Submitted to the House Committee on Energy & Environment May 22, 2017 Marshall Sanders, Mapleton OR

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2) SB 990 bypasses nuclear energy **Voter Approval** processes acquired in 1980.

3) Nuclear Energy is more toxic and dangerous than any process known to humanity other than an atomic blast. Radioactive waste elements have deadly half-life contamination periods of 300 to 250,000 years. Nuclear reactors last less than 50 years. Are we ready to pass on the environmental, health and economic black holes of nuclear waste storage to thousands of generations in the future? There is no method of decontaminating radioactive material. It must be stored forever. This is not an acceptable risk.

4) Three Mile Island, Chernobyl and Fukushima were all accidents that the nuclear industry declared impossible before the accidents happened and have falsely tried to declare what happened afterwards, harmless. Any ordinary person who has read about these events knows that the industry does not foresee and plan for disasters, and that radioactive materials are the greatest threat to human and animal life on the planet.

5) We are stupefied by the inability of elected officials to not see the obviousness of the above concerns and who continue to be persuaded by **an obsolete industry** with vast capital and taxpayer resources that their deadly polluting technology needs to be resurrected from the dead so the nuclear power industry can profit. Across the world countries like Germany **are abandoning deadly nukes for renewables**. It's high time we do the same.

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CONSULTANT REPORT

COST-EFFECTIVENESS OF ROOFTOP PHOTOVOLTAIC SYSTEMS FOR CONSIDERATION IN CALIFORNIA'S BUILDING ENERGY EFFICIENCY STANDARDS

DRAFT

Prepared for: California Energy Commission

Prepared by: Energy and Environmental Economics, Inc.

Energy+Environmental Economics

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ABSTRACT

This consultant report was written for the California Energy Commission in response to the requirements of Senate Bill 1 (Murray, Chapter 132, Statutes of 2006). The report provides information about the cost-effectiveness of rooftop photovoltaic systems, including the analysis approach and results. The report will be used to help the Energy Commission address the requirement in SB 1 for determining when and under which conditions solar electric systems should be required in the Building Energy Efficiency Standards. SB 1 guides the consideration of cost-effectiveness in making this determination.

Keywords: Photovoltaic, cost-effectiveness, Building Energy Efficiency Standards, rooftop.

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EXECUTIVE SUMMARY

This report was written for the California Energy Commission in response to the requirements of Senate Bill 1 (Murray, Chapter 132, Statutes of 2006), which calls for an evaluation of whether, and under what conditions, solar electric systems are cost-effective for inclusion in the state's Building Energy Efficiency Standards (Title 24, Part 6). The cost-effectiveness analysis, which forms the basis for the conclusions of this report, is based on the Warren-Alquist Act (1974), which requires the California Building Energy Efficiency Standards ("standards") to be cost-effective when taken in their entirety and when amortized over the economic life of the structure compared with historical practice.

Using the input assumptions and method described in this report, which projects the current trend in solar photovoltaic (PV) costs and maintains current rate structures and policies, we find that rooftop solar electric systems will be cost-effective in 2020 for a large portion of California's commercial and residential electricity consumers. The scope of this study is narrowly defined, with a particular focus on cost-effectiveness within the standards. Other factors besides cost-effectiveness must also be considered before PV installations are required in the standards. This report does not address any of the impacts of potential changes in practices within the construction or PV industries, nor does it consider the impacts of rooftop PV on the reliable operation of California's electric grid.

The cost-effectiveness analysis detailed here relies on several important assumptions about California's solar energy landscape through 2020. These key assumptions are:

- Utility electricity rate structures and Net Energy Metering (NEM) rules do not change significantly throughout the lifetime of rooftop PV systems installed through 2020. Changes in those areas could have a dramatic impact on solar's cost-effectiveness, but due to the difficulty in predicting what form such changes may take, the research team's analysis relies on existing rate structures and a continuation of the NEM policy.
- If rooftop PV systems are included in a Title 24 requirement, they will not be eligible for existing incentives such as the California Solar Initiative (CSI) and the New Solar Homes Partnership (NSHP).
- The federal investment tax credit (ITC) drops from 30 percent to 10 percent in 2017, as called for in existing legislation.
- Utility electricity rates increase at 2.11 percent per year through 2020 and 1.42 percent per year after 2020, in real terms. This is based on a forecast of retail rate escalation under an "AB 32" compliant scenario, which accounts for the impact of California's greenhouse gas reduction policies on retail electricity rates.
- Rooftop PV system costs continue to decline through 2020. The research team's PV cost forecast begins with reported 2012 costs from the CSI project database and then assumes that costs will drop significantly each year through 2020, continuing the trend in actual PV cost reductions observed from 2007 to 2012. For California's PV costs to meet this forecast, both module and installation costs must decline consistently, driven by a robust and competitive PV market.

The authors examine PV's cost-effectiveness using two approaches. The first approach, referred to as the average consumer analysis, follows the adopted time dependent valuation (TDV) method used in Title 24 evaluation since 2005. TDV is a time varying measure of energy that accounts for both the enery used at the building site and consumed in producing and delivering energy to the site, including, but not limited to power generation, transmission and distribution losses. Using the the average consumer analysis method, the authors find that rooftop PV will be cost-effective for both residential and nonresidential new construction across all climate zones by 2020.

The second approach, the market-segmented analysis, calculates PV's cost-effectiveness based on projected utility bill savings. Bill savings are calculated specific to different building types, annual electricity consumption, climate zones, and utility rates. The market-segmented analysis demonstrates the variability of PV cost-effectiveness based on those critical consumer characteristics. Rooftop solar installations are shown to be cost-effective in 2020 only for residential consumers whose annual electricity usage is above 5,000 kilowatt hours (kWh). Furthermore, while the average consumer analysis suggests that PV will be cost-effective for large and small commercial consumers in 2020, the market-segmented analysis projects that PV will be consistently cost-effective only for small commercial consumers, while cost-effectiveness for large commercial customers varies by utility service territory. This discrepancy is due to differences in rate structure: Small commercial consumers' rates allow them to access larger bill savings than large commercial customers. Contrasting the average consumer results to the market-segmented results demonstrates the importance of utility rate structures, climate zone, and annual consumption in determining PV cost-effectiveness.

CHAPTER 1: Introduction

This report prepared by Energy and Environmental Economics, Inc. (E3) was commissioned by the California Energy Commission to evaluate the cost-effectiveness of solar electric systems in the context of the state's Building Energy Efficiency Standards ("standards"). The report is written in compliance with the requirements of Senate Bill 1 (Murray, Chapter 132, Statutes of 2006) and is designed to help the Energy Commission determine whether, and under what conditions, solar electric systems[1] should be required on new residential and new nonresidential buildings as part of the state's standards. Furthermore, rooftop PV systems are expected to play an important role in meeting California's Long-Term Energy Efficiency Strategic Plan zero net-energy building goals and are included as part of the California Air Resources Board's *Scoping Plan* to meet the state's greenhouse gas reduction targets under Assembly Bill 32 (Nuñez, Chapter 488, Statutes of 2006).[2]

The conclusions in this report are based on a range of forecasts of the cost-effectiveness of rooftop photovoltaic installations on newly constructed buildings between 2014 and 2020. This report answers the following research questions:

- Under what conditions is rooftop PV on newly constructed residential and nonresidential buildings expected to be cost-effective from an average consumer savings perspective from 2014 to 2020?

- Is rooftop PV for newly constructed buildings expected to be cost-effective from 2014 to 2020 for specific residential or commercial market segments?

Approach

Cost-effectiveness is evaluated using two metrics: 1) average consumer savings, which evaluates whether PV is cost-effective to residential and commercial building owners on average across climate zones, and 2) market-segmented savings, which evaluates whether PV is cost-effective to building owners based on their specific retail rate and annual electricity consumption, again compared by climate zone. In both approaches, the life-cycle benefits and life-cycle costs of PV are evaluated over a 25-year horizon, corresponding with the current industry-standard PV module warranty lifetime. The life-cycle costs of PV are evaluated over a

1 For purposes of this report, solar electric systems are limited to rooftop photovoltaic (PV) systems.

2 See the *Energy Efficiency Strategic Plan* at http://www.cpuc.ca.gov/PUC/energy/Energy+Efficiency/eesp/ ; the *ZNE Action Plan* at: http://www.cpuc.ca.gov/NR/rdonlyres/6C2310FE-AFE0-48E4-AF03-530A99D28FCE/0/ZNEActionPlanFINAL83110.pdf ; and the California Air Resources Board *Scoping Plan* at: http://www.arb.ca.gov/cc/scopingplan/document/scopingplandocument.htm

20-year period, the standard duration of rooftop solar power purchase agreements (PPAs), followed by a 5-year period of no additional costs to the customer.

Average Consumer Savings Analysis[3]

The average consumer savings is analyzed for residential and nonresidential customer classes based on a forecast of average residential and nonresidential retail rates. The approach is the same as the one used to evaluate new building requirements in the Energy Commission Title 24 process based on time dependent valuation (TDV). The forecast reflects wholesale market forecasts for the future cost of electricity, including natural gas fuel, the cost of new conventional generation capacity, the cost of new renewable generation capacity, transmission, distribution, ancillary services, losses, and a forecast of market prices for carbon dioxide emissions and other air emissions criteria. The retail rate forecast includes the expected effects of current electricity sector policy goals, such as the 33 percent renewable electricity standard and higher levels of energy efficiency.

Market-Segmented Savings Analysis

In the market-segmented savings analysis[4], the benefits of a rooftop PV installation are calculated differently than for the average consumer analysis. The benefits include the avoided cost of retail electricity prices based on a customer's existing specific retail rate. Rate structures vary significantly by customer type. Most residential electricity rates in California are "inclining block," or tiered, meaning that the cost of electricity increases with higher volume consumption. In contrast, most commercial electricity rates in California do not increase with higher consumption. Many medium to large commercial rates vary based on the time of use (TOU) of electricity consumption. Under TOU rates, on-peak reductions in electricity use are valued more highly than off-peak reductions. An additional difference between residential and commercial rate structures is the inclusion of demand charges: Commercial consumers typically pay charges per their maximum energy demand in a specific period. For example, many TOU commercial rates include a high per kW demand charge during the summer on-peak period.

Key Assumptions

Evaluating the cost-effectiveness of rooftop PV installations for newly constructed buildings is complex and depends on many variables. The authors address this complexity by using scenario analysis and categorizing the results by climate zone and broad customer classes. However, it would be impossible to evaluate every possible combination of conditions that

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3 The average consumer savings analysis is based on the time dependent valuation "base" values developed as part of the Commission's update to the *2013 Building Energy Efficiency Standards*. For more information on this method,
see: http://www.energy.ca.gov/title24/2013standards/prerulemaking/documents/

4 The market-segmented savings analysis approximates consumers' bill savings.

could affect PV's cost-effectiveness across California. Therefore, the results of the analysis should be interpreted as broadly indicative of cost trends for PV across the state.

PV system costs and characteristics are one set of critical variables that affect the cost-effectiveness analysis. The authors assume that the capital cost of PV will continue to decrease over time, in line with historical trends that have shown significant cost reductions since 2007 and earlier. Because the expected electricity generation of a PV system varies by location based on the solar resource available, the authors show PV cost-effectiveness results for each of California's 16 climate zones. PV system size is another important input; in this analysis, the authors assume that all residential and small commercial systems are smaller than 10 kW in size, while all large commercial PV installations are between 10 to 100 kW. The authors assume that all PV systems are roof-mounted and do not evaluate the cost-effectiveness of ground-mounted systems or larger "community solar" type installations.[5] Throughout this analysis, the authors assume that rooftop PV systems accrue benefits over a 25-year economic lifetime.

Another factor in this analysis is the forecast of electricity retail rate escalation. The research team assumes that retail rates will increase by 2.11 percent per year through 2020 and 1.42 percent per year after 2020 (in real terms), as California replaces much of its electricity generation with less-polluting resources and implements other greenhouse gas reduction measures in compliance with the Global Warming Solutions Act of 2006 (AB 32)[6].

E3's analysis assumes that if PV were incorporated into the building code, installations would not directly receive a financial credit for helping to meet the state's Renewables Portfolio Standard (RPS), nor would they be eligible for current state solar incentives such as the California Solar Initiative (CSI) and the New Solar Homes Partnership (NSHP).[7]

The structure of electricity rates and the Net Energy Metering (NEM) program is also important to the analysis. The authors assume that the structure of California utility rates will not change dramatically before 2020. Changes to utility rates, such as increasing demand and/or service charges while decreasing energy charges, could have a large effect on consumers' utility bill savings upon installing PV. Furthermore, the authors assume that California's existing NEM program will remain in place in its current form for the lifetime of systems installed through

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5 Community solar projects are expected to show some cost benefits over rooftop-mounted PV systems because the larger systems could achieve economies of scale. However, there are significant challenges to widespread deployment of community solar including tariffs and interconnection rules that are beyond the scope of this analysis.

6 For more information about AB 32, please see the California Environmental Protection Agency Air Resources Board website at http://www.arb.ca.gov/cc/ab32/ab32.htm.

7 Depending on how the Commission chooses to implement the updated Base Code and CALGreen Tiers 1 and 2, the NSHP incentive could continue to be available to new home construction. However, this analysis does not predicate the cost-effectiveness results based on the presence of state solar incentives.

2020. In reality, there is a cap on the installed capacity of NEM generation, and the NEM rules may change before 2020. The cost-effectiveness of rooftop PV could vary significantly depending on the compensation to NEM generators for exports to the grid. For this analysis, the authors rely on existing rate structures and NEM rules due to the large uncertainty in exactly how they might change and what alternatives could replace them.

