranium more efficiently in the future, an analogy with automobiles and oil is useful. Electric cars consume no oil at all and have significantly lower fuel cost than conventional automobiles, but have been commercially unsuccessful to date because oil prices have remained too low to merit the higher manufacturing cost and inconvenient operational features of electric cars. Likewise, even though fast-spectrum reactors could operate for centuries on depleted uranium already mined, to date they have remained commercially unsuccessful due to high construction costs and reliability problems.

As coal-to-liquids does for oil, the maximum future price for uranium is back-stopped by technology to recover uranium from seawater. But just as coal-to-liquids has never emerged as an economically competitive source of transport fuel, few experts expect that uranium recovery from seawater will ever emerge as a replacement for conventional uranium mining. Most experts instead expect a more gradual and incremental set of evolutionary changes to occur as uranium prices eventually climb.

As with automobile engines, the efficiency of nuclear power plants in converting fuel into power can be expected to improve; with the transition from LWR to high-temperature reactor (HTR) technologies bringing similar benefits for efficiency as has the ongoing transition from gasoline to diesel engines. In analogy to plug-in-hybrid vehicles, which reduce but do not eliminate the consumption of oil, the addition of thorium to LWR and HTR fuels has the potential to boost the reactor conversion ratios and reduce uranium consumption. The use of LEU "seed" and thorium "blanket" fuel pins in LWRs can reduce uranium consumption modestly, while larger reductions are potentially possible in HTRs.

Because discharged reactor fuel will contain fissile material, recycling of spent fuel can further reduce uranium consumption, and can also have beneficial effects in reducing quantities of waste requiring geologic disposal. The fabrication of LWR fuel from recycled plutonium is very expensive, and requires very high uranium prices (potentially exceeding the cost of sea-water uranium recovery) to be economically justified. Conversely, both HTRs and fast-spectrum reactors can use fuel forms that are much more readily fabricated from recycled material. Because HTRs and fast-spectrum reactors can operate with higher conversion ratios than LWRs, the benefits from recycle in reducing uranium consumption are also larger.

Given the number of technology options available to extend uranium resources and the existence of an international market for fuel cycle services and technologies that includes many supplier nations, the question is not so much whether uranium scarcity might constrain a large expansion of nuclear energy by 2050, but instead whether the new technologies that will emerge will be optimized to minimize proliferation and physical security risks.

The United States is actively engaged in efforts to influence this evolutionary process, to encourage continued centralization of sensitive elements of the fuel cycle (enrichment and conventional reprocessing), to strengthen and improve technologies for International Atomic Energy Agency monitoring of civil nuclear energy systems to verify peaceful use and promote non-proliferation, and to develop advanced fuel cycle technologies that handle recycled materials in locations and forms that make them highly unattractive targets for theft.

With the breadth of options available to extend uranium resources, it can be expected that fuel costs will remain a small fraction of total nuclear generation cost, even under substantial world-wide expansion of total nuclear generation capacity by 2050.

Fusion Systems

In principle, bringing together isotopes of the lightest element, hydrogen, to make the heavier element, helium, can release large amounts of energy. There are two attractions that have been driving the program. No uranium or plutonium that can be used in nuclear weapons is involved, and the radioactivity produced in the systems is much less in intensity and of much shorter lifetime than from fission, easing the repository problem. Research has been ongoing for 60 years and the proponents believe that they are close to demonstrating feasibility.

The largest program involves what is called magnetic confinement fusion where strong magnetic fields hold the gases together. An international program has begun to build the International Tokomak Experimental Reactor (ITER) at a site in France to demonstrate fusion energy release on a large scale. Many nations, including the U.S., are partners in the venture. If all goes well initial tests of the device will begin late in this decade, and serious attempts to demonstrate that the system can produce energy will begin in the mid-2020s. If that works, a prototype power plant could be operating about 15 years later and the first commercial power plant might start up around mid-century.

There are smaller magnetic confinement programs going on in a few places that involve systems different from that used in ITER. They are in too early a stage to allow an assessment of promise, but the next decade should get them to the point of a reality check. Some of these systems claim they can get to small power plants faster than ITER can get to large ones.

There is a second program called inertial confinement fusion than is still confined to the laboratory, though several countries are working on systems. In the U.S., the main line is laser-driven compression of a tiny pellet of hydrogen isotopes. If it is compressed far enough and heated high enough, a tiny explosion occurs, releasing energy. A demonstration of the principle is expected in the next few years, but demonstrating commercial viability is still a very long way away.

Appendix 4: Acronyms

OECD	Organization of Economic Cooperation and Development
AB	Assembly Bill
CCST	California Council on Science and Technology
DOE	Department of Energy
EIA	Energy Information Administration
GEN II	Generation II
GEN III+	Generation III
GEN IV	Generation IV
GNEP	Global Nuclear Energy Partnership
GW	Gigawatts
GWe	Gigawatt of electrical capacity
HTR	High-temperature reactor
IEA	International Energy Agency
ITER	International Tokomak Experimental Reactor
KW-hr	Kilowatt hour
LEU	Low-enriched uranium
LWR	Light-water reactors
MIT	Massachusetts Institute of Technology
MWd/t	Megawatt days per tonne
MWe	Megawatt electrical
NAS	National Academy of Sciences
NRC	Nuclear Regulatory Commission
OECD	Organization for Economic Co-operation and Development
R&D	Research and Development
TWh/y	Terawatt-hours per year

Appendix 5: Author Biographies

Burton Richter is the Paul Pigott Professor in the Physical Sciences, Stanford University and Director Emeritus at the Stanford Linear Accelerator Center. His research has centered on experimental particle physics with high-energy electrons and electron-positron colliding beams. He began as a post doc at Stanford University in 1956, became a professor in 1967, and was Director of the Stanford Linear Accelerator Center from 1984 through 1999. Richter received the Nobel Prize in Physics (1976) and the E. O. Lawrence Medal of the Department of Energy (1976).

Robert J. Budnitz is on the Scientific Staff at the University of California's Lawrence Berkeley National Laboratory, where he works on nuclear power safety and security and radioactive-waste management. He has been involved with nuclear-reactor safety and radioactive-waste safety for many years. From 2002 to 2007 he was at UC's Lawrence Livermore National Laboratory, during which period he worked on a two-year special assignment (late 2002 to late 2004) in Washington to assist the Director of DOE's Office of Civilian Radioactive Waste Management to develop a new Science & Technology Program. Prior to joining LLNL in 2002, he ran a one-person consulting practice in Berkeley CA for over two decades.

Jane C.S. Long is currently the Principal Associate Director at Large for Lawrence Livermore National Laboratory and Fellow in the LLNL Center for Global Strategic Research. She works reinvention of the energy system, adaptation and in response to climate change and geoengineering. She is co-chair of both the California's Energy Future Committee and the National Commission on Energy Policy's Task Force on Geoengineering, and a member of the governor's advisory panel on adaptation. She is the former Dean of the Mackay School of Mines at University of Nevada, Reno, Director of the Great Basin Center for Geothermal Energy and Chairman of the Nevada State Taskforce on Energy Efficiency and Renewable Energy. Dr. Long also worked at Lawrence Berkeley National Laboratory where she served as Department Chair for the Energy Resources Technology Department including geothermal and fossil fuel research, and the Environmental Research Department.

Per F. Peterson is Professor and Chair of the Department of Nuclear Engineering at the University of California, Berkeley. He received his BS in Mechanical Engineering at the University of Nevada, Reno, in 1982. After working at Bechtel on high-level radioactive waste processing from 1982 to 1985, he received a MS degree in Mechanical Engineering at the University of California, Berkeley in 1986 and a Ph.D. in 1988. He was a National Science Foundation Presidential Young Investigator from 1990 to 1995. He is past chairman of the Thermal Hydraulics Division (1996-1997) and a Fellow (2002) of the American Nuclear Society. Peterson's work focuses on applications in energy and environmental systems, including passive reactor safety systems, inertial fusion energy, and nuclear materials management. In February 2010, Peterson was appointed by the Obama Administration to the Blue Ribbon Commission on America's Nuclear Future, to provide advice on U.S. policy for the back end of the nuclear fuel cycle.

Jan Schori is the former General Manager and Chief Executive Officer of SMUD, the Sacramento Municipal Utility District--the nation's sixth largest publicly owned electric utility. During her 14 year tenure as CEO, the utility earned a strong reputation for its renewable energy and energy efficiency programs as well as national number one ranking in commercial customer satisfaction by JD Power

& Associates in both 2006-7 and 2007-8. Prior to serving as general manager and CEO, she spent 15 years on the legal staff at SMUD, including five as general counsel. Jan is past chair of the American Public Power Association, the Large Public Power Council, and the California Municipal Utilities Association. She is also past chair of the Business Council for Sustainable Energy and served on the Board of the Alliance to Save Energy. She is of counsel to the law firm Downey, Brand LLP in Sacramento, CA and serves as an independent trustee on the board of the North American Electricity Reliability Corporation (NERC).

Appendix 6: California's Energy Future Full Committee

Jane C.S. Long (Co-chair), CCST Senior Fellow, and Associate Director at Large, and Fellow, Center for Global Security Research Lawrence Livermore National Laboratory

Miriam John (Co-chair), CCST Council Chair and Board Member, and Former Vice President, Sandia National Laboratories

Working Committee

Robert Budnitz, Staff Scientist, Earth Sciences Division, Lawrence Berkeley National Laboratory

Linda Cohen, CCST Senior Fellow and Associate Dean for Research & Graduate Studies and Professor of Economics, University of California, Irvine

Bill Durgin, Professor, Aerospace Engineering, California Polytechnic University San Luis Obispo

Bob Epstein, Founder, E2 Environmental Entrepreneurs

Chris Field, Director, Department of Global Ecology, Carnegie Institution

Jeffery Greenblatt, Project Scientist, Appliance Energy Efficiency Standards, Environmental Energy Technologies Division, Lawrence Berkeley National Laboratory

Bryan Hannegan, CCST Council Member and Vice President, Environment and Renewables for the Electric Power Research Institute

Susan Hackwood, Executive Director, California Council on Science and Technology

Roland Hwang, Transportation Program Director, Natural Resources Defense Council

Nalu Kaahaaina, Deputy Project Director, Energy and Environmental Security, Global Security Principal Directorate, Lawrence Livermore National Lab

Daniel Kammen, Class of 1935 Distinguished Professor of Energy, Energy and Resources Group and Goldman School of Public Policy, University of California, Berkeley (on leave) and Chief Technical Specialist for Renewable Energy and Energy Efficiency, The World Bank

Nathan Lewis, Director, Joint Center for Artificial Photosynthesis, California Institute of Technology

Bill McLean, CCST Senior Fellow and Emeritus Director, Combustion Research Facility, Sandia National Laboratories

James McMahon, Department Head, Energy Analysis, Lawrence Berkeley National Laboratory

Joan Ogden, Professor, Department of Environmental Science and Policy and Director, Sustainable

Transportation Energy Pathways Program, Institute of Transportation Studies, University of California, Davis

Lynn Orr, Director, Global Climate and Energy Project, Stanford University

Larry Papay, CCST Board Member and CEO and Principal of PQR, LLC

Per Peterson, Professor and Chair, Department of Nuclear Engineer, University of California, Berkeley

Burton Richter, CCST Senior Fellow and Paul Pigott Professor in the Physical Sciences Emeritus, Director Emeritus, Stanford Linear Accelerator Center, Stanford University

Maxine Savitz, CCST Senior Fellow and Vice President, National Academy of Engineering; Appointed Member of the President's Council of Advisors on Science and Technology (PCAST), Retired General Manager, Technology Partnerships, Honeywell, Inc.

Jan Schori, Former Director, Sacramento Municipal Utility District

George Schultz, Distinguished Fellow, Hoover Institution, Stanford University

Chris R. Somerville, Director, Energy Biosciences Institute, University of California, Berkeley

Daniel Sperling, Director, Institute of Transportation Studies, University of California, Davis

Jim Sweeney, CCST Senior Fellow and Director of the Precourt Institute for Energy Efficiency, and Professor of Management Science and Engineering, Stanford University

Margaret Taylor, Assistant Professor, Richard and Rhoda Goldman School of Public Policy, University of California, Berkeley

Max Wei, Researcher, Lawrence Berkeley National Laboratory and University of California, Berkeley

Carl Weinberg, CCST Senior Fellow and Principal, Weinberg and Associates

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Patrick Windham, Consultant

Chris Yang, Research Engineer and Co-leader of Infrastructure System Analysis Research Group, University of California, Davis

Heather Youngs, Bioenergy Analysis Team, Energy Biosciences Institute, University of California, Berkeley

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Kathy Yelick, Director, National Energy Research Scientific Computing Center (NERSC), Lawrence Berkeley National Laboratory

Rollin Richmond, President, Humboldt State University

Sam Traina, Vice Chancellor of Research, University of California, Merced

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California's Energy Future - The View to 2050

Summary Report

California Council on Science and Technology
May 2011

California's Energy Future: The View to 2050

Summary Report

May 2011

Jane C. S. Long (co-chair)

LEGAL NOTICE

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Message From CCST

CCST is pleased to present the results of the California's Energy Future (CEF) project, a study designed to help inform the decisions California state and local governments must make in order to achieve our state's ambitious goals of significantly reducing total greenhouse gas emissions over the next four decades.

This report is a summary of the CEF project and as such presents an overview of the project, the high-level findings, conclusions and recommendations. Subsequently, the CEF committee plans to produce a series of reports which give the details of the analysis.

California's Global Warming Solutions Act of 2006 (AB32) and Executive Order S-3-05 set strict standards for the state to meet. In order to comply, California needs to reduce its greenhouse gas emissions to 80% below 1990 levels by 2050 while accommodating projected growth in its economy and population.

The goal of the CEF project is to help California develop sound and realistic strategies for meeting these standards, by providing an authoritative, non-partisan analysis of the potential of energy efficiency, electrification of transportation and heat, low-carbon electricity generation and fuel. Our analysis is designed to identify potential energy systems that would meet both our requirements for energy and the emission target specified by executive order.

This study includes a set of energy system "portraits" which are descriptions of the set of energy demands, the portfolio of energy supply to meet these demands, and the associated emissions for each supply. Each portrait focuses on a different combination of energy strategies California might choose to provide the energy needed for future growth while aiming to reduce greenhouse gas emissions to the target amount. Each portrait incorporates strict accounting standards to ensure that trade-offs are made explicitly, energy measures are only counted once and all first-order emissions associated with various choices are counted.

The CEF study indicates that California can likely achieve significant reductions in greenhouse gas emissions by implementing technology we largely know about now. However, a combination of energy strategies and significant innovation will almost certainly be needed to achieve the 80% target, and the state will need aggressive policies, both near term and sustained over time, in order to make this possible.

We believe that the CEF project represents a valuable insight into the possibilities and realities of meeting California's electricity needs and emissions standards over the decades to come, and hope that you will find it useful.

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

Miriam John
California's Energy Future Committee
Co-chair

Introduction

This summary report synthesizes the results of a two-year study of California's energy future sponsored by the California Council on Science and Technology. The study was funded by the California Energy Commission and the S.D. Bechtel Foundation, and was completed by a committee of volunteers from major energy research institutions in California.

This report assesses technology requirements for reducing greenhouse gas (GHG) emissions in California to 80% below 1990 levels by 2050 as required by Executive Order S-3-05 (2005). Details of this analysis, assumptions and data are to be found in forthcoming reports, including a detailed analyses for specific energy technologies. The present document serves to synthesize the results and present the major findings.

The challenge of meeting these GHG emission targets is large:

- By 2050, California's population is expected to grow from the 2005 level of 37 million to 55 million. Even with moderate economic growth and business-as-usual (BAU) efficiency gains, we will need roughly twice as much energy in 2050 as we use today.

- To achieve the 80% reduction goal, California's greenhouse gas emissions will need to fall from 470 $MtCO_2e$/yr (million metric tons of CO_2 equivalent per year) in 2005 to 85 $MtCO_2e$/yr in 2050, with most of those emissions (77 $MtCO_2e$/yr) coming from the energy sector. Accomplishing this will require a reduction from about 13 tons CO_2e per capita in 2005 to about 1.6 tons CO_2e per capita in 2050 (Figure 1).

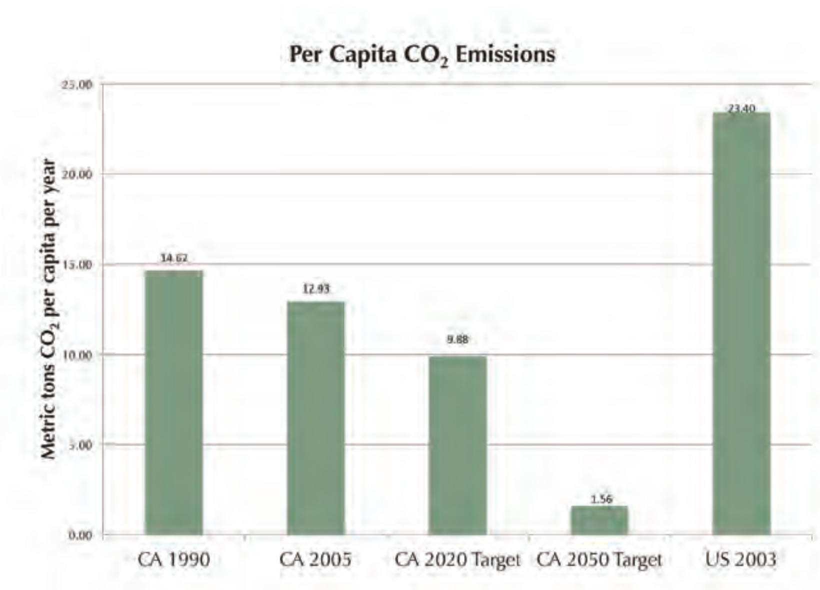


Figure 1. Per capita emissions.

This study has developed a set of energy system "portraits", each of which meets the challenge of providing the energy needed for future growth while striving to achieve the required greenhouse gas emissions reductions. We use the term energy system portrait to mean a set of energy sources, carriers and end-use technologies that meet all the energy needs of Californians projected for 2050. An energy system portrait describes an end-state or target energy system that could be a goal for California. This study connects related sectors of the energy system in order to account for trade-offs and inter-relationships. For example, if vehicle electrification is chosen as a strategy to reduce emissions, we also have to account for the emissions produced by the generation of the additional electricity needed for the vehicles.

Key Findings and Messages

California can achieve emissions roughly 60% below 1990 levels with technology we largely know about today if such technology is rapidly deployed at rates that are aggressive but feasible.

The following four key actions can feasibly reduce California greenhouse gas emissions to roughly 150 $MtCO_2e$/yr by 2050:

1. Aggressive efficiency measures for buildings, industry and transportation to dramatically reduce per capita energy demand.
2. Aggressive electrification to avoid fossil fuel use where technically feasible.
3. Decarbonizing electricity supply while doubling electricity production, and developing zero-emissions load balancing approaches to manage load variability and minimize the impact of variable supply for renewables like wind and solar.
4. Decarbonizing the remaining required fuel supply where electrification is not feasible.

Leaving any of these off the table will significantly increase the 2050 emissions.

- **The state will need aggressive policies, both near term and sustained over time, to catalyze and accelerate energy efficiency and electrification.** While innovation can improve the outlook for energy efficiency and electrification by reducing costs, we know how to improve efficiency or electrify for the majority of end uses.

- **The most robust, and thus most desirable, electricity system will not rely exclusively on a single generation technology.** We cannot predict with certainty the rate of technology or cost evolution of various approaches to generate low-carbon electricity. Moreover, each approach offsets the drawbacks of the others, and increases resiliency. It is imperative to pursue a suite of generation technologies, to keep options open as well as obtain the desired reliability in the full energy generation system:

    - Nuclear power provides reliable baseload power with very low emissions and can offset variability issues incurred by renewables, but faces obstacles with current public policy and public opinion. By law, new nuclear power in California is currently predicated on a solution for nuclear waste. Present electricity costs are expected to be higher than those from coal- or gas-fired plants if there are no emission charges. In addition, the recent 9.0 earthquake and tsunami in Japan, which led to a number of reactor explosions and radioactivity releases, will force a re-evaluation of nuclear power safety.
    - California has ample in-state renewable resources that can provide emission-free power and protect us from international energy politics that might affect fossil or nuclear power, but a high proportion of intermittent resources would result in significant emissions (if the power is firmed with natural gas) or a loss of reliability (if the power is not firmed), unless zero-emission load balancing technology

becomes available.

- ○ Fossil fuel with carbon capture and sequestration (CCS) would modify an existing electricity pathway to provide a transition to the future, but relies on the large-scale development of a system of underground CO_2 storage.

- All forms of electricity require load balancing services to meet peak demand, accommodate ramping, ensure grid reliability, and address resource intermittency. Currently, this is mostly accomplished through the dispatch of natural gas turbines to respond to rapid changes in supply or demand for electricity. Load balancing with natural gas produces significant emissions. **If electric generation is predominantly intermittent renewable power, using natural gas to firm the power would likely result in greenhouse gas emissions that would alone exceed the 2050 target for the entire economy.** Thus, development of a high percentage of intermittent resources would require concomitant development of zero-emissions load balancing (ZELB) to avoid these emissions and maintain system reliability.[1] ZELB might be achieved with with a combination of energy storage devices and smart-grid technology.

- High-density hydrocarbon fuels (both gaseous and liquid) are imperative for some uses which cannot be electrified and where CCS cannot be deployed. These include transportation sectors (especially heavy-duty trucks and airplanes), high-quality heat, some stationary uses and some load balancing.[2] In 2050, even after aggressive electrification and efficiency gains, we will likely require 70% as much liquid and gaseous fuel as we use today.[3] Current mean supply estimates of available, sustainable biofuels in 2050 are about 13 bgge/yr, or about half of the projected 2050 residual fuel demand including heavy duty transport, high quality heat, and gas needed to produce electricity for load balancing.[4] **Even after aggressive efficiency and electrification measures have reduced fuel use as much as feasible, if just half of the estimated residual fuel demand in 2050 is still supplied by fossil fuel, the resulting emissions alone will exceed the 2050 target.**

We could further reduce 2050 greenhouse gas emissions to 80% below 1990 levels with significant innovation and advancements in multiple technologies that eliminate emissions from fuels. All of these solutions would require intensive and sustained investment in new technologies plus innovation to bridge from the laboratory to reliable operating systems in relatively short timeframes.

1 We define zero-emissions for ZELB as adding no new emissions through the use of load balancing technology. The energy used to charge storage devices may incur emissions, but the storage device itself should have none if it qualifies as ZELB.

2 Hydrogen may be a viable substitute for some of these end uses; see discussions later in this report.

3 Exclusive of gas used for load balancing

4 Assuming renewable are limited to 33% of the electricity portfolio

- **The supply of renewable biomass, decisions regarding its use, and possibilities to import biofuels into the state will have a large impact on additional GHG reductions from fuels.** Large quantities of bio-energy could reduce emissions significantly primarily by displacing the use of fossil fuels, but quantities are uncertain. If biomass or biofuel becomes an energy commodity, ancillary impacts on food, water and fertilizer could become a serious problem.

- **There are many additional technologies that reduce emissions from fuels. In combination these could achieve the required additional emission cuts from 60% to 80% below 1990. Many require multiple simultaneous strategies, some are industrially complex and costly and some are actually offsets, but all of them require research and innovation.**

- CCS is likely to be an important part of several possible schemes to provide hydrogen, low-carbon fuels or offsets that allow continued fossil fuel use. **For California, the utility of CCS in achieving a low carbon fuel portfolio could be as important as the the utility of CCS for electricity production per se.**

- Possible breakthrough technologies such as carbon neutral fuel from sunlight or advances in nuclear power could be game changers. These would allow us to produce abundant electricity or fuel with nearly zero emissions.

Methodology

To arrive at these conclusions, the committee took a two step approach. First, we conducted a "stress test" to see if any one technology option (e.g. efficiency, nuclear power, renewable energy, biofuels etc.) could meet the 2050 energy requirements and not exceed the emissions target. The net result of these "stress tests," following considerable analysis, is "no single approach can solve the problem."

Secondly, the committee systematically examined various combinations of energy processes and technologies to find systems that could best reach the requirement with technology that is largely available today, i.e., either deployed or at least demonstrated at scale. These system combinations are referred to as "energy system portraits."

