Policies for California's Energy Future - How to Choose a Climate Friendly Electricity System for the Future

California Council on Science and Technology

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Policies for California's Energy Future – How to Choose a Climate Friendly Electricity System for the Future

A technical paper of the California's Energy Future Committee

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How to Choose a Climate Friendly Electricity System for the Future

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Abstract

California must nearly eliminate emissions from electricity to meet ambitious climate goals for 2050. The state could generate emission–free electricity three ways: renewable energy, fossil fuel with carbon capture and storage, or nuclear power. The issues associated with two canonical portfolios, one that is all renewable energy and one that is equal parts of all three sources cover the landscape of issues for any combination of sources. The types of critical key issues that affect implementation of these choices include: The full system requirements for running a reliable electricity system, the rate at which these systems could be built out relative to the 2050 target, and the costs associated with each portfolio. Each of the three sources of electricity has problems. Ancillary system requirements for intermittent renewables present a challenge. Lack of public support for nuclear, and dependence on a robust carbon market for CCS as well as lack of experience with industrial relationships and certification of storage stand in the way of these technologies. We conclude all of the options are uncertain and consequently, having more options available and the implications of these options better understood could be critical factors in achieving good outcomes for the State. Additional focus on the total system requirements for a strong renewable portfolio and efforts to keep CCS and nuclear options available could be of some value.

Introduction

California is on a path to significantly reduce greenhouse gas emissions by 2050. AB32 requires the state to reduce emissions to 1990 levels by 2020. By executive order, the state is also to reduce emissions by 80% below 1990 levels by 2050. This report examines the critical issues associated with two fundamentally different pathways that could eliminate emissions from electricity portfolios, necessary to facilitate overall economy-wide de-carbonization by 2050 in California.

The California's Energy Future (CEF) committee of the CCST studied the technical feasibility of reducing emissions in California by 80% below 1990 levels by 2050 (see http://www.ccst.us/publications/2012/2012ghg.php). The CEF study concluded that electricity would need to be almost completely decarbonized to make this goal. The study identified a number of 2050 electricity portfolios that would largely eliminate emissions from the electricity system while meeting expected growth in demand from increasing population, economic growth and electrification of as much transportation and heat as possible while assuming that aggressive efficiency measures were also taken. Although a wide variety of electricity choices is possible, perhaps the two most widely differing portfolios are one that is essentially all renewable power and one that is roughly an equal a mix of renewable energy, fossil energy with carbon capture and storage, and nuclear power—called "the median case". These two portfolios present very different implications and requirements. The all-renewables portfolio conforms to the policy direction in the state but would require that the electricity system be operated in a very different manner from today, whereas the median portfolio would require a concerted change in California policy on nuclear power and a new focus on carbon capture and storage, although the operation of the system would be much closer to that of today. Thus, these two portfolios provide bookends for the types of systems we might consider in California.

Any choice, including these two, will require concerted planning and early strategic investments. We should know what has to happen, what has to be gotten right and what must be accomplished in the near-term in order for California to be on track for a decarbonized electricity portfolio in 2050. The answers to these questions will differ significantly depending on the pathway chosen and there are near-term choices that foreclose options in the future. Relevant criteria for comparing pathways should include reliability (referring to the ability of supply to meet demand at all times), carbon performance, cost, and secondary impacts, such as land and water use. The purpose of this report is to describe many of the most important issues that will impact this choice. Many issues require further efforts to resolve. As such, this report can be seen as a research agenda to support electricity choices in the future.

The Two Electricity Portfolios

The All Renewables portfolio and the Median portfolio were described in the CEF reports available at http://www.ccst.us/publications/2011/CEF%20index.php and are reiterated here. The CEF report, as well as reports by E3[1] and the UC Berkeley/LBL "SWITCH" team[2] found that meeting the aggressive 80% reduction target requires electricity to do more than its share of reductions. Both these reports found that nearly complete elimination of emissions from the generation of electricity would be required. The CEF study made a single estimate of population and economic growth that would in a business-as-usual (BAU) scenario more-or-less double the demand for electricity. Through aggressive actions to reduce energy intensity (which reduces electricity demand) and deploy electrification (which increases electricity demand) the net result is still to more-or-less double the demand for electricity to approximately 500TWhrs/yr in 2050.

Both electricity portfolios are required to have nearly zero emissions. For the Renewables portfolio, we assumed the mix of generation would be largely achieved with new wind and solar power such that about 70% of the generation would be intermittent and the rest from hydro-power, geothermal or biomass. Meeting the projected 500 TWhrs/yr demand requires building about 1460 GW of capacity for a renewable portfolio with 70% intermittent resources. For the Median case, it would require roughly 25 GW each of nuclear power and fossil/CCS power and about 55 GW of renewable generation. The higher values for renewable energy reflect the intermittency of the resource. More base capacity is required because the capacity factors (how much of the time the facility produces name plate power) are significantly lower for intermittent resources. Capacity factors for intermittent renewables average about 35% as opposed to 80% to 90% for the nuclear and CCS options. In addition, the renewable portfolio will require more load balancing services to firm[3] intermittent power, many more relatively small power generating facilities, and more transmission to bring power to load.

Before the closure of San Onofre, nuclear power produced about 20% of California's electricity. However, California's law prohibits the siting of all new nuclear plants until the state commission determines that the federal government has identified and approved a demonstrated technology or means for the disposal of the high-level nuclear wastes, and public opinion about nuclear power has become ever more negative, especially following the Fukushima accident. The major source of electricity in California today is natural gas, but there is currently no fossil fuel generation in California which is coupled to carbon capture and storage and the state has no experience managing and regulating such projects. The two portraits present very different legal and regulatory challenges.

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[1] Williams, J., A. DeBenedictis, R. Ghanadan, A. Mahone, J. Moore, W. Morrow, S. Price, M. Torn (2012) "The Technology Path to Deep Greenhouse Gas Emissions Cuts by 2050: The Pivotal Role of Electricity," Science, 335:6064, 53-59.

[2] Wei, M., Nelson, J. H., Greenblatt, J. B., Mileva, A., Johnston, J., Ting, M., Yang, C., Jones, C., McMahon, J. E. and Kammen, D. M. (2013) "Deep carbon reductions in California require electrification and integration across economic sectors", *Environmental Research Letters*, **8.014038.**

[3] The term "firm" refers to backing up intermittent power.

For these two electricity portfolios, five types of issues characterize the choice:

1. The operational system requirements needed to provide power delivery, including issues in reliability, integration, load balancing and management.
2. The feasibility of scaling the system requirements by 2050 and how such a scale-up would be affected by factors such as a natural gas transition.
3. The cost of implementation of the system requirements at the rate required to meet the 2050 goal including all system components such as transmission, storage and pipelines.
4. The consideration of other environmental impacts including intensity of land use and water consumption that may preclude or promote electricity choices.
5. The policy requirements and business models required for deployment.

This report attempts to delve into the first three of these issues relative to the Renewables and Median electricity portfolios in order to highlight the important issues and describe why they are important. The report is informed by a series of white papers prepared for, and discussed at a one-day workshop on July 22, 2013 and were designed to be discussions of what we know and don't know about all five of these issues. The papers are available at http://www.ccst.us/projects/CEFP_public/oct2013meeting.php. (Issues 4 and 5 are not discussed further here; those interested in a discussion of these issues are directed to the white papers at this site.)

The importance of the first issue, system requirements, centers on the need to understand the full implications of any choice in electricity. An electricity portfolio with a mix of nuclear power, CCS and renewables maintains a physical system more like it is today from an operational perspective than a fully renewable portfolio. However, siting issues for nuclear power, as well as accommodating the need to transport both electricity and CO2, will affect the need for transmission and pipelines. If we choose the high renewables portfolio, then ensuring reliable power on many time scales and moving power from where it is generated to load become issues. The power system for an all-renewables portfolio will look very different than it is today. In the section below we attempt to outline these system elements. Both portfolios will present significant challenges.

A number of electricity portfolios can theoretically provide a decarbonized electricity system but these may differ significantly in deployment time. To achieve the 2050 target, electricity has to be decarbonized by 2050. Comparing the required build rate for each portfolio to historical build rates provides one good way to examine the feasibility of deploying these systems. To the extent that a given portfolio choice requires build-out rates that far exceed historical rates, the feasibility of the choice could be questioned. In choosing the next electricity system, we should know if the effort would require war-scale mobilization. Inexpensive, plentiful natural gas will affect the build-out of any carbon-free electricity choice. These factors are discussed in issue 2.

If we know what we have to build (the system requirements) and how fast the electricity choice has to be deployed then the next factor in the choice is cost. The cost of a single solar cell, for example, is only a piece of the puzzle. It is the cost of building the whole system (transmission, storage, smart grid, pipelines, etc.) in time for de-carbonization by 2050 that forms the discussion of issue 3.

Clearly these choices also involve important environmental considerations, public opinion, business models and policy not discussed further here. We hope this report can serve as a strategic document to guide further research. Our purpose is to identify important issues, many of which have not been quantified or analyzed in depth. Such study would surely inform our future choices.

Issue Number 1:

What are the system requirements for operations and planning including issues in reliability, integration, load balancing and management and power delivery issues?

"You got to be careful if you don't know where you're going, because you might not get there."
- Yogi Berra

The systems requirements for each of the two electricity portfolios present strikingly different requirements for both operation and management.[4] It is relatively easy to extrapolate the systems requirements for the median portfolio because the system will not be very different from what we have today. Some exceptions are described below.

For nuclear power, it is possible to estimate the configuration of the system with a high degree of confidence due to extensive experience in developing and studying its system requirements. In the previous CEF study on nuclear power, the committee found that there were no technical barriers to developing nuclear power. New requirements disallowing once-through cooling will present an efficiency cost and it would be possible to use non-fresh water sources for cooling. Following the Fukushima accident, the Nuclear Regulatory Commission has promulgated new safety standards that require power plants to prepare for multiple simultaneous events, which adds to the infrastructure and management required. By law, the federal government is responsible for nuclear waste, so this issue nominally does not increase the physical or management requirements for building nuclear power in the state. However, the federal government has so far failed to solve the problem of nuclear waste disposal, which does create both a public policy issue and an investment barrier. In sum, of all the choices for new electricity, nuclear power presents the fewest *systems* challenges in terms of requiring a significant change in the system requirements. The challenges are not in understanding or developing technology for what is required, but rather the economic barriers to implementation discussed under issue 3 and policy issues.