While the cost-effectiveness analysis accounts for the major costs and benefits of rooftop PV, there are other less readily quantified attributes of solar that are not included. For example, in comparison to other renewable resources, rooftop PV has the benefit of being relatively quick to deploy and does not require additional land. Rooftop installations also have the potential to avoid new long-line transmission to interconnect generation to loads. Furthermore, rooftop PV does not use large quantities of water for thermal generation cooling. On the other hand, this report does not address any potential distribution system costs that could arise from introducing large quantities of behind-the-meter generation onto the grid.

Key Findings

Using an average consumer savings approach, rooftop PV installations are projected to be cost-effective by 2020 in residential new construction and both large and small commercial construction. While the degree of cost-effectiveness varies by climate zone, the average consumer benefits of installing PV outweigh the costs across all climate zones. In contrast, the market-segmented results indicate that rooftop PV will be cost-effective only for certain sectors of consumers in 2020, depending on climate zone, utility rate, and annual electricity usage. The central results of both the average consumer and market-segmented cost-effectiveness analysis in 2020 are shown in Table 1 below, segregated by building type.

Table 1: Summary of Cost-Effectiveness Results of California Rooftop PV for Newly Constructed Buildings, 2020

	Average Consumer Results, 2020	Market-Segmented Results, 2020
Residential Consumers	Cost-effective	Cost-effective in all climate zones only for consumers with annual electricity usage above 5,000 kWh
Small Commercial Consumers	Cost-effective	Cost-effective in most climate zones/utility service territories
Large Commercial Consumers	Cost-effective	Not cost-effective in most climate zones/utility service territories

Source: Energy and Environmental Economics, Inc.

Ultimately, deciding whether to include PV in the California Building Energy Efficiency Standards requires consideration of more than just the cost-effectiveness issues raised here. The integration of PV into the energy code should happen in a well-planned and phased manner, taking into account the state's policy objectives, as well as the costs, benefits, and less tangible attributes of PV. Any PV requirement would ideally be designed to ensure that the solar and building industries in California are ready to meet the additional need for solar installations with each successive building standard requirement. In addition, the code would need to include provisions to handle locations that are not suitable for solar generation. These other considerations are not addressed in this study.

CHAPTER 2: Benefit–Cost Analysis Approach

The research team evaluates the cost-effectiveness of PV using an approach that compares the costs and benefits over the life of the system from the owner's perspective. To calculate a benefit-cost ratio, the life-cycle benefits of PV are divided by the life-cycle costs of PV. If the ratio of benefits to costs is greater than one with reasonable certainty, then PV is determined to be cost-effective.

The cost of electricity produced by a solar electric system depends on the installed capital cost, financing costs, taxes, and federal incentives associated with PV, as well as the amount of electricity generated by the PV system. The benefits of solar to the consumer (that is, building owner) are the avoided utility bills. In the average consumer savings analysis, average consumer savings are calculated using the hourly time dependent valuation (TDV) costs adopted in the 2013 Title 24 proceeding. These TDV factors reflect the shape of the underlying market value of electricity in each hour of the year, including avoided greenhouse gas emissions, avoided energy and capacity costs, and avoided transmission and distribution costs. In the market-segmented savings analysis, the current utility rates, such as tiered residential retail rates and time-of-use commercial retail rates, are used to calculate the bill savings by segmented customer class. Each component of these benefit-cost analyses is discussed in more detail below.

Costs: PV Cost Assumptions

Installed System Cost and Progress Ratios

Installed PV system costs are based on the PowerClerk database[8] of California Solar Initiative systems, with adjustments to create a forward-looking forecast of capital costs. The PowerClerk data reflect the "self-reported" cost of more than 100,000 actual PV systems installed on buildings between 2007 and 2012. This database was used because it is the most detailed rooftop PV dataset available for actual California installations. Installed capital cost data from the New Solar Homes Partnership program are used to benchmark capital cost data for rooftop PV installations on newly constructed buildings.

8 The research team obtained data directly from the PowerClerk database manager, Clean Power Research. The PowerClerk database holds solar system data from applicants who have participated California Solar Initiative solar incentive program.The data are available online at https://csi.powerclerk.com/CSIProgramData.aspx; however, some fields are not publicly available to protect customer identities.

Table 2 shows the median cost, in $/watt, of CSI installed systems by size category for the years 2007 to 2012, based on the system reservation date.

Table 2: CSI Installed Systems, in $/Watt, From the PowerClerk Database

System Size Category (kW)	2007	2008	2009	2010	2011	2012
< 10	$8.00	$7.95	$7.39	$6.55	$6.36	$5.38
10-100	$7.70	$7.68	$6.77	$5.89	$5.39	$4.52

Source: Energy and Environmental Economics, Inc.

Using data from the NSHP and CSI, the Lawrence Berkeley National Laboratory report *Tracking the Sun V*[9] compares the cost of rooftop PV systems installed as a part of a residential retrofit to those installed in residential new construction from 2007 to 2011. For new construction installations, the report distinguishes between rack-mounted and building-integrated systems. The comparison includes only systems between 2-3 kW, the most common size range for PV systems installed in residential new construction. Between 2007 and 2009, rack-mounted PV systems installed in newly constructed homes cost between $0.80-$1.20/watt less than those installed as a retrofit on an existing home. In 2010 and 2011, the cost difference was much smaller, possibly due to a reduced sample size driven by the slowdown in residential construction during those years. In this analysis, the authors assume a $1.20/watt cost difference for retrofit versus new construction rooftop PV systems. This cost difference represents some of the uncertainty in the future capital costs of PV systems.

9 Barbose, Galen, Naim Darghouth, Ryan Wiser. December 2010. *Tracking the Sun V: A Historical Summary of the Installed Price of Photovoltaics in the United States From 1998-2011.* Lawrence Berkeley National Laboratory.

The research team developed two scenarios of PV capital costs to reflect the uncertainty of the future cost of PV systems:

- In Scenario 1, the authors use the 2012 CSI capital costs as the starting point for the analysis. Since the CSI program provides incentives to retrofit installations, which are historically more costly than installations in new construction, the authors use CSI reported costs to represent a more conservative (higher) trajectory for solar capital costs. They apply the progress ratio assumption described below to the 2012 costs to develop a forecast through 2020.

- In Scenario 2, the authors adjust the 2012 CSI PV capital costs downward by $1.20/watt to reflect that PV systems on newly constructed buildings may cost less than installations on existing buildings. They apply the same progress ratio assumption to these costs to generate a lower cost forecast through 2020.

The authors use a "progress ratio" approach in their analysis to develop a forecast of PV system costs through 2020. A progress ratio estimates the change in capital cost of solar after a doubling in cumulative installed capacity. Based on evidence from the available literature, we apply an 80 percent progress ratio to 2012 installed system costs, meaning that for every doubling in cumulative installed capacity after 2012, installed system cost declines by 20 percent.[10]

While solar progress ratios generally apply to module cost, the research team applies the 80 percent progress ratio to the full installed system cost. A Lawrence Berkeley National Laboratory study found that markets with large solar deployment programs tend to have lower installed system costs, suggesting that balance-of-system costs (such as installation costs) decline with market growth.[11] Based on this evidence, the authors believe the simplifying assumption of applying an 80 percent progress ratio to total installed cost is reasonable over the period of this study. For more details about how the progress ratio is applied to PV costs, see the CPUC California Solar Initiative Cost-Effectiveness Evaluation.[12]

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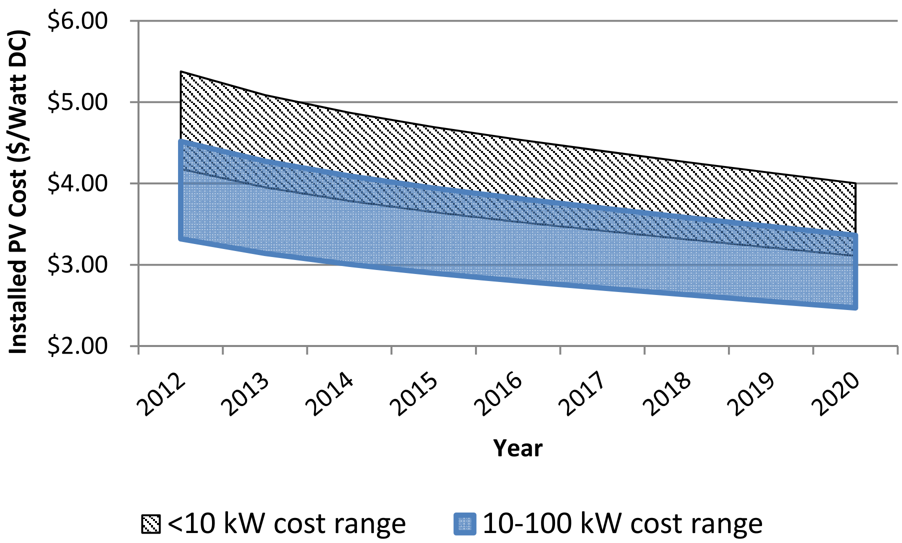
10 Surek, Thomas., 2007.National Renewable Energy Laboratory, *Progress in U.S. Photovoltaics: Looking Back 30 Years and Looking Ahead 20*; and, *Solar Energy Materials and Solar Cells Journal*.

11 Wiser, Ryan, Galen Barbose, and Carla Peterman. February 2009. *Tracking the Sun: The Installed Cost of Photovoltaics in the U.S. from 1998-2007.* Lawrence Berkeley National Laboratory,

12 CPUC CSI Program Evaluation, see the CSI Cost Effectiveness Evaluation of April 2011: http://www.cpuc.ca.gov/PUC/energy/Solar/evaluation.htm

The high and low forecasts of installed system cost for Scenarios 1 and 2 are shown in Figure 1 below.

Figure 1: High and Low PV Capital Cost Forecasts



Source: Energy and Environmental Economics, Inc

For this analysis, all residential and small commercial systems are modeled using the median cost of solar systems under 10 kW in size. For large commercial customers, the authors use the median average solar cost for systems between 10 and 100 kW in size.[13]

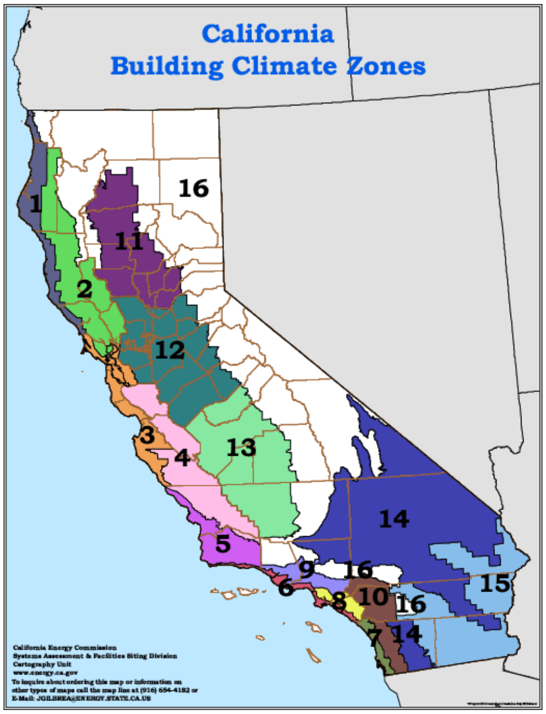
System Performance by Climate Zone

The amount of electricity generated by PV systems varies by climate zone based on the weather patterns and insolation (amount of solar radiation) in each region. The capacity factor of a PV system is a measure of the average energy produced over the year relative to the system's peak generating capacity. A difference in capacity factor of only a few percentage points can have a dramatic effect on solar's cost-effectiveness results.

The 16 climate zones used in this analysis are the same climate zones used in the Commission's Building Energy Efficiency Standards (see Figure 2).

13 *Small commercial* is defined as any rooftop PV installation under 10 kW in size, and large commercial is defined as any rooftop PV installation over 10 kW and under 100 kW in size.

Figure 2: California Building Energy Efficiency Standards Climate Zones



Source: California Energy Commission

Given the importance of the capacity factor assumption to the final results and the uncertainty in actual PV production forecasts for a given installation, the authors develop two scenarios of capacity factors by climate zone:

- Scenario 1 uses the capacity factor estimates by climate zone that are produced by the PVWatts model, a PV simulation tool developed by the NREL. [14]

- Scenario 2 uses capacity factors by climate zone based on actual, metered generation data from the CSI load impact studies.

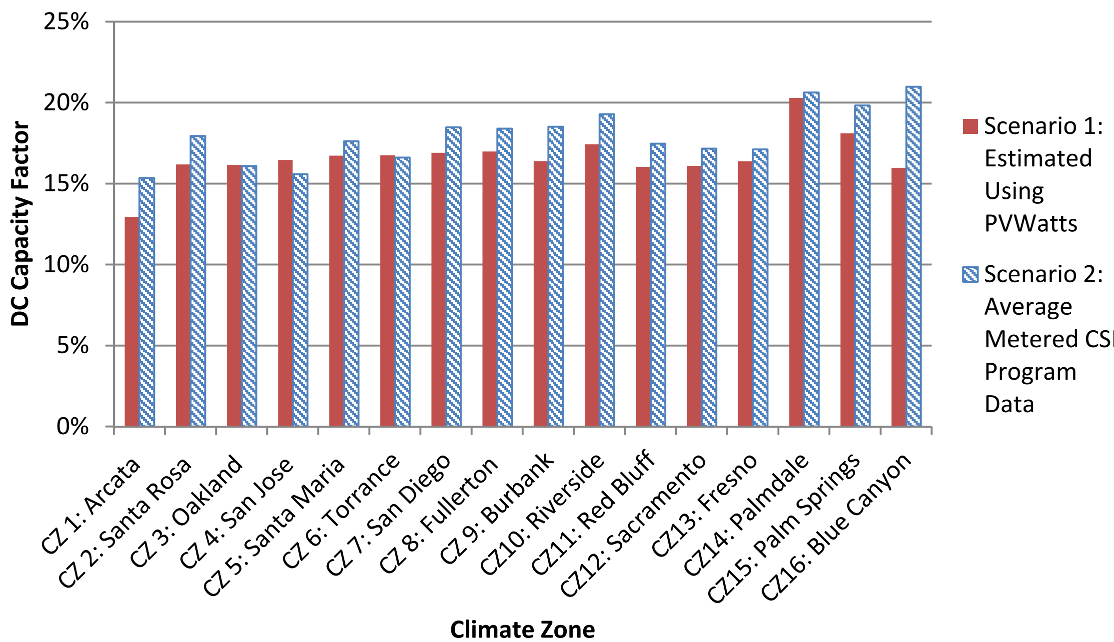
In general, the actual CSI database capacity factors are higher than the modeled PVWatts capacity factors. There could be a number of factors contributing to these differences, but the authors expect that the main difference is due to self-selection on the part of the CSI customers to install PV systems in areas with higher than average insolation within a given climate zone, coupled with the CSI program's performance-based incentive, which pays solar incentives based on a system's metered energy production.