Assuming that California's population and economy grow as expected, we addressed four key questions with each scenario:

1. How much can we control demand through efficiency measures in buildings, transportation and industry by 2050?	This measure will decrease the need for electricity and fuel. We evaluate efficiency measures in buildings, transportation and industry.
2. How much can we electrify (or convert to hydrogen fuel) for transportation and heat by 2050?	This measure will increase the demand for electricity (or hydrogen fuel produced with little or no emissions), but decrease the need for fuels that cause emissions.
3. How do we de-carbonize enough electricity to meet the resulting electricity demand and satisfy the need for load balancing with what remaining emissions?	We examine nuclear power, fossil fuel (both coal and natural gas) with carbon capture and storage (CCS) and renewable energy. We look at two ways to avoid the use of natural gas for load balancing: electricity storage and flexible load management.
4. How do we de-carbonize enough fuel (hydrocarbons or hydrogen) to meet the remaining demand and with what remaining emissions?	We examine the future of biomass to either make biofuels, or to produce electricity with CCS and therefore create offsets that allow continued use of fossil fuels, and examine the use of hydrogen produced with methane and CCS or other emerging technologies.

Table 1. Four key questions.

Our approach is a logical analysis, not a projection or a prediction. We have performed an "existence proof" – to see if we could identify energy systems that will meet our needs, including economic and population growth –while attempting not to violate very aggressive emission standards or demanding very large, obvious increases in cost.

The process of eliminating emissions from the energy system while still meeting our requirements for energy can be illustrated in Figure 2a-e. The width of the box represents the demand for energy we expect to need in 2050, divided into electricity and fuel, and the height of the box is the GHG intensity of that energy. Thus, the area of the box is the GHG emissions or "footprint" of the resulting energy system (a). We are reducing the 2050 BAU (business-as-usual) footprint into a smaller 2050 target footprint. We decrease the width of the box from both sides (b) by using less energy to do the same work (efficiency), and we shift the box to the right (c) by switching from fuel to electricity where it makes sense energetically[5] (electrification) because electricity is more easily decarbonized than fuel, and then we decrease the height of the box (d) by using de-carbonized electricity and fuel sources ("low-carb" energy).

5 For example, boiling water with fuel to make steam, which is then used to make electricity, which is then used to make steam again, doesn't make sense energetically. Using an efficient electric heat pump in lieu of gas heating in homes, however, does make sense.

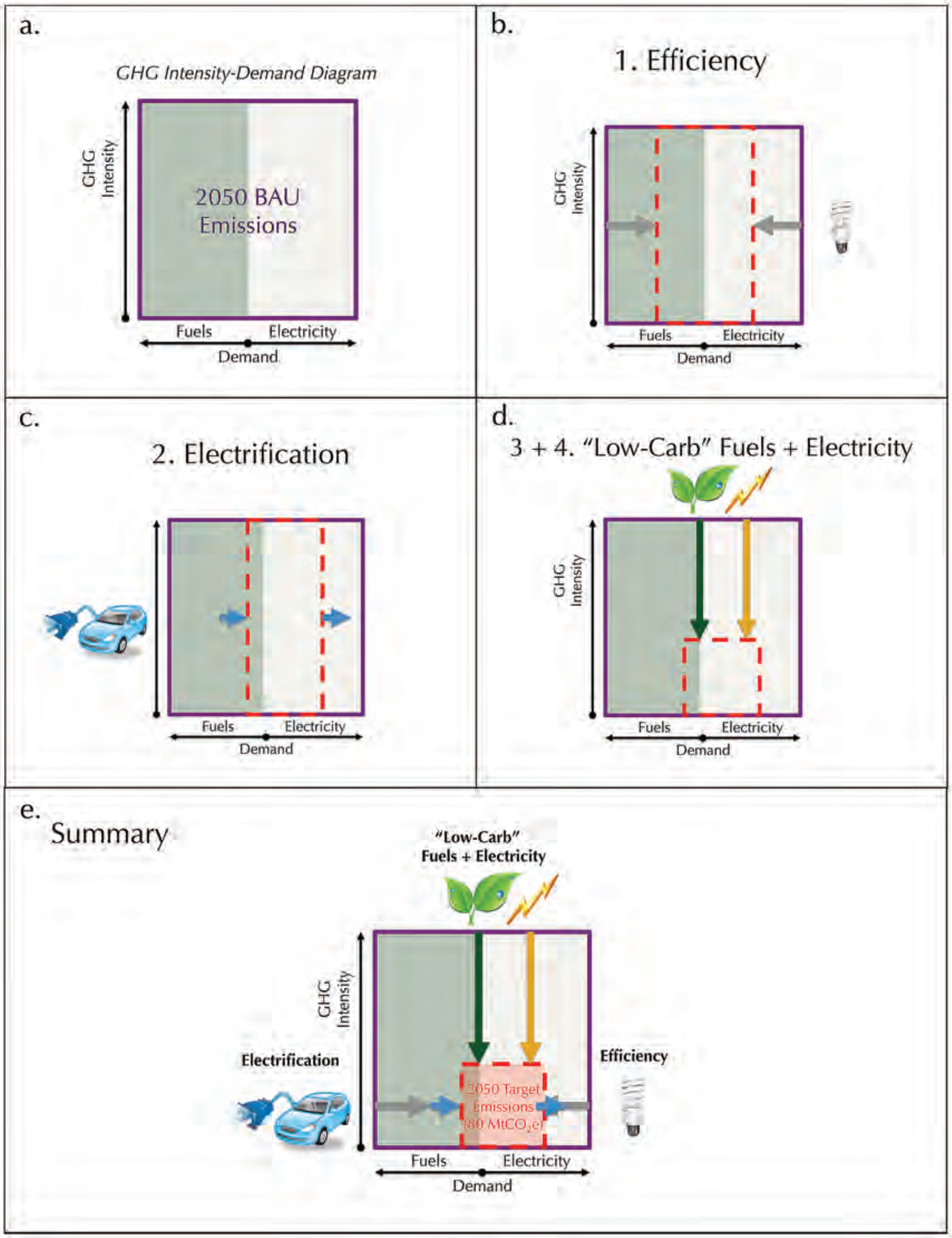


Figure 2. Schematic illustrating strategies for meeting our energy needs while eliminating emissions.

The calculations required for this process are embedded in a large, multi-tiered spreadsheet developed specifically for this study described in the sidebar, the California's Energy Future Spreadsheet. The quantification of the spreadsheet is based on a combination of state data, national data, prior analyses and the expert judgment of the committee. Some choices are expedient simplifications, such as choosing a single median value for population and economic growth. There are other choices where data is limited so we selected a median estimate from a very wide range of possibilities. The value of the observations and conclusions below are as good as the estimates we have made, but the tools and methodology we have produced are robust and can be used to examine different assumptions or incorporate new data as this becomes available. These tools and study methodology should be considered a major contribution of the CEF project.

The California's Energy Future Spreadsheet

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

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

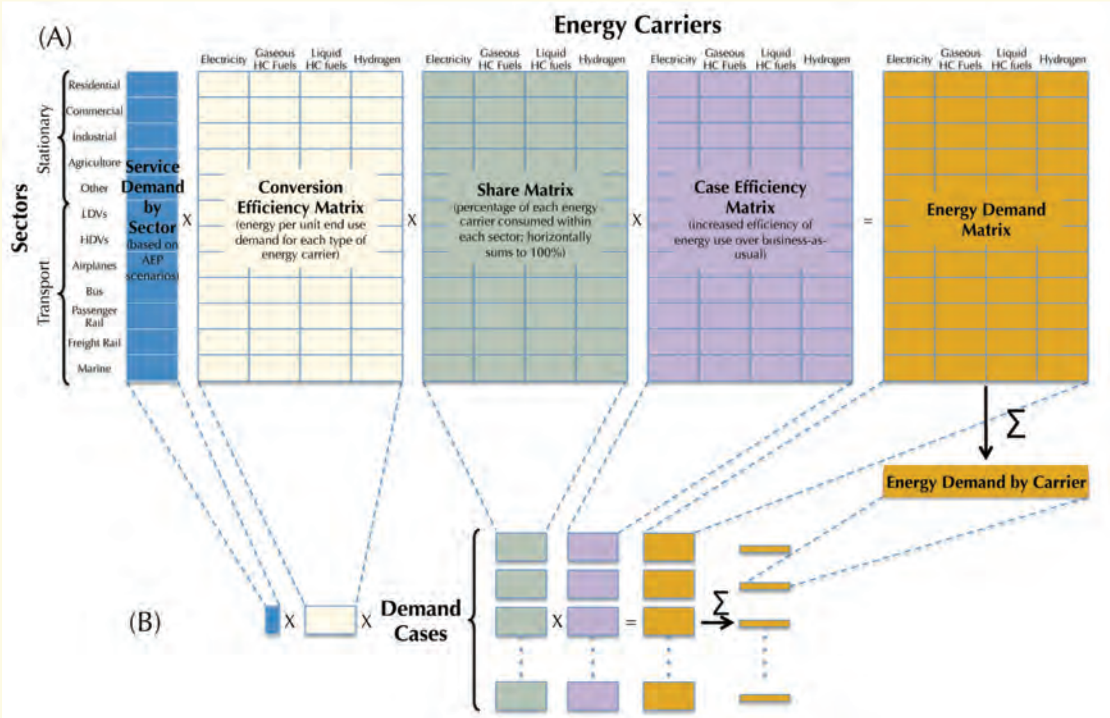
Efficiency, electrification and hydrogen fuel switching measures can be specified by the user. Because the end use efficiency also depends on the energy carrier, this factor is built into the spreadsheet. The user can also modify the technology used for load balancing and the spreadsheet will modify energy demands associated with this choice. In some cases, the choice of energy supply technology changes the total demand (e.g., use of fossil fuel increases the total demand for fuel because refining consumes some energy) and this calculation is also included. Resource limitations, such as the total amount of available biofuel, are also specified by the user.

Figure 1 illustrates the way the spreadsheet calculates the set of energy end-use demands separated into energy carriers: electricity, gaseous hydrocarbon fuels, liquid hydrocarbon fuels and hydrogen. Figure 2 illustrates how the choices of energy source for each carrier, as specified by the user, is used to calculate the total emissions.

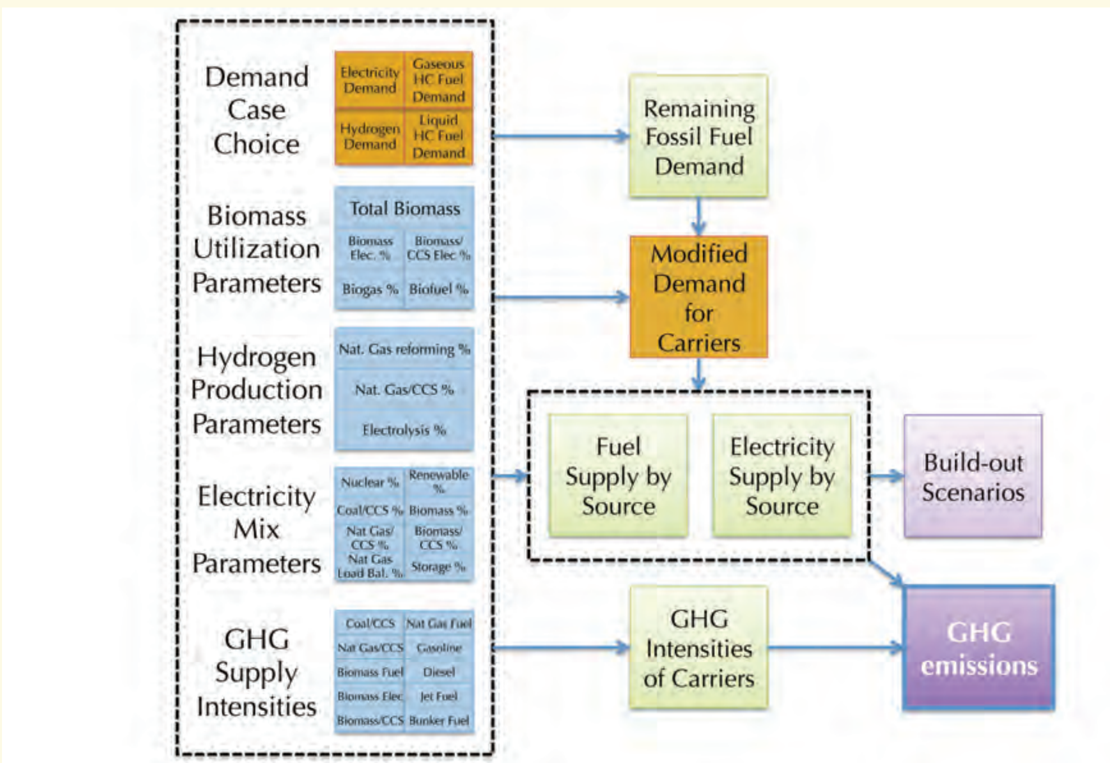
The spreadsheet is set up to calculate the GHG emissions of many dozens of portraits simultaneously, and group them for plotting in various ways. The adjustable input parameters that determine each portrait, including GHG intensities, are summarized in a single column.

While portraits describe the energy system for a single year (2050), the spreadsheet also makes some simple calculations concerning the build-out of various technologies from 2005 to 2050, using input parameters from selected portraits.

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



Calculation of energy system end-use demands categorized by energy carrier.



Calculation of emissions associated with the energy supply technologies needed to meet the end-use demands.

Our focus was to evaluate the capacity of technology to provide the solution. We discuss four kinds of technology (Table 2). We first invoked technology currently available at scale or currently demonstrated (almost entirely bins 1 and 2). Deployment of this technology was able to reduce emissions significantly. For the most part, we did not invoke technology in bin 3 except in a few cases where committee members thought implementation of this technology would in fact happen by 2050.

Bin 1 and 2 technology was not enough to reduce emissions by 80%. To meet this target, we had to draw on technology that was not currently available at scale (bins 3 and 4). Thus our assessments indicate where energy innovation will be needed to create energy systems that meet our needs without exceeding 2050 emission limitations.

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

Table 2. Technology readiness bins.

We assumed that scaling up energy technology in California would be performed in the context of scaling up the same technologies throughout the world. Thus California can only command its share of resources. Our analysis allows these "fair-share" imports, but requires that the emissions associated with these sources of energy are counted in our inventory. We do not allow "leakage" of emissions.

We did not perform our own economic projection analysis, as such an analysis was beyond the scope of this project. Instead, we qualitatively relied on several recent studies of energy systems for 2050, some of which show that prices estimated for 2050 (A study by E3 on California,[6] a European 2050 study,[7] and The National Academy of Sciences' America's Energy Future study.[8]) are not a significant differentiator of the major supply technologies. As well, escalating world-wide demand for fossil fuels might make low carbon energy relatively less expensive. We attempted to rule out choices that were clearly too expensive to consider based on economic information in other studies, and we asked our investigators to provide information on why prices might go down from where they are today (e.g., economies of scale) or why they might go up (e.g., resource limitations). We remain concerned about the level of capital investment required to create the energy systems we have described. These economic issues deserve further study. The technology analysis presented in this study provides strong guidance for subsequent economic analysis.

Our base study does not initially include any factors for behavioral change, in order to evaluate whether technology alone could solve the problem. At the end, we evaluated behavioral change as an added factor in reducing energy demand and making the problem easier to solve.

Finally, we evaluated how California's research institutions are contributing to the development of energy technology in Bins 3 and 4 and thus could contribute to new energy systems -- for California and for the world as well.

6 Energy and Environmental Economics, Inc., Meeting California's Long-Term Greenhouse Gas Reduction Goals, Novembver 2009: http://www.ethree.com/documents/2050revised.pdf,

7 Roadmap 2050, A Practical Guide to a Prosperous, Low Carbon Europe: http://www.roadmap2050.eu/.

8 National Academies Press, America's Energy Future: Technology and Transformation: Summary Edition 2009: http://www.nap.edu/catalog.php?record_id=12710.

Stress Tests

An initial analysis addressed the question: could any single, isolated approach solve this problem? To answer this question we proposed a series of "stress tests" for each set of technologies. Could we solve the whole problem if we just became more efficient? Could we solve the entire problem with just nuclear power, or CCS or renewable energy, without worrying about efficiency? Could we have enough emissions-free biomass to fuel our entire economy?

The answers to these questions are either categorically "no, it is not physically possible", or "yes, but the impacts and obstacles are so large, the concept does not appear rational":

- Energy efficiencies sufficiently great are possible in some building sectors, but ubiquitous implementation is likely prohibitively expensive; in other sectors they are thermodynamically impossible.
- Solving the whole electricity problem with renewable energy creates extremely large problems in load balancing due to intermittency, significant land-use issues.
- Fossil fuel with CCS alone would stress the emission target – as it is difficult to capture more than 90% of the CO_2 economically – and would push us quickly into using largely uncharacterized saline aquifers for storage.
- Nuclear power has perhaps the best technical chance to meet all our electricity needs, but the build out rate would be several large nuclear power plants per year and raises questions about nuclear waste and safety.
- If in addition we were to try to make liquid and gaseous fuels from electricity, we would create a nearly insurmountable demand for decarbonized electricity.
- The most optimistic possibilities with biomass indicate that, with significant innovation, and the highest estimates of biomass supply including imports, we could meet our needs for liquid and gaseous fuels, but there is significant uncertainty about supply and ancillary impacts on food, water and fertilizer.

The stress test indicates that even highly optimistic single solutions are most likely untenable and this leads to the conclusion that a portfolio of approaches will be required.

Energy System Component Analysis

Having determined that there are no simple solutions, the CEF committee searched for solutions that involved many components.

We assessed feasible progress in four major actions to modify the energy system: efficiency, electrification, decarbonizing electricity (including load balancing), and decarbonizing fuel.

1. Efficiency and Electrification

Efficiency and electrification measures are discussed together because many electrification measures are also often efficiency measures. Electrification refers to the process of switching from using a fuel to provide the desired end use service to using electricity-powered systems. For instance, replacing natural gas for water or space heating to high efficiency electric heat pumps, or switching from gasoline-powered cars to plug-in hybrid or all-electric vehicles.

Projected advances in 2050 are largely limited by turnover rates. We assumed aggressive turnover rates that are nonetheless within the range of historical precedents. These measures include:

- All new buildings built to new energy standards starting in 2015. These standards result in progressively more efficient buildings which, by 2040, use 80% less energy than business-as-usual. All remaining buildings are either aggressively retrofitted or replaced as part of their natural lifecycle, yielding 40% overall efficiency improvements in buildings.
- Seventy percent of building space and water heating shifts from natural gas to using electricity.
- A reduction of 30% in petroleum use and 50% in natural gas use from business-as-usual will be achieved in industry primarily through BAU efficiency gains and some electrification. Downsizing of the refining industry as the economy transitions to using biofuels could further reduce industrial fossil fuel use from BAU by about 15%.
- By 2050, approximately 70% of new light-duty vehicles (LDV), and about 60% of the fleet, are either plug-in hybrid or all-electric. The liquid fuel portion of vehicles is quite efficient relative to today: 64 mpg for new vehicles, and 58 mpg for the fleet average. Including electric vehicle miles in the average gives 87 mpgge[9] for new vehicles and 72 mpgge for the fleet. Bus and rail are 100% electrified.
- For the hydrogen scenario, approximately 60% of the 2050 LDV fleet are hydrogen-powered and 20% are either plug-in hybrid or all-electric, resulting in a lower conventional fuel usage than in the non-hydrogen scenario. The efficiency of hydrogen-powered vehicles is about 80 mpgge.
- Overall fuel use in aviation and trucks drops by about half due to significant efficiency and operational improvements and, for trucks, electrification of short-range vehicles.

In total, we find that aggressive efficiency measures could reduce the projected demand for electricity by 36% relative to BAU. The majority of technologies needed for these efficiency measures are either currently commercial or in demonstration. Technologies in demonstration or development will require innovation and widespread consumer adoption.

9 Miles per gallon gasoline equivalent.

The resulting demands, compared to 2005 and BAU estimates, are given in Table 3. These demands must be met under an energy sector emissions budget of 77 $MtCO_2e$/yr to comply with the 2050 target.

Energy Carrier *	2005	BAU 2050	2050 Efficiency only	2050 Efficiency and Electrification	2050 Efficiency, Electrification and Hydrogen
Electricity (TWh/yr)	270	470	330	510	460
Gaseous fuel** (bgge/yr)	12	24	13	9	6
Liquid fuel (bgge/yr)	24	44	22	16	12
Hydrogen (bgge/yr = TgH_2/yr)					8

Table 3. Projected energy demands in 2050. (Note that 1 gge of gaseous fuel is 1.15 Therms)
* See Appendix A for explanation of energy units.
** Some portfolios include additional gas for electricity generation (load balancing and/or CCS).

Enhanced electrification would simultaneously increase the demand for electricity by about 70%. The net effect is that electricity demand nearly doubles from 270 TWh/yr today to 510 TWh/yr in 2050 at the same time emissions from electricity must be largely eliminated.

The demand for gaseous and liquids fuels could be reduced by over 60% each relative to 2050 BAU demand by a combination of efficiency plus electrification. So, in 2050, we would use about 70% of the fuel we use today.

If hydrogen were readily available, its use as a fuel would decrease the need for gaseous fuels by about 40% and liquid fuels by 24%, and decrease the end-use demand for electricity by about 10% relative to the efficiency plus electrification case.

Today, a new building can be constructed to be 40-50% more efficient with no difference in up-front cost.[10] Estimates for the cost of "deep" efficiency retrofits (~70-80% energy use reductions) to existing buildings range from $40,000 to $100,000 per building.

For industry, the ACEEE[11] estimates a cost of $200-300 billion through 2025 for the U.S. for a 25-30% reduction in energy intensity. These figures are roughly 6-10% above what industry (manufacturing) historically spends on energy and capital expenditures on an annualized basis. In California, this would translate to $1.5-2.2 billion per year, assuming the state maintains a constant share of U.S. industry. Costs beyond 2025 are difficult to project since there is considerable uncertainty in electrification capital, re-tooling and design costs and actual state industry composition in 2050.

10 Walker I (2009), Personal communication, Lawrence Berkeley National Laboratory.
11 Elliott N (2009), Personal communication, American Council for an Energy-Efficient Economy.

Estimates are that advanced light-duty vehicles such as PHEVs and FCVs could become cost-competitive with conventional gasoline vehicles on a life-cycle basis as the price for conventional liquid fuels rises. However, reaching this point of cost-competitiveness will require several decades and require large subsidies (on the order of tens of billions of dollars in the U.S. as a whole) to buy down the vehicle costs.[12] Transitions to Alternative Transportation Technologies – Plug-in Hybrid Electric Vehicles.[13] An important challenge for adoption of these vehicles is that consumers are sensitive to initial cost and tend to discount future savings on fuel expenditures when considering vehicle purchases.

Efficiency and Electrification Research

UC Santa Barbara, UC Davis, and Lawrence Berkeley National Laboratory (LBNL) conduct valuable research on energy efficient LED lighting, and LBNL is also a world-class center for work on energy-efficient buildings (including appliances, equipment and electronics) and industry. In addition, both Stanford University and UC Davis have energy efficiency centers. These capabilities can help California companies become leaders in these areas.

Fuels cells can be used in both vehicles and buildings, and California has major hydrogen capabilities at UC Davis, UC Irvine, Sandia National Laboratory - California, Lawrence Livermore National Laboratory, and elsewhere. The “father” of the plug-in hybrid electric vehicle is at UC Davis.

2. Electricity

In general, three are three ways to produce de-carbonized electricity: nuclear power, fossil fuel with carbon capture and storage (CCS), and renewable energy. The stress test analysis indicated that, although we could not expect to solve the whole energy problem with any given electricity generation technology, we could theoretically meet the 2050 electricity demand given in the above table with any of the three sources of electricity (nuclear, fossil with CCS, or renewables). Further, we assumed that the California law requiring 33% renewables would remain in place, as would our existing hydropower resources. Therefore nuclear power or fossil with CCS would be asked to provide at most 67% of the electricity (340 TWh/yr), whereas renewable energy could be asked to provide 100% (510 TWh/yr).[14]

12 Committee on Alternatives and Strategies for Future Hydrogen Production and Use, National Research Council, National Academy of Engineering. The Hydrogen Economy: Opportunities, Costs, Barriers, and R&D Needs. National Academies Press, 2004. (http://www.nap.edu/catalog.php?record_id=10922#toc)

13 Committee on Assessment of Resource Needs for Fuel Cell and Hydrogen Technologies, National Research Council. Transitions to Alternative Transportation Technologies – Plug-in Hybrid Electric Vehicles. National Academies Press, 2010. (http://www.nap.edu/catalog.php?record_id=12826#toc)

14 Depending on how load balancing is accomplished, additional electricity generation might be required to make up for electrical storage losses—up to an additional 7% or 34 TWh/yr for renewables-only generation. Moreover, depending on the demand for fossil fuels, refining might add up to 15 TWh/yr in additional demand. Finally, if hydrogen is produced from electricity, demand could increase by 350 TWh/yr—a 70% increase above the median 2050 demand.