New system requirements associated with building CCS into an electricity system include a requirement for pipelines to link the electricity production to the sequestration facility. If the choice is made to locate the electricity generation close to a sequestration site, then additional transmission may be required to link generation to load. New monitoring, measurement and verification technology will be required to meet regulatory requirements designed to ensure the integrity of CO2 sequestration. Although the components of this problem are well understood, more experience is needed with integrating and managing the components.

[4] White papers from our workshop only addressed the operational issues for electricity systems with high percentages of intermittent renewable energy because these represent system requirements that are quite different from current norms and there is a lot more uncertainty about what will be required to make these systems work.

The remainder of this section deals with less well-understood systems requirements for a largely renewable portfolio that is largely intermittent. In this portfolio, about 70% of power is generated by intermittent renewable sources (wind and solar) with the balance made up from hydro, geothermal, and biomass energy. To meet the expected 2050 load forecast of 500TWhrs/yr, an additional 140 GW of capacity will be required, versus 80GW for the median case[5]. This represents a 75% increase in expected power needs over the median portfolio to compensate for the lower capacity factors associated with the renewable portfolio. However, a long-term capacity and energy needs analysis is only one part of the picture, and perhaps not the most important part.

Traditional planning practices have tended to consider generation integration and balancing issues as afterthoughts. Recent studies suggest that in fact higher penetration of variable renewable resources will pose novel impacts on the transmission and distribution systems, and need to be considered more carefully. Maintaining the reliability of power generation will become more challenging if the planning process for the required ancillary services does not evolve at a similar speed as the deployment of variable renewable resources. The collective impacts of cost, land-use, and power system management on systems more reliant on variable resources comprise an active area of research, but are not fully understood at present. We need a clearer picture of these system requirements before alternate pathways – be they the two we compare here, or any combination of choices – can be meaningfully compared. Large scale integrated data analytics and computational models based on specific geographic regions could help to understand what the various choices imply.

California has achieved its 20% renewable energy portfolio standard, and has approved a new target of 33% by 2020. The new target is much less than the Renewable portfolio discussed here, but about the same amount as the Median portfolio. Even at 33% operational issues present concerns. The operational requirements identified from recent experience in meeting the 20% standard and looking forward to the new target were outlined in a joint report by the California ISO and the North American Electric Reliability Corporation (NERC).[6] The report identifies a host of "essential reliability services" which must be present to assure reliable operation of the grid and continuity of electric service. These include:

1. **Inertia**—stored rotating energy--provided by synchronous and induction generation, the “battery” that helps the system adjust to constantly changing demand and generator input. Inertia is currently provided by the rapidly spinning generators of conventional power plants, but could be procured from a variety of sources in the future. In order to provide inertia-like response, a device must be able to increase power output significantly on the timescale of one second.

[5] For both cases, we assume that ~20 GW of existing renewables and hydro generation would be retained through 2050 (presumably with upgrades and/or license extensions).
[6] 2013 Special Reliability Assessment: Maintaining Bulk Power System Reliability While Integrating Variable Energy Resources- CAISO Approach, November 2013.

2. **Frequency response**—automatic corrective response of the system, currently provided by synchronous generation balancing demand and supply. In the short term, inertia is the first line of defense in frequency protection followed automatic generation control. System frequency—60 Hz in the United States—must be maintained between very narrow bounds.
3. **Regulation**--correcting for short-term fluctuations in electricity use that might affect the stability of the power system.
4. **Load following**--the ability to adjust power output as demand for electricity ramps throughout the day.
5. **Active power control**--the ability to control power output of a given electric resource.
6. **Reactive power and voltage control**--the ability to control production and absorption of reactive power to maintain voltage and optimize transmission and generation real power losses
7. **Disturbance ride-through tolerance**--the ability of a resource to remain connected through a system disturbance, such as a frequency excursion.

The report also notes the challenges of predicting steady-state and dynamic stability behavior through power flow analysis in a system with high levels of variable generation, as well as the increasing difficulty in load and generation forecasting in a variety of time frames ranging from real time to decades.

California's renewable portfolio target is now 33 percent by 2020. By then, as estimated in the CAISO report, the CAISO grid is expected to gain an additional 11,000 MW of variable generation. This will result in approximately 3,000 MW of intra-hour load following needs and nearly 13,000 MW of continuous up-ramping capability within a three-hour time period. This will require an accurate load forecast and a demand and generation resource pool with the capability to provide flexible, fast-acting response. Increased variability in the output of the supply portfolio will result in less predictability and greater operational uncertainty, which must be anticipated and managed to assure reliability. Greater uncertainty indicates the need for additional resources to provide dependability at an appropriate level of confidence.

Among the issues to be considered are the fact that steeper ramps of responsive demand programs and generating equipment are likely, perhaps more frequent and shorter in duration. This can result in "wear and tear" on equipment, especially gas- fired generators The output of variable generation, particularly solar photovoltaics, can drastically change within a matter of minutes. While geographical dispersion of such units helps, minute-to-minute variability of net load may increase regulation requirements to support reliability and must be planned in advance, as some electric systems may not have the physical capability to meet those requirements.

Over-generation during low load demand periods is another issue which can require the curtailment of production to maintain reliability, which becomes problematic when generation is non-dispatchable (such as certain renewables, combined heat and power, nuclear, run of river hydro and minimum thermal to assure grid stability, where such generation is greater than load plus exports, usually in spring or fall,[7] or in years with high rainfall or snowpack, which can result in hydro spill conditions. While flexible generation, responsive load, electricity storage, increased regional coordination, and renewable portfolio diversification can help mitigate these situations, such options may be limited by cost and availability.

In a new study on increasing California's renewable portfolio standard (RPS) above the current 33% by 2020 target, E3 finds that in a 50% RPS scenario with large amounts energy from solar photovoltaics, 5,000 MW of integration solutions such as scheduled curtailment of renewable energy production, enhanced regional coordination, a diverse portfolio of renewable resources, energy storage, and advanced demand response, would reduce the amount of overgeneration by more than half, from 9% to between 3% and 4%. These numbers assume significant investments and upgrades to both the California electrical grid and thermal fleet occur between 2013 and 2030.

A related risk with similar mitigation possibilities was identified in thinking about long term reliability--the so-called "Gigawatt-Day Problem"[8]. (Because of the possibility of infrequent but large scale weather events that may suppress wind and/or solar output for many hours or days at a time), a longer term risk assessment is part of the analysis required when adding significant amounts of wind and solar energy to the system, particular when thinking about a future where dispatchable fossil capacity is limited due to greenhouse gas constraints. Citing a recent study model by Short and Diakov (2013), researchers found that they could provide roughly 50% of annual demand with intermittent generation (using 2005 Western Interconnect load data and a geographically diverse set of wind and solar farms) and 50% with dispatchable fossil, but there were numerous periods throughout the year when the combination of wind and solar output is less than 10% of peak demand. Even with some storage added, there are periods of time where there is no leftover wind or solar power to charge the storage reservoir. The interplay between variable resource output, meteorology, the availability and scale of electricity storage, the efficacy of non-generations options, such as demand-response, urgently demand more detailed investigation. Without such efforts, the carbon impact, cost and secondary environmental consequences of alternate system configurations cannot be reasonably understood.

[7] E3, Investigating a Higher Renewables Portfolio Standard in California, p 1-2.
[8] Jeffrey Greenblatt, Risks of a High Renewable Electricity Future: the "Gigawatt-Day" Problem, July 2013.

Compared to conventional generation, variable generation is less effective in providing the system with sufficient inertia to arrest frequency decline and may not create adequate governor-like response to stabilize system frequency following the loss of a large generator. Frequency excursions caused by over-generation are possible during periods of high variable generation production and low system demand. Additional sources of inertia may need to be added in concert with increasing penetrations of variable generation in order to maintain grid stability. For example, some types of wind turbines can adjust power output in real time to respond to variations in grid frequency. Successful operation of these types of turbines (or future better ones) could reduce the need for other system tools. System operators will need variable generators connected to the grid to have the ability to limit active power output to control the generator's ramp up following a disturbance. Automatic restarts without control could create further system disturbances. System operators also need the ability to limit power production or disconnect units from the system to prevent overloads due to congestion, risk of islanding[9], risk to steady-state or dynamic network stability, frequency excursions, and relating to routine or forced maintenance. Finally, there is presently no uniform requirement regarding the need for asynchronous (such as wind) generators to provide reactive power support to maintain voltage schedules with static and dynamic components within a tolerance of nominal voltage.

Forecasting variable generation, like wind and solar, depends on weather, which does not occur in regular patterns and is not strongly correlated to demand patterns. Ramping up or down dispatchable power sources (gas turbines, hydroelectric power) to follow variable generators is a fundamental reliability challenge. More accurate weather forecasts would address this issue, as well as the use of telemetry (wind speed and direction) in wind park locations and irradiance value at solar plants, to better predict generation production.

Various operating tools (models) must be developed to dynamically (in real time) correlate system conditions, and the additional ramping and regulation needs to be triggered by the deviation between forecasted and actual load and variable resource output. The goal should be to create a high confidence level that the generation requirements forecast can meet the uncertainty and variability associated with load, wind, and insolation for any particular hour.

[9] **Islanding** refers to the condition in which a distributed (DG) generator continues to power a location even though electrical grid power from the electric utility is no longer present. Islanding can be dangerous to utility workers, who may not realize that a circuit is still powered, and it may prevent automatic re-connection of devices. For that reason, distributed generators must detect islanding and immediately stop producing power; this is referred to as anti-islanding.

In sum, while the list of potential issues above is not comprehensive, the point is that the operating characteristics of variable generation, both in the short term (minute to minute, hour to hour, and day to day), as well as the long term (seasons, decades), not just the energy or capacity being provided, must be considered and addressed to assure the continuing reliability of the electricity system. The equipment, additional flexible capacity, improved forecasting, and necessary operation-management requirements will significantly affect electricity planning, economics and system design. Failure to consider the operational impacts of steadily increasing amounts of renewable energy needed to achieve greenhouse gas targets could result in the inability to assure a reliable and continuous supply of electricity to consumers.

Issue Number 2:

Is it feasible to build out the technology by 2050 and achieve the required emission trajectories?

"We didn't lose the game; we just ran out of time."
- Vince Lombardi

Build-out Rate Historical Comparison

A first step in designing the energy system of the future is to evaluate whether we even have the resources for a particular choice of portfolio. The California's Energy Future Study evaluated this question and found that resources were not a limiting factor for any choice of portfolio. The next question is more difficult: How long would it take to build out the electricity system? Which choices are more likely to allow us to build about twice as much generation as we have now and at the same time decarbonize the system by 2050? We can examine the required build-out rates and compare them both to history and to our current rate of expansion to learn something about the implications of our choices.