14 Another potential source for capacity factors would be the CECPV model. In general, the CECPV model results in slightly higher capacity factor estimates compared to PVWatts and is closer to measured performance. The PVWatts capacity factors used here are conservative input assumptions for the "more expensive solar" scenario.

Although it is likely that the effects of shading differ between retrofit and newly constructed buildings, the authors have not found any documented evidence to suggest that the capacity factor varies for retrofit versus newly constructed building installations or between residential and commercial installations (for a given system type). Figure 3 shows the capacity factors by climate zone applied in Scenario 1 (PVWatts) and Scenario 2 (average metered CSI generation data).

Figure 3: PV Capacity Factors by Climate Zone

Scenario 1 Uses PVWatts Data, Scenario 2 Is Based on Average Performance of Actual CSI Installed Systems



Source: Energy and Environmental Economics, Inc.

Treatment of Uncertainty Through Two Scenarios

The research team uses two scenarios to reflect the uncertainty in forecasting PV cost-effectiveness. By combining the range of capital costs described in the section "Installed System Cost and Progress Ratios" and the range of capacity factors described in the section "System Performance by Climate Zone," the authors generate the following two scenarios:

1. Scenario 1 reflects a forecast of "more expensive solar" using higher capital costs and lower capacity factors.

2. Scenario 2 reflects a forecast of "less expensive solar" using lower capital costs and higher capacity factors.

These scenarios create reasonable uncertainty bounds on a range of potential PV costs and are summarized in Table 3 below.

Table 3: Assumptions Applied in Scenarios 1 and 2

Scenario	Capital cost assumptions	Capacity factor assumptions
Scenario 1: More expensive solar	Higher capital costs: CSI data based on retrofit installations, adjusted for 80% progress ratio	Lower capacity factors: PVWatts modeled data
Scenario 2: Less expensive solar	Lower capital costs: CSI costs reduced by $1.20/watt to approximate installations on newly constructed buildings, adjusted for 80% progress ratio	Higher capacity factors: actual CSI program metered generation data

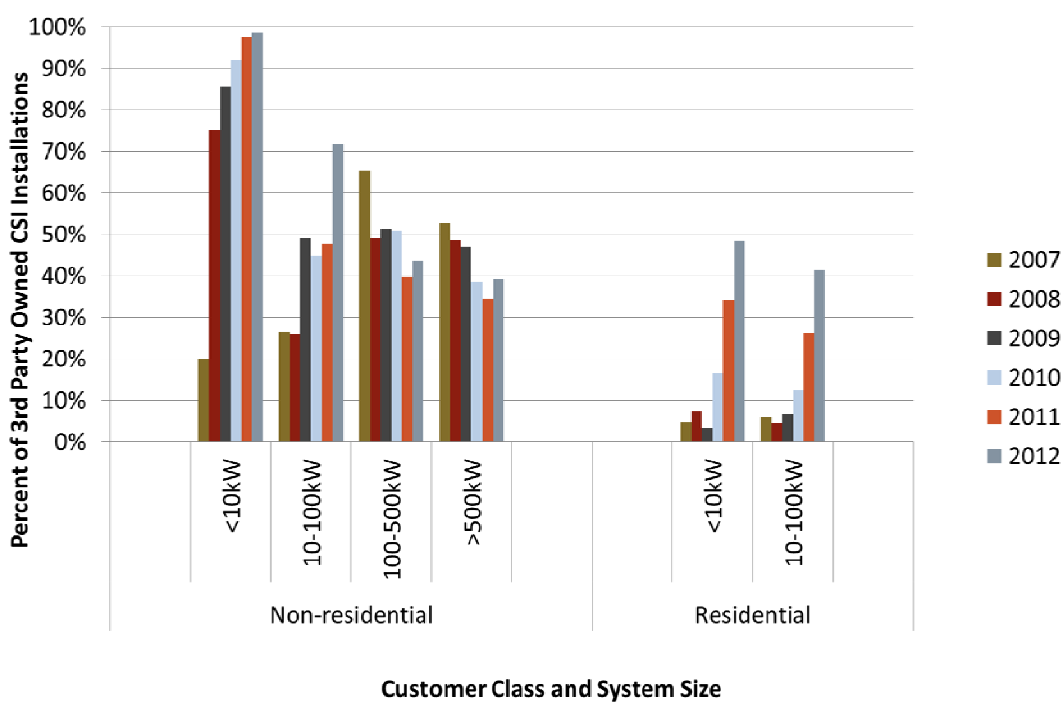
Source: Energy and Environmental Economics, Inc.

Levelized Cost of Energy Produced by PV Systems

System Financing

Several financing options exist for residential and commercial rooftop PV systems. Third-party ownership (power purchase agreement [PPA]) financing is very common among large commercial systems and is rapidly becoming more common for residential systems; we expect this trend to continue. The following figure shows the increasing share of third-party financed residential and non-residential systems participating in CSI since the program began in 2007.

Figure 4: Percentage of Third Party-Financed PV Installations in CSI Database



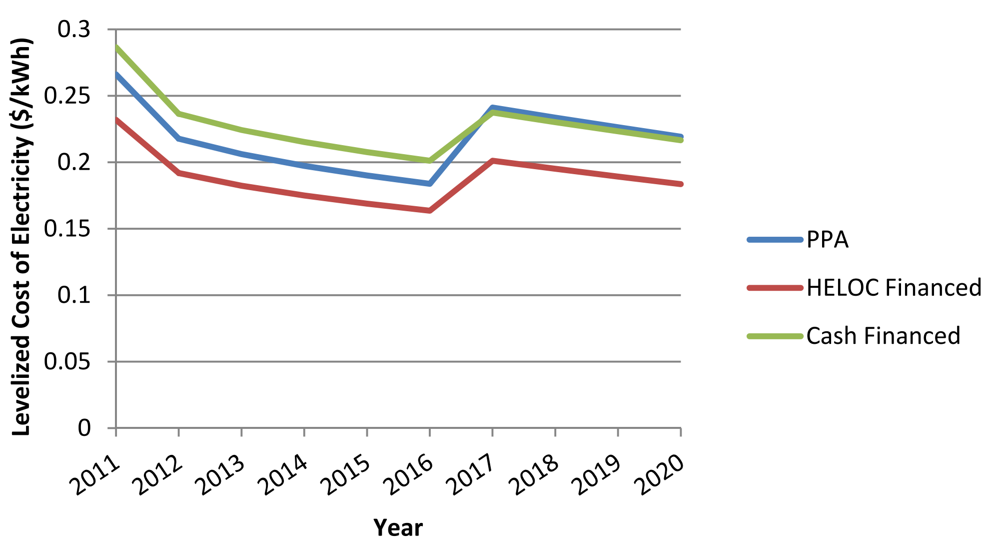
Source: California Solar Initiative

The research team assumes third-party ownership financing in the analysis due to its prevalence in the California market and because it allows straightforward comparison between the cost of commercial and residential systems. To calculate the life cycle or levelized cost of energy (LCOE) using third–party ownership financing, the authors calculate the revenue stream that a third party would need to collect from the customer to receive a return on investment, based on a financial *pro forma,* that is, a standardized financial cost model. The authors assume that PPAs are signed for a 20-year duration, which is the current PV industry standard. The resulting LCOE reflects the underlying assumption that PPA pricing is highly competitive and and that PV leases are priced to generate a 7.7 percent return on capital (10 to 12 percent return on equity); in reality, PPA prices may be higher based on dynamics and competition in the California market.

A common alternative to third-party finance for PV systems is private homeowner purchase of the system using a home equity line of credit (HELOC), or a second mortgage. A HELOC allows the homeowner to borrow the full value of the system cost at a low interest rate, and the loan interest is tax deductible. As a result, purchased systems yield a slightly lower LCOE than third-party owned systems. However, homeowners are continuing to opt for third party-owned PV systems, likely due to reduced hassle and relief of maintenance obligations. In addition, not all homeowners have the ability to qualify for a HELOC or increased borrowing from an existing loan. Figure 5 below compares the levelized cost of solar in Climate Zone 3 under the "less expensive solar" scenario, calculated using three different financing options: third-party ownership with a PPA, private ownership purchased with a HELOC, and private ownership purchased with cash. For this comparison, the authors assume a 20-year financing term and system lifetime for all financing structures.

Figure 5: PV Levelized Cost by System Financing Structure

Climate Zone 3, "Less Expensive Solar" Scenario (Scenario 2)



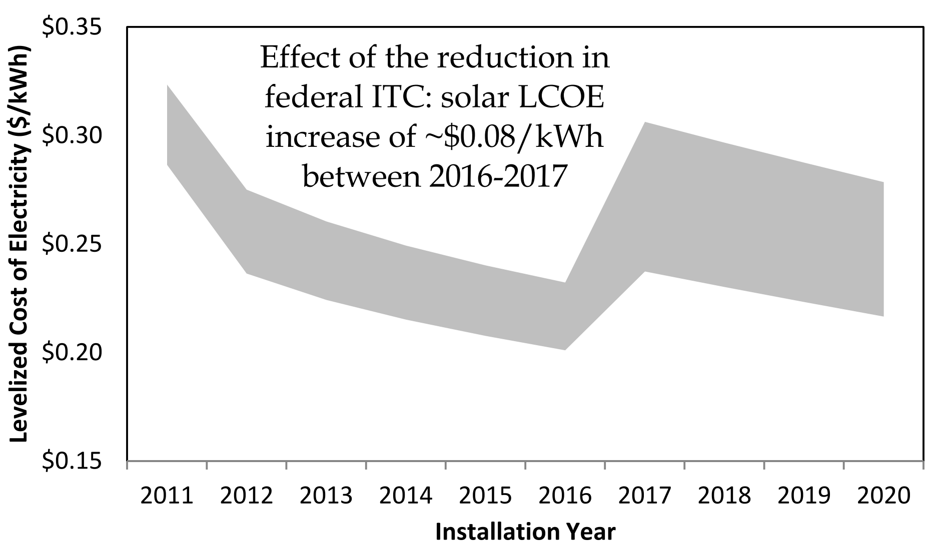
Source: Energy and Environmental Economics, Inc.

Taxes and Incentives

Tax considerations are another important component of the cost of solar electric systems in California. The research team's financial analysis applies state and federal taxes at the relevant rate for residential and commercial customers (see Table 4). The authors also include the federal investment tax credit (ITC) in their modeling, which they assume drops from 30 percent to 10 percent at the start of 2017, consistent with current federal policy. The dramatic effect of the expected change in the federal ITC after 2016 is shown in Figure 6. The LCOE of rooftop PV projects is shown to generally decline between 2011 and 2020 due to expected reductions in the capital cost of PV driven by industry growth; technology improvements; and streamlined manufacturing, marketing, and installation processes. However, the LCOE of solar is expected to increase significantly in 2017 with the reduction in the federal ITC from 30 percent to 10 percent. Figure 6 below shows the forecasted range of the LCOE of solar from 2011 to 2020. The top of the range reflects the Scenario 1 assumptions (more expensive solar), while the bottom of the range reflects Scenario 2 assumptions (less expensive solar).

Figure 6: Effect of the Expected Reduction in the Federal Investment Tax Credit on the Levelized Cost of Electricity From Rooftop PV Projects

2011 – 2020, Climate Zone 3 (Bay Area)



Source: Energy and Environmental Economics, Inc.

California's existing incentive programs, CSI and NSHP, are not included in this analysis. The authors assume that if PV systems are included in the building code, they will not qualify for incentive programs.

Table 4 summarizes the key financing and tax assumptions used in the analysis.

Table 4: Key Financing Assumptions

Financing Term	Input Assumption
After-tax weighted average cost of capital (WACC)	7.7%
Debt interest rate	6.8%
Cost of equity	10.15%, 12.2% after 2016
Debt period	20 years
Federal tax rate	35%
State tax rate	8.84%
Federal tax credit	30%, 10% after 2016
Percent financed with equity	60%, 45% after 2016
California state incentive (CSI or NSHP)	None
Accelerated depreciation (MACRS term)	5 years

Source: Energy and Environmental Economics, Inc.