Our analysis focused on three key issues:

1. What are the emissions associated with meeting the increased demand for electricity in 2050 with either nuclear power, fossil with CCS, or renewables?
2. What are the requirements for scaling up?
3. What are the ancillary impacts?

For nuclear and renewable energy, the emissions associated with generation are nearly zero. For fossil fuel with CCS, CO_2 capture technology with a 90% removal rate would result in residual emissions of 28 $MtCO_2$/yr for coal - and 13 $MtCO_2$/yr for gas - fired electricity in 2050. Technologies with greater than 90% capture will likely suffer from severe energy penalties or are considered bin 3 or 4 technology which may not be available by 2050.[15] Thus providing 67% of electricity in 2050 through coal with CCS would produce about one third of the allowed 2050 emissions, leaving significantly less left for remaining distributed fuel use requirements. Natural gas with CCS has a lower GHG footprint and would produce about a fifth of the allowed emissions.

Nuclear Power

The requirements for scaling up nuclear power include:

1. Either licensing a national nuclear waste repository or changing the California law which requires a licensed repository before new reactors can be built;
2. Building about one new plant per year starting in about 2020;
3. Licensing Gen III[16] reactors;
4. Reducing costs, which are currently high (if the nuclear industry were reinvigorated, costs might be reduced to about $60-80/MWh.);
5. Renewing the Price Anderson Act, which indemnifies operators against catastrophic accidents with costs exceeding $10 billion; and
6. Reassessing the safety of nuclear power, especially given the recent events in Japan.

We would have to build approximately one new power plant a year from 2020 to 2050 in order to provide 67% of California's expected 2050 baseload electricity demands, which is deemed possible with standardized designs. The technology to build advanced (Gen III) nuclear power plants is commercially available now. Costs, although high now, are expected to decline significantly if construction cost reductions observed in Japan, Korea, and China also occur in the U.S.

The potential ancillary impacts of expanding the use of nuclear power in California include public opinion and nuclear waste. The waste issue is currently being examined by a Presidential Blue Ribbon Commission that is likely to recommend changes to the Nuclear Waste Policy Act. The issue of nuclear waste disposal remains unresolved, but is deemed technically solvable, as it has been solved in Sweden and Finland.[17] New nuclear power is currently banned in California until a geologic disposal facility for nuclear wastes is licensed by the federal government. Proliferation

15 This assumption is consistent with estimates used in the Intergovernmental Panel on Climate Change Special Report on Carbon Dioxide Capture and Storage (2005), http://www.ipcc.ch/pdf/special-reports/srccs/srccs_summaryforpolicymakers.pdf, and the National Academies Summit on America's Energy Future (2008), http://www.nap.edu/openbook.php?record_id=12450&page=143.

16 Gen III refers to third generation or advanced nuclear technology.

17 "Nuclear Power in Sweden." Feb. 2011. World Nuclear Association. 3 May 2011. (http://www.world-nuclear.org/info/inf42.html)

concerns are not an issue for expanding nuclear power in California, but would be an issue for the federal government if the whole world expands nuclear power.

Water for cooling nuclear reactors can be a sustainability concern. However, progress in the use of waste water, sea water, and air-cooled systems can reduce freshwater impacts. Air cooling is an alternative but would reduce efficiency and increase costs.[18] Siting in an earthquake-prone state is feasible, as demonstrated with the State's two existing sites. However, additional concerns about having a source of water for emergencies and siting in seismic zones may arise on review of recent events in Japan (see below). Uranium fuel assessments indicate that adequate amounts will be available through 2050 and beyond, and fuel reprocessing technologies exist in the event uranium fuel supplies were to run short.[19]

In March of 2011, Japan experienced a record breaking earthquake of magnitude 9.0 followed by a 30-50 ft high tsunami. The consequent damage to reactors at the coastal Fukushima Daiichi Nuclear Power Station has resulted in the worst nuclear accident since the Chernobyl reactor disaster a quarter century ago. This episode included multiple, simultaneous damaged re-actors and breached containment, and has resulted in radiation leakage and loss of life. It is too early to completely understand the full impact and importance of this accident, as events are still unfolding. We will need to evaluate exactly what happened and why, and interpret these events in a variety of relevant contexts to determine what it is we should learn from them. However, what is clear even now is that this event will have a major impact on the way we think about nuclear power and will be a factor in considering the future of nuclear power in California.

Fossil with Carbon Capture and Storage (CCS)

Given the stringency of the 2050 greenhouse gas emissions target, any use of fossil fuel for electricity generation would need to be paired with capture and geologic storage of the resulting CO_2 emissions. There are a number of approaches to pairing CCS with combustion or gasification of fossil fuels, each of which has its advantages and drawbacks. Much of the technology required for CCS is in the demonstration phase (bin 2).

Natural gas with CCS is a better choice than coal with CCS from an emissions standpoint (e.g. fewer CO_2 molecules overall to capture and store), but natural gas availability and costs are volatile. It is unlikely that California would begin to develop coal-fired electricity in-state, but we might import electricity produced this way and thus have to count the emissions. As a result, any imported electricity from coal would have to be produced with CCS. Environmental issues with gas and coal production are mainly outside of California, but remain significant, including degradation from coal mining and issues with water used for hydrofracking[20] tight gas reservoirs in the production process.

Based on assessments from the U.S. Department of Energy and others, it is estimated that California has only a few decades' worth of CO_2 storage capacity in well-characterized, abandoned oil and gas

18 Planning for cooling without using water is likely to be the norm. Recently, the State Water Resources Control Board has mandated the retrofit of 19 of the State's largest fossil and nuclear power plants to prohibit the use of once-through cooling with ocean or estuarine waters. Estimated costs for retrofit for Diablo Canyon and San Onofre nuclear plants are in excess of $2 billion each, casting doubt on those plants' continued operations.

19 Supply estimate per Uranium 2007: Resources, Production and Demand, jointly prepared by the OECD Nuclear Energy Agency (NEA) and the International Atomic Energy Agency (IAEA)

20 Hydraulic fracturing (hydrofracking) is a process of fracturing rock in reservoir rock formations in order to increase the rate and recovery of oil and natural gas.

reservoirs in California, perhaps enough to last through the 21st century[21]. Saline aquifers could provide many decades of storage capacity beyond this, but more research is required to establish their safety and suitability for CCS.

The capacity factor[22] for fossil with CCS is 80%, somewhat lower than that for nuclear power. But in addition, the capture and sequestration of the CO_2 requires energy that is then not available for distribution. This energy is known as "parasitic load." The aspirational goal of CO_2 capture research is to reduce parasitic load down to 10%. This has been demonstrated in the laboratory but not at commercial scale; therefore this is a "bin 2" technology need. If there is a 10% parasitic load for CO_2 capture, the gross amount of fossil with CCS capacity needed is 54 GW (for the case where fossil with CCS serves 62% of 510 TWh/yr). However, if we limit ourselves to "bin 1" (e.g. current amine scrubbing), parasitic loads are in the neighborhood of 30% - which would result in a need for 64 GW of capacity in that case and increasing the cost of electricity from this source accordingly.

The build rate would be similar to nuclear power, about one plant per year (China builds one conventional coal-fired plant about every two weeks). The cost of capture remains quite high at $20 – 40/ MWh. The cost of sequestration in oil and gas reservoirs is a small fraction of the capture costs. Should pipelines be required, these are estimated at $500,000 per mile, as compared to $1+ million per mile for electricity transmission.

Renewable Electricity

California has a wide variety of renewable resources – wind, solar, biomass, geothermal, hydro, and marine energy offshore. As estimated in several California Energy Commission studies, the total available resources are more than sufficient to meet the expected demand for electricity required in 2050 and beyond.

Because renewable resources (particularly wind and solar) tend to have a lower capacity factor than other generation resources, much more renewable generation capacity would need to be built than in the other cases. If an average capacity factor of 37% is assumed, annual installed renewable energy generation would need to increase by an order of magnitude, from 16 GW in 2009 to 165 GW in 2050. To put this in perspective, this implies a growth rate for wind power of about 7.5% per year, and for solar power of about 12% per year, even with assumed increases in biomass and geothermal power and the assumption that California's large hydro resources remain in operation.

Most of the renewable generation technology is commercially available and much innovation is underway to improve performance or decrease generation cost. Most renewables will become competitive with a price for CO_2 of about $30/t. In some recent power purchase agreements, larger solar photovoltaic (PV) facilities were priced at or below the price of new natural gas facilities (thanks to Federal and State tax incentives), enabling them to compete with grid power. Wind energy in areas of good wind resource can be cost-competitive given this same favorable tax treatment, and conventional geothermal and hydropower resources are already among some of the lowest-cost resources in California.

21 Herzog, Howard, Weifeng Li, Hongliang (Henry) Zhang, Mi Diao, Greg Singleton, and Mark Bohm. 2007. West Coast Regional Carbon Sequestration Partnership: Source-Sink Characterization and Geographic Information System-Based Matching. California Energy Commission, PIER Energy-Related Environmental Research Program. CEC-500-2007-053.

22 The net capacity factor of a power plant is ratio of the actual output of a power plant over a period of time and its output if it had operated at full nameplate capacity the entire time.

However, most renewable energy resources must be located near the resource rather than near the load they serve. Thus in most cases, projects must also factor in the costs of increased requirements for transmission. Another key issue for renewable electricity is that only hydropower and biomass are "dispatchable" (e.g. they can be adjusted to meet available load). The other types of renewable generation are either baseload (marine and geothermal) or intermittent and variable (wind and solar). Neither of these types of generation is able to follow load and therefore require some other "load balancing" resource to satisfy changing electricity demand at all times (which is a requirement for reliable grid operations).

Harvesting of energy from the natural environment at such a scale will have obvious land use impacts. We estimate the land area required to produce 100% of California's electricity needs in 2050 will be about 5% of the land area in California. Wind farms only directly displace about 2% of the required land areas, with the rest available for other activities (e.g., ranching); distributed (rooftop) PV does not displace new land; and virtually all California biomass is assumed to come from municipal, agricultural and forest waste streams, and marginal lands not currently in agricultural production. So, the amount of land that would be directly displaced by renewable energy will be about 1.3% of California.

Other environmental impacts of concern associated with a large build out of wind energy may include adverse impacts on birds and other avian species, turbine noise effects on nearby communities, and downstream impacts on local weather and climate. For solar thermal systems (concentrating solar power (CSP)) and biomass systems, there are water impacts for cooling unless dry cooling is utilized, and a small amount of water is required for cleaning of solar PV installations. Geothermal energy may require water to keep the reservoirs from depletion, but, as with nuclear power, this can be waste water as is used at The Geysers. Hydro and marine resources significantly impact fish and other aquatic species if fish protection technologies or operations such as fine-mesh screens, spill, or diversions are not employed.

Load Balancing

To maintain a reliable electricity grid, grid operators (such as the California ISO) must ensure that supply of electricity is equal to demand for electricity at all times. In a conventional electricity generation mix, certain assets are operated in "baseload" mode, i.e. at a constant power output over all times. Other assets are operated in "intermediate" mode with a defined output curve, i.e., meeting the expected, predictable daytime increase in electricity demand associated with air conditioning use. Finally, additional resources are operated in "peaking" mode to close the residual gap between what baseload and intermediate assets are scheduled to provide, and the actual demand for electricity at any given time. If such "peaking" resources are not available or too expensive, imports of excess power from nearby regions can be used. Emerging technology approaches, such as energy storage or controllable loads (e.g., interruptible air conditioning) offer still further flexibility in grid system operations and planning. Finally, if no other resources are available to meet demand, electric loads are curtailed either voluntarily as part of a utility-offered rate program, or, as an absolute last resort, involuntarily through rotating "blackouts" (loss of service).

In each portrait considered here, we must make the assumption that "the lights stay on", i.e. the supply and demand are balanced at every point. We use the term "load balancing" to include all aspects of this matching of supply and demand as a function of time, including firming intermittent renewables, energy required to meet peak load over baseload, and energy for ramping. The additional energy requirements for load balancing and their corresponding GHG emissions signatures prove difficult to estimate. To do so, we would need to match the output shapes of the various resources (nuclear, fossil with CCS, renewables) with the expected demand curves of consumers in 2050 after all of the efficiency and electrification actions described above have been taken, and derive from that an estimate of additional generation resources needed for load balancing. This is a very large chain of poorly understood factors.

Rather than make a specific point estimate about how the 2050 electricity system is likely to evolve (and incorporate all of the uncertainty that would entail), we chose instead here to look at two extremes: (1) all load balancing met with natural gas turbines (with a 30% average efficiency and no CCS); or (2) all load balancing met with zero-emissions load balancing (ZELB) resources such as energy storage, or smart grid-connected controllable loads. For renewables, this would include ramping and storage to counter the variability in wind and solar resource availability due to wind gusts, clouds, storms, etc. For nuclear or fossil with CCS, this would include load-following dispatch of additional resources to meet peak demand that the baseload nuclear or fossil units could not or would not meet alone.

There is very little experience with electricity portfolios that have 33% or more variable renewable energy and a wide range of estimates in the literature. However, we are beginning to see the relationship between large percentages of renewable energy and reliability. The German electricity grid now faces instability because of very rapid growth of intermittent solar power as a result of laws that incentivize solar power through feed-in tariffs.[23]

The California renewable portfolio could be about 75% variable resources from solar and wind power based on the direction it is headed today. Without any hard estimate of the progress in ZELB technology and adoption, we made a median estimate that we will need natural gas to firm about half this power in 2050 to maintain system reliability. This estimate does not have a strong basis however and the topic is worthy of further study.

There is a significant difference between the load following services required for systems that are dominated by intermittent generation, versus those that have significant baseload. Not only do these resources require more storage to allow the peak of resource availability to be shifted to the time of peak demand, intermittent resources may also require storage that can provide gigawatt-days of energy if, for example, the wind does not blow for many days. Consequently, the difference in emissions from the three possible sources of electricity have mostly to do with assumptions about load balancing. Figure 3 shows the total energy system emissions for the major ways of generating electricity using either 100% natural gas for load balancing, or 100% ZELB. The use of natural gas (without CCS) to balance variability in electric generation units will eat up a significant fraction of the 77 MtCO_2e/yr GHG target allotted to the energy sector if the 2050 goals are to be met.[24]

If we use natural gas to firm the power, nuclear is estimated to have the lowest emission profile of any generation choice. Without ZELB, a 100% renewable portfolio will have more emissions than

23 http://www.solardaily.com/reports/German_grid_aching_under_solar_power_999.html#.

24 The use of biomass to provide some of this gas lowers emissions for load balancing and provides GW-days of low emission storage. Consequently, we add the required amount of gas to our total residual fuel demand estimates below. However, median estimates of biomass supply are inadequate for all the total of proposed uses and therefore emission reductions for electricity by using biomass for load balancing simply result in higher emissions for transportation.

any other electricity portfolio, about 30% more than a nuclear power portfolio. Without ZELB, natural gas or even coal plus CCS has fewer emissions than renewables.

With ZELB, emissions for fossil with CCS are the highest of the three choices, and a 100% renewable portfolio would have about the same emissions as nuclear power. No electricity portfolio does better than nuclear power from an emissions standpoint, but renewable energy can have as few emissions as nuclear power if ZELB is 100% available. Clearly, it will be easier to insure reliability and there will be a lower need for load balancing without emissions if there is a significant fraction of base-load power available through either nuclear or fossil with CCS.

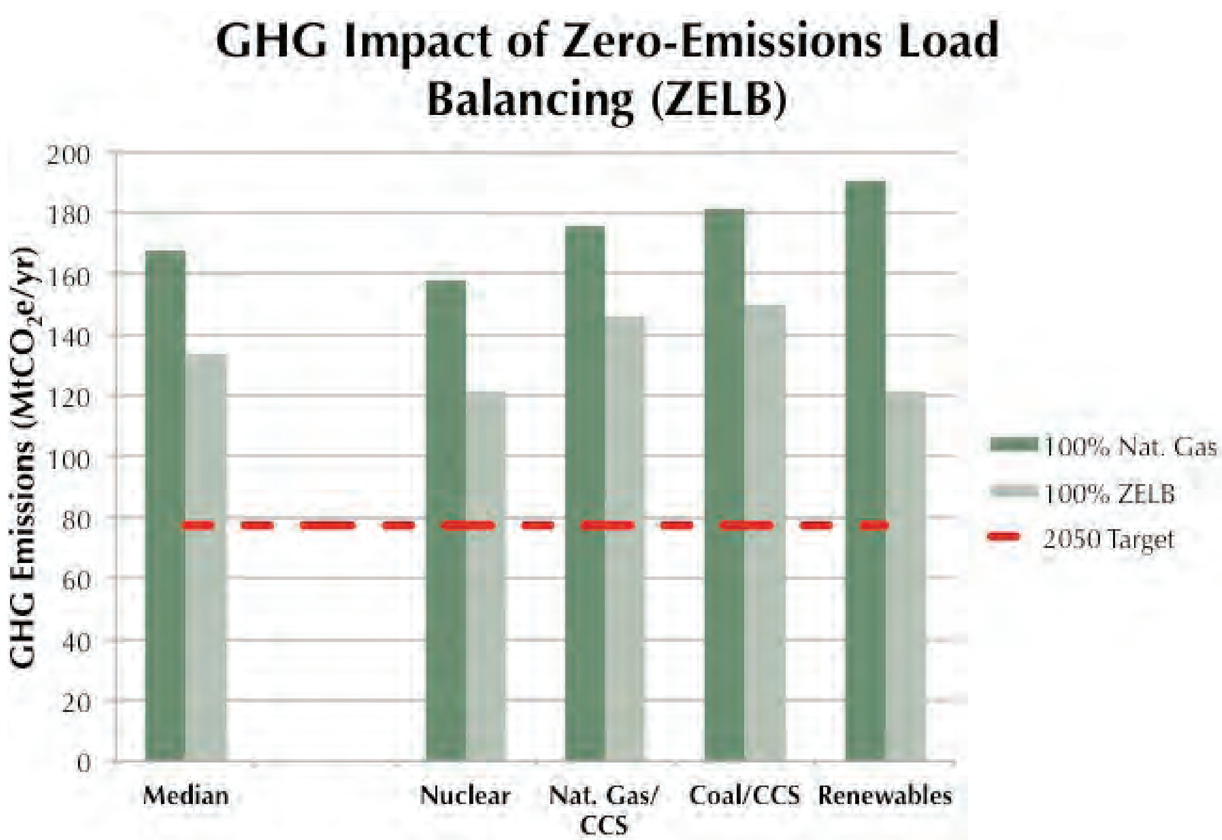


Figure 3. Impact of ZELB on total energy system emissions for two scenarios, one using natural gas for load balancing and the other employing zero-emissions load balancing technology (ZELB) as a function of the type of electricity generation. Note that all cases have at least 33% renewable energy in the mix. The renewables case is 100% renewable energy. The additional emissions from using natural gas to firm renewable energy (i.e. the difference between the light and dark bars for the renewable case) alone almost exceed the target emissions.

The technologies for ZELB include a wide variety of ideas for energy storage, including pumped hydro, compressed air energy storage (CAES),[25] flywheels and various battery designs. The cost barrier is quite high, with natural gas turbines currently providing load following services for about $0.10/kWh and commercial batteries being from 4 to 10 times that value. Pumped hydro and CAES are more competitive, but are more limited to specialized geography. There are a number of battery designs in demonstration (Na/S, advanced Pb/Acid, Ni/Cd, Li ion as found in electric vehicles) and more advanced batteries (Pb/Acid, Vanadium redox, Vanadium flow, Zn/Br redox, Zn/Br flow, and Fe/Cr) are under development. It remains a concern that few or none of these energy storage technologies would be able to manage multiple GW-days of storage which might be required in the case where wind and solar are used for a substantial (>50%) fraction of the State's energy mix. The use of fossil fuel fired plants with CCS to manage variable loads could do this and is in development.[26] Off-peak hydrogen production could do this as well, although there are economic penalties associated with part-load operation of these plants.

Although some demand-side management is currently in place for commercial scale critical peak demand response, the technology for widespread residential time-of-use demand side management is only in development. System management technology is not yet available that would allow us to shift the business model from one in which the consumer buys and the utility supplies, to one in which the consumer is more in control of how much electricity is used, where it comes from and when. Beyond technology, such a system also requires the market to include as many consumers as possible, so that the load can be balanced over a larger group. Smart-grid pilot studies and projects currently ongoing in California and nationally will improve our understanding of the potential for -- and barriers to -- use of smart grid-connected demand response as a load balancing approach.

100% ZELB requires either major technology advances to decrease the cost of storage or a major shift in the electricity delivery system to having the load adjust to the supply, rather than vice versa. If the cost of energy storage can be reduced and the duration increased significantly, this would transform the energy business by allowing large quantities of reliable energy from intermittent resources. Alternatively, if the smart grid allows successful emission–free load balancing this would transform the industry in an entirely different way, most likely shifting control away from the utility by requiring the consumer to make more decisions about when to use power and from whom to buy the power. If neither ZELB strategy is successful, we will be choosing between emissions from natural gas load balancing or a loss of energy reliability.

25 Technically, CAES is not a zero-emission storage technology because it requires some natural gas combustion to regenerate the stored electricity. However, CAES technology that does not require fuel combustion has been proposed (bin 3), and it is possible to use biomass-based natural gas or even hydrogen to provide the fuel.

26 "Workshop on Operating Flexibility of Power Plants with CCS." Nov. 11-12, 2009. International Energy Agency Greenhouse Gas R&D Programme. 3 May 2011. (http://www.ieaghg.org/index.php?/20100113168/workshop-on-operating-flexibility-of-power-plants-with-ccs.html)

3. Fuel Supply

After all possible transportation and heat has been electrified, there remains a need for about 25 bgge/yr of liquid and gaseous hydrocarbon fuels for mobile and stationary uses (see table 3), plus approximately 2 bgge/yr of gaseous fuel to provide for half the required load balancing.[27] Therefore we are likely to require roughly 27 bgge of fuel in 2050. This fuel use will not be amenable to CCS and thus the only possible way to eliminate emissions from this fuel use is to use low-carbon fuels. We can meet this demand partly from biofuels made from biomass, with some associated emissions. Alternatively, we evaluated the option to burn biomass to make electricity and to sequester the associated emissions. This creates negative emissions which could then be used to offset some continued use of fossil fuels.

State resources alone could provide between 3 and 10 bgge/yr of biofuels from waste products, crop residues, and marginal lands not usable for agriculture. These sources are chosen because they would have minimal impact. It is possible that our “fair share” of likely world-wide production could make up the difference between the state’s needs and in-state supplies. As this is uncertain, we chose a median estimate of 7.5 bgge/yr in-state production, of which 2.0 bgge/yr would be burned directly as biomass for electricity, and 5.5 bgge/yr would be available for fuel production. A similar amount of 7.5 bgge/yr as California’s “fair share” of imported biofuel was included, for a total of 13 bgge/yr available biofuel. It is important to recognize that the amount of biomass or biofuel that might be available to California could be much smaller or much larger.

Currently, biofuel is produced from food crops such as corn, sugarcane and soybean with about 40% - 50% of the emissions of fossil fuel. Future technologies are expected to reduce this to 20% (80% reduction over current fossil) by 2050 for both liquid and gaseous biofuels. The renewable fuel standard (RFS2) has set caps on the production of corn ethanol and conventional biodiesel, thus bin 2 and bin 3 technologies such as cellulosic ethanol, renewable diesel and production of drop-in hydrocarbons were analyzed. The E85/biodiesel scenario (bin 1 and 2 technology) does not contribute to meeting the GHG reduction targets; whereas, the drop-in fuel scenario (bin 2 and 3 technology) does. These renewable gasoline and diesel replacement fuels can be made by several routes from biomass.

In addition, some biomass and wastewater will likely be used to produce methane through anaerobic fermentation followed by clean-up to prevent the release of nitrous oxide or sulfur compounds during combustion.

Various kinds of biomass can be routed into various forms of fuel (gas or liquid) or even burned for electricity. Conversion efficiencies and end-use requirements for gaseous and/or liquid fuel production should be weighed to determine the best use of the biomass.