1. How fast can we build out nuclear power?

The Median Case requires construction of roughly 25 GW of additional nuclear power capacity in California by 2050, or about 700 megawatts per year over the next 35 years. Analysis of historical nuclear build-out suggests that this pace can be met once underway, assuming that policies are in place to permit this build out to occur. For example:

- From 1977-2000 (23 years), France built 63 GW of nuclear capacity, or 2.7 GW per year. Scaling to population (California's population is about 60% that of France), a California-scaled build rate comparable to population at French build rates would be 1.6 GW/year, more than twice the pace required in the Median case.
- During the 13-year period from 1972-1985, Sweden, with a population roughly a quarter of California's, built 9.5 GW of nuclear capacity, or about 730 MW per year, more than the 700 MW per year required for the Median Case.
- Germany, with a population twice California's, built 30 GW of nuclear capacity from 1975-1989, or about 1400 MW/year.
- South Korea, with a population about a third larger than California's but a GDP only 60% as large, built roughly 20 GW of nuclear capacity in the 29-year period 1983-2012, or about 680 MW/year.
- China is presently building 28 new reactors, with an estimated addition of 41 GW by 2020, or about 8.2 GW/year. While China's population is substantially larger than California's, its GDP is less than five times the size of California's; a GDP-adjusted nuclear build rate for California would be 1.8 GW/year.

In sum, the Median Case California build rate of 700 MW/year is not out of line with historical or current experience. (See Figures 1 and 2, below.) However, a nuclear plant typically takes 4-5 years to go from breaking ground to operation, the availability of initial capacity in the study may be delayed by that amount of time; rather than being smooth, the cumulative capacity addition curve would likely start later and rise more steeply.

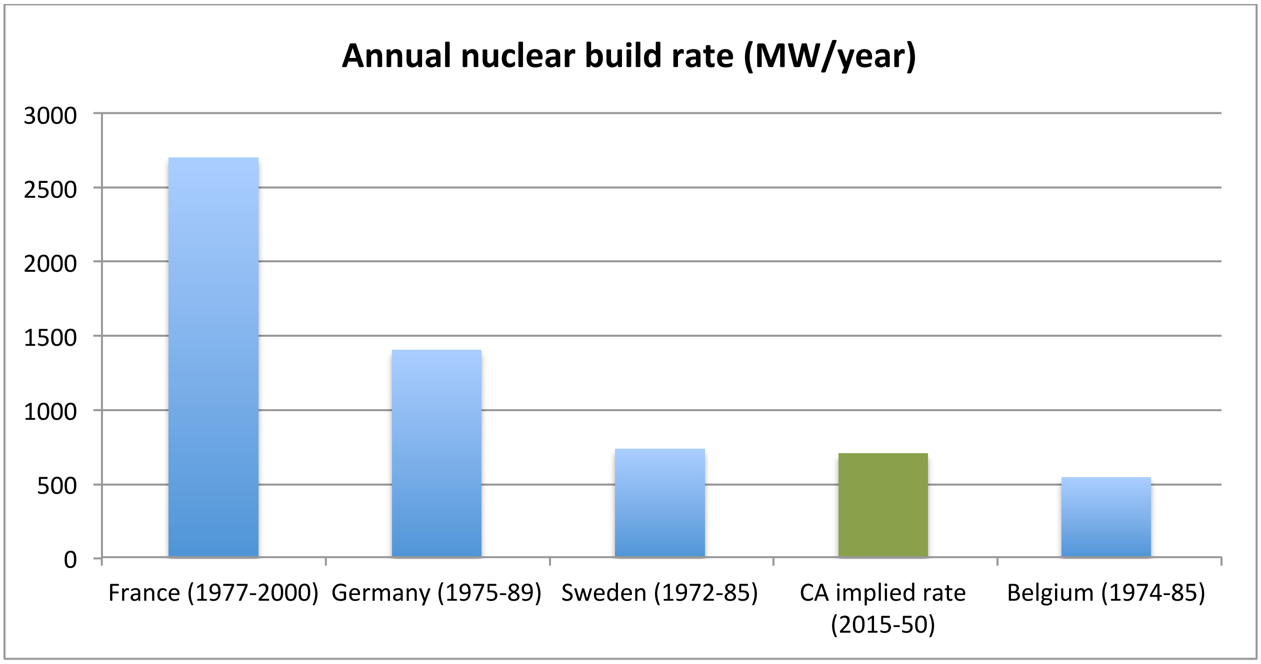

Figure 1: *Annual nuclear build rate for CA Median goal versus historical experiences and China plans. Source: Clean Air Task Force from World Nuclear Association data.*

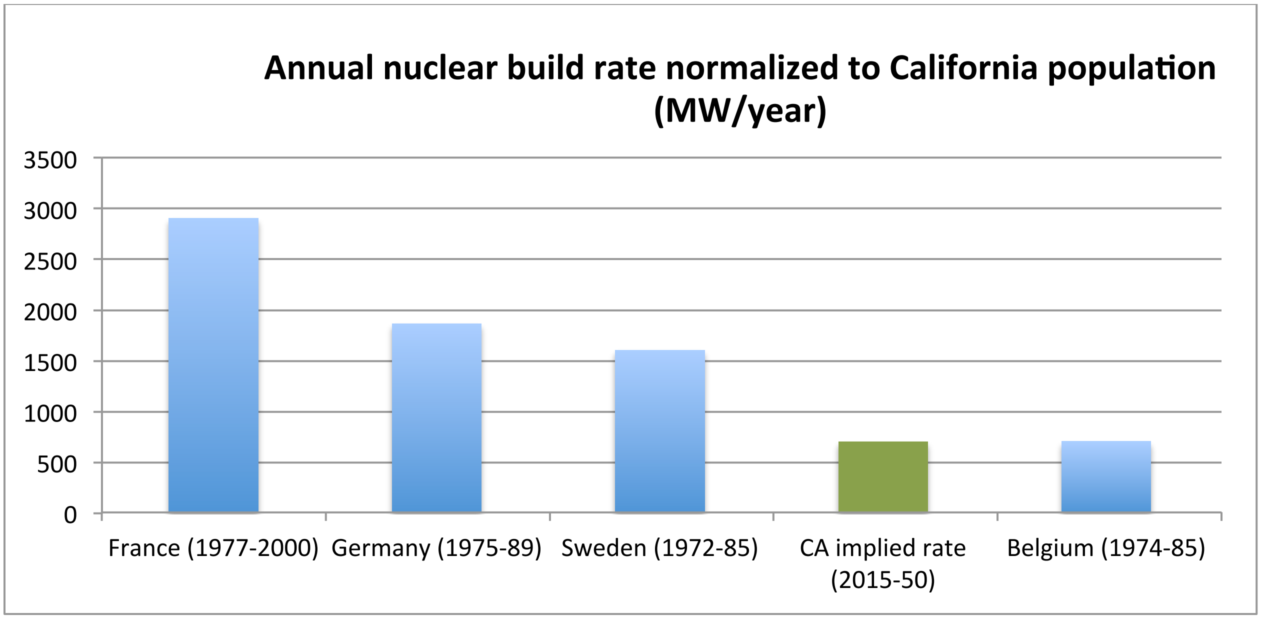

Figure 2: *Annual nuclear build rate for CA Median goal versus historical experiences and China plans normalized to California population (and, in the case of China, California GDP). Source: Clean Air Task Force from World Nuclear Association data (nuclear build) and World Bank (population and GDP).*

It should be noted that the higher build rate of France is often attributed to increasing standardization, although this began to reverse itself as the reactors became larger and more complex.[10] China appears to be moving in the same direction, with an adoption of new standardized designs such as the Westinghouse AP-1000.

2. How fast can we build CCS?

Integrated carbon capture and subsurface carbon injection – the two main components of carbon capture and storage – have been successfully demonstrated at pilot scale in the US power sector.[11] Two integrated fossil power plants with CCS are under construction in North America, the Kemper plant in Mississippi and the Boundary Dam Project in Saskatchewan, Canada. Moreover, these technologies have also been demonstrated at full commercial scale outside the power sector – in synthetic natural gas production.[12] However, no integrated fossil power/CCS project has been built at commercial scale in California. Accordingly, for scale-up rates we must look to other historical data.

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[10] Arnolf Grubler, An assessment of the costs of the French nuclear PWR program 1970–2000, Interim Report, IIASA publication IR-09-036, subsequently published as Arnulf Grubler, The costs of the French nuclear scale-up: A case of negative learning by doing, Energy Policy, Volume 38, Issue 9, September 2010, Pages 5174-5188, ISSN 0301-4215, http://dx.doi.org/10.1016/j.enpol.2010.05.003.

[11] The AEP Mountaineer project in West Virginia is an integrated coal power/CCS pilot at 30 MW, but it was never expanded due to lack of approved funding by state regulators. See https://sequestration.mit.edu/tools/projects/aep_alstom_mountaineer.html. Plant Barry in Mississippi is also presently capturing a 25 MW CO2 slipstream, with injection into an oil field for enhanced oil recovery, see https://sequestration.mit.edu/tools/projects/plant_barry.html.

[12] See http://sequestration.mit.edu/tools/projects/weyburn.html.

The median scenario posits the building or retrofitting of 25 GW of CCS-equipped gas-fired power plants by 2050. This works out to about 700 MW/year, well within historical precedent For example, the US EIA reports that California increased its gas-fired capacity from 28.8 GW to 45.6 GW between 2000 and 2010, or about 1680 MW/yr, more than double the required rate for the Median Case. It is likely, however, that the first few gas/CCS plants will experience delays, as is likely with any "first of a kind" power technology.

The additional CO2 removal equipment (amine scrubbing) is fully commercially demonstrated in refinery contexts, and has been demonstrated at commercial scale at gas power plants in Massachusetts and Oklahoma; it is unlikely to add significantly to construction times.

Storage capacity does not appear to be a constraint to scale-up. The National Technology Energy Laboratory 2012 Carbon Utilization and Storage Atlas estimates California's onshore CCS storage capacity at between 37 and 463 GT CO2[13], while NETL estimates the offshore resource at 8-91 GT CO2. Even at the low end of these estimates, there is more than enough storage for many centuries to accommodate the approximately 64 million tons of CO2 per year[14] from 25 GW of gas power plants.