Resulting Costs

Given the financing, tax, and incentive assumptions detailed above, the resulting levelized costs of electricity produced by PV systems vary by scenario, climate zone, and customer type. These costs range from $0.13/kWh to $0.25/kWh in 2014, as summarized in Table 5 below. This cost range is fairly wide due to the range of solar capacity factors and solar capital costs used in the scenarios. Climate Zones 3 and 10 are selected as examples in Table 5 because they are two highly populated areas of California and they represent the range of PV energy costs across the state. The solar resource in Climate Zone 3, located in the coastal San Francisco Bay Area, is not as good as the rest of the state on average, resulting in higher PV costs. Climate Zone 10 is located in inland Southern California and reflects a relatively plentiful solar resource, leading to lower PV costs.

Table 5: 20-Year Levelized Cost (LCOE) for Rooftop PV in 2014, Examples of Climate Zone 3 and Climate Zone 10 ($/kWh)

	Size	2014		2017		2020	
Climate zones	kW	Scenario 1	Scenario 2	Scenario 1	Scenario 2	Scenario 1	Scenario 2
3,10	< 10	$0.20, $0.16	$0.25, $0.23	$0.24, $0.20	$0.31, $0.28	$0.22, $0.18	$0.28, $0.26
3,10	10-100	$0.16, $0.13	$0.21, $0.19	$0.19, $0.15	$0.26, $0.24	$0.17, $0.14	$0.23, $0.21

Source: Energy and Environmental Economics, Inc.

In the next section, the levelized cost of solar by climate zone is compared to the 25-year life-cycle benefits for solar to determine cost-effectiveness.

Benefits: Avoided Cost of Electricity

The benefits of a rooftop PV system to a building owner are the retail electricity bill savings resulting from the system's generation. In this analysis, the bill savings are calculated using two approaches: 1) average consumer savings and 2) market-segmented savings. Each perspective is described in more detail below.

Average Consumer Savings

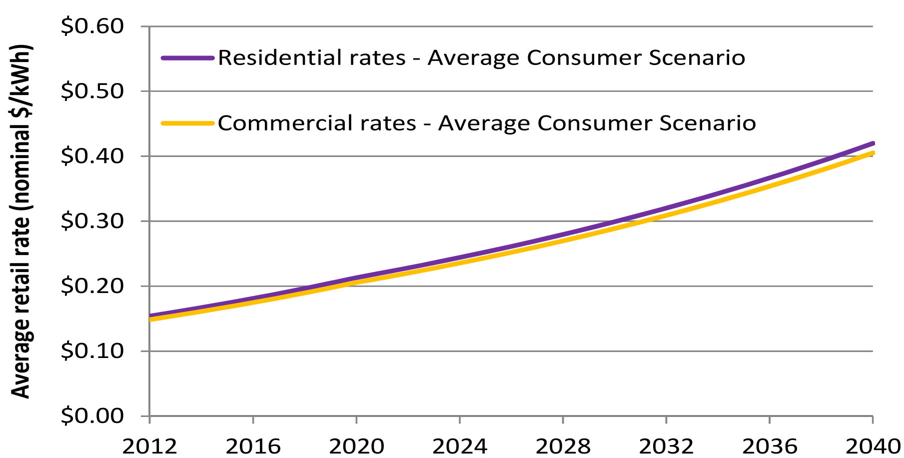
The average consumer savings analysis values energy savings (in the case of energy efficiency) and energy production (in the case of rooftop PV) based on an estimate of cost savings to the average consumer using a forecast of statewide average retail rates. The average consumer savings analysis approach has formed the foundation for the avoided cost of energy calculation underlying the *Building Energy Efficiency Standards* since 2005.[15] In this analysis, the value of electricity generated by PV varies on an hourly basis to reflect the actual costs of producing and delivering electricity to consumers. Specifically, the benefits of rooftop PV include a 25-year life-cycle assessment of PV's avoided energy costs, avoided capacity costs, avoided transmission

15 The average consumer savings analysis is based on the time dependent valuation "base" values developed as part of the Commission's update to the *2013 Building Energy Efficiency Standards*. For more information on this method, see: http://www.energy.ca.gov/title24/2013standards/prerulemaking/documents/

and distribution costs, and avoided greenhouse gas emissions, among other factors. These benefits are calculated based on a simulation of hourly market prices for electricity and depend on factors such as typical hourly temperatures by climate zone and season, a forecast of statewide electricity demand, and the forecasted future supply portfolio of generators. A retail rate adder is applied to these hourly values to bring the average hourly "market" avoided costs of electricity equal to statewide average retail rates in each year of the forecast. The authors use a 25-year PV lifetime in this analysis to represent the current industry-standard PV module warranty duration.

The retail rate adder escalates each year. From 2012 to 2020, retail rates are assumed to escalate at 2.11 percent per year, in real terms. This is based on a forecast of retail rates under an AB 32-compliant scenario, whereby the electricity sector meets the targets in the California Air Resources Board *Scoping Plan*" and achieves a 33 percent RPS by 2020, increased energy efficiency and other greenhouse gas reduction policy goals. Beyond 2020, retail rates are forecast to escalate at 1.42 percent per year, in real terms. This assumption reflects the assumption that California meets remaining load growth with natural gas generation after 2020. The retail rate escalation factors are calculated using the E3 RES Calculator, which was developed for the California Air Resources Board 33 percent RES proceeding.[16] This is the same retail rate forecast used in the adopted 2013 Title 24 building standard proceeding. Figure 7 below shows the retail rate forecast applied in this analysis, which is equivalent to the annual average benefit of PV generation.

Figure 7: Average Consumer Savings Analysis: Retail Rate Forecast



Source: Energy and Environmental Economics, Inc.

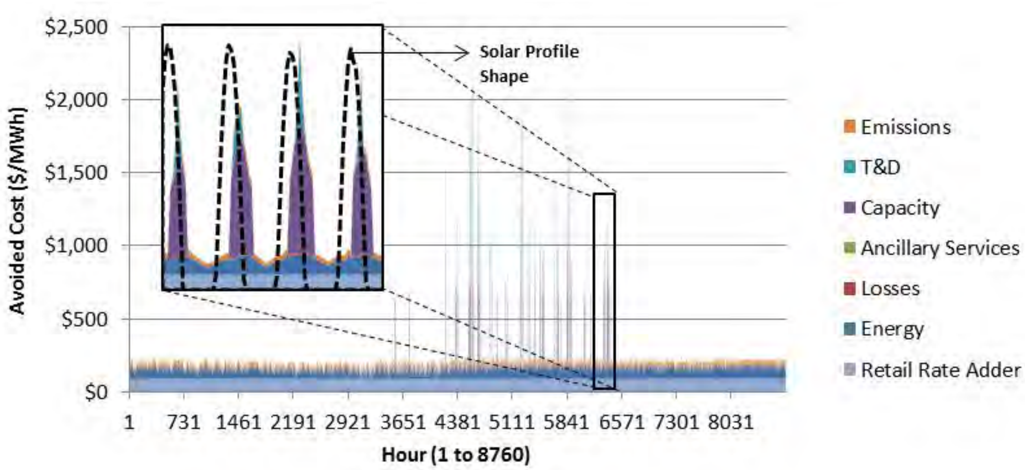
16 The E3 RES Calculator used to develop this rate forecast is available on the ARB website at: http://www.arb.ca.gov/research/econprog/econmodels/econmodels.htm

Using the average consumer approach, energy savings during summer peak hours are valued more highly than energy savings during the off-peak hours of the year. The average consumer savings approach values electricity as if residential and commercial retail customers in California paid their electric bills based on the retail value of electricity production and delivery in each hour of the year. In other words, this approach represents a hypothetical rate where customers would pay retail rates at an hourly price that reflects the underlying marginal cost in each hour, plus an additional amount to collect utility fixed costs.

The hourly value of electricity is correlated with the statewide typical weather files used in compliance software for the *Building Energy Efficiency Standards*. This is important because in California hotter weather tends to be correlated with increased demand on the electrical system, increasing the value of energy savings from energy efficiency and distributed generation during those hours.

The hours of PV output tend to be fairly well correlated with the hours of high electricity demand in California. For example, PV generation can offset a significant share of a house's electricity consumption during summer afternoons, when the cost of producing and delivering electricity is highest. This close link between hourly PV output and the hourly value of electricity is shown in the upper left-hand box in Figure 8 below. Solar PV output tends to peak in the early afternoon, while systemwide peak demand on the California grid tends to occur a little later in the afternoon, often between 4p.m. and 6p.m. In the average consumer analysis, the fact that electricity is valued more highly during hours of peak demand tends to improve the cost-effectiveness of PV.

Figure 8: One Year of Hourly Avoided Costs of Electricity, Average Consumer Scenario
Call-out box shows how the hourly PV generation profile correlates with the hourly value of electricity



Source: Energy and Environmental Economics, Inc.

As shown in the figure above, the hourly value of avoided cost of electricity in the average consumer analysis is made up of a number of components including: the wholesale value of energy, transmission and distribution losses, ancillary services, capacity costs, transmission and distribution costs, greenhouse gas emissions, and a statewide average retail rate adder. For more details about the method for calculating the hourly avoided cost of electricity for the average consumer savings analysis, see the Energy Commission report *Time Dependent Valuation of Energy for Developing Building Standards.*[17]

The table below describes some of the key input assumptions for the average consumer savings analysis. This analysis reflects a forecast of current and expected market conditions.

Table 6: Average Consumer Savings: Key Input Assumptions

Input	Description
Overview of Scenario:	*Average Consumer avoided cost of electricity is reflective of current state policy and energy trends.*
PV system lifetime	25 years, based on duration of industry-standard PV module warranty.
Retail rate	Statewide average rate for residential and commercial. Based on weighted average of 2008 rates for PG&E, SCE, SDG&E, LADWP and SMUD, derived from the Commission's *2010 Integrated Energy Policy Report* energy demand forecast.
Retail rate escalation	Retail rates escalate at a rate consistent with the E3/ARB 33% RES Calculator impacts: real rate of 2.1%/yr for 2011 – 2020. Beyond 2020, rates are escalated at real rate of 1.4%/year, the rate of the "natural gas only" build-out case from the E3/ARB 33% RES Calculator tool.
CO_2 price	Net present value of 2009 Market Price Reference CO_2 price forecast, which begins at about $14/ton in 2011 and escalates to $57/ton, in real $2010 dollars, by 2040.
CO_2 price policy	Assumes that a CO_2 pricing policy will not further increase rates beyond the retail rate assumptions above (i.e. revenue from CO_2 cap-and-trade market is used to offset any impacts to residential retail rates). However, CO_2 prices do affect the electricity market price shape, increasing the value of on-peak electricity.

17 Report available at: http://www.energy.ca.gov/title24/2013standards/prerulemaking/documents/

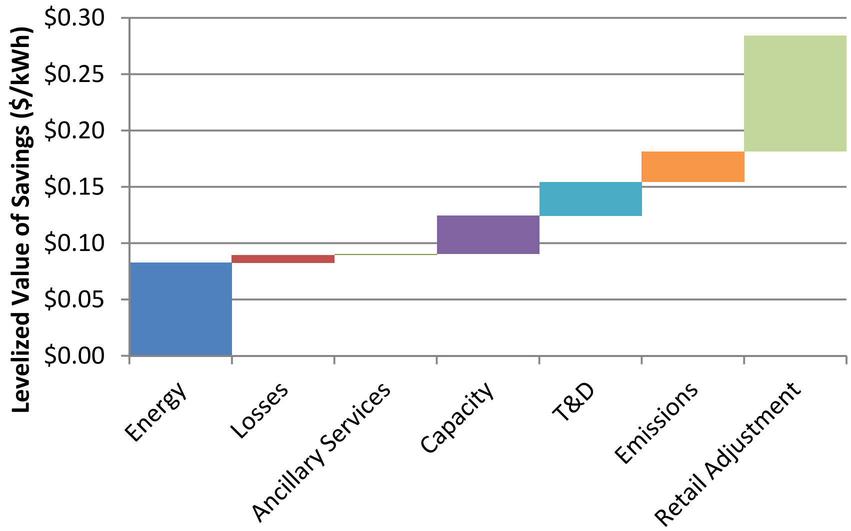
Input	Description
Electricity market price shape	The market price shape of electricity in 2020 is determined by the "High Wind" 33% RES case developed as part of the Commission's "Electricity System Implications of 33 Percent Renewables" Study completed in June 29, 2009. For years between 2008 and 2020, the change in the market price shape is based on an hourly linear extrapolation. No changes to the market price shape are forecast beyond 2020.
Other Policies (AB 32 Scoping Plan, Once-through cooling regulations)	Assumes statewide energy efficiency, rooftop PV and combined heat and power generation by 2020 are consistent with the *AB 32 Scoping Plan* goals and statewide compliance with proposed regulations on once-through cooling of coastal thermal power plants. The impact of these policies is reflected in the market price shape from the "High Wind" 33% RES case developed as part of the Commission's *Electricity System Implications of 33 Percent Renewables* study completed in June 29, 2009.
Real Discount Rate	3% real discount rate, consistent with Building Energy Efficiency Standards assumptions.

Source: Energy and Environmental Economics, Inc.

Using these input assumptions, the analysis shows that on a life-cycle (levelized) basis, the value of PV generation is expected to range from $0.27/kWh - $0.29/kWh for a residential PV system installed in 2014, depending on the climate zone. The example in Figure 9 below shows the components of the overall PV benefits in Climate Zone 3 for a residential system. The total life-cycle benefits of residential rooftop PV in Climate Zone 3 total $0.28/kWh in 2014.

Figure 9: 2014 Life-Cycle Benefits of PV Generation Average Consumer Savings Assumptions

This example uses Climate Zone 3, residential data, nominal levelized $/kWh



Source: Energy and Environmental Economics, Inc.