Total emissions from fuel use are mostly dependent on the amount of fossil fuel still required, and this depends on how much low-carbon biofuel is sustainably available to displace fossil fuel use. Thus the amount of biomass supply, either in-state or in the form of sustainable imported fuel, is more important to meeting the target than is reducing biofuel-derived emissions from 80 to 100% below fossil fuel (see Figure 4). Thus the ability of biofuels to solve the problem of emissions from fuel use will depend first on the amount of biomass available and secondly on technology developed to improve the carbon signature of the fuel. The majority of the required technology is in the development stage.

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27 The total demand for gas would be larger by about 10 bgge/yr if we use natural gas plus CCS to generate 31% of electricity. This amount is not counted here because the emissions can be sequestered. The amount of fuel required for load balancing assumes that the electricity portfolio is 33% renewable energy, i.e. the “median case.”

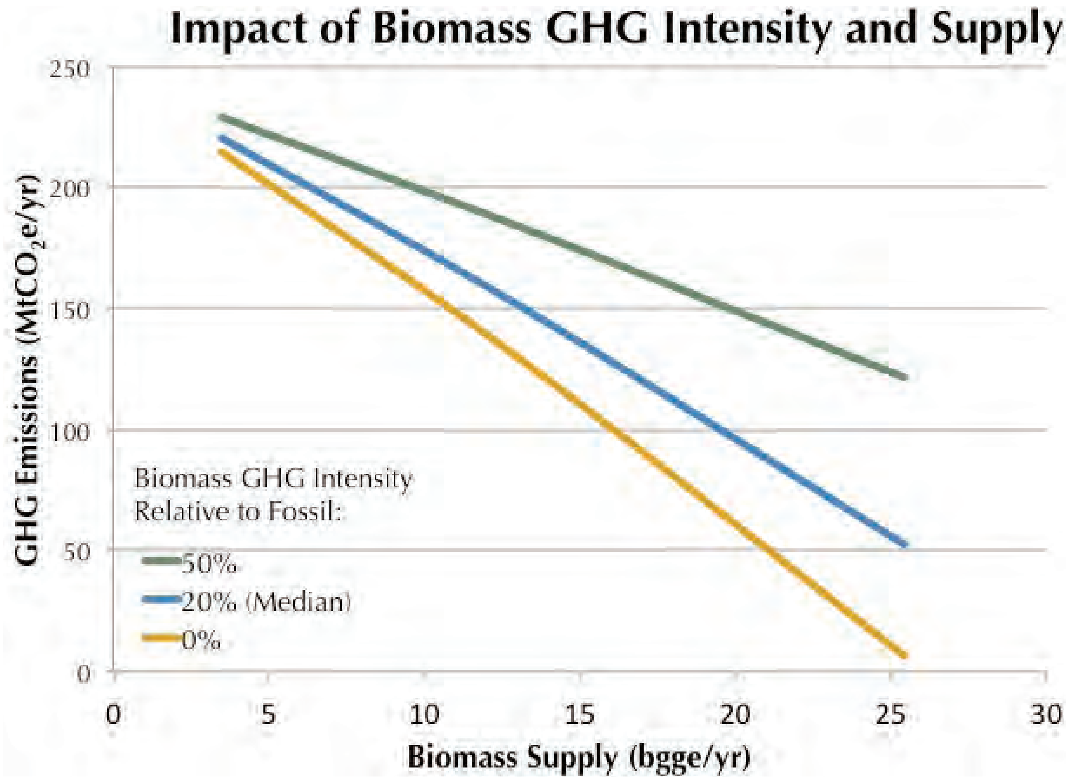

Figure 4. Total greenhouse gas emissions vs. increasing biomass supply curves for constant levels of carbon intensity in fuel.

The investments required for, and ancillary impacts of, biofuels could be significant. We estimate that producing 5.5 bgge/yr of biofuels in California would require building 110 plants, each with 50 Mgge/yr capacity at a cost of $300-$500 million for a total investment of about $33 to $55 billion over 40 years.

Although water, land, and fertilizer requirements could be significant, we have limited our analysis to low-impact biomass sources. Seventy percent of the biomass in our estimates is from waste, with no additional water, land or fertilizer requirements. The remaining 30% is derived from specialized energy crops grown with low inputs (no added fertilizer or irrigation) on marginal lands.

Currently evolving definitions of renewable biomass include considerations regarding prior land use, precluding the use of land in current agricultural production. We look to newly-emerging energy crops that could tolerate arid conditions and poor soils, such as agaves and salt-tolerant grasses and trees, to avoid possible impacts on current agricultural or silvicultural land use.

Worldwide, we will not only need about twice as much energy by 2050, but in this same time period we are expected to need twice as much food we produce now. Thus, care will have to be taken to insure that we account for unwanted impacts resulting from importing biofuel and international scale-up of this technology. Efforts to increase the biomass supply to meet the emissions targets must be approached carefully with attention to all life-cycle issues and in accordance with emerging certification programs for sustainable biomass production.

Fuel Supply Research

The Energy Biosciences Institute (lead by UC Berkeley and LBNL in partnership with BP and the University of Illinois), the Joint BioEnergy Institute, and UC Davis' partnership with Chevron on fuels from biomass all illustrate how deep California's strengths are in biofuels technology and the development of new energy crops to increase sustainable biomass supplies. They play a vital role in ensuring that the state can meet its future GHG reduction goals in the critical liquid fuel supply sector. While this center conducts fundamental scientific research, it will also build operational prototype processes with direct applications to industry. UC Merced works to produce county-level maps of lands availability for biofuels production and algae biofuels.

Alternatively, continued fossil fuel use could be offset with verifiable and validated sequestration. One choice is burning carbon–neutral biomass to make electricity with carbon capture and storage to create negative emissions. This solution requires the same advances in CCS that are required for fossil fuel plus CCS and could involve the same concerns for impacts in food, water and fertilizer as biofuel production. On paper, this solution is somewhat more advantageous from an emissions standpoint than using biomass for biofuels. However, siting could be a challenge. Biomass has a relatively low energy density and high moisture content, making it expensive to transport. Thus, the utility of this approach may be limited by the proximity of the biomass to potential electric generation sites or the ability to pipe CO_2 to the sequestration site.

Hydrogen

Starting with the high efficiency case, we estimated how much hydrogen might be used if hydrogen were freely available.[28] To meet this demand we examined various sources for hydrogen. Hydrogen burns without emitting CO_2, but the hydrogen must be produced without emitting CO_2 as well. Hydrogen can be made by reforming natural gas or gasifying coal and using CCS to take care of the emissions produced in the process, or by electrolysis using low-carbon electricity. The latter option, however, would significantly increase California's 2050 electricity demand (by 350 TWh/yr, or 70%) to more than triple the 2005 levels of electricity production in order to make the required hydrogen.

28 Electrification was then applied to end uses not entirely satisfied by hydrogen, up to the levels obtained in the efficiency plus electrification base case.

4. Technology Readiness

Tables 4A, 4B, 4C and 4D summarize the technology readiness of supply technologies. The highlighted cells of the table indicate the technology invoked in our 2050 energy system portraits (mostly bins 1 and 2 technology). Table 5 summarizes required build rates. Of the electricity supply cases, nuclear power appears to be the most technically certain way of providing reliable baseload electricity if issues with cost, safety and waste can be dealt with. Fossil with CCS remains the most technically challenging way of producing baseload. A renewable energy portfolio made of mostly intermittent resources will have much larger requirements for load balancing which is not in an advanced state of deployment. A very large percentage of the technology we need for decarbonized fuel supply is in the developmental stage. Our fuel problems cannot be solved without significant new technology. Innovation will be required to make the technology available that we require for emission reductions while meeting our energy needs.

Bin	Nuclear Technology	Coal or Natural Gas CO_2 Capture	CO_2 Storage
1	Generation III+ reactors	High-efficiency coal gasification, high-efficiency natural gas combined cycle, ultra-supercritical pulverized coal combustion, solid-oxide fuel cell (SOFC), solvent separation	Injection into oil/ gas reservoirs
2	Small modular reactors (LWR)	Post-combustion CO_2 capture technologies with 80% capture efficiency, integrated gasification systems with CCS, amine solvent separation	Saline aquifer injection
3	Generation IV (including small modular Na-cooled reactors)	New capture methods with >90% effectiveness, lower cost CO_2 capture technologies of all kinds, metal-organic framework separations, membrane separation	Coal bed injection
4	None	None	Shale injection

Table 4A. Summary of technology readiness for nuclear and CCS. The technologies in the highlighted rows were invoked to develop a feasible energy system portrait for 2050.

Bin	Wind	Concentrated Solar Power (CSP)	Solar Photovoltaic (PV)	Geothermal	Hydro and Ocean	Biomass
1	Onshore, shallow offshore turbines	Parabolic trough, central receiver	Silicon PV, Thin-film PV, Concentrating PV	Conventional geothermal	Conventional hydro	Coal/biomass co-firing, direct fired biomass
2		Dish Stirling				Biomass gasification
3	Floating (deepwater) offshore turbines		"Third generation" PV		Wave, tidal and river turbines	
4	High-altitude wind			Enhanced geothermal systems (EGS)		

Table 4B. Summary of technology readiness for renewable energy supply. The technologies in the highlighted rows were invoked to develop a feasible energy system portrait for 2050.

Bin	Natural Gas	Storage	Demand Side Management
1	Combustion turbine	Pumped hydro	Commercial-scale critical peak demand response
2		"First generation" compressed air energy storage (CAES), battery technologies (Na/S, advanced Pb/Acid, Ni/Cd, Li ion as found in electric vehicles)	Commercial time-of-use demand-side management
3	Combustion with CCS in load following mode	Battery technologies (some advanced Pb/Acid, Vanadium redox, Vanadium flow, Zn/Br redox, Zn/Br flow, Fe/Cr redox, some Li ion), flywheel, "second generation" CAES	Residential time-of-use demand-side management

Table 4C. Summary of technology readiness for supply-demand balancing technologies. The technologies in the highlighted rows were invoked to develop a feasible energy system portrait for 2050.

Bin	Biofuel Technology	Hydrogen
1	Ethanol from sugar and starch (e.g., corn, sugar cane, sugar beet, wheat) Biodiesel from oil crops (e.g., FAME=Fatty Acid Methyl Ester)	Natural gas reforming, H_2 electrolysis, H_2 pipeline network
2	Cellulosic ethanol Fischer-Tropsch diesel Hydrogen-treated biomass Improved lignocellulosic and oil-crop feedstocks (Miscanthus, Jatropha, etc.)	Gasification of coal or biomass with CO_2 capture for H_2 production, CO_2 storage in saline aquifers
3	Advanced biofuels (sugar to hydrocarbons) Algal biodiesel	
4	Improved enzymes, catalysts, microbes, feedstocks	Fuel from sunlight

Table 4D. Fuel technology readiness. The technologies in the highlighted rows were invoked to develop a feasible energy system portrait for 2050.

Strategy	Assumed Plant Size	Total Plant Capacity Needed in 2050	Build Rate 2011-2050 (Plants/Year)
Nuclear	1.5 GW	44 GW	0.73
Fossil/CCS	1.5 GW	54 GW*	0.90
Renewables Mix total		165 GW**	
- Wind	500 MW	59 GW	3.0
- Central Solar (CSP and PV)	500 MW	65 GW	3.3
- Distributed Solar PV	5 kW	22 GW	110,000
Biomass/CCS	500 MW	1.5 GW	0.77
CA Biofuels	50 Mgge/yr	5.5 bgge/yr	2.8
Hydrogen		8.0 bgge/yr	
- Natural Gas Reforming	0.5 Mgge/yr	0.8 bgge/yr	40
- Central Plant	440 Mgge/yr	7.2 bgge/yr	0.41

Table 5. Summary of supply build rates required.
*Gross capacity, assuming 10% parasitic loss from CCS (net capacity = 49 GW)
**Includes geothermal and hydropower not included in this table

The 2050 Energy System Portraits

We assembled the energy system components into a series of energy system portraits that met our demand for energy and lowered emissions by a feasible amount[29]. In each case we tracked the total GHG emissions. If we take no measures, emissions are likely to double by 2050 relative to 1990 levels. If we only employ efficiency measures, we could hold emissions to about 20% over 1990 levels. We define a median energy system portrait that uses roughly equal amounts of nuclear power, CCS and renewable energy, assumes that we have solved about half the load balancing problem without emissions and the other half is done with natural gas, and assumes we can meet about half of our remaining fuel requirements with biofuel that has 20% of the carbon signature of fossil fuel. For this median system, only by employing all four strategies (efficiency, electrification, decarbonized fuel and decarbonized electricity) did we find an energy portrait that reduces 2050 GHG emissions to 150 $MtCO_2e$/yr, still about twice the emission limit specified by the target value and only 60% below 1990 levels.

Figure 5 shows emission reductions associated with the four major strategies. The left side of the chart shows 1990 emissions (targeted by AB32 in 2020), 2005 emissions, and the projected BAU emissions in 2050 of over 800 $MtCO_2e$/yr. The vast majority of these emissions come from residual use of liquid and gaseous fuel, used primarily for transportation, with some used for heat. Next are a series of energy portraits that each use only one of the four key approaches to reducing future GHG emissions. Of these four, efficiency is the largest single contributor to reducing emissions. However, no single measure can reach the emission limits. Neither can any two measures, any three measures, or even all four. The lowest 2050 emissions would be obtained by using all four measures, and even this portrait only reduces emissions to 60% below 1990 levels.

29 The determination of what is “feasible” was based on a combination of historical precedent and judgments about the technical maturity, economic prospects, ancillary impacts and required policies.

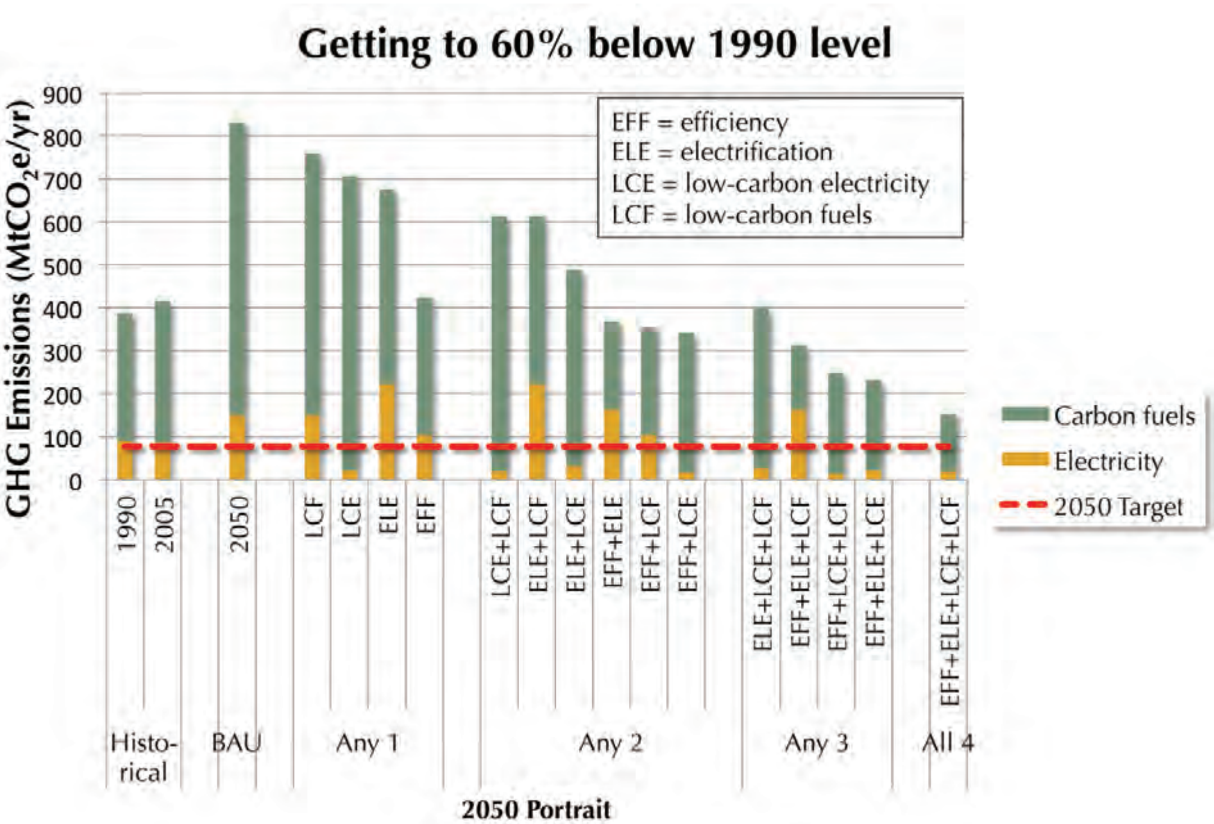

Figure 5. Using feasible technology scale-up to reach 60% reductions in emission below 1990. The red dashed line is the emission target. The figure shows the effects of using the four key strategies for reducing emisisons: efficiency, electrification, decarbonizing electricity and decarbonizing fuel. Historical and business-as-usual (BAU) emissions are shown on the left, the next group of bars shows emissions from deploying only one key strategy, then any two, any three and all four. Emissions from carbon fuels and electricity are depicted with different colored bars. Note that fuel use (green) accounts for the vast majority of emissions in almost every case.

Another way to think about this four-strategy portrait is illustrated in the diagram shown in Figure 6. Efficiency reduces both the need for electricity and fuel (grey arrow). Electrification further increases efficiency and reduces the need for fuel (blue arrow) but expands the use of electricity. Then we reduce the carbon content of the energy we use (yellow and green arrows). The carbon emitted per unit energy can be reduced much further for electricity than for fuels, mainly because biomass supplies are limited and significant usage of fossil fuels continues.

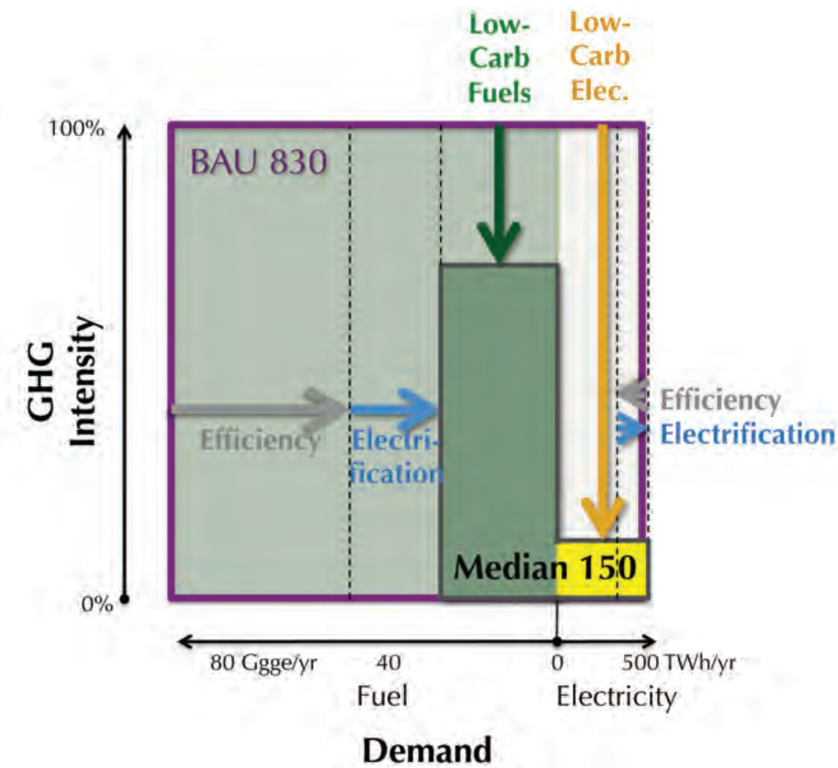

Figure 6. Strategy for reducing emissions from business-as-usual (BAU) to 60% below 1990 levels. The area of the box outlined in purple represents BAU emissions, while the smaller area of the darker colored boxes inside represent emissions in the "median" case (60% reduction below 1990). The horizontal axis indicates the relative demand for fuels and electricity, and the vertical axis indicates GHG intensity of each.

The build rates required for the median portrait are approximately 1 nuclear plant every 3 years (including retirements of older units) and 1 fossil plant with CCS every 2.5 years. These are likely to be co-located with prior nuclear or fossil power plants. Significantly more renewable power plants will be required: about 1 wind farm, 1 central solar plant, and about 40,000 distributed PV systems each year. Clearly any solution will require aggressive and expedited permitting processes to enable these build rates.

What does getting to 60% below 1990 levels look like?

- A "median" portrait that emits 150 $MtCO_2$/yr
- Efficiency + Electrification
  - Building stock 40% more efficient than today
  - 70% of heat is electrified
  - 60% of light-duty vehicles are plug-in hybrids or all-electric vehicles
  - 50% reduction in truck and aviation fuel use per mile compared to BAU
  - 30% reduction in liquid fuel, 50% reduction in gaseous fuel compared to BAU
  - Approximately double today's electricity use
- Low-carbon electricity: 522 TWh/yr
  - 95% of electricity capacity [from nuclear (31%, 22 GW), natural gas/CCS (31%, 27 GW), renewables (33%, 61 GW)
  - 5% of electricity for load balancing (from natural gas without CCS for half of the requirement)
  - Other half of load balancing provided with zero-emissions technologies such as hydropower, batteries, grid–connected controllable loads, etc. (ZELB)
- Low-carbon fuels for transportation, heat and electricity load balancing
  - Hydrocarbon fuel demand: 27.2 billion gallons gasoline equivalent (bgge/yr):
    - 11.7 bgge/yr gaseous fuel (not including 10.0 bgge/yr for natural gas with CCS)
    - 15.5 bgge/yr for liquid fuels
  - Biomass supply that can be burned directly or made into fuel: 94 mdt/yr, producing 5.5 bgge/yr biofuels plus 25 TWh/yr biomass electricity (equivalent to 2.0 bgge/yr), and an additional 7.5 bgge/yr imported biofuel. Total biofuels: 13.0 bgge/yr, with 20% GHG intensity of fossil fuels

Getting to the 80% Target (and Beyond)

We next examined further measures that would get California's emissions in 2050 to 80% below the 1990 level. In order to concentrate on the remaining problem of emissions from fuels, we assumed one electricity portfolio, the "median case" which has roughly equal amounts of nuclear power, fossil with CCS and renewables and we assumed that half the load balancing was accomplished with ZELB without emissions. We have already seen that an entirely renewable electricity portfolio is likely to exceed the emission target if load balancing is accomplished with natural gas. So, the ZELB variable has been set to "half way" as a means of roughly leveling the playing field for various methods of producing electricity, and to allow us to explore the fuel problem. As shown in Figure 7, we need to cut about 50% of the emissions in the median portrait in order to attain the carbon footprint of the 2050 goal. Nearly all these emissions are coming from remaining fossil fuel use for transportation and heat.

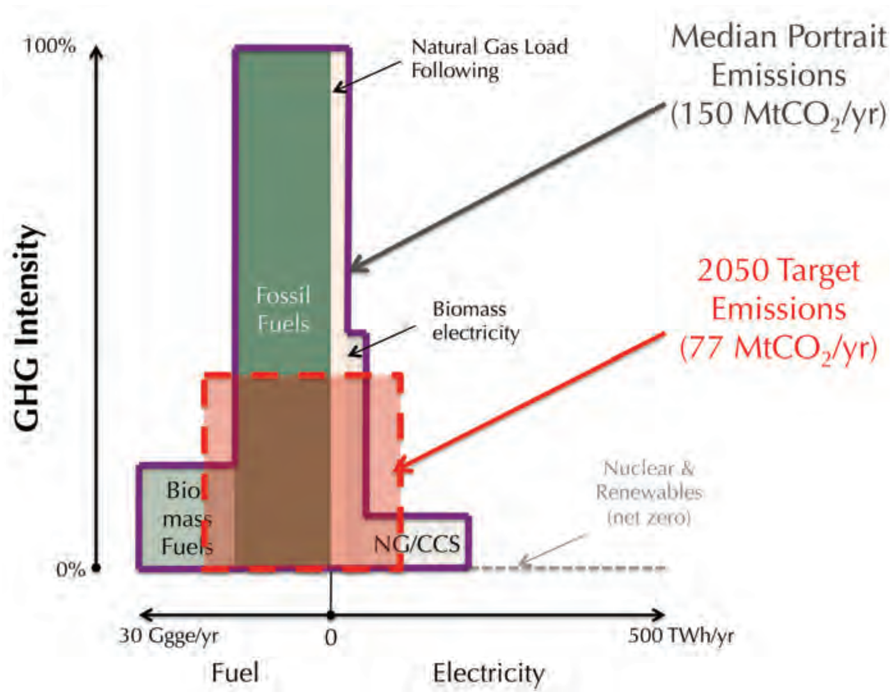

Figure 7. The difference between the carbon footprint of the median portrait and the required carbon footprint of the 2050 target. Note that remaining fossil fuel use is primarily for heavy duty transportation and heat. The horizontal axis has been rescaled from Figure 6, and areas of each component indicate their GHG emission contributions. The area surrounded by purple indicates median portrait emissions, while the area of the red box represents 2050 target emissions.