Given experience in California with other forms of energy infrastructure, the permitting process for CCS sites could take as long as a decade, and therefore the adoption curve for CCS might be back-loaded to meet the implied rates. Use of CO2 for enhanced oil recovery (EOR) could jump-start the industry as a near term utilization strategy. US DOE estimates a capacity of up to 8 GT CO2 for EOR in California.[15] EOR is a fully commercial practice in the Southwest United States, and has a well-developed permitting regime. Ultimately, however, the social acceptability of CCS in California is unknown, and the permitting process could delay projects or even make them impossible.

3. How fast can we build out renewables and associated infrastructure?

The renewable build-out required is 140 GW in the High Renewables Case (or 4 GW/yr) and 55 GW for the Median Case, along with associated storage and transmission infrastructure. For comparison purposes, the 140 GW target is 1.75 times the wind and solar build-out of Germany over the last 20 years, with a population twice California's.

Yet the implied High Renewables case build rate of roughly 4 GW/year is not out of line with recent global experience building wind and solar. Figure 3 below shows that the required 4 GW/yr build rate would mean doubling the combined California wind and solar build rate in 2012, which itself was roughly tripled from the 2008-2011 build rate. Figure 3 also shows that the required California build rate is smaller than that recently achieved in Germany and Italy.

[13] http://netl.doe.gov/research/coal/carbon-storage/atlasiv, p 120.
[14] (25 GW x 8760 hours) x .8 capacity factor x .8 LBS CO2/MWH)/2205 lbs/ton = 64 million tons CO2 per year.
[15] US DOE, BASIN ORIENTED STRATEGIES FOR CO2 ENHANCED OIL RECOVERY: CALIFORNIA (April 2005) (3.9 Billion barrels of oil recoverable through EOR; EOR absorbs approximately 2 tons of CO2 per barrel).

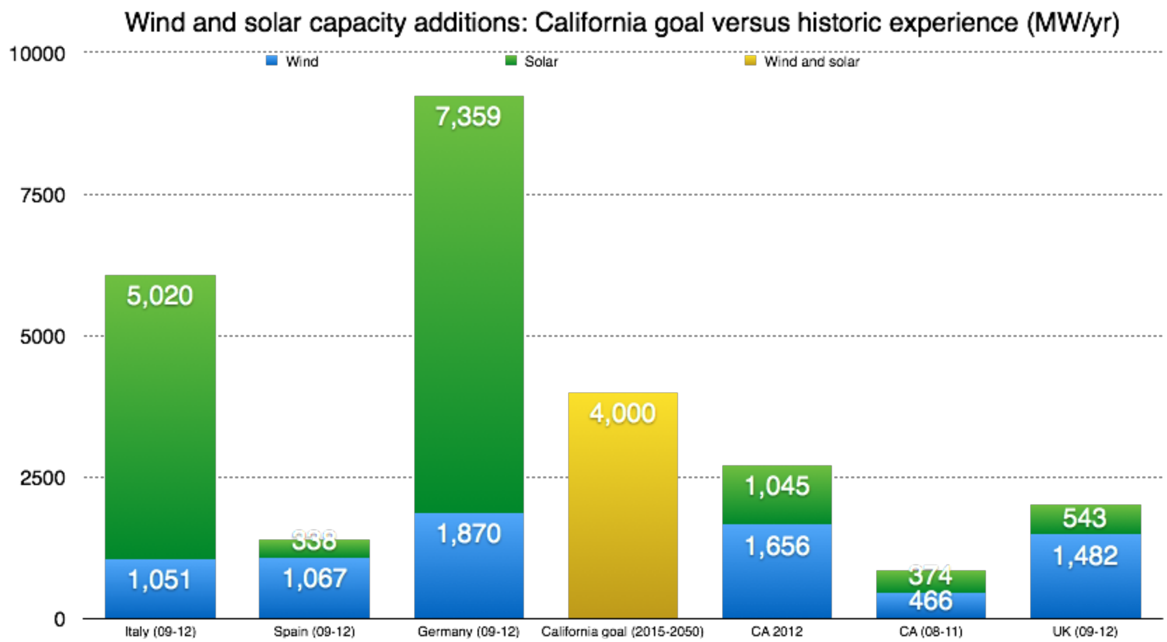

Figure 3*: Recent build out rates for wind and solar in selected countries compared to California 140 GW goal build rate. Sources: Clean Air Task Force utilizing data from IEA and EIA, except for California 2012 data, which is from Solar Energy Industries Association and the American Wind Energy Association.*

Even when normalized for population, as Figure 4 portrays, the required California rate is somewhat less than that recently achieved in Germany.

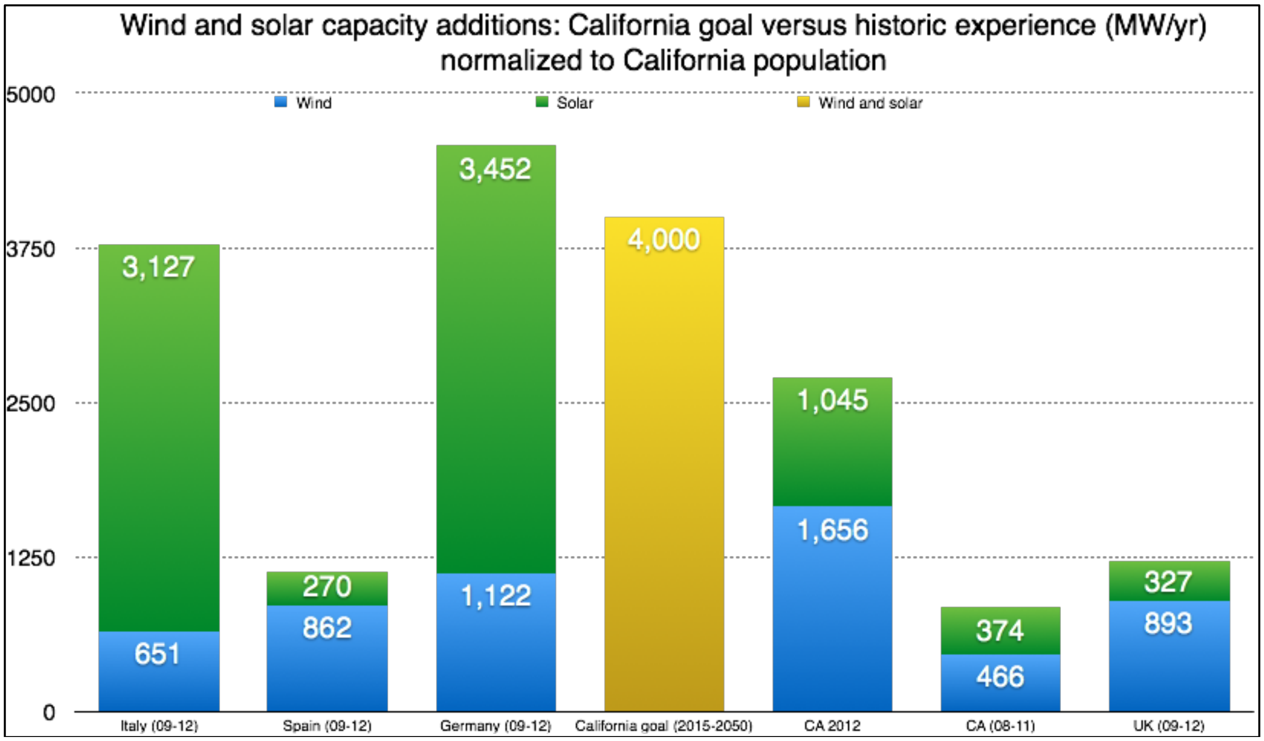

***Figure 4**: Recent build out rates for wind and solar in selected countries, normalized to population. Sources: Clean Air Task Force utilizing data from IEA and EIA, except for California 2012 data, which is from Solar Energy Industries Association and the American Wind Energy Association; population data is from World Bank and US Census.*

However, a significant additional infrastructure requirement of transmission, storage and back-up generation also needs to be taken into account in scaling to 140 GW.

- *Transmission.* A recent National Renewable Energy Laboratory analysis[16] provides some perspective on the amount of transmission that might be required. NREL concluded that in order to provide a little less than 50% of the nation's electricity from wind and solar (much less than in the High Renewables Case here for California), roughly a doubling of 2011 transmission capacity would be ideal. A doubling of California's current 26,000 miles of transmission would require about 750 miles of transmission to be constructed every year until 2050; for scale purposes that is the recent average rate of annual construction for the entire United States, which has eight times California's population.[17] It should be also pointed out that a doubling of transmission capacity (as measured by the ability to move power from one place to another) could mean more or less than a doubling of the transmission infrastructure.

[16] Renewable Electricity Futures Study. Hand, M.M.; Baldwin, S.; DeMeo, E.; Reilly, J.M.; Mai, T.; Arent, D.; Porro, G.; Meshek, M.; Sandor, D. eds. 4 vols. NREL/TP-6A20-52409. Golden, CO: National Renewable Energy Laboratory, 2012. http://www.nrel.gov/analysis/re_futures/.

[17] http://www.naruc.org/grants/Documents/Silverstein%20NCEP%20T-101%200420111.pdf.

- *Load-following balancing generation.* While energy storage technologies, such as batteries and compressed air, are often cited as preferred option for balancing variable wind and solar, grid scale storage is still in its early days. In any event, even with substantial grid scale lossless, cost-effective storage, the “Gigawatt day” problem described previously implies that California could need to site significant additional capacity over and beyond the 25 GW assumed in the Median Case simply to supply sufficient energy --perhaps as much as a tripling of that capacity in the high renewables case. This capacity could come from a number of sources, including conventional fossil generation, storage technologies, demand response, hydroelectric facilities, increased coordination with out-of-state generation facilities, etc.

- *Storage.* Any scenario in which solar and wind provide more than 50% of California’s electricity is likely to require a substantial amount of grid scale storage. For example, as a rough gauge, the previously cited NREL study estimated that a United States electricity system with 50% variable generation could involve 100-152 GW of grid scale storage. Scaled to California population, that would conservatively suggest that 12.5-19 GW of grid scale storage might be needed, or up to 540 MW per year to 2035. The amount is likely to be significantly larger in a High Renewables Case. In comparison, the recent CPUC storage order mandated that utilities acquire roughly 1.3 GW by 2024, or about 130 MW/yr.

Natural Gas and the Energy Transition

The recent growth in US production of natural gas from unconventional sources appears to offer a plentiful, inexpensive fuel for the foreseeable future. With only a few decades left to meet a 2050 goal of de-carbonizing electricity, California must consider how it should deal with this phenomenon.