Market-Segmented Savings

The market-segmented savings analysis calculates the avoided cost of electricity using the current rate structures of California's three largest investor-owned utilities: PG&E, SCE, and SDG&E. By using actual utility rate structures, the market-segmented analysis calculates the value of electricity generated by rooftop PV to different customer classes in California. As in the average consumer analysis, the authors assume a 25-year PV system lifetime. While the average consumer analysis calculates savings to the statewide average residential or commercial customer, the market-segmented savings analysis provides for a more disaggregated look at utility bill savings based on a typical residential or commercial building's annual electricity consumption. The research team's analysis focuses exclusively on single-family residential consumers and does not apply to multifamily residential buildings. The table below shows the primary utility retail rates used in the market-segmented analysis.

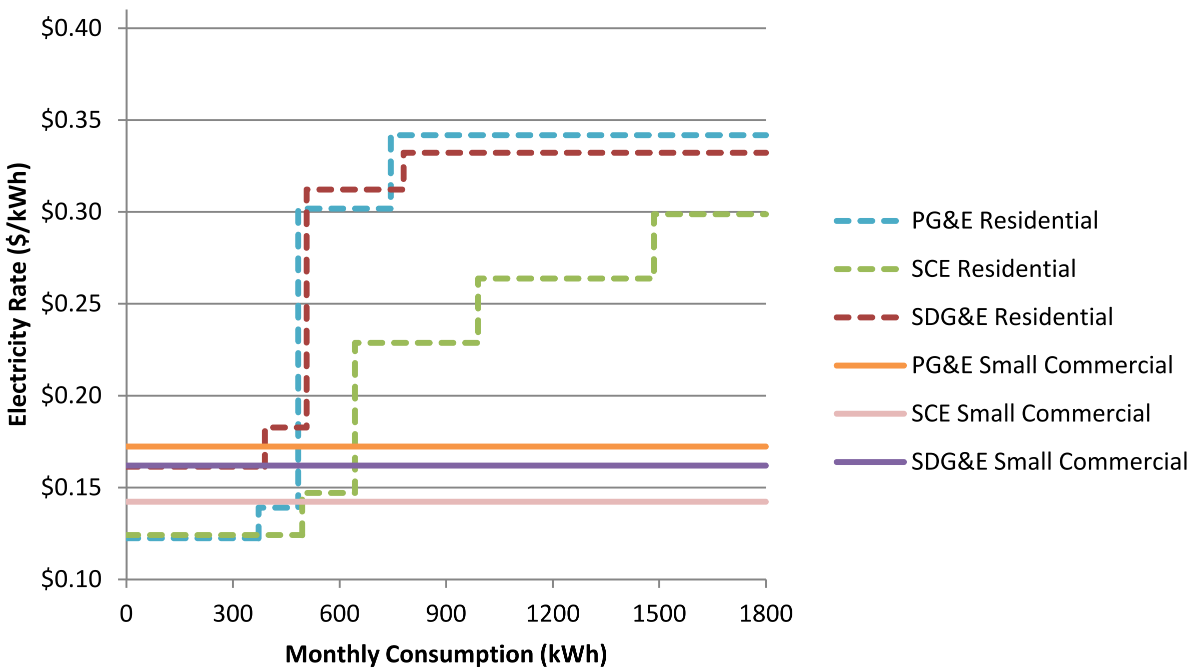
Table 7: Investor-Owned Utility Retail Rates Used in the Market-Segmented Analysis

	Residential	Small Commercial	Large Commercial
PG&E	E-1 (tiered)	A-1 (flat, seasonal)	A10S (time of use)
SCE	D (tiered)	GS-1 (flat, seasonal)	GS-2 (time of use)
SDG&E	DR (tiered)	A (flat, seasonal)	A6 (time of use)

Source: Energy and Environmental Economics, Inc.

Figure 10 illustrates the difference between the residential tiered rate structures that are common for residential customers in California and the small commercial rate structures. The chart does not include the large commercial rates, which are time-of-use (TOU) rates. These 2011 retail rates are assumed to escalate at the same annual rate as in the average consumer retail rate forecast.

Figure 10: 2011 Residential and Commercial Retail Rates ($/kWh, 2011)



Note: Baseline kWh allocation for Tier I rates varies by climate zone, not shown in figure above. Rates shown are for standard electric customers.

Source: Energy and Environmental Economics, Inc.

The market-segmented bill savings calculations are developed based on two hourly load shapes: (1) customer gross load without PV and (2) customer net load after PV is installed. The analysis applies billing determinants for each hourly load shape (including energy charges, demand charges, and other rate charges) and calculates monthly bills, including the effect of net metering rules in California. The process of calculating bills was performed using E3's bill calculation tool and summarized billing determinants developed as part of the analysis performed for the California Public Utilities Commission under the California Solar Initiative (CSI) cost-effectiveness evaluation[18].

Under California's NEM rules, any bill credits from excess PV production in one month are applied against the following month's bill. The authors also consider effects pursuant to Assembly Bill 920 (Huffman, Chapter 376, Statutes of 2009), under which customers receive compensation for any net-surplus energy carryover at the end of the 12-month billing period. A more detailed discussion of NEM effects may be found in the CPUC's NEM cost-effectiveness

18 See note 12

report.[19] The table below summarizes the key input assumptions applied in the market-segmented analysis.

Table 8: Market-Segmented Savings: Electricity Input Assumptions

Input	Description
Overview of Scenario:	*Market-Segmented analysis reflects the expected bill savings resulting from installing PV on a typical residential or commercial building in investor-owned utility service territories.*
PV system lifetime	25 years, based on duration of industry-standard PV module warranty.
Retail rates used	Uses 2011 residential and commercial rates for PG&E (E-1, A-1, A10S), SCE (D, GS-1, GS-2) and SDG&E (DR, A, A6)
Retail rate escalation	Retail rate escalated at a rate consistent with the E3/CARB 33% RES Calculator impacts: real rate of 2.1%/yr for 2011 – 2020. Beyond 2020, rates are escalated at real rate of 1.4%/year, the rate of the "natural gas only" build-out case from the E3/CARB 33% RES Calculator tool.
Bill savings calculation	Bill calculations performed in E3 tool developed for California Public Utilities Commission under the NEM Cost-Effectiveness Evaluation. Uses two hourly load shapes: (1) customer gross load in the absence of PV and (2) customer net load after PV is installed.
CO_2 price policy	Assumes that a CO_2 pricing policy will not further increase rates beyond the retail rate assumptions above (i.e. future CO_2 value is used to offset any impacts to residential retail rates).
Electricity market price shape	Not applicable. Retail rate structures are used.
Other policies (AB 32 Scoping Plan, Once-through cooling regulations)	Assumes statewide energy efficiency, rooftop PV and combined heat and power generation by 2020 are consistent with the AB 32 Scoping Plan goals and state compliance with proposed regulations on once-through cooling of coastal thermal power plants.

19 Energy and Environmental Economics, Inc.. January 2010. *Net-Energy Metering (NEM) Cost-Effectiveness Evaluation.*, Available at: http://www.ethree.com/documents/CSI/Final_NEM-C-E_Evaluation_with_CPUC_Intro.pdf.

Input	Description
Real discount rate	Residential: 3.43%, reflective of a low interest rate mortgage-style cost of borrowing Nonresidential: 6.13%, reflective of the commercial cost of borrowing

CHAPTER 3: Results

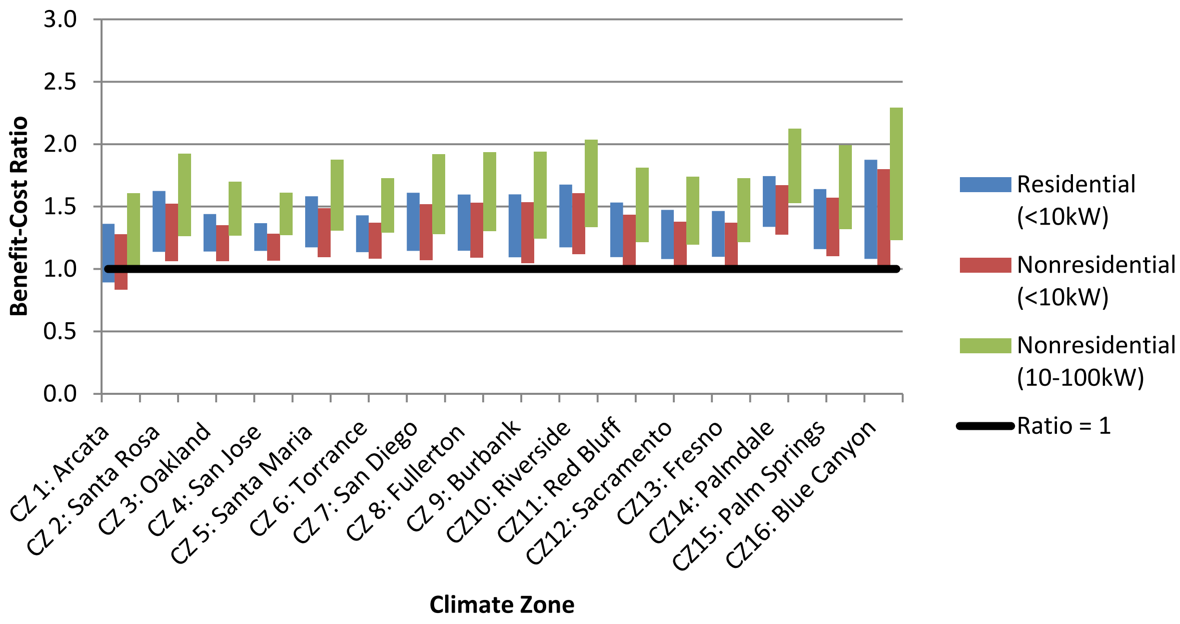
The cost-effectiveness of rooftop PV for newly constructed buildings is forecasted for 2014, 2017, and 2020. Cost-effectiveness results are shown using both Scenario 1 and Scenario 2 capital cost and solar capacity factor assumptions for both the average consumer analysis and the market-segmented analysis.

Average Consumer Results

The benefit-cost ratio is a way to summarize the results of the cost-effectiveness analysis and is calculated by dividing the benefits (levelized bill savings) by the cost (levelized cost of solar electricity). If the value of the benefit-cost ratio is greater than one with a reasonable level of certainty, then PV is determined to be cost-effective.

Figure 11 below shows the benefit-cost ratio for PV using the average consumer analysis for 2014. The bottom of the bars represents the results for Scenario 1 (higher cost solar); the top of the bars represents the results for Scenario 2 (lower cost solar). As can be seen, solar is generally cost-effective for both scenarios for residential customers and nonresidential customers installing systems with capacity between 10-100 kW. The notable exception to these results is Climate Zone 1, where the relatively weak solar resource means that PV is not cost-effective for any customers under Scenario 1. For nonresidential customers with system capacity below 10 kW, PV is cost-effective under Scenario 2 but is generally not cost-effective under Scenario 1. This is because the benefits of solar are smaller for nonresidential customers who pay lower average electricity rates, and the cost of solar installations smaller than 10 kW is higher per kW than the cost of larger systems.

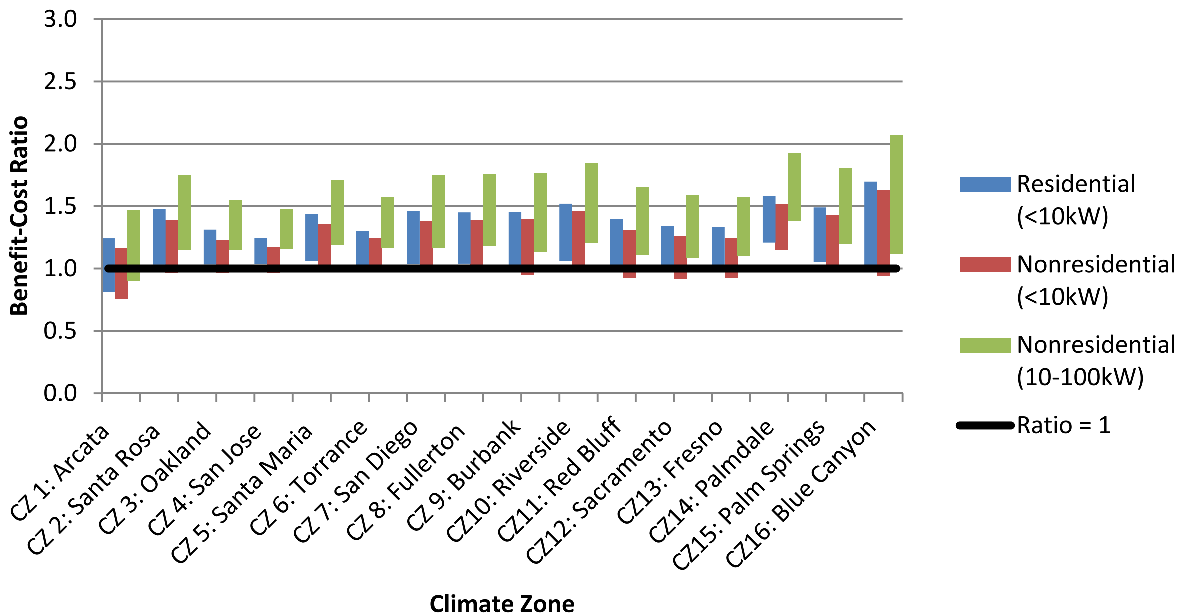
Figure 11: Average Consumer Cost-Effectiveness Results, 2014



Source: Energy and Environmental Economics, Inc.

Forecasting PV costs farther into the future, 2017 is expected to be the first year in which the federal investment tax credit (ITC) for PV will decrease from 30 percent to 10 percent. This means that while the capital costs of solar are expected to fall over time, the overall cost-effectiveness of PV declines slightly in 2017.