To illustrate how we might go beyond the median case, we looked at a few possible strategies. These strategies are not comprehensive and we have not evaluated their relative efficiencies or costs, but they illustrate some possible pathways with combinations of technologies that are more or less available:

1. Develop the technology to make CCS 100% effective and economical.
2. Eliminate fossil fuels with CCS from the electricity mix.
3. Increase the amount of load balancing that is achieved without emissions from 50% to 100%.
4. Produce biomass with net zero carbon emissions.
5. Reduce energy demand through ubiquitous behavior change.
6. Burn all domestic biomass supplies with natural gas and use CCS to make electricity with net negative GHG emissions, creating an offset for the required fossil fuel use. The same amount of biomass would be used as in the other portraits, and would supply about 20% of electricity demand. Imported biofuels would still be used.
7. The hydrogen case: reform hydrogen fuel from natural gas with CCS and use it to reduce fuel and electricity use.[30]
8. Increase the supply of sustainable biomass twofold, and use it to make low-carbon biofuels, using feedstocks that best fit efficient conversion to the needed energy mix.

Figure 8 shows the impact of the eight strategies on GHG emissions. Observations about specific strategies follow.

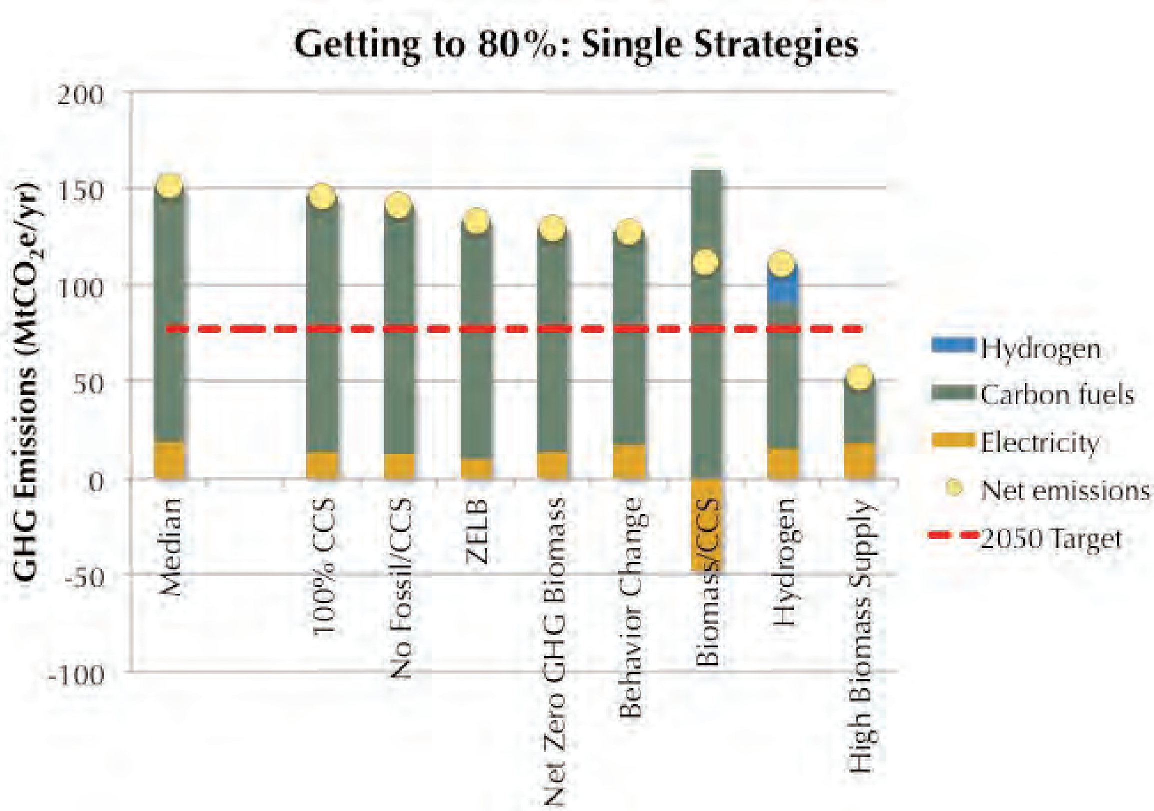

Figure 8. The effects of single strategies on reducing GHG emissions.

30 Making the required hydrogen from electricity results in a portrait with similar net GHG emissions, but is deemed more difficult due to the challenge of almost doubling electricity supply. However, if CCS is unavailable, this may be the only way to make low-carbon hydrogen.

1. Achieving CCS with 100% CO_2 removal would likely be through the use of fuel cells for generating electricity instead of thermal plants, or oxyfiring which separates out oxygen from air to burn the fuel and produces relatively pure CO_2 flue gas. While helpful, the median case only includes about 30% of fossil fuel with CCS, so it only saves roughly an additional 6 $MtCO_2$/yr and likely involves a substantial cost or power penalty and additional fundamental CO_2 capture research.
2. Eliminating fossil/CCS from the electricity portfolio would reduce emissions by 10 $MtCO_2$/yr, slightly more from than making CCS 100% effective, because it also reduces refining emissions from the production of natural gas. However, the use of fossil fuels with CCS for electricity would likely be very useful, provided CCS were successfully developed on a large scale, so would be difficult to justify eliminating it for a small reduction in emissions.
3. Achieving 100% zero-emission load balancing (ZELB) would save 18 $MtCO_2e$/yr compared with the median scenario. It might be accomplished with advanced batteries or smart grid solutions, load-following fossil generation with CCS, hydrogen generation with off-peak or renewable electricity, or carbon-neutral fuels from sunlight. However, all of these strategies are difficult with today's technologies.
4. Producing biofuels with net zero GHG emissions would save 22 $MtCO_2e$/yr, but as already discussed above in Figure 4, the amount of biomass supply has a larger effect on statewide emissions than reducing biofuel-derived emissions from 80% to 100%. Moreover, achieving this total life-cycle decrease may be technically very difficult.
5. Behavioral change including smaller houses and cars, less miles traveled, more use of public transportation, smaller industry footprints, etc., might reduce demand and lower emissions by 24 $MtCO_2e$/yr based on a 10% reduction across most sectors of the economy; studies by Dietz et al. and others indicate that even larger reductions in use (up to 20%) are possible in the household sector.[31]
6. Using biomass with CCS to produce electricity rather than fuels would save about 40 $MtCO_2e$/yr compared with the median scenario. Our calculations suggest that this option may result in lower net GHG emissions than the biofuel route, because more CO_2 can be captured during biomass combustion for electricity than is saved by using biomass-derived fuels in place of fossil fuels. It is an interesting option that deserves further examination.
7. Producing 8 bgge/yr of hydrogen and using it to run parts of the California economy would save more than 40 $MtCO_2e$/yr. However, it is challenging both from an infrastructure as well as a technology perspective, particularly for mobile uses that will consume the majority of the hydrogen in the portrait, because low-cost, high-density on-board hydrogen storage is not yet technically feasible, and fuel cell technology, while progressing, is still very expensive.
8. Doubling biofuel supply (by 188 mdt/yr or 15 bgge/yr, presumably through imports), achieves the greatest reduction in GHG emissions on its own: 99 $MtCO_2$/yr. This solution seems technically possible, but the impacts on food, water and mineral nutrients must be considered.

A combination of strategies would meet or exceed the 80% GHG reduction goal in 2050 as shown below in Figure 9. Here the impact on GHG emissions of sequentially applied strategies is illustrated. These are: burn domestic biomass (with CCS) for electricity rather than making biofuels; reform hydrogen fuel from natural gas with CCS; develop 100% zero-emission load balancing or ZELB; encourage widespread behavior change to reduce demand; increase biomass supply (as discussed above); and produce biomass with net zero GHG emissions. The application of the first two strategies could bring emissions down to the 2050 target, while the application of five or more strategies, though unlikely, could result in net emissions below zero.

31 Dietz, Thomas et al. "Household actions can provide a behavioral wedge to rapidly reduce U.S. carbon emissions." Sept. 2009. Proceedings of the National Academy of Sciences. 11 May 2011. (http://www.pnas.org/content/106/44/18452)

As well, combining the same amount of domestic biomass as in the other portraits (94 mdt/yr) with coal and CCS in an apparently highly efficient process that produces both fuel and electricity, and provides a very low emission profile while producing almost double the fuel from biomass alone, appears worthy of further examination.[32] This is done by efficiently converting the biomass and coal to "syngas" (a mixture of hydrogen and carbon monoxide) in a gasifier, making as much hydrocarbon fuel as required, burning the extra hydrogen in a turbine to make electricity, and converting the remaining carbon monoxide to CO_2 that is captured and sequestered. The technical challenges are similar to those encountered for biomass or fossil fuel electricity with CCS; the process for making fuels from syngas, known as Fischer-Tropsch, is well understood. It was not possible to estimate the GHG reduction impact precisely, but it is expected to be fairly sizable.

It is clear that the availability of sustainable biomass is an important factor in reaching the State's 2050 GHG goal. The most efficient use for different biomass types, availability of certified imported bioenergy, and proximity to meet end-use needs should be carefully considered to make the best use of available biomass. Reducing the carbon footprint of using biomass for energy is also important. Care must be taken to ensure that implementation and expansion of biomass for energy does not result in unwanted social, economic, or environmental impacts. It is possible to conceive of biomass derived energy without disastrous impacts on food supply if the biomass for energy production is limited to marginal lands, wastes and off-season cover crops, but this is not something to take for granted. Additional study of the sustainable biomass potential for energy use in California, in the context of bioenergy potential in the U.S. and globally, will be needed to thoroughly assess our options. Having alternatives to biomass for low-carbon fuel is an important hedge against the probability that there will not be enough biomass to provide all the fuel we would like. Carbon capture and storage (CCS) is likely to play a role in at least some of these alternative strategies for low-carbon fuel.

32 Guangjian Liu, Eric D. Larson, Robert H. Williams, Thomas G. Kreutz and Xiangbo Guo (2010) Making Fischer-Tropsch Fuels and Electricity from Coal and Biomass: Performance and Cost Analysis. Energy Fuels, Article ASAP doi: 10.1021/ef101184e.

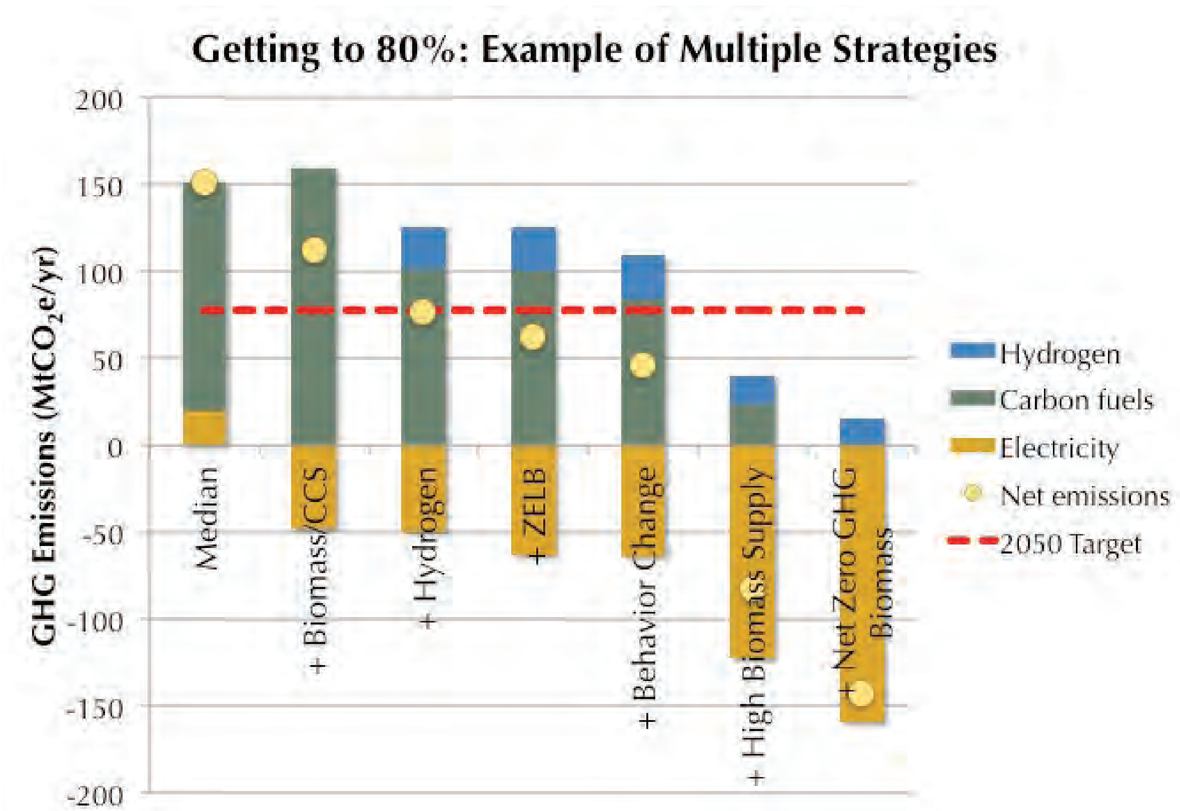

Figure 9. Example of multiple strategies that reduce emissions to 80% below 1990 levels and beyond.

Breakthrough Technology?

Breakthrough technologies -- game changers -- will undoubtedly surprise us in the next decades. These could allow us to produce fuel without emissions or provide very inexpensive carbon-free baseload electricity, making electrification adoption more successful and perhaps even allow fuel production from electricity. These technologies are unlikely to be fully deployed by 2050, although they may well start their deployment by then. Given the finite limits to other resources, these new technologies will be critical to ensuring that our 2050 GHG emissions goals are sustained well into the next century.

Energy technology for 2050 will come from around the world, but just within California institutions there is ongoing research on important breakthrough energy technologies with the potential for offering game-changing solutions to the energy problem. Most funding for this research comes from the Federal government and deserves support from the California delegation. The California Energy Commission funds critical research through the Public Interest Energy Research program for work specific to, and critical for, our state. About 25% of all U.S. patents are filed from California. We should expect our State to lead in energy technology as well.

The Joint Center for Artificial Photosynthesis (JCAP)

Fuel from sunlight could allow us to meet our needs for liquid and gaseous fuels without resorting to any fossil fuel. California Institute of Technology and LBNL share a DOE research hub on this topic. The goal of JCAP is to develop an integrated solar energy-to-chemical fuel conversion system and move this system from the bench-top discovery phase to a scale where it can be commercialized. Research will be directed at the discovery of the functional components necessary to assemble a complete artificial photosynthetic system: light absorbers, catalysts, molecular linkers, and separation membranes. JCAP will then integrate those components into an operational solar fuel system and develop scale-up strategies to move from the laboratory toward commercial viability. The objective is to drive the field of solar fuels from fundamental research, where it has resided for decades, into applied research and technology development, thereby setting the stage for the creation of a direct solar fuels industry.

Laser Fusion Energy a Potential Game Changer

California is the world leader in laser fusion energy—a potential game changer for supplying zero-carbon electricity and producing zero-carbon fuel sources such as hydrogen. To date, $5 billion has been invested in the National Ignition Facility (NIF) and its associated research and development programs, which are poised to demonstrate ignition and energy gain (producing more energy than the amount of energy used) in the laboratory by the end of 2012. When harnessed for electricity production, a Laser Inertial Fusion Energy (LIFE) power plant would be capable of supplying between 500 and 1500 MW net electricity to the grid, at very high energy density (> 1000 MWe/km^2). LIFE power production would meet baseload demand and be compatible with the existing power grid. Additional benefits of LIFE include the absence of any long-lived radioactive waste (obviating the need for geological repositories) and the inherently safe mode of operation (since there is no stored energy in the fusion system). It is also important to note that the high-temperature operation of a LIFE power plant will allow for co-generation of synthetic fuels, the production of hydrogen, and the potential for using the low grade waste heat for other industrial uses, given the ability to site these plants near load centers.

Conclusions

Overview

Our study shows that emission reductions of 80% can be achieved by 2050 with feasible technology implementation plus research, development and innovation. However, no single technological approach can accomplish this. We will require a portfolio of solutions.

As a first step, we can feasibly cut emissions to about 60% below 1990 levels with technology that is largely in use today or in a demonstration phase. From a technical perspective, we know how to do this much, but the existing policy framework of AB32 related laws and rules would need to be strengthened and supplemented with some new policies. We thus first need the societal will to implement technology that we know how to construct and deploy today.

The magnitude of the changes required and the pace of implementation will not occur without sustained and substantial capital investment and policy interventions. However, neither economic analysis of such interventions nor examination of alternative policies were within the scope of this study and should be the focus of follow-up work.

The remainder of the emission cuts to obtain the full 80% reduction below 1990 levels can also be accomplished, but this will require development and deployment of new or currently undeployed technology. Achieving this second cut will thus require a substantial commitment to technology development and innovation. To get this job done, we would have to bring technologies that are currently in the development and research stages into widespread implementation.

California can continue to be a leader in cutting GHG emissions

***California could achieve roughly 60% emission reductions of below 1990 levels with technology that we largely know about today, provided that four key strategies are implemented in a fashion that yields deployment at rates that are aggressive but feasible*:**

1. Aggressive efficiency measures for buildings, industry and transportation, to dramatically reduce per capita energy demand.
2. Aggressive electrification, to avoid fossil fuel use wherever technically feasible.
3. Complete decarbonization of the electricity supply while at the same time roughly doubling electricity production, and developing zero-emissions load balancing approaches to manage variability in loads as well as in supply.
4. Decarbonizing the remaining required fuel supply wherever electrification is not feasible.

We have to electrify the majority of end-uses that currently use fossil fuel in transportation and heat, in order to avoid emissions from that part of the energy system. If we do not at the same time institute aggressive efficiency measures, the demand for electricity would grow dramatically, to about two-and-a-half times the current level. Efficiency measures can help keep electricity demand to less than double current levels, while still supplanting fossil fuel use for transportation and heat.

We can decarbonize the electricity system using three fundamental methods of generation. Each of these methods involves very different benefits and penalties. Moreover, all generation schemes have the need for services to address load balancing, including peak loads, ramping, and firming intermittent power. Today, we largely provide load balancing service with natural gas, which produces emissions. But solutions that would reduce emissions are in development, including energy storage and smart grid solutions which include demand response, as well as the possibility of load-following fossil generation with CCS.

If we try to generate 100% of electricity with largely intermittent renewables, such as wind and/or solar, we will need a lot of innovation and systems management changes to deal with intermittent and distributed resources and to enable firming the power. We would need zero emission load balancing (ZELB) technology to work otherwise emissions from firming the power with natural gas (the primary current method) alone will nearly equal the 2050 emissions target. In order to maintain reliability and concomitantly eliminate emissions, we would need some combination of energy storage systems, the ability to capture sequester CO_2 from gas plants used to firm power, and smart grid technology to modify the demand to match load. Also, because of intermittency, we would have to build about 3 times the capacity we would need with non-intermittent power.

If we use 67% nuclear plus 33% renewables, the requirements for ZELB would be significantly less. We would have to build and permit a few tens of nuclear generation facilities, but we will have to deal with nuclear waste issues including California law which prohibits new nuclear power until a waste repository is licensed, as well as public opinion and new considerations of nuclear safety as a result of recent events in Japan.

Using 67% fossil with CCS and 33% renewable is similar in many ways to nuclear power, but we would only be able to sequester 90% of the emissions cost-effectively, and we would have to plan on using largely uncharacterized saline aquifers for CO_2 storage. Moreover, we would need to provide the pipeline infrastructure required for CCS. (As well, it may be best to reserve CCS as part of a process to make decarbonized fuel for transportation and heat.) Required generation capacity could be 10% to 25% higher than for the equivalent service from nuclear power.

To oversimplify for the purpose of illustration, the state will, at a minimum, need to overcome the legal problems with nuclear power related to the requirement for nuclear waste storage, or solve the load balancing problem without emissions for renewable energy.

If we electrify as much as we can and make all end uses as efficient as we can, we will still need about 70% of the fuel we use today, mainly for heavy duty transport and high quality heat. The use of biomass to make carbon-neutral fuel is promising and is a critical component for eliminating the use of fossil fuels. But the quantity of available biofuels is highly uncertain. The amount of biomass from low impact sources (wastes, residues, and crops grown on marginal lands without irrigation or fertilizer) that could be used for energy in California ranges from 3 to 10 billion gallons of gasoline equivalent per year (bgge/yr). However, the demand for fuel in California in 2050, even with aggressive electrification wherever technically feasible, is nevertheless likely to be three times the high end estimate of the availability of biofuels.

As well, the carbon signature of current commercial-scale biofuels is on average about 50% that of fossil fuel. With technologies in the pipeline for drop-in advanced fuels, we could lower this to 20%.

If we use a median estimate for the amount of biomass that could be used for energy – including some imports—we can thus displace about half of the remaining the fossil fuel demand.

With aggressive electrification and efficiency and:

- ***An electricity portfolio that is roughly equal parts nuclear, natural gas with CCS, and renewables;***
- ***half of the ZELB problem solved and the rest managed with natural gas; and***
- ***a median estimate for the amount of available sustainable biomass,***

we can achieve 60% cuts in emissions below 1990 levels.

California can cut emissions to 80% below 1990 levels, but this will require significant new research and development as well as deployment of the resulting technologies.

It is the remaining fossil fuel use that provides almost all of the remaining emissions. ***Thus, getting the rest of the way to an 80% reduction essentially means dealing with the problem of decarbonizing fuels.*** If we had all of the biomass that we wanted for energy, we could address all of our fuel needs in this way, including load balancing. This scenario is not completely outside the range of the possible, as there are several novel bioenergy feedstocks that could increase the potential for in-state biomass production that is economically, socially, and environmentally sustainable over the long term. However, we will want to plan for a limited use of biomass because of uncertainties around land-use and interactions with current and future agricultural and silvicultural practice. So, robust solutions to the problem will require invention, innovation, development and alternatives to using biomass for low-carbon fuel.

There are a large number of possible technologies, including some possible breakthrough technologies, which can help to solve our problem with decarbonizing fuel. If we convert as much of the 2050 fuel use as possible to hydrogen, generate hydrogen from methane and sequester the resulting CO_2, this gets us very close to the 80% cut. Adding zero emission load balancing (ZELB) or having zero emission bio-energy would then finish the job of achieving the 2050 target. Another technology which could theoretically reduce most of the remaining emissions involves burning some of the biomass to make electricity with CCS, thereby creating negative emissions. Again, with zero-emission load balancing or bio-energy with zero emissions, this gets to the target. Each strategy will reduce more emissions, and if applied in combination, could bring us below the target 2050 level. In the long run, we may learn to make fuels directly from sunlight and solve many of the emission problems this way. ***All of the approaches that will reduce emissions from 60% below 1990 levels to the target value of 80% below 1990 levels are going to require significant levels of research, technology development, invention and innovation. This part of the problem is therefore as much a technology problem as it is a policy problem.***

California needs a set of analytical tools to support strategic planning and inform strategic decision and investments. This report developed one such approach and analytical tool, which is capable of interrogating a wide range of outcomes from a variety of assumptions about our energy future. Other approaches may be available. Any tool or tool set must keep track of sources, carriers and end uses of energy and all associated emissions. Such tools could then be used to examine the impact of various energy choices, and most importantly, the tool should be capable of informing policy choices.

Although this report has shown that a number of low emission energy systems are technically feasible, the study team's analysis did not explicitly examine which of these portraits is likely to be the most advantageous and least costly for California, nor did it draw time-based roadmaps to reach the desired end state. A more detailed analysis which includes economic, strategic, and policy analyses would be the next step.