Natural gas generation is currently pushing all non-subsidized sources of energy out of the market. For example, established nuclear power plants are closing in part because energy from a new combined cycle natural gas plant is less expensive than maintaining the power plant, and perhaps also in part because of the ability of natural gas plants to match their dispatch to times of high system price. Present market and policy structures do not create incentives for nuclear power plant owners to maintain capacity in the hope of future price shifts.

The current dominance of natural gas is a two-edged sword. In the near term, as gas pushes coal out of the electricity portfolio, prices drop and emissions fall. The natural gas boom is credited as a major factor in the US GHG emission decline over the last few years. This has had less impact in California because little of the state’s electricity comes from coal to begin with.

A switch from coal to gas may or may not provide a net benefit for the climate. Gas production and distribution are also a source of fugitive methane emissions and methane is a powerful greenhouse gas. Data collection campaigns have started to try to quantify these emissions. Several studies suggest that if fugitive emissions exceed even a few percentage points, then the switch from coal to gas will not create net GHG reductions. The facts remain to be determined.

Even if gas turns out to have the short-term benefit by displacing coal and reducing GHG emissions, the use of gas in electricity still does not reduce CO2 emissions enough to meet ambitious long-term targets. Gas has been called the "bridge fuel" but unless we have a plan for getting off the bridge, the uncontrolled use of gas leaves us with too much CO2. The problem is exacerbated by the fact that gas is currently displacing important sources of carbon-free electricity, especially nuclear power. The transition to carbon-free electricity, no matter what portfolio we choose, means that we must address the implications of the natural gas boom.

New gas plants with CCS or CCS retrofits on existing natural gas plants are a viable way for gas to play a continuing role in the transition of California's electric system. If CCS is to be available for a 2050 energy portfolio, California needs experience with actual applications in the state, including managing the integration of electricity and sequestration and defining the costs and regulatory challenges. How much will it actually cost? Can the projects be permitted? Can the sequestration process with its own physical requirements be synchronized with the CO2 production, which is proportional to electricity production with load following requirements? Hard data from experience will provide a much better basis for future decisions about the use of CCS as part of California's energy future.

There are several companies interested in moving the CCS industry forward, and at least two major commercial scale power/CCS projects (both coal) underway in North America -- the Kemper County, Mississippi plant, and the Boundary Dam project in Canada. The long run economic viability of CCS projects depends on a carbon price to offset the cost of separation and sequestration; as the California carbon market develops, a carbon price might well provide the revenue needed for CCS projects to pencil out. At this time, the only way to get sufficient revenue is to sell the CO2 for industrial purposes. All of the CCS projects proposed for California want to sell the CO2 to oil producers for enhanced oil recovery (EOR) operations and at the same time sequester the gas in the petroleum reservoir. These projects also want to garner economic benefits available from California's low carbon fuel standard and carbon market. These projects represent a special class of CCS called Carbon Capture, Utilization and Sequestration (CCUS).

CO2 floods are not commonly done in California because the state lacks economical sources of CO2. However, EOR of this type may be successful in California reservoirs and producers are interested in this option. From the perspective of the electricity producer, being able to sell the CO2 for EOR is critical for commercial success because the cost of CO2 capture cannot be recovered any other way in current electricity markets. As capture is the vast majority of the cost of CCS, reducing the cost of capture is a topic of DOE sponsored research and should be a major focus of learning-by-doing. Boosting the commercial viability of a CCS project through CCUS will allow the technical learning that could lead to reduced costs.

Four major policy issues must be addressed to make CCS a viable option in California

1. How much carbon goes where? What is the carbon life-cycle for a project combining the CO_2 production during power production, sequestration, and fuel production and how should carbon be counted in this industrial system for both LCFS applications and cap and trade?
2. CCUS, LCFS, and C&T: How should a CCUS project play in the California carbon market and LCFS? Who should get the carbon credits? Should they belong to the power plant, the oil producer or perhaps the oil refiner? Financially whoever gets them will essentially use them in the business deal between the power company and the oil companies. But different outcomes and incentives will arise depending on where they are assigned. Does it make sense to have CCUS projects play simultaneously in the LCFS and carbon market and why?
3. Verification issues: How can these credits be verified? Can we measure how much CO_2 is actually sequestered? How will verification choices affect the business deals that might start CCUS?
4. Linking the carbon, electricity and oil production enterprises: How will power purchase agreements (PPAs) need to be constructed to encourage, or just allow, the combined enterprises to work together?

Issue Number 3:

Cost of implementation including transmission?

"Prediction is very difficult, especially about the future."
Niels Bohr Danish physicist (1885 - 1962)

Analysts often compare various electricity solutions simply by comparing the cost of building the capacity to generate a kilowatt-hour. Such limited analysis raises serious concerns when the choices imply that many other aspects of the electricity system would also have to be built and managed to make the entire system work. In the discussion of issue 1 above, we bring up three major requirements in designing a reliable electricity system:

- Capacity requirements
- Transmission requirements
- Ancillary services requirements including frequency regulation, reactive power, balancing energy and voltage regulation.

Wise choices in our electricity future require understanding the entire system costs generated by all three of these as well as infrastructure required to provide grid backup etc. [18]

The table below addresses expectations for the first two of these factors. A striking conclusion can be drawn from this table. If:

- these costs do not change with scale or time, and
- the ancillary services issue is not considered, and
- hydro cannot expand for environmental reasons, and
- GHG emissions are not allowed,

then *on an economic basis alone* the electricity system would most likely become some combination of:

- gas generation with CCS,
- geothermal energy, and
- wind

[18] For example, system cost issues have been identified as the result of policies that allow home-owners to be paid by the utilities for electricity they generate with solar PV on their rooftops. Utilities claim that, that without time of generation pricing, and to the extent that the PV cells produce electricity in off-peak times, the system still has to provide power generation to meet peak demand, but the installed peak-load generators are often idle when solar energy kicks in. Consequently, peak energy is more expensive and homeowners who do not have solar PV on their roofs are essentially subsidizing those that do. Time-of-use pricing would address this issue.

which all come in below $100/megawatt-hour. Of these, gas with CCS and geothermal have lower issues with ancillary services than wind. Geothermal produced traditionally provides a baseload, renewable resource, but may have limitations in scale-up. In a second tier, just above $100/megawatt-hour would be:

- advanced nuclear and
- biomass.

Biomass may be limited by the availability of biomass and competition for the use of this biomass with fuel production. So, based on these cost data alone, the least expensive carbon-free electricity system might be based largely on gas with CCS, advanced nuclear power, with some wind, geothermal, and biomass.

Key questions arise from this simple analysis:

1. How much will ancillary services add to the cost of wind as the percentage of this resource comes on line? Wind would be a preferred resource from an economic perspective only if the ancillary services do not increase the cost significantly above gas with CCS or advanced nuclear. The ancillary services required for a high percentage of wind on the grid exceed those required for a high percentage of nuclear power or CCS system. Consequently, understanding how much it will cost to deploy wind, especially as the percentage of wind on the grid increases, becomes a dominant factor in an *economic* choice to develop this resource extensively over nuclear power or gas-CCS.
2. How is the price of gas-CCS likely to change? This technology appears cost competitive now because gas prices are currently extremely low. How much will the cost of capture decline in CCS? The vast majority of costs in CCS are from capture, which is an industrial process amenable to innovation. To what extent can early CCS build costs be amortized by use of CO2 for enhanced oil recovery? Is it likely that coal prices be driven down such that coal with CCS is competitive? At what level of deployment will the cost of storage increase or decrease dramatically?
3. How is the cost of nuclear power likely to change? What are reasons to think costs will decline and reasons to think they will increase? How will China affect the cost of nuclear power? How will small, modular reactors affect the cost?
4. Will the cost of solar PV decline to something close to the cost of wind power, and how much will the ancillary services cost as a function of PV generation on the grid? Are there reasonable scenarios that would make this option cost competitive? Is there a scenario to support solar thermal generation becoming cost competitive?

***Table 1**: Anticipated long-term levelized cost of electricity generation (EIA, 2013) [5]*[19]

U.S. average levelized costs (2011 $/megawatt-hour) for plants entering service in 2018

Plant type	Capacity factor (%)	Levelized capital cost	Fixed O&M	Variable O&M (including fuel)	Transmission investment	Total system levelized cost
Dispatchable Technologies						
Conventional Coal	85	65.7	4.1	29.2	1.2	100.1
Advanced Coal	85	84.4	6.8	30.7	1.2	123.0
Advance Coal with CCS	85	88.4	8.8	37.2	1.2	135.5
Natural Gas-fired						
Conventional Combined Cycle	87	15.8	1.7	48.4	1.2	67.1
Advanced Combined Cycle	87	17.4	2.0	45.0	1.2	65.6
Advanced CC with CCS	87	34.0	4.1	54.1	1.2	93.4
Conventional Combustion Turbine	30	44.2	2.7	80.0	3.4	130.3
Advanced Combustion Turbine	30	30.4	2.6	68.2	3.4	104.6
Advanced Nuclear	90	83.4	11.6	12.3	1.1	108.4
Geothermal	92	76.2	12.0	0.0	1.4	89.6
Biomass	83	53.2	14.3	42.3	1.2	111.0
Non-Dispatchable Technologies						
Wind	34	70.3	13.1	0.0	3.2	86.6
Wind - Offshore	37	193.4	22.4	0.0	5.7	221.5
Solar PV[1]	25	130.4	9.9	0.0	4.0	144.3
Solar Thermal	20	214.2	41.4	0.0	5.9	261.5
Hydro[2]	52	78.1	4.1	6.1	2.0	90.3

1. Costs are expressed in terms of net AC power available to the grid for the installed capacity.
2. As modeled, hydro 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.

Note: These results do not include targeted tax credits such as the production or investment tax credit available for some technologies, which could significantly affect the levelized cost estimate. For example, new solar thermal and PV plants are eligible to receive a 30-percent investment tax credit on capital expenditure if placed in service before the end of 2016, and 10 percent thereafter. New wind, geothermal, biomass, hydroelectric, and landfill gas plans are eligible to receive either: (1) a $22 per MWh ($11 per MWh for technologies other than wind, geothermal and closed-loop biomass) inflation-adjusted production tax credit over the plant's first ten years of service or (2) a 30-percent investment tax credit, if placed in service before the end of 2013 (or 2012, for wind only).

Source: U.S. Energy Information Administration, Annual Energy Outlook 2013, December 2012, DOE/EIA-0383 (2012).