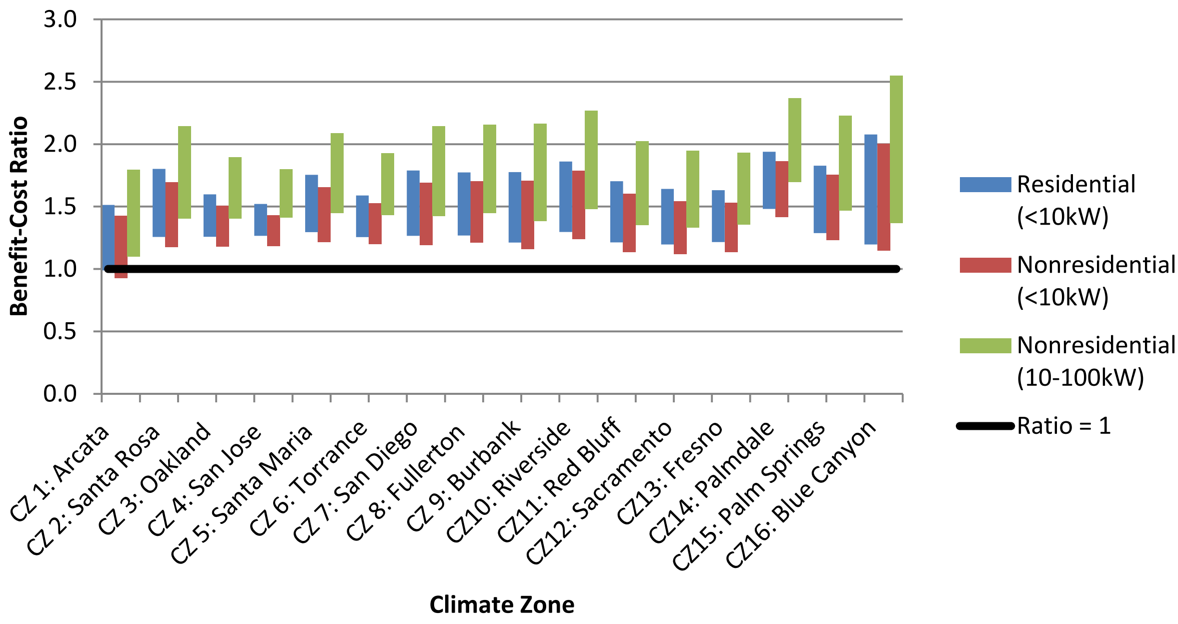
Figure 12**: Average Consumer Cost-Effectiveness Results, 2017**



Source: Energy and Environmental Economics, Inc.

By 2020, PV is expected to be more cost-effective than in 2014 due largely to the expected decrease in the installed capital cost of solar through continued technology development and learning. However, the lower ITC in 2020, at 10 percent, also reduces the cost-effectiveness of solar. Overall, by 2020, PV is expected to be cost-effective under Scenario 1 assumptions in all climate zones except for Climate Zone 1. Under Scenario 2 assumptions, PV is expected to be solidly cost-effective by 2020 in all climate zones.

Figure 13**: Average Consumer Cost-Effectiveness Results, 2020**



Source: Energy and Environmental Economics, Inc.

The results for 2020 are summarized in Table 9 below.

Table 9: Summary of Average Consumer Analysis Results, 2020

	Scenario 1: More expensive solar	Scenario 2: Less expensive solar
Residential *(<10 kW solar system)*	**Sometimes.** Solar is cost-effective in all climate zones except CZ1.	**Yes.** Solar is cost-effective in all climate zones.
Small commercial *(<10 kW solar system)*	**Sometimes.** Solar is cost-effective in all climate zones except CZ1.	**Yes.** Solar is cost-effective in all climate zones.
Large commercial *(10 – 100 kW solar system)*	**Yes.** Solar is cost-effective in all climate zones.	**Yes.** Solar is cost-effective in all climate zones.

Source: Energy and Environmental Economics, Inc.

Market-Segmented Results

The market-segmented analysis results vary between large and small residential and commercial customers because electricity rate structures are different for these different customer classes. Furthermore, the market-segmented savings of a given residential customer depends on how much electricity per month is consumed, due to the “inclining block” or tiered residential rate structure of most California utilities.

To select appropriate utility rates to use in the bill savings calculation in each climate zone, the authors assign each zone to one of California’s three investor-owned utilities: PG&E, SCE, or SDG&E. The table below shows the assignment for each climate zone.

Table 10: Utility Assignment by Climate Zone

Climate Zone	Utility	Climate Zone	Utility
1: Arcata	PG&E	9. Burbank	SCE
2: Santa Rosa	PG&E	10. Riverside	SCE
3: Oakland	PG&E	11. Red Bluff	PG&E
4: San Jose	PG&E	12: Stockton	PG&E
5: Santa Maria	PG&E	13: Fresno	PG&E
6: Torrance	SCE	14: Palmdale	SCE
7: San Diego	SDG&E	15: Palm Springs	SCE
8: Fullerton	SCE	16: Blue Canyon	SCE

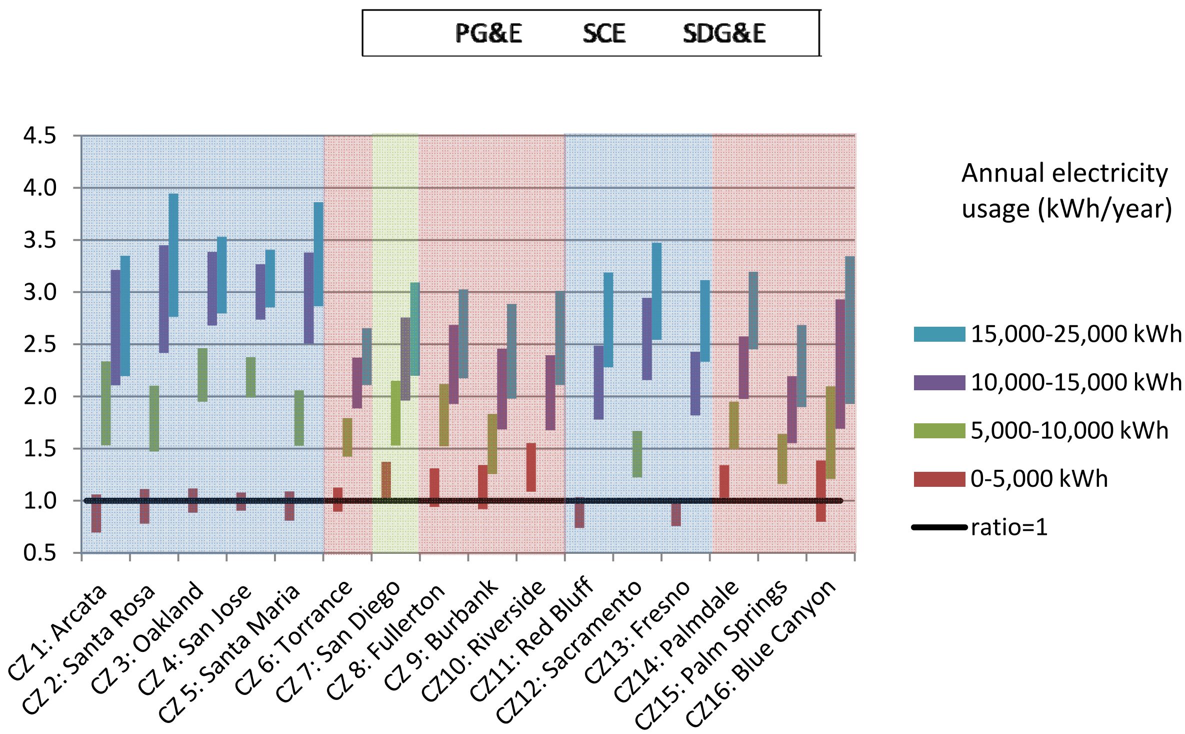
Source: Energy and Environmental Economics, Inc.

Residential Market-Segmented Results

The residential market-segmented cost-effectiveness results show dramatic differences based on a building’s annual electricity consumption. This is due to California’s utilities’ tiered electricity rate structures. Tiered rate structures protect lower-income consumers and those who consume lesser amounts of electricity from higher electric rates. Tiered rates also make energy efficiency and rooftop PV more cost-effective for customers with higher electricity usage. The rates selected for this analysis represent single-family customers only. The results are not indicative of the cost-effectiveness of installing rooftop PV on multifamily residences.

In Figure 14 below, the benefit-cost ratios of PV systems are shown by climate zone and by a building’s annual electricity consumption. A benefit-cost ratio above one determines that PV systems are cost-effective. As before, the bottom of the bars represents Scenario 1 (higher cost solar) assumptions and the top of the bars represents Scenario 2 (lower cost solar) assumptions.

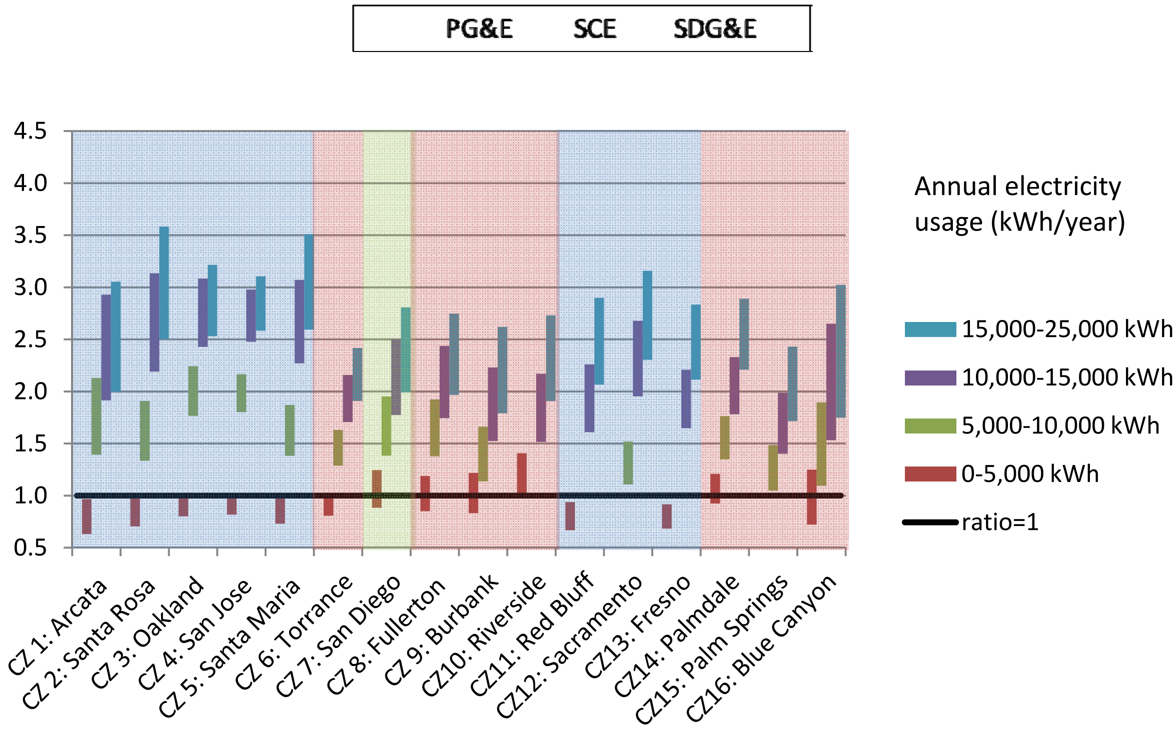
Figure 14: Residential Market-Segmented Results Based on a Building's Annual Electricity Consumption, 2014



Source: Energy and Environmental Economics, Inc**.**

PV is expected to be slightly less cost-effective in 2017 due to the reduction of the federal ITC at the end of 2016.

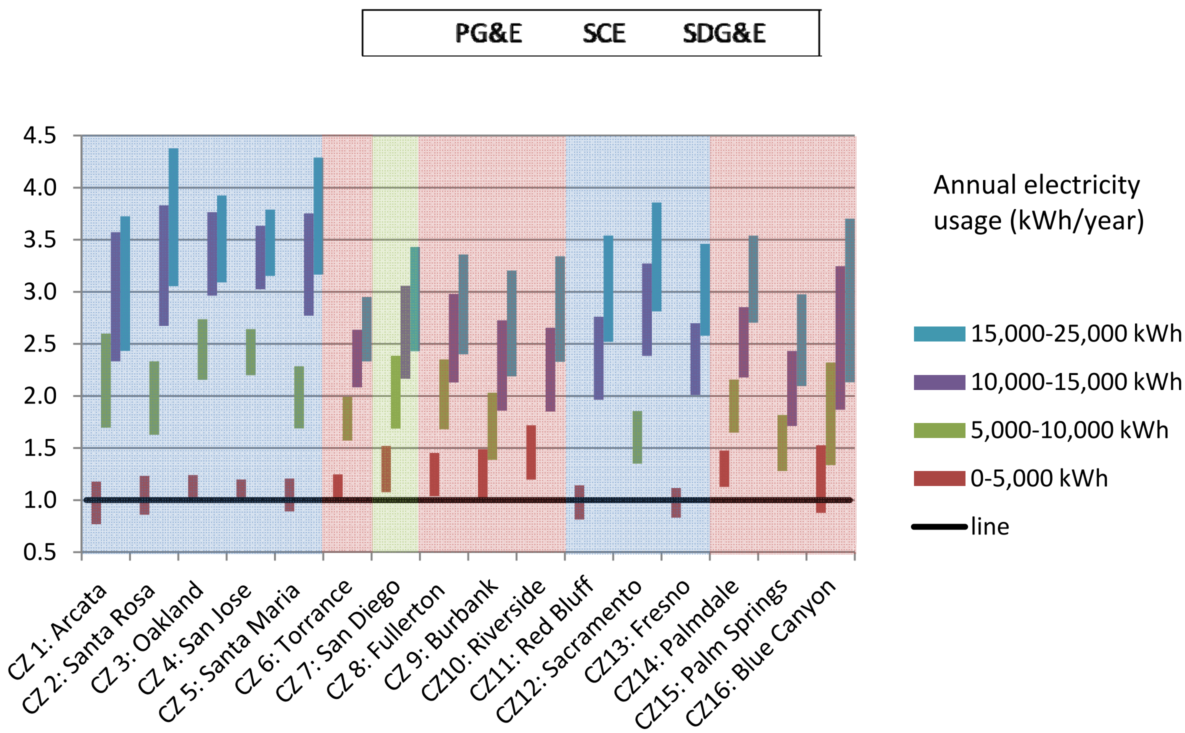
Figure 15: Residential Market-Segmented Results Based on a Building's Annual Electricity Consumption, 2017



Source: Energy and Environmental Economics, Inc.