In pursuit of the 2050 target, California is capable of leading the world in energy innovation with concurrent economic benefits to the state. The 80% reduction scenario assumes innovation that can, and should, be done in California. The state needs to be aggressive in competing for Federal funds. It should also be attentive to the California investment community to insure that existing leadership is not lost by California companies, and to insure that we attract private capital to support this endeavor.

Recommendations

California is an international leader in the reinvention of energy systems and is poised to expand that leadership. AB32 and a suite of other legislation, regulations, and executive orders have provided a framework for decreasing GHG emissions from the energy system using elements of all four strategies (efficiency, electrification, low-carbon electricity, and low-carbon fuels). The AB32 family of regulations and complementary laws forms a policy framework for accelerating the development and commercialization of low-carbon technologies, and was the inspiration for this report.

The AB32 set of policies is largely premised on placing a price on carbon and utilizing performance standards. The policies include carbon cap and trade; performance standards on vehicles and fuels; renewable requirements for electricity, efficiency standards for appliances and buildings; and performance targets for metropolitan areas to reduce GHGs from passenger travel and sprawl. Other rules, such as the zero emission vehicle program, are intended to jumpstart advanced technologies and set the stage for their large scale commercialization.

Recommendation #1: Achieving more than a 20% GHG emissions reduction fron the current level

Strengthen existing AB32-related laws and rules to accelerate innovation and advance commercialization of cost-effective, advanced low-carbon technologies. Few entirely new rules or policies would be needed. What will be needed is a continual tightening of carbon caps and performance and efficiency standards, and reconciling these rules and policies to make sure that they are well aligned. For example, it will be necessary to:

1. Ensure that aggressive performance standards are aligned with price signals to customers (for instance, with pricing of vehicle use, feebates for purchased vehicles and appliances, higher prices for high-carbon electricity and fossil fuels, etc);
2. Ensure that the electricity infrastructure (e.g. vehicle recharging facilities and distribution transformers) is sufficient to accommodate the rapid adoption of electrification, including uses for vehicles as well as for heat; and
3. Continually examine the low carbon fuel standard to ensure that it adequately addresses potential impacts on water, land, food, biodiversity, and perhaps social impacts (especially for biofuels imports).

Recommendation #2: Getting to a 60% GHG emissions reduction from the 1990 level

The following 7 items represent potential policy gaps that need to be considered in order to achieve the technically feasible 60% reduction outlined in the report:

1. Ensure that all existing buildings are either aggressively retrofitted, or replaced as part of their natural lifecycle. Require rapid implementation of high efficiency standards for buildings, appliances, equipment and vehicles, to reduce energy consumption in new buildings by 80% relative to 2010. The overall energy reduction in buildings must increase to 40% or greater by 2050. Vehicle efficiency improvements and electric vehicle adoption rates need to result in a light duty fleet average of at least 72 mpgge by 2050.
2. Effect rapid and ubiquitous electrification of all technically feasible transportation and heat.

Electrify all bus and rail transportation, and 70% of building heating and cooking.

3. Ensure that new clean electricity is being developed at a rate of about 1.3 GW/yr (baseload) or 4.0 GW/yr (intermittent), so that by 2050 we have the capacity to meet twice the demand we have today from sources that all have extremely low life-cycle emissions.
4. Decide how to provide de-carbonized baseload electricity and especially whether to develop this de-carbonized electric generation system with, or without, nuclear power. To provide 67% (about 44 GW) of our electric power in 2050 with nuclear facilities would require about 30 new nuclear power plants and would require the need to manage waste (a federal responsibility). To replace this amount of nuclear power with renewable energy, the state will need to build about 110 GW of capacity (in addition to the 55 GW that would be required under the state's renewable portfolio standard) to allow for intermittency and will have to clearly commit to a plan for firming variable supply without associated emissions.
5. Fill the low-carbon fuel gap with multiple strategies, including, but not exclusively, those based on biomass. Work with agriculture to assess, increase and delineate sustainable amounts of biomass for energy. Support the development of biofuel technology to reduce the life-cycle emissions from these fuels and to reduce the land and water use associated with them. Develop import standards to prevent leakage of emissions and ancillary impacts of using biomass. Develop carbon-neutral alternatives to biofuel.
6. Advance carbon capture and storage, especially as a technology that supports low-carbon fuel production. A number of possible methods for solving the low-carbon fuel problem involve CCS, including producing hydrogen from methane with CCS, and combing CCS with biomass combustion for electricity, to achieve emission credits.
7. Develop a plan for emission-free reliable electric load balancing, including some combination of energy storage, smart grid, bio-electricity, load-following fossil generation with CCS, use of renewable hydrogen in load-following turbines for ramp-up generation, etc.

Recommendation #3: Monitor the implementation rate: actual versus what is needed

Monitor the rate of actual implementation for efficiency, electrification, clean electricity generation and de-carbonized fuel production, and provide an annual report of progress against plan, with a listing of the specific actions that are required to keep progress on target.

For example, based on the assumptions regarding population growth, economic growth, electrification and efficiency in this report, the state needs to almost double the production of electricity by 2050, and at the same time decarbonize this sector. So, we need an average of 1.3 GW (baseload) or 4.0 GW (intermittent) near-zero carbon electricity generation every year from now until 2050. In 2050, the state will also need about 70% as much fuel as we use today. We should be reducing fuel use while we substitute low carbon fuel for fossil fuel. A standard part of the Integrated Energy Policy Report (IEPR) should look at the rate of new construction and implementation compared to the needed rate and remove barriers that can be eliminated without risk to public health and safety.

Recommendation #4: Support the innovation needed to achieve an 80% GHG emissions reduction from the 1990 level

The State of California, working where appropriate with the U.S. Federal Government and industry, should foster, support and promote an innovation ecosystem in energy including universities, national laboratories, small business, innovation hubs, regional clusters, etc. The California delegation should support federal funding for this activity and the CEC should work with California institutions to develop successful proposals to harness and nucleate efforts around the energy R&D capability of the state.

Recommendation #5: Put in place the structure needed to inform future portraits

Consider the potential utility of the energy system-wide analytical tools in strategic planning and evaluate how to manage the future use of such tools to inform strategic decisions and investments. Analytic tools and methodologies such as those developed for this report should keep track of all end-use requirements, sources of energy, energy delivery mechanisms and associated emissions. The assumptions used in this report are very likely to change over time as conditions evolve and some new technologies become more realistic, and the tool can be used to examine the impact of these changes. Most importantly, the tool can help to show the system-wide effects of policy choices. For example, does a policy simply raid one part of the energy system to optimize another, or does it in fact set us on a path to reduce emissions and provide for our energy needs overall?

Recommendation #6: Maintain a long-term plan

The Governor should direct the key agencies (CEC, CARB, CPUC etc.) to jointly examine a range of pathways to determine the most desirable 2050 energy system configurations from a combination of economic, policy and technology perspectives. Interagency efforts will benefit from using system-wide analyses, such as the approach used in this study, as the basis for creating the long-term plans and near-term priorities for securing California's energy future as well as viable infrastructure pathways to get to the 2050 GHG target. A key element of the long term plan should be to maintain several future pathways, in order to maximize options under uncertainty and increase the probability that innovation may make significant contributions in the future.

Appendix A: Units and Conversion Factors and Acronyms

The following table shows the conversion between the most commonly used units in this report. Conversion was performed in order to compare different types of energy use, and in particular for estimating the total demand for fuels (both liquid and gaseous) that could be supplied by biomass:

	To Units					
From Units	**Electricity (kWh)**	**Gaseous fuel (therms)**	**Liquid fuel (gge)**	**Hydrogen (kg H_2)**	**Thermal (million Btu)**	**Biomass (dry tons)**
Electricity (kWh)	1.	0.03412	0.029567	0.030016	0.0034120	0.00036958
Gaseous fuel (therms)	29.308	1.	0.86655	0.87973	0.1	0.010832
Liquid fuel (gge)	33.822	1.1540	1.0	1.0152	0.1154	0.012500
Hydrogen (kg H_2)	33.315	1.1367	0.98502	1.	0.11367	0.012313
Thermal (million Btu)	293.08	10.	8.6655	8.7973	1.	0.10832
Biomass (dry tons)	2,705.7	92.320	80	81.21	9.2320	1.

Electricity (W, MW, GW): One hundred watts (W) is the typical power consumption of an incandescent light bulb, equal to about a 25 W compact fluorescent bulb. A household space heater can consume 1,000 W or more. Power plants are typically measured in millions of watts (megawatts or MW) or billions of watts (gigawatts or GW).

Electricity (kWh, TWh): Electrical energy consumption is measured in kilowatt-hours (kWh). One kWh is the energy consumed by 1,000 W in an hour. California's current demand is roughly 300 billion kWh (terawatt-hours or TWh) per year. This is the output of roughly 40 one-gigawatt nuclear plants operating 85% of the time.

Gaseous fuels (therms, Mtherms): One therm is equal to approximately 30 kWh of electricity. In 2005, California consumed approximately 15,000 million therms (Mtherms) of natural gas.

Liquid fuels (gge, bgge): One gallon of gasoline equivalent (gge) is, by definition, equal to one gallon of gasoline, or approximately 0.9 gallons of diesel, 1.4 gallons of ethanol, or 1.15 therms of natural gas. California's current demand for liquid fuels is approximately 25 billion gge (bgge) per year.

Hydrogen (kg H_2, MtH_2): One kg of hydrogen (H_2) is almost exactly equal to one gge. One billion kg H_2 is equal to 1 million metric tons H_2 (MtH_2).

Thermal (million Btu, TBtu): One million British thermal units (million Btu) is equal to approximately 300 kWh of electricity, 10 therms of natural gas, or 9 gge of liquid fuel. California's total energy demand in 2005 from all sources was approximately 5,000 trillion Btu (TBtu).

Biomass (dry tons, dt, mdt): One dry ton (dt) of biomass can produce approximately 80 gge of biofuels or biogas. California's biomass supply is estimated at approximately 40-120 million dry tons (mdt) per year.

Acronyms

AB	Assembly bill
ACEEE	American Council for an Energy-Efficient Economy
BAU	Business-as-usual
CAES	Compressed air energy storage
CARB	California Air Resources Board
CCS	Carbon capture and sequestration
CCST	California Council on Science and Technology
CEC	California Energy Commission
CEF	California's Energy Future
CPUC	California Public Utilities Commission
CSP	Concentrating solar power
FCV	Fuel cell vehicle
GHG	Greenhouse gas
GW	Gigawatts
IEPR	Integrated Energy Policy Report
ISO	Independent System Operator
JCAP	Joint Center for Artificial Photosynthesis
LBNL	Lawrence Berkeley National Laboratory
LLNL	Lawrence Livermore National Laboratory
LDV	Light-duty vehicles
LED	light emitting diode
LWR	Light water reactor
NIF	National Ignition Facility
PHEV	Plug-in hybrid electric vehicles
PV	Photovoltaic
UC	University of California
ZELB	Zero-emissions load balancing

Appendix B: California's Energy Future Full Committee

Jane C.S. Long (Co-chair), CCST Senior Fellow, and Associate Director at Large, and Fellow, Center for Global Security Research Lawrence Livermore National Laboratory

Miriam John (Co-chair), CCST Council Chair and Board Member, and Former Vice President, Sandia National Laboratories

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Bill Durgin, Professor, Aerospace Engineering, California Polytechnic University San Luis Obispo

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Roland Hwang, Transportation Program Director, Natural Resources Defense Council

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Mason Willrich, Board Chair, California Independent System Operator Corporation

Patrick Windham, Consultant

Appendix C: California Council on Science and Technology Board and Council members

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Susan Hackwood, Executive Director, California Council on Science and Technology

Bryan Hannegan, Vice President of Environment and Renewables, Electric Power Research Institute

Sung-Mo "Steve" Kang, Chancellor, University of California, Merced

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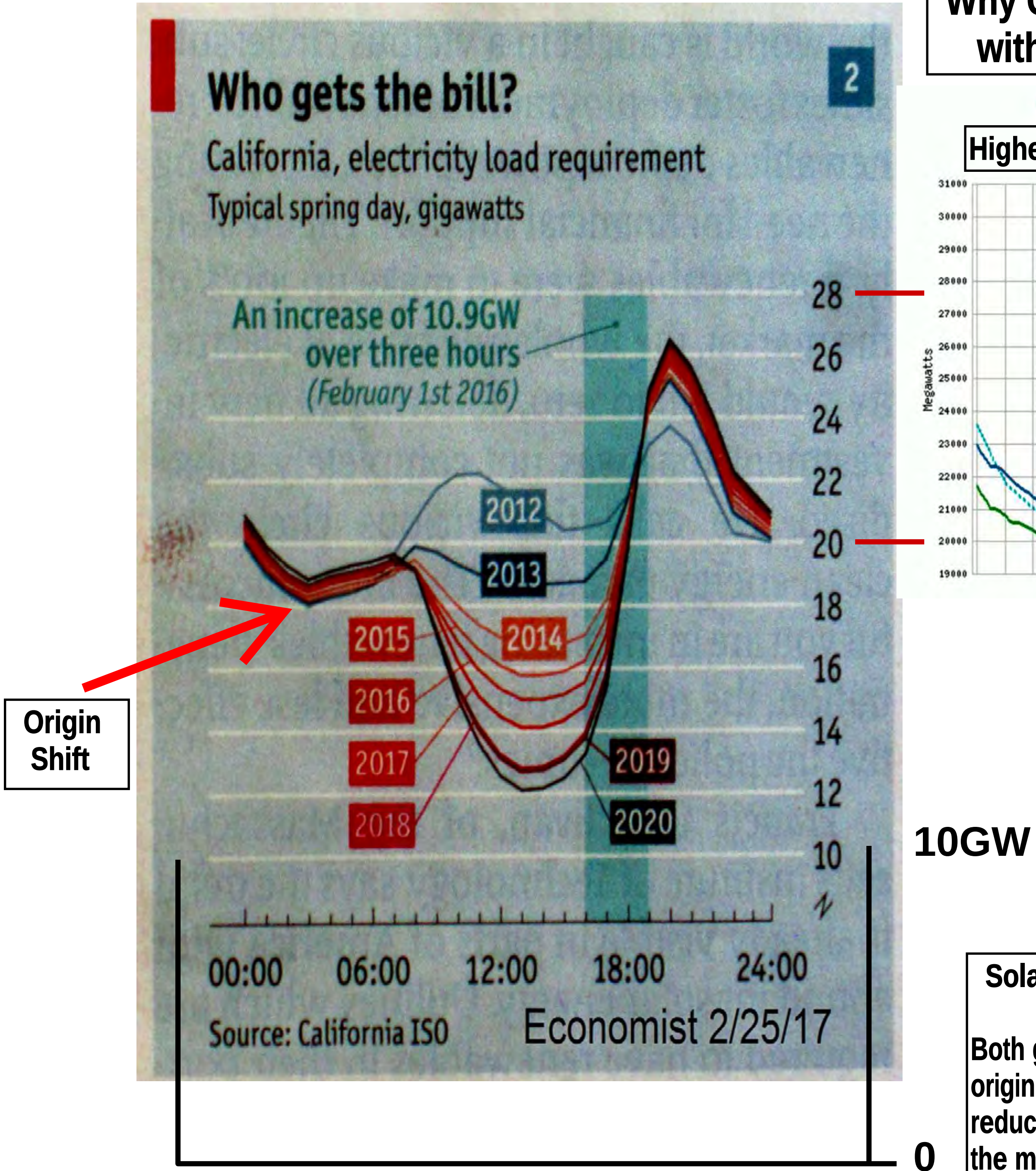
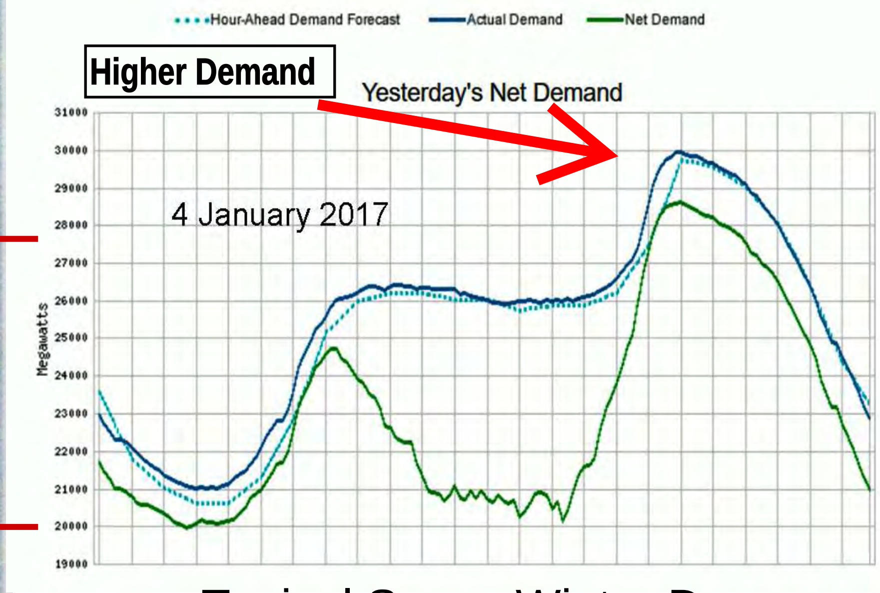
Why California Needs 24/7 DCPP Nuclear with Helms Pumped Storage (>3GW):





Typical Sunny Winter Day

Peak Demand is Understated

The 04 January 2017 peak demand is 30 GW, substantially greater than the peak demand shown in the 02/25/2017 *The Economist* article of about 26.5 GW. Solar power cannot generate any power during this time, as the Sun has either set or is about to set.

Solar Generation is Exaggerated by Origin Shift

Both graphs have been set to the same scale and origin. Net, non-solar and wind generation actually reduced mid-day demand by about 6 GW. However, the minimum demand of 20 GW has been reduced to 18 GW in the graphic

143 FERC ¶ 61,298
UNITED STATES OF AMERICA
FEDERAL ENERGY REGULATORY COMMISSION

Before Commissioners: Philip D. Moeller, John R. Norris,
Cheryl A. LaFleur, and Tony Clark.

California Independent Operator Corporation   Docket No. ER13-1372-000

ORDER ACCEPTING IMPLEMENTATION AGREEMENT

(Issued June 28, 2013)

1. On April 30, 2013, the California Independent System Operator Corporation (CAISO) filed an Implementation Agreement between itself and PacifiCorp setting forth the terms under which CAISO will modify and extend its existing real-time energy market systems to provide energy imbalance market service to PacifiCorp. This will include imbalance services to transmission customers taking transmission service under PacifiCorp's open access transmission tariff (OATT).

I. **Implementation Agreement**[1]

A. **Project Scope and Schedule**

2. According to CAISO, the Implementation Agreement establishes the scope and schedule of implementing the energy imbalance market service and requires both CAISO and PacifiCorp (collectively, Parties) to complete a variety of project tasks necessary for development and implementation of an energy imbalance market in which PacifiCorp and its OATT customers can participate by October 1, 2014. CAISO explains that the Parties chose this date to allow for completion of all necessary activities because it is outside of the summer peak operational period. CAISO states it developed the timeline for its current stakeholder process to allow for stakeholder input in developing the market design and rules, so that CAISO could file necessary tariff changes in time for a Commission decision in early 2014. CAISO notes that the necessary tariff revisions and

[1] In addition to the provisions discussed below, the Implementation Agreement includes a variety of provisions including confidentiality; limitations of liability; representations and warranties; general provisions such as notices, amendments, etc.; governing law and venue; communication; and dispute resolution. Transmittal Letter at 9; Implementation Agreement, sections 5-11.

service agreements will be the subject of the stakeholder process regarding the energy imbalance market design and rules.[2]

3. According to the Implementation Agreement, either party may propose a change in the project scope or the implementation date (as set forth in Exhibit A to the Implementation Agreement). Such a proposed change would trigger a 30-day negotiation period between the Parties in an attempt to reach agreement as to the proposal and any necessary changes to the scope and schedule, provided that any such change must be mutually agreed to by the Parties.[3] Any changes beyond Exhibit A (i.e., other than the project scope and schedule), shall be reflected in an executed amendment to the Implementation Agreement and filed with the Commission.[4] The Implementation Agreement also provides for, at least, monthly meetings of the Parties' executives, or their designees, to discuss the continued appropriateness of the project scope and to ensure that the project can meet the implementation date.

B. Implementation Fee

4. The Implementation Agreement specifies that PacifiCorp will pay to CAISO a fixed implementation fee of $2.1 million, subject to the completion of specified milestones.[5] CAISO states that this fee will be charged to PacifiCorp through five milestone payments for the recovery of the portion of the costs attributable to CAISO's configuration of its real-time energy market to function as an energy imbalance market available to PacifiCorp and its transmission customers.[6] CAISO explains that the amount of the implementation fee is based on PacifiCorp's portion of the estimated $18.3 million

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[2] Transmittal Letter at 5.

[3] Transmittal Letter at 5; Implementation Agreement, section 3.

[4] Implementation Agreement, section 3(c).

[5] The agreed-upon milestones are: a detailed project management plan by July 1, 2013; expansion of CAISO's full network model to include PacifiCorp by November 22, 2013; system implementation program improvements, including CAISO providing to PacifiCorp all final technical specifications by April 8, 2014; construction, testing and training in preparation for market simulation by July 1, 2014; and system deployment and "go live" by October 1, 2014. Implementation Agreement, section 4 and Exhibit A.

[6] On March 20, 2013, CAISO's Board of Directors authorized CAISO to enter into the Implementation Agreement and increase its 2013 capital budget by $2.1 million to account for the anticipated associated revenues. Transmittal Letter at 5.

cost CAISO would incur if it were to configure its real-time energy market to function as an energy imbalance market available to all balancing authority areas in the Western Electricity Coordinating Council (WECC).[7] In addition, CAISO maintains that it confirmed the reasonableness of the implementation fee by comparing it to an estimate of the costs CAISO projects it will incur to configure its real-time energy market to function as an energy imbalance market that serves both CAISO and PacifiCorp, prior to expansion to include other entities.[8]

5. Section 4(b) of the Implementation Agreement provides that the implementation fee shall be subject to adjustment only by mutual agreement of the Parties in either of two circumstances: (1) if the Parties agree to a change in the project scope, schedule or implementation date, and the Parties agree that an adjustment to the fee is warranted in light of such change; or (2) CAISO provides notice to PacifiCorp that the sum of its actual costs and its projected costs to accomplish the balance of the project exceed the implementation fee. Similarly, under section 2 of the Implementation Agreement, PacifiCorp may provide a notice to terminate the agreement and CAISO must discontinue work on the project and will not invoice PacifiCorp for any subsequent milestone payments. In such case, after 30 days' good faith negotiations, CAISO will invoice PacifiCorp for any milestones completed but not already invoiced.

C. Key Principles

6. The Implementation Agreement notes that CAISO will develop the energy imbalance market rules through a stakeholder process in which PacifiCorp will participate.[9] Section 14 of the Implementation Agreement states that CAISO and PacifiCorp recognize and acknowledge that adjustments in the project may be required by input received from stakeholders, conditions imposed or questions raised in the

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[7] CAISO states that it derived a rate that would allocate the projected $18.3 million to potential entrants into the energy imbalance market according to their proportionate share of the total WECC load (excluding CAISO's load) using data reported to WECC. CAISO explains that it applied this amount to PacifiCorp's share of the WECC load to obtain the implementation fee amount. Transmittal Letter at 5-6.

[8] *See* Attachment B, Declaration of Michael K. Epstein, April 30, 2013. We note that CAISO has stated that it will not incur the entire costs of expanding the energy imbalance market up front, but instead will incur these costs incrementally *if and when* the imbalance energy activity from additional balancing authority areas is incorporated into the market. *See id*. at 2.

[9] Implementation Agreement, Recital C.

regulatory approval process of the energy imbalance market rules,[10] and analyses CAISO and PacifiCorp may perform or information they receive or develop in the course of implementing the market through the stakeholder process or otherwise.