[19] Energy Information Administration (EIA), *Levelized Cost of New Generation Resources in the Annual Energy Outlook 2013*. 2013, U.S. Department of Energy: Washington D.C.

These questions are discussed below highlighting analysis that would support the answers.

Cost of Ancillary and Balancing Services for Wind and Solar

At low levels of penetration, integration and balancing costs for wind and solar have been estimated to be between $5 and $10 per MWH.[20] The recent E3 study of a 50% RPS suggests incremental cost increases of 9-23% over a 33% RPS[21], at an implied carbon abatement cost of $403-627/ton of CO2.[22] However, Idaho Power has found that integration and balancing costs grow exponentially on its system – to an 1.9 cents/kwh to as much as 5 cents/kwh at the margin -- once installed wind capacity exceeds roughly 30% of peak demand.[23] Other studies have suggested a potential doubling or trebling of wind and PV costs as penetrations exceed 20%.[24]

Recent work by Nelson (2013) indicates that the cost of balancing variable renewable resources becomes similar to that of the cost of energy from these resources as carbon emissions from electricity generation are reduced to very low levels. Using the SWITCH model, these authors depict the minimum cost deployment of generation, storage and transmission capacity for the WECC region while the economy-wide emission cap is lowered to 80% below 1990 levels in 2050. They found that costs increase substantially just before 2050 and that the increase in costs is largely due to the increased requirement for balancing services. This report highlights the need for coordinated deployment of intermittent resources and balancing solutions, as well as innovation in balancing technologies to bring the full system cost down. For example, implementing wide-scale demand response programs alone are shown to reduce the cost of the entire power system by 16% relative to a power system that does not have demand response available.

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[20] US DOE EERE, 2012 Wind Technologies Market Report, August 2013.

[21] Energy and Environmental Economics, Investigating a Higher Renewables Portfolio Standard in California (January 2014), https://ethree.com/documents/E3_Final_RPS_Report_2014_01_06_with_appendices.pdf at p. 20.

[22] Ibid. at p. 29.

[23] https://www.idahopower.com/AboutUs/PlanningForFuture/WindStudy/default.cfm at p. 8.

[24] See e.g. Purvins et al, Challenges and options for a large wind power uptake by the European electricity system, *Applied Energy*, Volume 88, Issue 5, May 2011, Pages 1461–1469 cites; Denholm, P., Hand, M., Grid flexibility and storage required to achieve very high penetration of variable renewable electricity. *Energy Policy* (2011); Managing Large-Scale Penetration of Intermittent Renewables, An MIT Energy Initiative Symposium, April 20, 2011, http://web.mit.edu/mitei/research/reports/intermittent-renewables.html.

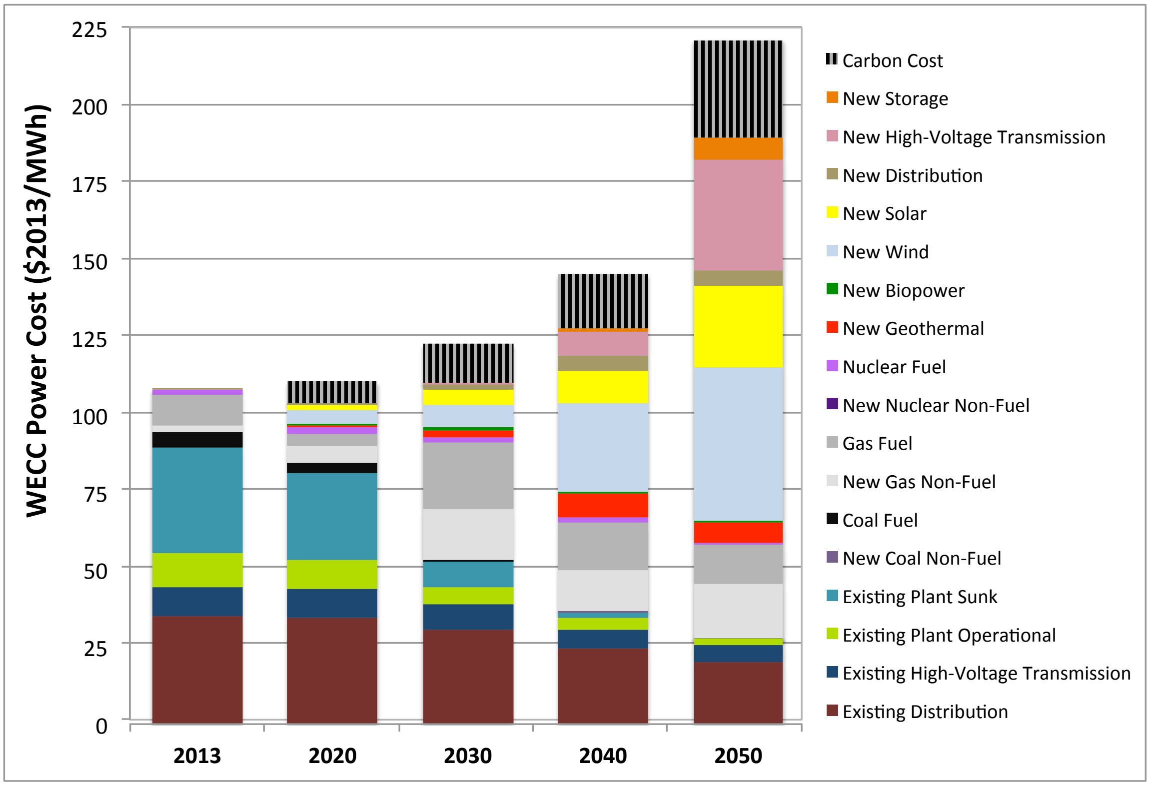


***Figure 5**: Projected power costs through 2050. Power costs increase substantially near 2050 when the economy-wide carbon cap drops to 80% below 1990 levels, due to the need to balance intermittent renewable energy. (Nelson, 2013)*

Future Price of CCS

A variety of studies have attempted to characterize the potential decline in costs for CCS through learning by doing and various technical innovations.[25] And, indeed, there is powerful evidence of some cost declines from pollution control equipment in the power sector as its penetration increases (see Figure 6 below).[26] However, barring successful commercialization of advanced CCS technologies,[27] significant price declines for CCS in advance of market penetration are unlikely; current CCS capture is inherently a highly capital intensive process using a relatively mature amine technology with a significant energy penalty.

[25] For a bibliography of such studies, see http://www.globalccsinstitute.com/key-topics/cost-of-ccs.

[26] See, e.g., S. Yeh, E. Rubin, D. Hounshell, M. Taylor, Uncertainties in Technology Experience Curves for Integrated Assessment Models.

[27] One such advanced technology that may be commercially available soon is offered by the NETPower consortium. NETPower's technology is an oxycombustion process with advanced turbines that utilizes CO2 as a working fluid, allowing for 100% levels of carbon capture. The company, along with Toshiba, Chicago Bridge & Iron, and Exellon, is in the process of developing a 25MW pilot in the US Gulf coast. The company expects to be able to generate power at a price that is competitive with new uncontrolled fossil energy units. "Fossil Fuel Power Generation Without CO2 Air Emissions", The Energy Industry Times, August 2012.

The most immediate opportunity for lowering the cost of CCS infrastructure, however, is the use of CCS for enhanced oil recovery (EOR). EOR revenue[28] can buy down the capital costs of capture and transport capital costs – so that future permanent storage in saline aquifers can be effected at a much smaller incremental cost. It should be noted in this regard that the cost figures from EIA included in the table above assume saline aquifer storage with no offsetting revenue from EOR. While EOR isn't a complete storage solution, it can play a crucial role in building needed pipeline infrastructure, widely spreading CO_2 storage know-how, and creating a larger market for carbon capture and therefore demand-pull for lower cost capture technology.

(a)

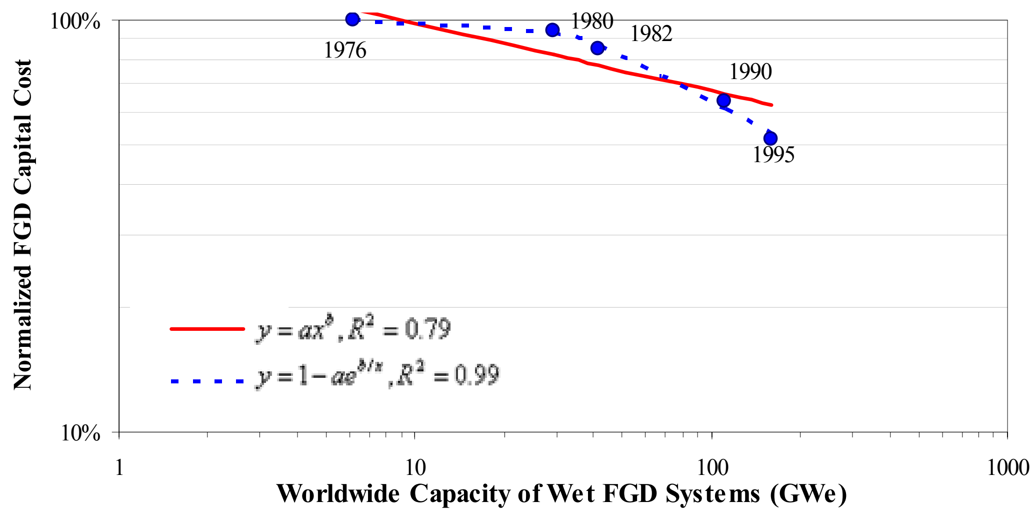


Figure 6: *A 20% decline in wet scrubber costs with a ten-fold increase in installations.*

Future Price of Advanced Nuclear Power

There are at least two indications that there are opportunities for meaningful reductions in nuclear power costs: currently low price points for nuclear plants being built in Asia; and technical innovations that may simplify reactor designs and increase their reliability and safety at reduced costs.

It is first worth noting that 50% of nuclear plant construction costs are capitalized direct costs (concrete, steel, and equipment), while 25% are absorbed in capitalized indirect services (engineering, design, licensing, project management) and another 25% in financing costs.[29] Therefore, while direct capitalized costs are somewhat globalized, "soft" costs can be greatly affected by specific management practices and speed to construction.

[28] Presently, CO2 in the Permian Basin is commanding a market price in the $40/ton range, see http://www.globalccsinstitute.com/publications/global-technology-roadmap-ccs-industry-sectoral-assessment-co2-enhanced-oil-recovery-11.