By 2020, PV is expected to be slightly more cost-effective than in 2014, due to expected reductions in the capital cost of solar which counteract the reduction in the federal ITC.

Figure 16: Residential Market-Segmented Results Based on a Building's Annual Electricity Consumption, 2020



Source: Energy and Environmental Economics, Inc.

The cost-effectiveness results of the 2020 residential market-segmented analysis are summarized in the table below.

Table 11: Summary of Residential Market-Segmented Cost-Effectiveness Results, 2020

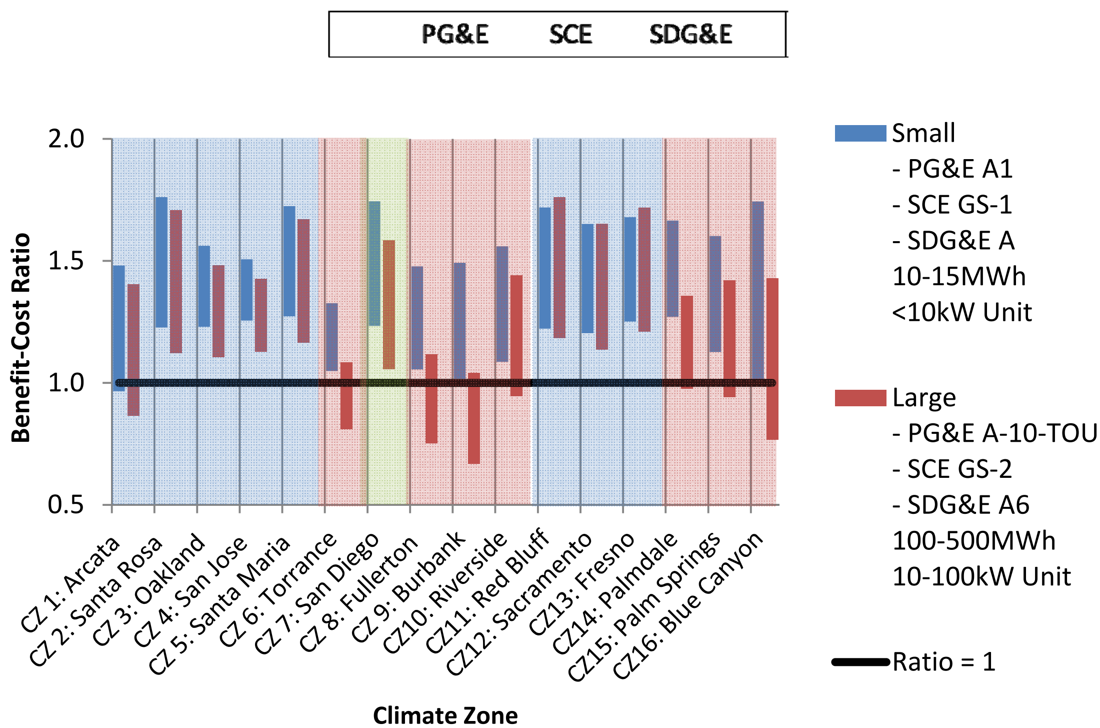
Customer class	Scenario 1 More expensive solar	Scenario 2 Less expensive solar
Residential, >5,000 kWh/year electric consumption	**Yes.** Cost-effective	**Yes.** Cost-effective
Residential, <5,000 kWh/year electricity consumption	**No.** Not cost-effective	**Yes.** Cost-effective

Source: Energy and Environmental Economics, Inc.

Commercial Market-Segmented Results

The commercial market-segmented results show that PV is expected to be less cost-effective as compared to installations on residential buildings. This is because, in California, commercial retail rates usually are lower than the upper tiers of residential rates. Commercial retail rate structures also vary more by utility than the residential rates do, making it difficult to generalize the cost-effectiveness results across climate zones. Figure 17 shows that solar is expected to be cost-effective for large commercial customers only under Scenario 2 (low-cost solar) and only in certain climate zones. The differences between climate zones are driven by both the natural solar resource and the applicable utility rate in that region. The results for climate zones in SCE's territory are notably less cost-effective, due to lower bill reductions driven by a combination of rate structure and rate levels for SCE's large commercial customers relative to the other utilities. For small commercial customers, Figure 17 shows that PV is cost-effective under Scenario 2 for all climate zones but is only cost-effective under Scenario 1 in a few climate zones.

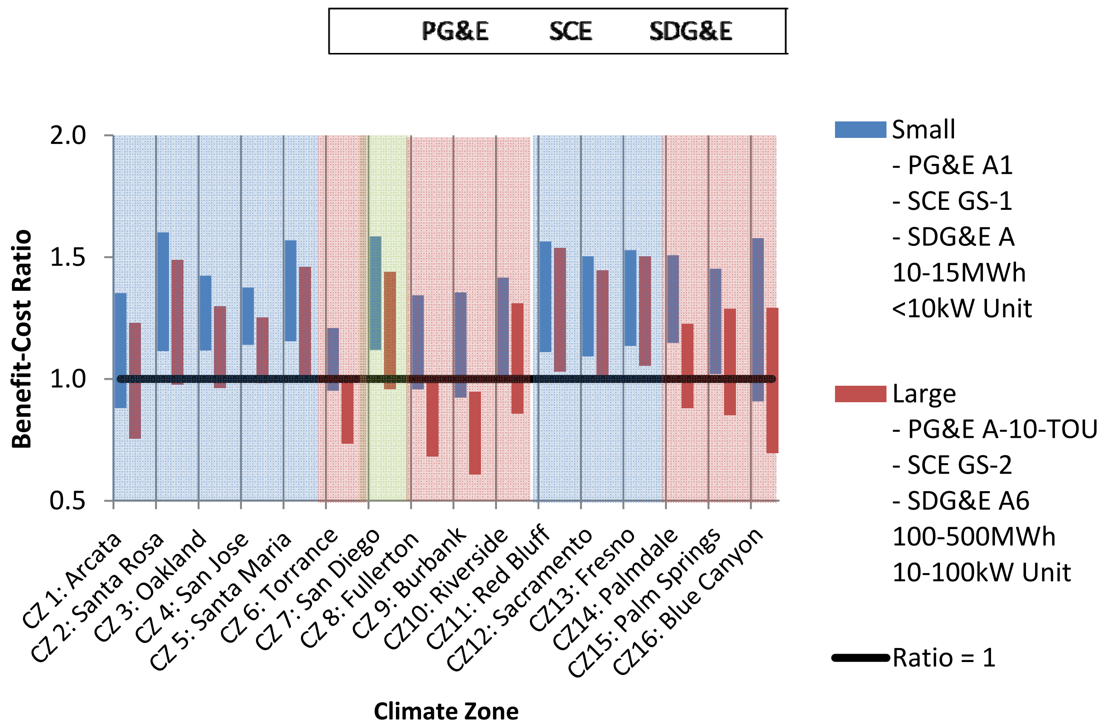
Figure 17: Commercial Market-Segmented Results, 2014



Source: Energy and Environmental Economics, Inc.

By 2017, PV is expected to be less cost-effective due to the reduction in the federal ITC in 2016.

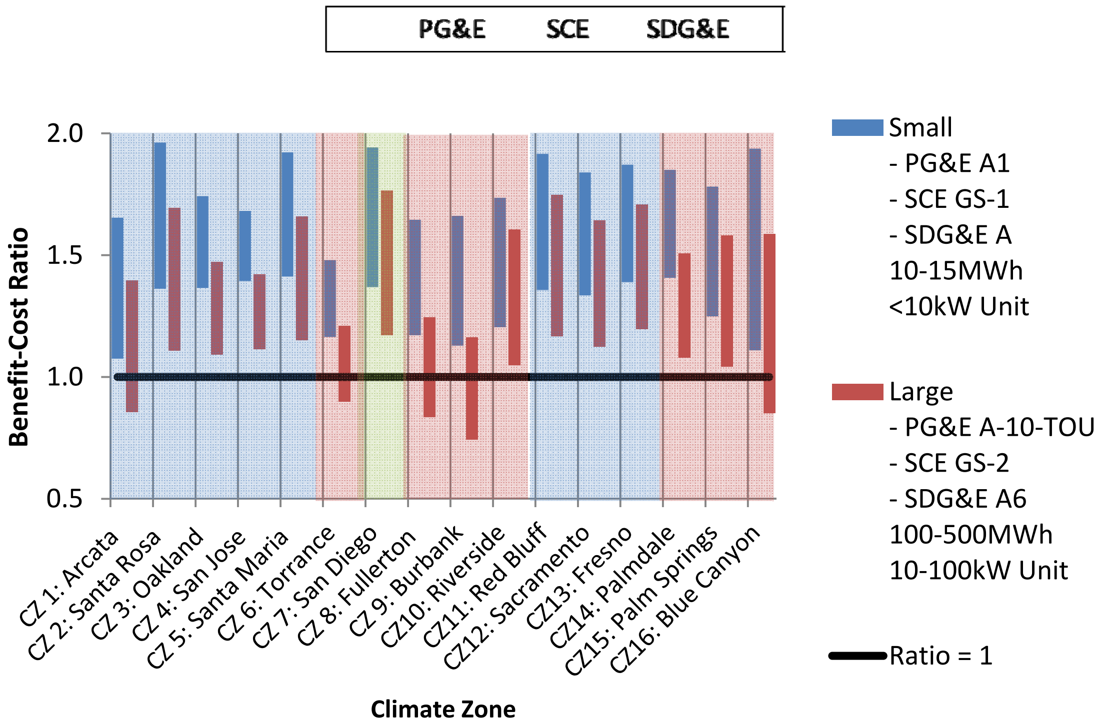
Figure 18: Commercial Market-Segmented Results, 2017



Source: Energy and Environmental Economics, Inc.

By 2020, PV is expected to be more cost-effective than in 2014 due to forecast reductions in the capital cost of rooftop PV for newly constructed buildings.

Figure 19: Commercial Market-Segmented Results, 2020



Source: Energy and Environmental Economics, Inc.

The cost-effectiveness results of the 2020 commercial market-segmented savings analysis are summarized in the table below.

Table 12: Summary of Commercial Market-Segmented Cost-Effectiveness Results, 2020

Customer class	Scenario 1 More expensive solar	Scenario 2 Less expensive solar
Medium to large commercial, 100 – 500 MWh/year	**Sometimes.** Solar is marginally cost-effective, depending on the utility service territory and climate zone.	**Yes.** Solar is cost-effective.
Small commercial, 10-15 MWh/year	**Yes.** Solar is cost-effective.	**Yes.** Solar is cost-effective.

Source: Energy and Environmental Economics, Inc**.**

CHAPTER 4: Summary of Results

Evaluating the cost-effectiveness of PV is a complex task, involving multiple uncertain variables. The authors have applied what they consider to be the best publicly available, unbiased assumptions about the future costs of PV. The conclusions in this report are based, in part, on the following key assumptions, which have a strong influence on the cost-effectiveness results:

- Increase in retail electricity rates, at 2.11 percent per year through 2020 and at 1.46 percent per year thereafter, in real terms.
- In the market-segmented analysis, existing utility retail rate structures (TOU rates and tiered rates) are maintained.
- Rooftop PV installations in the building standards are assumed to ***not*** qualify for state CSI and NSHP incentives but do qualify for the federal ITC.

Other key input assumptions that have a greater effect on the long-term, 2017 and 2020, results include:

- Steadily falling capital costs for PV through 2020 due to industry economies of scale and the effect of "learning by doing" on installer costs.
- Current net-energy metering rules remain applicable to all new PV installations.
- Maintenance of the federal investment tax credit for PV at 30 percent through 2016 and at 10 percent after 2016.

Any major changes to these assumptions could alter the cost-effectiveness of PV. The market-segmented results are especially sensitive to the structure of California utility rates and NEM rules, since they use utility bill savings to determine PV benefits and customer bill savings are very sensitive to rate structure under existing NEM policy. If the structure of utility rates is changed, for example by reducing energy-based charges and increasing demand-based and/or service charges, utility bill savings achieved installing PV could drop significantly. Similarly, if NEM were replaced with a different policy, for example, a flat compensation rate per kWh of distributed generation, the cost-effectiveness of solar may decrease. In this report's cost-effectiveness projections, the research team assumes that utility rates and the NEM program will not change other than the overall forecasted rate level increase.

Given the key assumptions above, the cost-effectiveness results for each of the two analysis approaches are shown in the following tables.

Average Consumer

Table 13 summarizes the results of the average consumer savings analysis for 2014, 2017 and 2020. The results are divided by PV cost scenario (lower cost or higher cost solar) and customer type (residential, small commercial, and large commercial).