7. Acknowledging such expected adjustments, CAISO states that section 14 of the Implementation Agreement incorporates several agreed-upon key principles including: (1) the new energy imbalance market rules shall be contained in a discrete part of the CAISO tariff; (2) initial governance and market rule oversight of the energy imbalance market shall be consistent with existing CAISO governance, allow for voluntary participation and expansion of participants and market activities, and evolve based on stakeholder feedback; (3) the Parties shall consider in the energy imbalance market stakeholder process whether and how to account for transmission service; (4) the energy imbalance market shall include an appropriate means to identify transactions associated with California specific greenhouse gas compliance obligations; (5) the energy imbalance market shall be implemented in a manner compatible with existing and emerging market initiatives including the Northwest Power Pool reserve sharing program and the Commission's Order No. 764; and (6) other entities will have an opportunity to participate in the energy imbalance market within a timeframe to be determined by CAISO if the entities agree to fund their share of implementation costs pursuant to a Commission-accepted implementation agreement.[11] CAISO underscores that these principles are necessarily dependent on the outcome of the market design and development process, including input from stakeholders.[12]

8. Section 12 provides the opportunity for CAISO and PacifiCorp to work with customers in the PacifiCorp balancing authority area, or with other third parties, to ensure accommodation of their interests when the energy imbalance market is implemented. Section 13 provides that both Parties will continue to comply with their respective compliance obligations, including WECC and NERC Reliability Standards.[13]

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[10] The timeline attached to the Implementation Agreement provides for CAISO and PacifiCorp to file tariff changes to the Commission in time for a Commission decision by September 30, 2014. Implementation Agreement, Exhibit A: Project Scope and Schedule.

[11] Transmittal Letter at 7 and 8.

[12] *Id.* at 6-7.

[13] *Id.* at 8.

D. Framework to Resolve Differences

9. CAISO states that the Implementation Agreement allows either of the Parties to terminate the agreement for any reason, provided it has first entered into good faith discussions for 30 days in an effort to resolve differences.[14] The Parties also acknowledge that CAISO is required to file a notice of termination with the Commission.[15]

E. Obtaining Stakeholder Input

10. CAISO explains that following Commission acceptance of the Implementation Agreement, CAISO will continue its stakeholder process and initiate activities necessary to incorporate PacifiCorp into the energy imbalance market.[16] The Implementation Agreement allows for the termination of the Implementation Agreement upon Commission acceptance of the energy imbalance market rules and the associated tariff amendments and service agreements, which CAISO hopes to file subsequently.[17]

II. Notice of Filing and Party Filings

11. Notice of CAISO's filing was published in the *Federal Register*, 78 Fed. Reg. 28, 210 (2013), with interventions or protests due on or before May 21, 2013. Timely motions to intervene were filed by Transmission Agency of Northern California, Xcel Energy Services, Inc., the cities of Santa Clara and Redding, California and the M-S-R Public Power Agency, Bonneville Power Administration, Turlock Irrigation District, Portland General Electric Company, Alliance for Retail Energy Markets, Northern California Power Agency, J.P. Morgan Ventures Energy Corporation, Modesto Irrigation District, and California Department of Water Resources State Water Project. Motions to intervene out-of-time were filed by Arizona Public Service Company and the Northwest and Intermountain Power Producers Coalition.

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[14] Implementation Agreement, section 2(a) and section 11.

[15] Implementation Agreement, section 2(g).

[16] CAISO notes that, in parallel with its process, implementation of the energy imbalance market may require modifications to PacifiCorp's OATT. CAISO states it recognizes that PacifiCorp will be working with its transmission customers and other interested parties to facilitate implementation of the energy imbalance market. Transmittal Letter at 9.

[17] *Id.*

12. The Cities of Anaheim, Azusa, Banning, Colton, Pasadena, and Riverside, California (Six Cities) filed a timely motion to intervene and protest. Timely motions to intervene and comments were filed by Morgan Stanley Capital Group, Inc., Southern California Edison Company (SoCal Edison), Valley Electric Association, Inc. (Valley Electric), Powerex Corporation (Powerex), Calpine Corporation, Pacific Gas and Electric Company (PG&E), PacifiCorp, Utah Associated Municipal Power Systems (UAMPS), and the Western Power Trading Forum. On June 5, 2013, both CAISO and PacifiCorp filed answers.

III. Comments, Protests and Answers

13. Several of the commenters objected to section 2 (Termination) and section 4 (Implementation Charges, Invoicing and Milestone Payments) of the Implementation Agreement. Six Cities and PG&E both claim that the Implementation Agreement is not just and reasonable because section 4 imposes all the risk of overruns for estimated development costs on CAISO market participants.[18] Six Cities argues that since the expanded energy imbalance market will be based on CAISO's existing real-time market systems, which were funded by market participants, the entities that will benefit from the implementation of the expanded energy imbalance market should be responsible for the full incremental costs of the modifications.[19]

14. SoCal Edison also argues that it would not be appropriate to require CAISO market participants to pay the incremental costs associated with extending CAISO's systems to include PacifiCorp's service area. SoCal Edison asserts that the Implementation Agreement should be modified to require PacifiCorp to pay these implementation costs.[20] Both SoCal Edison and PG&E contend that the implementation fee should be viewed as an estimate and trued up based upon actual costs.[21]

15. In its answer, CAISO notes that no party challenges CAISO's evidence supporting the estimated implementation costs.[22] According to CAISO, whether the implementation fee is based on a reasonable estimate of costs is the primary issue before the Commission

[18] Six Cities Protest at 3; PG&E Comments at 4.

[19] Six Cities Protest at 3.

[20] SoCal Edison Comments at 2-3.

[21] SoCal Edison Comments at 3; PG&E Comments at 6-7.

[22] CAISO Answer at 3. PacifiCorp also asserts that no party challenges the reasonableness of CAISO's estimated costs. PacifiCorp Answer at 2.

and no party contested the reasonableness of the estimates.[23] In response to the request for a true-up based on the actual costs, CAISO argues that fixed fees have long been accepted by the Commission. Moreover, according to CAISO, the possibility that the stated rate might diverge from the actual costs does not render the rate unjust and unreasonable so long as sufficient justification is provided for the level of the rate.[24]

16. CAISO contends that the Implementation Agreement is an initial rate because it is a new service to a new customer. Thus, CAISO argues that these initial rates are appropriately based on projected costs. Furthermore, even if the Implementation Agreement is characterized as a change in rate, CAISO asserts that the stated rate can be based on projected costs if the projections are reasonable when made.[25]

17. With regard to the potential allocation of implementation costs to CAISO market participants, CAISO notes that no provision of the Implementation Agreement establishes a rate authorizing CAISO to charge any costs of its implementation efforts to its existing customers.[26] Thus, CAISO contends that these cost allocation issues are beyond the scope of this proceeding and should be addressed if CAISO seeks to recover costs from other customers.[27] Finally, CAISO also disputes the commenters' contention that they will not benefit from the implementation of the expanded energy imbalance market.[28] Similarly, PacifiCorp contends that the commenters are asking the Commission to ignore the anticipated benefits of the expanded energy imbalance market to CAISO market participants and prematurely preclude these beneficiaries from bearing costs associated with those benefits.[29]

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[23] CAISO Answer at 3-4.

[24] *Id.* at 5.

[25] *Id.*

[26] *Id.* at 6.

[27] *Id.* at 7. CAISO notes that it has committed to address costs associated with enabling the broader energy imbalance market in the proceeding where it will seek authority to implement the expanded energy imbalance market and the broader Grid Management Charge proceeding.

[28] *Id.* at 7-8.

[29] PacifiCorp Answer at 9.

18. Six Cities similarly objects to section 2, arguing that allowing PacifiCorp to terminate the agreement and avoid any costs that CAISO has not invoiced PacifiCorp for as of the termination date means that CAISO market participants are at risk for any commitments that cannot be cancelled following PacifiCorp's termination.[30] Six Cities asserts that PacifiCorp should be responsible for all necessary and unavoidable costs arising from the development of an expanded energy imbalance market.[31]

19. Six Cities and PG&E also assert that the Commission should require CAISO to publish periodic reports on the costs incurred to date, plus updated estimates for total anticipated costs for developing and implementing the expanded energy imbalance market.[32] According to Six Cities, the report also should include a breakdown of costs allocated to PacifiCorp and any implementation costs CAISO proposes to allocate to future energy imbalance market participants.[33] PG&E also proposes that CAISO be required to submit a progress report if the total costs to complete the project reach $4.2 million.[34]

20. UAMPS contends that the filing is premature and represents possibly imprudent expenditures by PacifiCorp in light of other regional proposals under development.[35] According to UAMPS, the execution of the Implementation Agreement is not necessary to CAISO's efforts to create an expanded energy imbalance market.[36] UAMPS also asserts that the filing is deficient because CAISO fails to address how the other $16.2 million in development costs will be recovered if no other participants join the expanded energy imbalance market.[37]

21. UAMPS also is concerned about the ratemaking effects of PacifiCorp's payments to CAISO, and objects to the lack of information regarding the effects on PacifiCorp's

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[30] Six Cities Protest at 4.

[31] *Id.*

[32] Six Cities Protest at 4-5; PG&E Comments at 8-9.

[33] Six Cities Protest at 4-5.

[34] PG&E Comments at 8.

[35] UAMPS Comments at 4.

[36] *Id.* at 5.

[37] *Id.* at 6.

wholesale transmission customers of the implementation of the energy imbalance market and the anticipated implementation fee payments.[38] UAMPS notes that there is no provision for a downward adjustment of the implementation fee should the development costs come in under budget.[39] Finally, UAMPS contends that CAISO failed to submit any evidence establishing the benefits of developing the expanded energy imbalance market.[40] UAMPS requests that the Commission reject the filing as premature, or, in the alternative, clearly state that the Commission's acceptance of the agreement does not constitute approval of PacifiCorp's participation in the expanded energy imbalance market or approval of the recovery of any associated costs from PacifiCorp's transmission customers.[41]

22. In its answer, CAISO contends that UAMPS' concerns are beyond the scope of this proceeding. CAISO asserts that UAMPS' speculation regarding what other parties might do is not relevant to the reasonableness of the Implementation Agreement.[42] Furthermore, according to CAISO, if UAMPS believes that the expenditures are imprudent, it can pursue that issue when PacifiCorp seeks to recover its costs.[43] Similarly, CAISO asserts that since CAISO is not proposing a broader energy imbalance market at this time, UAMPS' complaint that CAISO has failed to specify how it will recover the costs of implementing a broader energy imbalance market are outside the scope of this proceeding.[44] PacifiCorp also disputes UAMPS' contention that the execution of the Implementation Agreement is unnecessary, arguing that the Implementation Agreement provides a starting point for the detailed work involved with the development of an expanded energy imbalance market.[45]

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[38] *Id.* at 4.

[39] *Id.* at 7.

[40] *Id.* at 8-9.

[41] *Id.* at 13.

[42] CAISO Answer at 9. PacifiCorp states that its execution of the Implementation Agreement does not mean that it will no longer participate in other energy imbalance market efforts. PacifiCorp Answer at 7.

[43] CAISO Answer at 9.

[44] *Id.* at 9-11.

[45] PacifiCorp Answer at 5.

23. Morgan Stanley asserts that fundamental elements of the market design remain undefined. Both Morgan Stanley and Powerex support CAISO's request for acceptance of the Implementation Agreement, but ask the Commission not to prejudge the merits of the proposal to be developed.[46]

24. Powerex supports the initiation of a stakeholder process to develop the expanded energy imbalance market and suggests that the Commission provide guidance regarding key issues to be considered in the stakeholder process.[47] Specifically, Powerex contends that the parameters of the expanded energy imbalance market should be narrowly proscribed to provide only energy and generator imbalance service.[48] Powerex also contends that transmission pricing and transmission seams are important design issues.[49] Finally, both Powerex and Calpine are concerned that the "key principles" set forth in the Implementation Agreement were not developed by a stakeholder process and requests that the Commission state that the Implementation Agreement does not dictate the parameters of the expanded energy imbalance market.[50]

25. In its answer, CAISO avers that the Implementation Agreement unambiguously recognizes that the ultimate design of the expanded energy imbalance market will be determined through the stakeholder process and subsequent authorization and approval by the Commission and specifically acknowledges that the market rules may deviate from the principles set forth in the Implementation Agreement.[51]

26. Valley Electric contends that the Implementation Agreement should be accepted by the Commission because expansion of CAISO's real time dispatch market outside CAISO's footprint will be beneficial to all CAISO market participants and may be beneficial to the entire Western Interconnection.[52] Valley Electric asserts that participants will benefit from the diversified market created by the development of the expanded energy imbalance market and that it will facilitate the integration of large-scale

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[46] Morgan Stanley Comments at 3-4; Powerex Comments at 1-2.

[47] Powerex Comments at 5-6.

[48] *Id.* at 7.

[49] *Id.* at 8-9.

[50] Powerex Comments at 13-14; Calpine Comments at 2-3.

[51] CAISO Answer at 10-11. *See also,* PacifiCorp Answer at 10.

[52] Valley Electric Comments at 3-4.

renewable solar energy in Nevada.[53] Valley Electric believes that entities that may be skeptical of a regional energy imbalance market will be more willing to consider participation in an incremental model, and thus, the incremental model proposed has a greater chance of success than the creation of a comprehensive model.[54]

27. PacifiCorp asserts that the expanded energy imbalance market will produce benefits to PacifiCorp's customers through improved dispatch and operation of PacifiCorp's generation fleet and through efficient use of transmission facilities. PacifiCorp further contends that the expanded energy imbalance market will provide regional benefits by capturing diversity benefits and increasing the pool of resources available to obtain imbalance energy.[55] According to PacifiCorp, the expanded energy imbalance market will also improve the ability to integrate and manage variable resource deviations, smooth power flows, and strengthen grid reliability.[56] PacifiCorp contends that the justness and reasonableness of the implementation fee is supported by CAISO's estimate of the costs CAISO will incur, as well as the anticipated quantitative and qualitative benefits of the expanded energy imbalance market.[57]

28. WPTF contends that the design of the expanded energy imbalance market should include open access, comparable transmission fee treatment, transparency, proper cost allocation, recognition of capacity burdens and benefits, and careful treatment of greenhouse gas impacts. WPTF also asserts that the market design must be workable for other western market participants and not simply focus on PacifiCorp.[58]

IV. Discussion

A. Procedural Matters

29. Pursuant to Rule 214 of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.214 (2012), the notice of intervention and the timely, unopposed motions to intervene serve to make the entities that filed them parties to this proceeding. Pursuant

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[53] *Id.* at 4.

[54] *Id.*

[55] PacifiCorp Comments at 4-5.

[56] *Id.*

[57] *Id.* at 6.

[58] WPTF Comments at 3-5.

to Rule 214(d) of the Commission's Rules of Practice Procedure, 18 C.F.R. § 385.214(d) (2012), the Commission will grant late-filed motions to intervene of Arizona Public Service Company and the Northwest and Intermountain Power Producers Coalition given their interest in the proceeding, the early stage of the proceeding, and the absence of undue prejudice or delay.

30. Rule 213(a)(2) of the Commission's Rules of Practice and Procedure, 18 C.F.R. § 385.213(a)(2) (2012), prohibits an answer to a protest unless otherwise ordered by the decisional authority. We will accept the answers filed in this proceeding because they have provided information that assisted us in our decision-making process.

B. Commission Determination

31. The Implementation Agreement is a bilateral agreement between CAISO and PacifiCorp that sets forth the terms under which CAISO will modify and extend its existing real-time energy market systems to provide energy imbalance service to PacifiCorp and its OATT customers. The Implementation Agreement also provides for PacifiCorp to pay CAISO a fixed implementation fee of $2.1 million, subject to the completion of specified milestones. We find that the Implementation Agreement is just, reasonable, and not unduly discriminatory or preferential. Accordingly, we will accept the Implementation Agreement, effective July 1, 2013, as requested.

32. CAISO has stated that the implementation fee is based on CAISO's estimate of the costs it would incur if it were to configure its real-time energy market to function as an energy imbalance market available to all balancing authority areas in WECC. The implementation fee allocates a portion of that projected overall cost to PacifiCorp in an amount proportionate to PacifiCorp's benefits from the energy imbalance market, as measured by usage. In addition, CAISO has confirmed that the implementation fee amount is comparable to the estimate of the costs CAISO projects it will incur to configure its real-time energy market to function as an energy imbalance market that serves both CAISO and PacifiCorp, even without expansion to include other entities in WECC. No party has contested the reasonableness of the estimate on which the implementation fee is based. Accordingly, we find the proposed implementation fee for developing the energy imbalance market for PacifiCorp is reasonable.

33. We disagree with SoCal Edison and PG&E that the Implementation Agreement should provide for a true-up of the implementation fee. The Implementation Agreement provides for adjustment of the fixed implementation fee by mutual agreement of the Parties in the event CAISO's actual or expected costs exceed the estimate that forms the basis of the implementation fee. We expect that if CAISO approaches the cap, it will raise the issue with PacifiCorp. At that time PacifiCorp can agree to pay an increased

implementation fee or CAISO can terminate the agreement, as provided in section 2 of the agreement. In either instance, a filing with the Commission will be required to reflect such a change.[59] Thus, we find that the failure to provide a true-up provision does not demonstrate that the fee is unjust and unreasonable. Similarly, we disagree with UAMPS' contention that the Implementation Agreement must include a provision for a downward adjustment of the implementation fee should the development costs come in under budget.

34. With regard to Six Cities' concern that CAISO market participants are at risk for any commitments that cannot be cancelled if PacifiCorp terminates the Implementation Agreement, we note that the Implementation Agreement does not contain any provision authorizing CAISO to charge any costs of the expanded energy imbalance market effort to its existing customers. As such, these cost allocation issues are beyond the scope of this proceeding and should be addressed if CAISO seeks to recover costs from other customers.[60] Similarly, Six Cities, PG&E and SoCal Edison's concerns over potential allocation to CAISO customers of costs incurred in connection with the Implementation Agreement are premature. The issue is more appropriately addressed at this time in the stakeholder process.

35. We find unavailing UAMPS' assertion that CAISO failed to address how the remaining $16.2 million in development costs will be recovered if no other participants join the expanded energy imbalance market.[61] The expansion of the energy imbalance market and the resulting costs beyond PacifiCorp involvement is not being proposed at this time, so we agree with CAISO that UAMPS's concern is outside the scope of this proceeding. Morgan Stanley and Powerex's concern that the Implementation Agreement will foreclose certain energy imbalance market design issues is unfounded. According to

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[59] Implementation Agreement, section 2(g) "The Parties acknowledge that the ISO is required to file a timely notice of termination with FERC.;" section 3(c) "Changes that require revision of any provision of the Agreement other than Exhibit A shall be reflected in an executed amendment to the Agreement filed with FERC for acceptance."

[60] CAISO notes that it has committed to address costs associated with enabling the broader energy imbalance market in the proceeding where it will seek authority to implement the expanded energy imbalance market and the broader Grid Management Charge proceeding. Implementation Agreement, section 4(c).

[61] As previously noted, CAISO has stated that it will not incur the entire costs of expanding the energy imbalance market up front, but will incur these costs incrementally if and when the imbalance energy activity from additional balancing authority areas is incorporated into the market. *See* Attachment B, Declaration of Michael K. Epstein at 2.

CAISO's representations, the Implementation Agreement correctly recognizes that the ultimate design of the expanded energy imbalance market will be determined through a stakeholder process, the resulting section 205 filing to the Commission, and the Commission's ruling on that filing. We find that nothing in the Implementation Agreement prejudges or predetermines any market design issues.

36. Finally, we disagree with those commenters who recommend that CAISO make available periodic reports on the status of its implementation of the expanded energy imbalance market. We expect CAISO will keep participants informed of relevant changes through the ongoing stakeholder process. We also note that, as acknowledged in section 3(c) of the Implementation Agreement, any changes other than the project scope and schedule shall be reflected in an executed amendment to the Implementation Agreement and filed with the Commission.

<u>The Commission orders</u>:

The Implementation Agreement is hereby accepted for filing, effective July 1, 2013, as requested, as discussed in the body of this order.

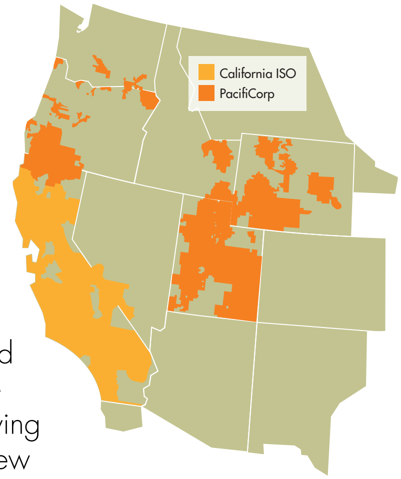
By the Commission. Chairman Wellinghoff is not participating.

(S E A L)

Nathaniel J. Davis, Sr.,
Deputy Secretary.

California ISO PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

FAQ



Expanding regional energy partnerships

WHAT HAVE THE CALIFORNIA ISO AND PACIFICORP AGREED TO DO?

The two organizations have signed a memorandum of understanding (MOU) that commits the parties to explore the feasibility, costs and benefits of full participation by PacifiCorp in the California ISO. A comprehensive benefits study is underway and expected to be completed this summer. Should PacifiCorp decide to take additional steps to pursue joining the ISO following the benefits study, a full stakeholder and regulatory review and input process would be initiated. Both organizations have also committed to work with leaders in all affected states to review issues associated with governance over a regional organization. PacifiCorp has been clear that this is a critical factor in PacifiCorp's ability to move forward with the commitments made in the MOU.

WHAT WOULD FULL PARTICIPATION BY PACIFICORP IN THE ISO MEAN?

Since the launch of the regional Energy Imbalance Market in November 2014, PacifiCorp has been participating in the ISO's 15-minute and 5-minute markets to better manage short-term fluctuations in energy supply and demand. Joining the ISO would extend this participation to the day-ahead energy market and allow for full coordination of the region's two largest high-voltage transmission grids, as well providing customers access to renewable and other power generation sources across a much broader area. PacifiCorp's retail customers in the six states it serves would still receive retail electrical serve from Pacific Power and Rocky Mountain Power.

WHAT WOULD BE THE BENEFITS OF PACIFICORP JOINING THE ISO?

While a full benefits study is underway, both organizations have realized customer benefits from increased coordination since launch of the Energy Imbalance Market last November. Significant benefits of increased regional coordination of energy generation and delivery are anticipated in three main areas:

- Reduced costs for PacifiCorp customers and ISO market participants by enhancing coordination of a broader array of resources in the day-ahead market, sharing reserve resources, and better planning and use of the regional high-voltage transmission system.
- Reduced carbon emissions and more efficient use and integration of renewable energy due to the day-ahead visibility and fully coordinated planning. For instance, when PacifiCorp's service areas are generating excess power due to hydro and wind conditions, the ISO can commit output from PacifiCorp's wind fleet to serve customers in California. Likewise, when California is experiencing oversupply situations, excess solar energy can be committed to meet customer demand in PacifiCorp's states that otherwise would be met by more expensive coal or gas generation.
- Enhanced reliability through broader visibility across grids and better planning and management of congestion across more of the region's high-voltage transmission system.

WHAT WOULD THE BENEFITS BE TO THE ISO'S EXISTING MARKET PARTICIPANT AND THEIR CUSTOMERS SHOULD PACIFICORP JOIN THE ISO?

In addition to the benefits of coordination noted above that the ISO market participants will realize, it is likely that expanding the ISO's footprint will make it easier and less costly than it otherwise would be for California to meet its renewable energy and carbon reduction goals by gaining access in the day-ahead timeframe to a larger market for the power and additional renewable energy resources located across the region.

WHAT WOULD THE IMPACT BE ON CURRENT AND FUTURE EIM PARTICIPANTS?

There is no impact to existing and future Energy Imbalance Market participants. Should PacifiCorp eventually join the ISO, it would continue participating in the ISO's real-time markets with other EIM participants. NV Energy is planning to start participation in the EIM in October 2015, with Puget Sound Energy scheduled to begin participation in the fall of 2016. The EIM will continue as voluntary, real-time regional market for existing and future participants.

WHAT ARE THE NEXT STEPS?

PacifiCorp has commissioned a feasibility and benefits study that should be finalized and publicly available this summer. If the results are favorable, PacifiCorp and the ISO would aim to reach a transition agreement later this year to fully outline the steps and timeline required for the transition. Necessary steps would include a full stakeholder process to consider the tariff, policy and process changes that are necessary to complete prior to implementation. In addition, approval would be sought from the ISO Board of Governors, the public utility commissions in the six states where PacifiCorp serves customers and the Federal Energy Regulatory Commission.

AT A GLANCE

PACIFICORP
A BERKSHIRE HATHAWAY ENERGY COMPANY

Serves: 1.8 million customers across 136,000 sq. miles in six Western states (Oregon, Washington, California, Utah, Wyoming and Idaho)

Employees: 6,000

Headquarters: Portland, Oregon

Generation capacity: 10,595 megawatts

Transmission: Over 16,300 miles of transmission lines
Over 62,930 miles of distribution lines

PacifiCorp is a wholly-owned subsidiary of Berkshire Hathaway Energy and regulated by the public services commissions in the six states it serves.