[29] Florian Metzler, MIT Edward S. Steinfeld, MIT, Sustaining Global Competitiveness in the Provision of Complex Products and Systems: The Case of Civilian Nuclear Power Technology (Massachusetts Institute of Technology Political Science Department Working Paper No. 2013-3), Electronic copy available at: http://ssrn.com/abstract=2243726.

Recent reports have suggested lower total costs for new nuclear plants built in Asia. For example, the four Westinghouse AP-1000 reactors currently being built in Georgia and South Carolina are estimated to cost $5,800/kw or more[30] while those being built in China are estimated at roughly half that cost- $2,500 per kilowatt.[31] Korean designs being built in Korea and sold globally are reported at under $3,000 per kilowatt. The lower costs may reflect efficiencies in engineering and project management, especially where identical reactors such as the AP-1000 are being built at much higher costs in the West.

With regard to future cost reductions in advanced light water reactor such as the AP-1000, which are most relevant to the next thirty years, there are several possible downward drivers:

- "First of a kind" technology problems should be resolved (among the four US and four China units being developed)
- The US should have re-established an effective large project management capability as well as new NRC staff experience regulating construction and startup; this experience has been eroded through retirement of staff and no new builds
- Construction times could be reduced
- Project risk and associated financing interest rates should be reduced
- Standard design/module manufacturing and large structure pre-fabrication benefits should finally be realized
- Passive design benefits (reduced complexity, fewer pumps, etc.) should also be realized

It is also possible that small modular light water reactors could reduce overall costs because they involve:

- Smaller incremental projects that lower risk for large capital allotments
- Shorter construction times than for LWR – degree of prefabrication will likely impact construction time.
- Potentially significant reductions in capitalization of indirect costs and financing costs due to lower project risks plus short project construction times)
- Faster learning due to centralized manufacturing process and smaller unit size

For purposes of this analysis, we do not consider advanced non-light water reactor such as thorium-fueled, sodium cooled, fast reactors and others, as their price points are speculative at this time, and their commercial availability in the US is likely to take well more than a decade.

[30] C. Summer Nuclear Station Units 2 & 3 Quarterly Report to the South Carolina Office of Regulatory Staff, Submitted by South Carolina Electric & Gas Company Pursuant to Public Service Commission Order No. 2009-104(A) Quarter Ending September 30, 2013.

[31] Berthélemy, Michel and François Lévêque. "Korea nuclear exports: Why did the Koreans win the UAE tender? Will Korea achieve its goal of exporting 80 nuclear reactors by 2030?" *Cerna Working Paper Series*. Cerna, Centre d'économie industrielle MINES ParisTech, April 12, 2011.

Future Price of Solar Power

While household-and commercial scale solar PV panel prices have come down substantially in recent years, partly due to oversupply from China, balance of system costs (inverters, mounts, etc.) have experienced a less rapid decline. Nonetheless, the result is that overall US installed costs have fallen by roughly 75% from 2000:[32]

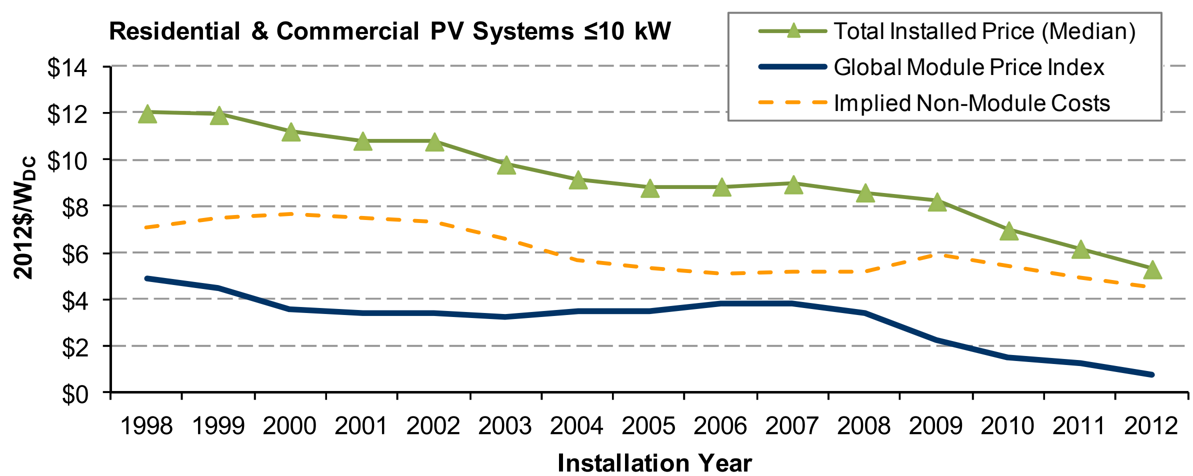


Figure 7*: Residential & Commercial PV Systems*

Given recent improvements in module manufacturing, future cost reductions will depend on improvements in balance of system costs. Yet, as Lawrence Berkeley Laboratory summarizes:

> International experience suggests that greater near-term price reductions in the United States are possible, as the median installed price of small residential PV installations in 2012 (excluding sales/value-added tax) was just \$2.6/W in Germany, \$3.1/W in Australia, \$3.1/W in Italy, and \$4.8/W in France, compared to \$5.2/W in the United States.[33]

It is worth noting that, in contrast to household and commercial PV, utility scale PV price declines have been a mixed bag -- there was a 50% decline in the cost of crystalline installations during this period but not similar cost progress for other technologies.

[32] Galen Barbose, Naïm Darghouth, Samantha Weaver, and Ryan Wiser, Tracking the Sun IV, An Historical Summary of the Installed Price of Photovoltaics in the United States from 1998 to 2012 (July 2013), http://emp.lbl.gov/sites/all/files/lbnl-6350e.pdf.

[33] Ibid. at page 2.

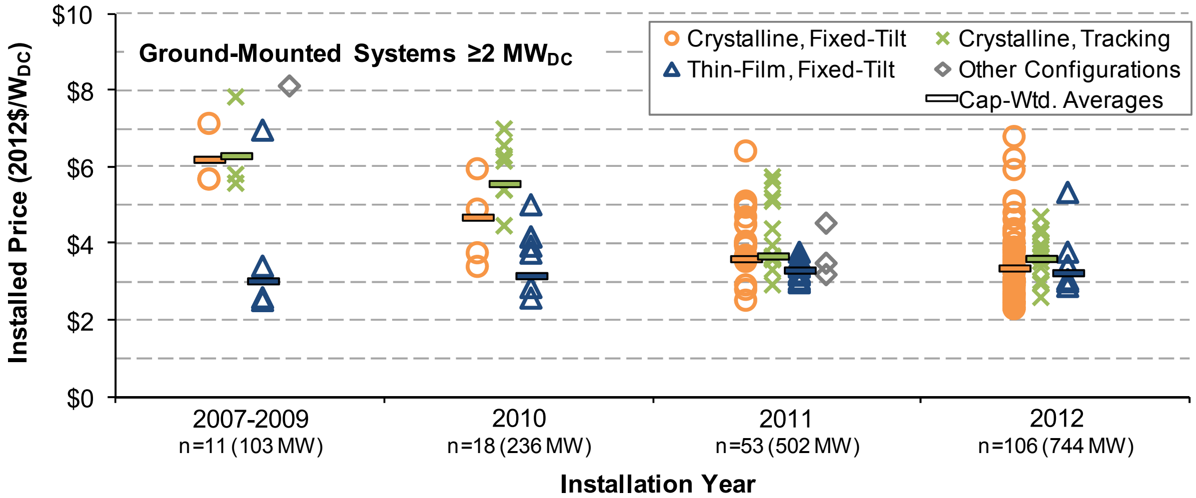


Figure 8: *Ground-mounted systems*

A Solar Example:
The SunShot Initiative for Aggressive Solar Power Deployment

The SunShot Initiative is an example of one of the high-renewable deployment options being explored. The Initiative is an energy research and development and policy framework established by the United States Department of Energy; it sets cost-reduction targets of $1/watt for central-station solar technologies. Various estimates exist to the price of solar in the coming years, but based on assessments of the both the technology push and market pull dynamics in the solar industry, the $1/watt (commercial) and $1.50/watt (residential) price called for in the SunShot program appears to be entirely achievable by 2020[34].

SWITCH[35], a high-resolution electricity system planning model utilized elsewhere in this report, was used to study the implications of achieving these targets for technology deployment and electricity costs in western North America, focusing on scenarios limiting carbon emissions to 80% below 1990 levels by 2050. We find that achieving the SunShot target for solar photovoltaics would allow this technology to provide more than a third of electric power in the region, displacing natural gas in the medium term and reducing the need for nuclear and carbon capture and sequestration (CCS) technologies, which face technological and cost uncertainties, by 2050. We demonstrate that a diverse portfolio of technological options can help integrate high levels of solar generation successfully and cost-effectively[36]. The deployment of GW-scale storage plays a central role in facilitating solar deployment and the availability of flexible loads could increase the solar penetration level further. In the scenarios investigated, achieving the SunShot target can substantially mitigate the cost of implementing a carbon cap, decreasing power costs by up to 14% and saving up to $20 billion ($2010) annually by 2050 relative to scenarios with Reference solar costs.