California ISO

Serves: over 30 million consumers in California and small portion of Nevada, plus the populations of the voluntary Energy Imbalance Market.

Employees: 580

Headquarters: Folsom, California

Generation capacity: 65,000 megawatts

Transmission: controls over 26,000 miles of high voltage transmission lines

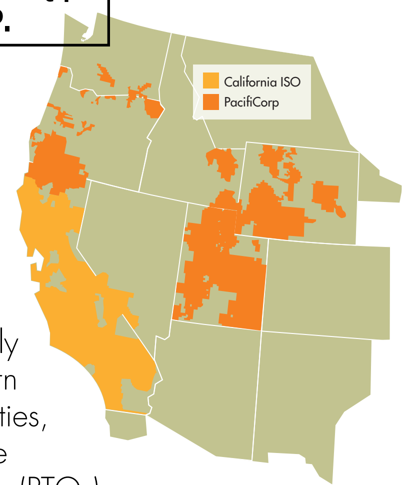
The ISO is a non-profit, public benefit corporation with an independent Board of Governors and regulated by the Federal Energy Regulatory Commission.

"Coal" appears 16 times in this 6-page document. See highlights. However the word "Audit" does not appear. PacifiCorp's 2008 "Energy Gateway" newsletter notes that there is no way to determine the source of electrons coming from the PacifiCorp's Eergy Gateway.
- GAN for CGNP

California ISO

https://www.caiso.com/Documents/ISORegionalEnergyMarketFAQ.pdf
Archived 02 24 17 by Gene A. Nelson, Ph.D. (GAN) for CGNP.

FAQ



Is the ISO merging with PacifiCorp?

No. A merger is a deal to unite two existing companies into one company. This is different; the California ISO will continue as a nonprofit public benefit corporation. This proposal would implement the same agreement the ISO currently has with other major utilities in California, such as Pacific Gas & Electric, Southern California Edison and San Diego Gas & Electric, as well as seven municipal utilities, one federal agency and four merchant transmission owners in California and one cooperative in Nevada. The entities are called Participating Transmission Owners (PTOs), and they participate in the ISO market in accordance with a Transmission Control Agreement. The agreement gives the ISO the authority to have operational control over the PTOs' high-voltage grids.

What is the current timeline on this effort?

SB 350 requires the ISO complete two tasks before the end of 2017: conduct studies on the environmental and economic impacts of a regional grid; and submit a proposal to the governor for the expanded ISO governance design. The ISO released the final study results on July 12, and submitted them to the governor's office on September 15, 2016. The ISO also drafted initial and revised proposals for governance structure, which is needed for other states to have a voice in policy-making for the new energy market. The governance proposals included input from hundreds of stakeholders in and out of California. On August 8, Governor Edmund G. Brown, Jr. announced his support for a regional grid operator, and that governance design legislation will be taken up in 2017. While the ISO had originally envisioned legislation in 2016, many stakeholders commented they needed time to fully understand the governance piece, and that there were some areas in the proposal that would benefit from more stakeholder input. The governor responded to those concerns, and the ISO, PacifiCorp and regional grid supporters are pleased with the direction, and look forward to developing a strong proposal for consideration by the Legislature in January. It is still important to regional grid supporters to stay focused and move forward, as the new market is seen as critical to California reaching its 50-percent renewable goal, and there is potential market competition from other grid operators in the Midwest to expand into western states.

Who would govern the ISO if it becomes a full-time day ahead regional energy market?

As envisioned in the ISO's latest revised proposal on principles for governance of a regional ISO, the ISO would be governed by an independent board that would be selected in a process determined by participating western states and stakeholders. The ISO proposed a set of principles for regional ISO governance after many months of consideration of various white papers and testimony from state energy leadership and a broad range of stakeholders from California and across the West. The ISO presented this proposal at two public workshops, Sacramento and Denver, on June 16 and June 20 respectively, with 42 sets of comments submitted by July 7. The ISO considered the feedback and presented a revised proposal at a joint state agency workshop on July 26. Click here to visit the California Energy Commission's webpage dedicated to this effort, and sign up to receive docket notices.

What layers of oversight have been put in place to ensure California, and other states' interests, would be protected under a regional ISO governance model?

A regional ISO allows for the preservation of state authority over each state's energy policies. This key principle is supported by all states and stakeholders engaged in this process. While significant, although limited, market issues are of shared interest amongst states, the proposal suggests that these issues be the primary authority of a Western States Committee, comprised of state's energy leadership and other key stakeholders. The ISO is also suggesting that a Transitional Committee develop the details of the governance structure, adhering to the principles set forth in legislation, and that committee's proposal would need certain state and FERC approvals before implementation could occur.

How are technical challenges regarding the shaping of the new grid being reviewed and solved?

While the governance design keeps moving toward state legislation in 2017, technical issues already are being evaluated and discussed by the ISO, stakeholders and existing and potential market participants. Currently, three stakeholder initiatives are underway to do a detailed analysis on the inner workings of the new grid: Transmission Access Charge options, Regional Resource Adequacy, and Metering Rules Enhancements. An initiative on Greenhouse Gas Emissions accounting will soon be launched. So the two components, governance and stakeholder initiatives, are on separate but parallel tracks. The governance component will provide a strong framework for decision- and policy-making, while complex technical pieces are resolved through the ISO's stakeholder process.

If the regional energy market is created, would California cede its authority to control its energy to the Federal Energy Regulatory Commission (FERC)?

No. The ISO is already under FERC's jurisdiction, and that would not change with a regional energy market. The ISO would also continue to remain subject to the grid standards established by the North American Electric Reliability Corporation (NERC) and its reliability coordinator, the Western Electricity Coordinating Council (WECC). Under a regional grid the Legislature, the Public Utilities Commissions, and local regulatory bodies will continue to maintain the authority and ability to dictate procurement decisions over the state's utilities as it does today.

Why is a governance change necessary when PacifiCorp and other out-of-state utilities are already buying and selling power through the ISO's Energy Imbalance Market (EIM)?

There are significant differences between the real-time EIM, and becoming a PTO with the full services of the ISO, including a day-ahead regional energy market serving about 95 percent of California's load. The EIM is voluntary, and is limited to balancing real-time demand for electricity with supply every 15 minutes, while dispatching the least-cost resources to meet that demand every five minutes. A full-service day-ahead regional energy market offers more comprehensive benefits, as the ISO would have full visibility of markets and networks, and could optimize all the available transmission capacity and generation – across a wider geographic area and using an expanded resource pool – in the day-ahead market to deliver the lowest cost energy to consumers. It also would allow the ISO to better plan for regional transmission projects and the efficient interconnection of renewable resources and avoid what a utility might have to provide for if it were to stand alone. The current governance structure of the ISO, including the newly formed EIM Governing Body, provides an appropriate voice in EIM-related issues and gives primary authority over market changes related to EIM. Without changes to the ISO Board and governance structure, non-California utilities have stated they have no interest in entering into a Transmission Control Agreement with the ISO. The differences between EIM and regional expansion was discussed on a public conference call on Wednesday, February 10, 2016. Click here to view the presentation.

What steps did the ISO take to ensure the SB 350 study process was transparent and inclusive?

Since the beginning of the study process, the ISO has been committed to hosting a robust, open and inclusive process. All meeting notices, documents and comments received were sent directly to stakeholders through public market notices as well as posted on the ISO's public website. The ISO has been active in encouraging stakeholders, consumer and environmental groups and everyday consumers to engage with us to ask questions, seek information and provide comments verbally and in writing. Some other important information to note:

- Over 1,400 stakeholders have participated in the process. All meetings have been publicly noticed and have been well attended. The ISO has made it easy to submit comments and share feedback. We have notified interested parties of next steps at each stage of the study, so they could plan their participation.
- The ISO has taken public feedback into consideration in crafting our governance proposal. This included adjusting its process and modeling assumptions. It has been transparent in its communication with stakeholders.
- The ISO discussed the framework, analysis and data with stakeholders on February 8 to ensure the study had an effective launch.
- When the ISO completed preliminary results of its studies on May 20, it made them publicly available and conducted a two-day workshop on May 24 and 25 to solicit public input. The results were posted on the ISO's public website.
- The study results summary is meant to provide a detailed overview of the findings. The final report, nearly 700 pages, provides significant details in the six areas of analysis. More than 3,000 megabytes of raw data is posted on the ISO website, and we clearly communicated with the public that confidential data can be obtained by executing a non-disclosure agreement and to email us with their request.

What did the SB 350 studies find?

The final study results show that by expanding the energy grid, California would reach its 50 percent renewable energy goal while saving consumers up to $1.5 billion annually by 2030, lowering greenhouse gas emissions and adding jobs in California.

Other potential effects of a regional energy market include:

- Creation of 9,900 to 19,400 new jobs in the state by 2030, primarily as a result of lower energy rates;
- A slight increase in the state's household income of $300 to $550 on average by 2030;
- Increased investment in low-cost clean energy generation, including new wind and solar resources to meet the state's renewable energy targets;
- Reduced emissions of carbon dioxide, nitrous oxide, sulfur dioxide and hazardous particulate matter in California and across the western states;
- Economic benefits to disadvantaged communities, including stimulating job growth and increasing incomes;
- Lower energy costs due to load diversity that results in smaller operating reserves requirements;
- Better real-time visibility of system conditions in the larger geographic footprint and enhanced management of regional power flows; and
- Increased integration of renewables and reduced need for curtailment of renewable resources by offering excess energy across the West.

The ISO has made more than 3 gigabytes of underlying data used for the studies available.

Why do I have to sign a nondisclosure agreement to access some of the raw study data?

A nondisclosure agreement is required to comply with the ISO's rules regarding market-sensitive information. Some of the data is critical energy infrastructure which the National Electric Reliability Corporation (NERC) requires entities to maintain sensitive information as confidential. Because this information has the potential of influencing market prices or could compromise national security, it is important for the ISO to know who is accessing this data and restrict its use.

One stakeholder claims that the SB 350 study findings show the regional energy market will increase greenhouse gas emissions. Is that true?

No. The study shows that in 2020, there's a potential for a fractional increase as the regional market just begins operating. That result stemmed from some limitations in modeling for individual generator characteristics and imports to California, and lack of increase in renewable generation. However, once the market is in full swing, there is a substantial carbon emission reduction in a regional market compared to the California-only system. By 2030, as renewable development increases to 50 percent under the regional market, the results show a carbon emissions reduction of 8 to 10 percent annually for California, and 3.5 percent for the western states. The projected reduction for California in 2030 is about 40 times that of the small increase in year one.

PacifiCorp still has a large coal fleet. How can the ISO assure that the regional energy market won't facilitate the transmission of more coal into California?

Regional coordination will displace coal and carbon generation from PacifiCorp for two main reasons: California's policy adds a fee to carbon coming into the state; and the market is designed to dispatch the lowest cost resource. These two factors working together mean coal resources will be at a price disadvantage in the market, automatically reducing or eliminating coal from the market. Over time, that will decrease coal output, as the business model will not be sustainable. Under a day-ahead regional energy market, this dynamic can repeat itself during a 24-hour cycle. For example, when California is experiencing oversupply situations, excess solar energy can be committed to meet customer demand in PacifiCorp's states, which allows backing down or not even starting more expensive coal or gas generation. Likewise, when California is experiencing peak electrical demand later in the day, it can tap into PacifiCorp's large wind fleet to serve consumers.

There is evidence that this market structure already successfully displaces coal in the EIM. A 2015 report on coal use in the EIM shows that zero, or less than 1 percent of monthly energy supplies were generated from coal. Click here to view the report (see page 40). Rather than increasing coal generation, a regional energy market with PacifiCorp's full participation in the ISO would result in coal generation being displaced by a more comprehensive optimization of renewable and transmission resources across a broad region and decrease emissions for the West.

California has established policies to prevent more coal-generated energy from coming into the state. However, other states do not have those policies and may be fine with coal coming in. How can the ISO assure that its technology won't be used to help PacifiCorp shuffle its coal around to other states?

PacifiCorp wants to join the ISO because it is committed to reducing its coal fleet and is already investing in various forms of renewable energy. In fact, because of the steps it has already taken, PacifiCorp's carbon emissions in 2016 are approximately 18 percent lower than the average of its previous five years. It is expanding its portfolio of renewable resources, both directly and through power purchase agreements. It is the second largest owner of wind generation assets among regulated utilities in the United States. Renewable and non-carbon resources currently make up 25 percent of PacifiCorp's owned and contract generation capacity. Within the next two years, PacifiCorp plans to add even more new wind and solar capacity via purchase power agreements with independent power producers.

Here are some facts about its portfolio.

- PacifiCorp has 34 megawatts of geothermal.
- PacifiCorp has 951 megawatts of contracted solar expected to come online by the end of 2017.
- PacifiCorp has more than 42 megawatts of customer solar generation in Pacific Power service area.
- PacifiCorp has partnered with dozens of developers to help deliver more solar generation to its customers.
- PacifiCorp is adding to its solar generation in Oregon with a contract for a new 5 MW facility in Bly, which will be the largest solar generation facility in the state.
- PacifiCorp supported efforts to create a 50 percent RPS goal in the state of Oregon

Joining the ISO as a full participant will allow PacifiCorp to invest even more heavily in renewable energy. Using the ISO's advanced dispatch increases the efficiency and cost competitiveness of renewables. Since three of the six states that would be joining the regional energy market already have an RPS policy, as a market participant, PacifiCorp would have an incentive to continue investing and expanding its portfolio of renewables across its entire service area.

How will California's climate and environmental policy goals be protected in a regional market?

Senate Bill 350 (2015) explicitly calls for California to get 50 percent of its electricity from renewable energy by 2030 with clear milestones that include satisfying 33 percent of its retail electricity sales with renewable energy by 2020. The policy objective is clear—increase renewables and reduce carbon emissions.

Is California at risk of having to pay a significant share of new transmission facilities built in the PAC sub-region?

If the ISO forms an expanded balancing authority by integrating PacifiCorp, then each of the current areas would become a "sub-region" of the expanded "region." Also, once the expanded balancing authority is formed, the ISO would initiate an integrated transmission planning process (TPP) for the entire expanded area. To begin consideration for "regional" cost allocation – i.e., cost allocation to multiple sub-regions – the transmission facility must be planned under the new integrated TPP. Second, for new facilities that meet this first requirement, the ISO will perform an assessment of the monetary value of economic benefits each of the sub-regions would receive from the facility. This means that in order for the current ISO area to be allocated any costs of a new transmission facility built in the PacifiCorp sub-region, the benefits assessment under the integrated TPP would have to demonstrate that the current ISO area receives economic benefits from the facility, and then the amount of cost that could be allocated to the current ISO area would be commensurate with its share of the economic benefits.

Is this proposal trying to resurrect a plan from 20 years ago to expand California's power grid?

No. Much has changed in energy over the past 20 years. Technological advancements, load growth, and billions of dollars in grid upgrades have brought us to the point that we can use our state-of-the-art market platform to tap economies of scale to generate significant cost savings in producing and delivering energy. This effort to evolve the ISO into an organization that can serve the West is being driven by a provision in SB 350 (2015) that requires California to achieve a 50 percent renewable portfolio standard by 2030. It is also being driven by western utilities' need to integrate more renewables to meet their own state mandates for clean energy. In addition, the cost of building renewable resources is competitive with traditional forms of resources, and the energy from sun, wind, biomass and geothermal sources is virtually free, which creates a strong business case for utilities to pursue. Renewables are not only cleaner, but more cost-effective sources of energy. These major policy drivers are being experienced throughout the country and around the world.

Does this proposal increase California's risk of having another electricity crisis?

No. The California markets have been completely reworked and now have stringent safeguards to prevent the market manipulation that exacerbated the previous issue. In the past 16 years since the California energy crisis, more transmission has been added to reduce congestion and generators must comply with strict rules to offer their energy into the market for resale. In addition, independent market monitors watch market participants and their bidding behaviors closely to detect attempts to circumvent the new strong rules or covertly game the market. Additionally, the California Public Utilities Commission and other local regulatory authorities enforce resource adequacy rules that ensure sufficient capacity is made available to the ISO to meet load under a variety of conditions. That same market design would be maintained and only spread over a larger geographical footprint.

Will the expansion of the grid result in more gas burning in disadvantaged communities?

The SB 350 studies show that a regional energy market will reduce emissions of GHGs and other air pollutants in California by 2030, including disadvantaged communities. In fact, the studies show that air basin in disadvantaged communities in California in 2030 would have the lowest emission rates if the ISO is expanded to western states.

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American Clean Skies Foundation (ACSF)
The American Clean Skies Foundation is an independent nonprofit working for cleaner, lower carbon energy uses in the U.S. transportation and power sectors. To advance its mission, the Foundation encourages large scale fuel switching (e.g, greater use of renewables and natural gas) for electricity generation through innovative regulatory and business initiatives. ACSF also works to advance the deployment of alternative fuel vehicles with public purchasing reforms and regulatory interventions. The Foundation is based in Washington D.C. and has a field office in San Francisco.

American Wind Energy Association (AWEA)
Since 1974, AWEA has advocated the development of wind energy as a reliable, environmentally superior energy alternative in the United States and around the world. With over 2,000 members and advocates, AWEA is the hub of the wind energy industry. AWEA is a national trade association representing wind power project developers, equipment suppliers, services providers, parts manufacturers, utilities, researchers, and others involved in the wind industry — one of the world's fastest growing energy industries.

Berkshire Hathaway Energy
Berkshire Hathaway Energy owns a portfolio of locally managed businesses that share a vision for the energy future, make sustainable investments to achieve that vision, and had $70 billion of assets as of Dec. 31, 2013. These businesses deliver safe, reliable service each day to more than 8.4 million customers and end-users around the world and consistently rank high among energy companies in customer satisfaction. Berkshire Hathaway Energy is headquartered in Des Moines, Iowa, U.S.A.

BrightSource Energy Inc
BrightSource Energy, Inc. develops, builds, owns, and operates large-scale solar plants that reliably deliver low-cost solar energy to industrial and utility companies worldwide. BrightSource Energy's proprietary Luz Power Tower (LPT) 550 technology seeks to offer the highest operating efficiencies and lowest capital costs in the industry. Its solar plants are designed to minimize environmental impact and help custom¬ers reduce their dependence on fossil fuels. When completed, their Ivanpah project in California's Mojave Desert will be the largest solar thermal plant in the world.

CYRQ Energy
Headquartered in Salt Lake City, Utah, Cyrq is a renewable energy company with geothermal interests in both generating and/or supplying energy to California, New Mexico, Utah, Oregon, Nevada and Indonesia. Currently under a 20-year contract with SMUD, Cyrq provides geothermal energy from its Patua plant in Nevada. The Patua plant produces up to 25 MW of geothermal energy and provides renewable energy power for up to 20,000 homes.

Duke-American Transmission Company
DATC is a transmission developer jointly owned by Duke Energy, the largest utility in the U.S., and American Transmission Co., a national leader in transmission development. Formed in 2011 to plan and develop strategic transmission projects across the U.S. and Canada, DATC partners share the same vision for transmission development.

EDF Renewables
EDF Renewable Energy, a subsidiary of EDF Energies Nouvelles, is a leading U.S. independent power producer boasting 30 years of experience across a broad spectrum of services. Our core competencies in Project Development, Operations and Maintenance, and Asset Management enables us to ensure each project we touch performs at the highest level possible.

EDP Renewables
EDP Renewables (Euronext: EDPR) is a leading, global renewable energy company devoted to value creation, innovation and sustainability. We operate in markets around the globe and are continuously expanding our business to new regions, making the commitment to lead in each market as well as create value for our stakeholders and shareholders.

Energy Source
Energy Source is a turnkey implementer of comprehensive energy savings projects within the Commercial, Industrial, Hospitality, Retail, Education and Municipal sectors. We have been in the industry for over 20 years, and understand the nuances of delivering savings to our customers. Energy Source works closely with our clients to identify energy conservation opportunities from "broad stroke" identification through actual implementation of projects. Our services also include obtaining all applicable incentives for our clients, this helps to reduce simple paybacks and maximize Return On Investments (ROI's).

EnerNOC
EnerNOC is transforming the way the world uses energy. The company helps commercial, institutional and industrial organizations use energy more intelligently, pay less for it, and generate cash flow that benefits the bottom line. Its technology-enabled energy management solutions help meet the needs of utilities and grid operators that deliver energy and are responsible for maintaining the real-time balance between supply and demand.

Environmental Defense Fund
Environmental Defense Fund is a leading national environmental organization representing more than 400,000 members. Since 1967, EDF has linked science, economics and law to create innovative, equitable and cost-effective solutions to society's most urgent environmental problems. EDF is one of America's most influential environmental advocacy groups, with over 500,000 members and more than 350 scientists, economists, attorneys and other professionals on staff.

Fuel Cell Energy
FuelCell Energy, Inc. is an integrated fuel cell company that designs, manufactures, installs, operates and services stationary fuel cell power plants. As a leading global fuel cell company, we provide ultra-clean, efficient and reliable baseload distributed generation for electric utilities, commercial and industrial companies, universities, municipalities, government entities and other customers around the world.

GE Energy
We are here to solve the most complex challenges across the globe. With a full array of advanced power generation and energy delivery technologies, we work collaboratively with customers to drive growth & progress, anticipate energy needs of the future, and power a cleaner, more productive world.

Geothermal Resources Council
With the experience and dedication of its diverse, international membership and a 40-year plus track record, the Geothermal Resources Council (GRC) has built a solid reputation as the world's premier geothermal association.

Iberdrola Renewables
Iberdrola Renewables, an Oregon-based company, specializes in providing alternative energy solutions to large corporate customers. Iberdrola Renewables is able to work with wind energy, natural gas, energy and asset management, and fuel procurement. Iberdrola Renewables is unique in its ability to make available a wide variety of services and products to meet a customer's specific needs.

Natural Resources Defense Council (NRDC)
The Natural Resources Defense Council (NRDC) is a national nonprofit environmental organization. NRDC has more than 350,000 members and contributors nationwide, and a staff of lawyers, scientists, and other environmental specialists. NRDC's Energy Program works on the reinvention of the electric industry by helping to rewrite the rules of electric competition; works for the adoption of energy-efficient codes for appliances and buildings; and promotes renewable energy technologies and design standards for "green" buildings. It also works on issues of sustainable land use; clean vehicles, and clean transportation infrastructure/smart transit.

Pattern Energy
Pattern Energy has a portfolio of 17 wind power facilities, including one it has agreed to acquire, with a total owned interest of 2,554 MW in the United States, Canada and Chile that use proven, best-in-class technology. These facilities generate stable long-term cash flows in attractive markets that have strong growth potential. Each of our facilities has contracted to sell all of its energy output, or a majority, on a long-term, fixed-price power sale agreement. Eighty-nine percent of the electricity to be generated by our facilities will be sold under these power sale agreements, which have a weighted average remaining contract life of approximately 14 years.

Pure Resource, LLC
Provide consulting services regarding renewable energy project development and the sale and purchase of renewable energy to project developers, utilities, energy retailers, private and public companies, land owners, regulators, and legislators.

Renewable Northwest Project
In 1994, a broad coalition of public-interest organizations and energy companies created the Renewable Northwest Project (RNP) to actively promote development of the region's untapped renewable resources. RNP has proven to be a forceful advocate for expanding solar, wind and geothermal energy throughout Oregon, Washington, Idaho, and Montana. RNP works on three strategic objectives: 1) to encourage the development of new renewable projects; 2) to promote policies that support additional renewable resource development; and 3) to help build a credible green market in the region.

Sacramento Municipal Utility District (SMUD)
The Sacramento Municipal Utility District was founded with the idea that providing electric power to Sacramento was a job best done by a public utility overseen by an elected board of directors. As the sixth largest publicly owned utility in the country in terms of customers served, its innovative energy programs are known throughout the state, nation and world. SMUD's purpose is to provide solutions for meeting its customers' electrical energy needs. Its vision is to be a leader in customer satisfaction and a positive force in promoting community benefits.

SunPower Corporation
Since 1985 SunPower has been leading global solar innovation. SunPower solar panels consistently deliver more energy and long-term peace of mind with the highest performing solar power systems available. SunPower is the solar energy choice of more homeowners and businesses around the world.

Union of Concerned Scientists (UCS)
At the Union of Concerned Scientists, we put rigorous science to work to build a healthier planet and a safer world.

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