Figure 9: *Energy Mix by Fuel and Investment Period (from ref. 33).*

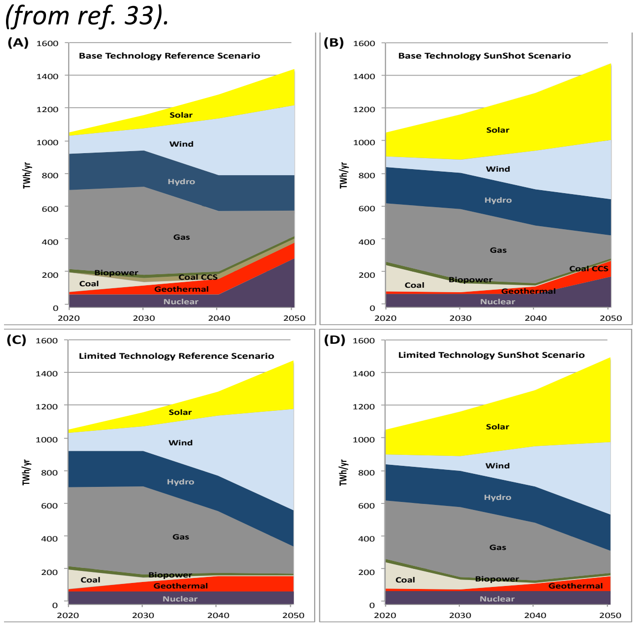
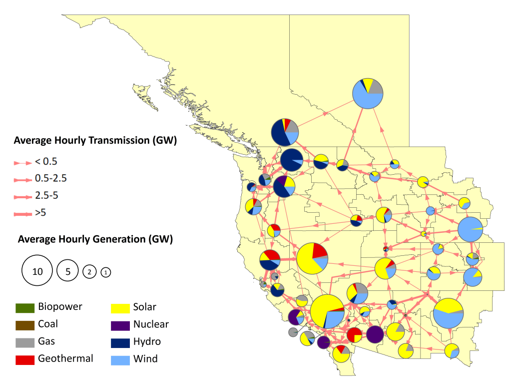


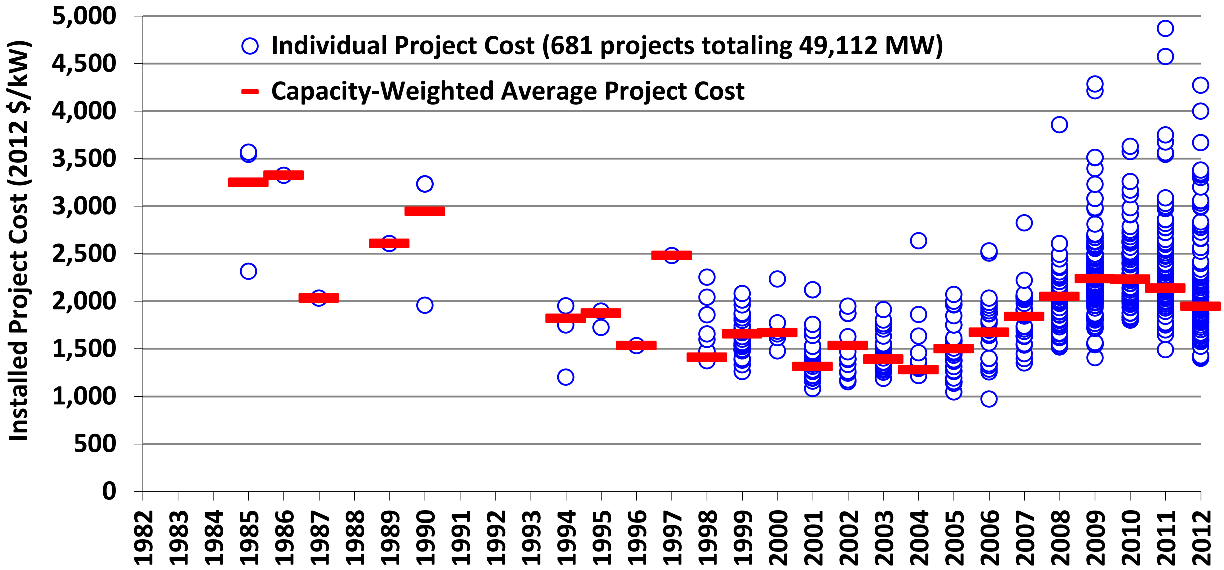
Figure 10: *Map of Generation and Transmission in the Limited Technology SunShot Scenario.*



[34] Zheng, Cheng and Kammen, Daniel (2014) "An Innovation-Focused Roadmap for a Sustainable Global Photovoltaic Industry", *Energy Policy,* in press.
[35] Nelson, J. H., Johnston, J., , A., Fripp, M., Hoffman, I., Petros-Good, A., Blanco, C., and Kammen, D. M. (2012) "High-resolution modeling of the western North American power system demonstrates low-cost and low-carbon futures", *Energy Policy,* **43**, 436–447.
[36] Mileva, A., Nelson, J. H., Johnston, J., and Kammen, D. M. (2013) "SunShot Solar Power Reduces Costs and Uncertainty in Future Low-Carbon Electricity Systems," *Environmental Science & Technology, **47*** **(16)**, 9053 – 9060.

Future Price of Wind Power

US wind project costs have not shown the same dramatic downward trajectory in recent years as household and commercial scale PV, as shown in Figure 11 below from the 2012 Lawrence Berkeley Laboratory wind market report:[37]



Source: LBNL

Figure 11: *US Wind Project Costs, 1982-2012.*

The report cites downward cost drivers including larger and taller turbines leading to greater nameplate capacity. At the same time, the report notes that curtailment of wind, and lower quality sites, work against project economics. Both of those factors in California – which would be expected to be become more significant as wind power density increases – would need to be considered in future analysis of wind economics in the state.

[37] Ryan Wiser, Lawrence Berkeley National Laboratory Mark Bolinger, Lawrence Berkeley National Laboratory, 2012 Wind Technologies Market Report, http://emp.lbl.gov/sites/all/files/lbnl-6356e.pdf.

Conclusions

California needs to contemplate significant changes to its electricity system as the state leads the way in climate policy for the country. We have examined two of these, chosen because they will reveal the issues with any portfolio. Three key points emerge from examining different pathways for decarbonizing electricity.

The first is that any solution for de-carbonizing electricity in California faces obstacles and difficulties exacerbated by the state's continually growing economy and population. The scale of the problem is significant, and the problem is urgent. Outcomes are fundamentally uncertain for any path. Ancillary system requirements for intermittent renewables present a challenge. Lack of public support for nuclear, and dependence on a robust carbon market for CCS as well as lack of experience with industrial relationships and certification of storage stand in the way of these technologies. However, in such circumstances, where the future is obscure, having more options available and better understood could be critical factors in achieving good outcomes for the State. Additional focus on the total system requirements for a strong renewable portfolio and efforts to keep CCS and nuclear options available could be of some value.

Second, many of the issues we bring up in this paper should be investigated further. The electricity system of today functions well based on many years of heuristic observations about what works and what causes problems. If we are to change this system significantly in the effort to eliminate GHG emissions, we should do everything possible to improve our understanding of the issues involved. Some of the key issues that deserve attention include:

- Models of reliability for highly intermittent systems that include all relevant potential instabilities. These likely need to be geographically focused.
- Grid modeling of high (e.g. 80%) renewable penetration, with various assumptions about storage and reasonable demand response.
- Technical research and development to improve ability of wind to provide grid support services.
- Public opinion analysis of nuclear acceptability in California in context of climate change, and under assumptions that the waste problem is "solved."
- Life-cycle analysis for all system components.
- Going beyond “levelized cost of electricity”: Better methods for comparing the system costs for various choices.
- As briefly mentioned in the introduction, characterization of key land use issues for large scale wind, solar, and associated transmission, including GIS mapping overlays of public lands, conservation lands, sensitive ecosystems, proximity to national parks that might trigger lengthy public reviews, etc. and some case study work of past conflicts.
- Conduct CCS EOR and saline reservoir pilots, to build understanding, and, to some extent, gauge public reaction.

Finally, nothing can substitute for real experience. The more we can try out ideas for the new electricity system by actually building experimental, demonstration and pilot projects, the better the chances are that California can make informed decisions in planning and implementing a system capable of meeting both its power generation needs and its greenhouse gas emissions goals.

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Dr. Long is currently the Principal Associate Director at Large and Fellow in the LLNL Center for Global Strategic Research for Lawrence Livermore National Laboratory, Senior contributing scientist for the Environmental Defense Fund, Visiting Researcher at UC Berkeley, and Consultant for geoengineering at the Bipartisan Policy Center. Her work is in strategy for climate change including reinvention of the energy system, adaptation and geoengineering. From 2004 to 2007, as Associate Director, she led the Energy and Environment Directorate for the Lawrence Livermore National Laboratory. The Energy and Environment Directorate included programs in Earth System Science and Engineering, Nuclear System Science and Engineering, National Atmospheric Release Advisory Center, and the Center for Accelerator Mass Spectrometry. In addition, the directorate included 12 disciplinary groups ranging from Earth sciences, to energy efficiency to risk science. From 1997 to 2003 Dr. Long was the Dean of the Mackay School of Mines. The Mackay School of Mines had departments of Geological Sciences, Mining Engineering and Chemical Engineering and Materials Science and Engineering as well as the Nevada Seismological Laboratory, the Nevada Bureau of Mines and Geology and the Keck Museum. Dr. Long led the University of Nevada, Reno's initiative for renewable energy projects and served as the Director of the Great Basin Center for Geothermal Energy and initiated the Mining Life-Cycle Center. Prior to this appointment, Dr. Long worked at Lawrence Berkeley National Laboratory for 20 years. She served as Department Chair for the Energy Resources Technology Department including geothermal and fossil fuel research, and the Environmental Research Department. She holds a bachelor's degree in engineering from Brown University and Masters and PhD from U. C. Berkeley. Dr. Long has conducted research in nuclear waste storage, geothermal reservoirs, petroleum reservoirs and contaminant transport.

Dr. Long currently co-chairs the "California's Energy Future" study conducted by the California Council on Science and Technology (CCST) and was recently elected as a Senior Fellow of CCST. She is co-chair of the National Commission on Energy Policy's Task force on geoengineering and a member of the steering committee for the Royal Society Solar Radiation Management Governance initiative. For the Dr. Long is an Associate of the National Academies of Science and was chairman of the US National Committee for Rock Mechanics, the Committee for Fracture Characterization and Fluid Flow and a committee to recommend a research program for the Environmental Management Science Program for DOE. She served on the NAS/NRC Board on Radioactive Waste Management, as well as several study committees under the aegis of this board, and had been a member of the Board on Energy and Environmental Systems. In 2001, she was appointed as a member, subsequently chair of the State of Nevada Renewable Energy Task Force., She is a Senior Fellow of the Breakthrough Institute,, member of the board of directors for Clean Air Task Force, and member of the Stanford University College of Earth Sciences Advisory Board. She has been a member of the UC Berkeley Department of Nuclear Engineering Advisory Board, the Colorado School of Mines Department of Geophysics Advisory

Board, the American Geological Institute Foundation Board, and the Energy and Environment and National Security Visiting Committee for Brookhaven National Laboratory, the Intercampus Advisory Board for the UC Energy Institute, the chairman for the mitigation advisory committee of the NAS Koshland Science Museum's Climate Change exhibition, and member of the Governor's Task Force on California's Adaptation to Climate Change sponsored by the Pacific Council.

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Review Process

The California Council on Science and Technology adheres to the highest standards to provide independent, objective and respected work. All work that bears CCST's name is reviewed by Board and Council Members. In addition the Council seeks peer review from external technical experts. The request for rigorous peer review results in a protocol that ensures the specific issue being addressed is done so in a targeted way with results that are clear and sound.

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