Table 13: Average Consumer Savings Results

PV Cost Scenario	Consumer Type	2014	2017	2020
More expensive	Residential (<10 kW PV system)	Sometimes. Cost-effective in all climate zones except zone 1.	No. Not cost-effective in most climate zones.	Sometimes. Cost-effective in all climate zones except zone 1.
	Small commercial (<10 kW PV system)	Sometimes. Marginally cost-effective, depending on climate zone.	No. Not cost-effective in most climate zones.	Sometimes. Cost-effective in all climate zones except zone 1.
	Large commercial (10-100 kW PV system)	Sometimes. Cost-effective in all climate zones except zone 1.	Sometimes. Cost-effective in all climate zones except zone 1.	Yes. Cost-effective in all climate zones.
Less expensive	Residential (<10 kW PV system)	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.
	Small commercial (<10 kW PV system)	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.
	Large commercial (10-100 kW PV system)	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.	Yes. Cost-effective in all climate zones.

Source: Energy and Environmental Economics, Inc.

In the "more expensive solar" scenario, average consumer savings results vary between the different sectors examined because the average retail rate is higher for residential than non-residential consumers, increasing the savings potential for residential consumers, while the cost of solar is less expensive per watt for commercial consumers who have adequate energy usage to install a system larger than 10 kW. In the "less expensive solar" scenario, PV is cost-effective for all customer types in 2020.

Market-Segmented

Residential

Table 14 shows the results of the residential market-segmented savings analysis for 2014, 2017, and 2020. The results are divided by PV cost scenario (lower cost or higher cost solar) and customer size (annual consumption less than 5,000 kWh, annual consumption greater than 5,000 kWh). These results are representative of single-family residential consumers only.

Table 14: Residential Market-Segmented Savings Results

PV Cost Scenario	Consumer Type	2014	2017	2020
More expensive Solar	Residential, <5,000 kWh/year electric consumption	No. Not cost-effective.	No. Not cost-effective.	No. Not cost-effective.
	Residential , >5,000 kWh/year electric consumption	Yes. Cost-effective.	Yes. Cost-effective.	Yes. Cost-effective.
Less expensive Solar	Residential, <5,000 kWh/year electric consumption	Sometimes. Marginally cost-effective.	Sometimes. Marginally cost-effective.	Yes. Cost-effective.
	Residential , >5,000 kWh/year electric consumption	Yes. Cost-effective.	Yes. Cost-effective.	Yes. Cost-effective.

Source: Energy and Environmental Economics, Inc.

The market-segmented results highlight the importance of rate structure in determining whether solar is cost-effective. The average consumer analysis projects that PV will be cost-effective for all residential customers in 2020, based on statewide average electricity rates. The market-segmented results show that with California's current tiered residential rates, a customer's annual energy consumption is an important consideration in measuring the cost-effectiveness of solar. This result is particularly relevant for new residential construction, where energy efficiency standards are likely to result in lower annual electricity usage before the addition of a PV installation.

Commercial

Table 15 shows the results of the commercial market-segmented savings analysis for 2014, 2017, and 2020. The results are arranged by PV cost scenario (lower cost or higher cost solar) and customer size (annual consumption 10,000-15,000 kWh, annual consumption greater than 100,000-500,000 kWh).

Table 15: Commercial Market-Segmented Savings Results

PV Cost Scenario	Consumer Type	2014	2017	2020
More Expensive Solar	Small commercial, 10,000-15,000 kWh/year electric consumption	Sometimes. Cost-effectiveness depends on climate zone and utility service territory.	Sometimes. Cost-effectiveness depends on climate zone and utility service territory.	Yes. Cost-effective.
	Large commercial, 100,000-500,000 kWh/year electric consumption	Sometimes. Cost-effectiveness depends on climate zone and utility service territory.	No. Not cost-effective.	Sometimes. Cost-effectiveness depends on climate zone and utility service territory.
Less Expensive Solar	Small commercial, 10,000-15,000 kWh/year electric consumption	Yes. Cost-effective.	Yes. Cost-effective.	Yes. Cost-effective.
	Large commercial, 100,000-500,000 kWh/year electric consumption	Yes. Cost-effective.	Sometimes. Cost-effectiveness depends on climate zone and utility service territory.	Yes. Cost-effective.

Source: Energy and Environmental Economics, Inc.

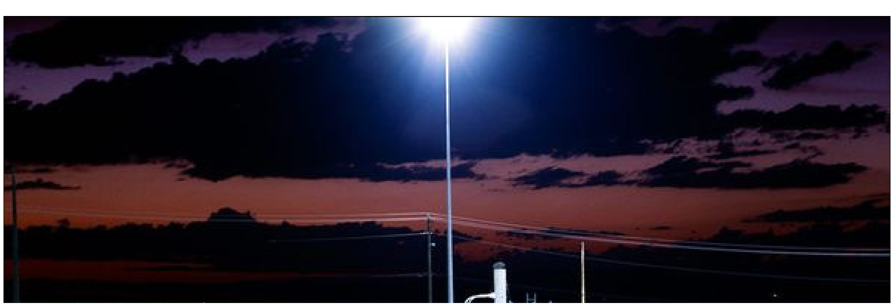
Comparing the average consumer and market-segmented results for the commercial sector also demonstrates the effect of utility rates on solar's cost-effectiveness. In the average consumer analysis, the benefit of solar is based on average retail rates for all commercial consumers statewide. As a result, solar looks more cost-effective for large commercial consumers, who can purchase larger PV systems at a lower cost per watt. In the market-segmented analysis, it becomes apparent that large commercial customers actually pay retail rates that are less conducive to solar cost-effectiveness than the rates paid by small commercial customers, so that solar is less cost-effective for large customers than small despite the lower cost to install PV.

ACRONYMS

Acronym	Definition
ACM	Alternative Calculation Method
ARB	California Air Resources Board
Energy Commission	California Energy Commission
CO_2	Carbon dioxide
CPUC	California Public Utilities Commission
CSI	California Solar Initiative
DC	Direct current
GHG	Greenhouse gas
ITC	Investment tax credit
kW	Kilowatt
kWh	Kilowatt-hour
LADWP	Los Angeles Department of Water & Power
LCOE	Levelized cost of energy
NREL	National Renewable Energy Laboratory
NSHP	New Solar Homes Partnership
PG&E	Pacific Gas and Electric
PPA	Power purchase agreement
PV	Photovoltaic
RES	Renewable Electricity Standard
RPS	Renewables Portfolio Standard

Acronym	Definition
SCE	Southern California Edison
SDG&E	San Diego Gas & Electric
SMUD	Sacramento Municipal Utility District
TDV	Time dependent valuation
TOU	Time of use

Half Life—The Lethal Legacy of America's Nuclear Waste



A tank farm at Hanford, Washington, built in the 1940s, uses only single-wall tanks to store radioactive sludge from plutonium processing. Many of the tanks have leaked, tainting groundwater.

Photograph by Peter Essick

Written by Michael E. Long
Republished from the pages of *National Geographic* magazine

World War II was still being fought in the Pacific during the first week of August 1945, a time when my father and I were vacationing in Atlantic City, New Jersey, eating softshell crabs and lazing by the ocean. In a games arcade I fed nickels to a toy machine gun and fired at Japanese Zero fighters flitting across a screen. On the boardwalk, rifles shouldered, platoons of United States soldiers marched and sang:

The Stars and Stripes will fly over Tokyo,

Fly over Tokyo, fly over Tokyo,

The Stars and Stripes will fly over Tokyo,

When the 991st gets there:

One morning my dad showed me a newspaper with red headlines that said a huge bomb had been dropped on Hiroshima, Japan. Three days later another bomb was dropped on Nagasaki, and Japan surrendered. The bombs were so big that the boys of the 991st wouldn't have to go to Tokyo after all.

The strong nuclear force, the binding energy that makes atomic nuclei the most tightfisted entities in all creation, had been sundered, unleashing enormous power—the equivalent of 15,000 tons (13,608 metric tons) of TNT in the Hiroshima bomb—as well as a race to create bigger weapons. Seven years later our first hydrogen device, code-named Mike, yielded a blast equal to 10.4 million tons (9.4 million metric tons) of TNT. Mike would have leveled all five boroughs of New York City.

By the mid-1960s, the height of the Cold War, the U.S. had stockpiled around 32,000 nuclear warheads, as well as mountains of radioactive garbage from the production of plutonium for these weapons. Just one kilogram, or 2.2 pounds, of plutonium required around a thousand tons (907 metric tons) of uranium ore. Generated from uranium bombarded by neutrons in a nuclear reactor, the plutonium was later separated from the uranium in hellish baths of acids and solvents still awaiting disposal.

A long-deferred cleanup is now under way at 114 of the nation's nuclear facilities, which encompass an acreage equivalent to Rhode Island and Delaware combined. Many smaller sites, the easy ones, have been cleansed, but the big challenges remain. What's to be done with 52,000 tons (47,174 metric tons) of dangerously radioactive spent fuel from commercial and defense nuclear reactors? With 91 million gallons (344.5 million liters) of high-level waste left over from plutonium processing, scores of tons of plutonium, more than half a million tons (453,592 metric tons) of depleted uranium, millions of cubic feet of contaminated tools, metal scraps, clothing, oils, solvents, and other waste? And with some 265 million tons (240 million metric tons) of tailings from milling uranium ore—less than half stabilized—littering landscapes?

For an idea of scale: Load those tailings into railroad hopper cars, then pour the 91 million gallons (344.5

million liters) of waste into tank cars, and you would have a mythical train that would reach around the Equator and then some.

In a decade real trains and trucks carrying high-level waste may head to Yucca Mountain, Nevada, the government's choice, and a controversial one, for a permanent repository.

In addition to storing the waste, contaminated soil and groundwater must be treated and stabilized, nuclear reactors decommissioned, buildings demolished, some buried waste exhumed, sorted, and buried again because it wasn't buried right in the first place. The bill for all this will be staggering—perhaps 400 billion dollars over 75 years.

Several federal agencies share the task. The Department of Energy (DOE) runs the facilities and supervises cleanup performed by commercial contractors. The Environmental Protection Agency (EPA) sets health and environmental standards for long-term storage of waste. Meanwhile the Department of Transportation supervises most shipments of nuclear materials using standards set by the Nuclear Regulatory Commission (NRC), which also licenses all except military reactors, which are—to come full circle—supervised by the Department of Energy.

I spent six weeks traveling to major nuclear facilities in several states, talking with managers, scientists, and engineers. Many cheerily took time to explain nuclear physics and radiation, but it took the Department of Energy more than four months to respond to an important question: How much nuclear waste in its various forms exists in the U.S.?

I also spoke to environmentalists, who are satisfied that a cleanup is finally taking place but suspicious whether it will be done to their standards. "The government," summed up one environmentalist, "will just lie to you."

In truth, our nation's nuclear weapons establishment operated in secret for many years, creating a deep vein of public distrust. As a result, emotions can run high when you're talking nuclear waste, weapons, and power. I'll state my bias now—as a former Marine Corps officer I value the profession of arms as honorable and necessary. I view nuclear weapons as a proven deterrent to war, not as a threat to peace. And I support the role of nuclear power in our energy mix. Yet during my reporting I found myself conceding points to environmentalists and even questioning government plans for permanent storage of high-level waste.

Cleaning up nuclear garbage would be a lot easier if we didn't have to face the chemical and physical chaos of health-threatening radiation, the emission of energy from a radioactive material.

Plutonium or cesium or strontium or other "-ium" elements created in a nuclear reactor emit dangerous radiation that can literally knock electrons off the atoms in our cells, disrupting or destroying cellular function or even causing cells to mutate. This radiation comes in the form of tiny alpha or beta particles or gamma rays traveling with great energy.

Radioactive elements emit radiation because they are unstable; they'd rather be something else. They achieve this by literally going to pieces; many emit particles and waves billions and billions of times each second.

Every radioactive element, including the -ium elements, has a half-life, the time it takes for half of its atoms to decay. Half-lives range from a fraction of a second to billions of years—4.5 billion for uranium 238. Paradoxically, the longer the half-life the less intense the radiation. Slightly radioactive uranium is no health threat if handled properly. After ten half-lives, an element is usually harmless.

Scientists quantify radiation received by people with a unit called a rem. A single wholebody dose of 400 rem, equivalent to more than 40,000 chest x-rays, will kill half the people receiving it. The maximum exposure permitted nuclear plant workers is 5 rem a year.

Everywhere, we experience background radiation, so-called because it's there all the time, mainly cosmic rays and alpha particles from radon gas. Other sources include medical x-rays, TV sets, even bricks, which pick up some uranium from the clay they're made of. Our bodies are slightly radioactive, mostly from everyday exposure to potassium.

The background radiation on a windswept Colorado mesa called Rocky Flats is around 450 millirem a year (a millirem is one thousandth of a rem), but the problem at a weapons plant there of the same name is big-league radioactivity from some of those -ium elements, principally plutonium. From 1952 to the end of the Cold War in 1989, technicians there fashioned chunks of plutonium into tens of thousands of spheres capable of triggering thermonuclear weapons.

Rocky Flats sits between Denver and Boulder and their galleries of critics who religiously chronicled tainted groundwater; drums oozing waste; plutonium-contaminated air ducts, pipes, and soil. Plutonium's nasty habit of being pyrophoric—igniting spontaneously—caused two major fires and myriad small ones, contributing to Rocky Flats' reputation as one of the most vilified weapons plants in the U.S.

Rockwell, the plant's contractor, eventually plea-bargained environmental crimes including acid spills and four other felonies and paid 18.5 million dollars in fines.

Today the buck of criticism stops at Barbara Mazurowski, DOE manager at Rocky, who supervises a cleanup crew of some 5,000 people at a cost of two million dollars a day. Mazurowski confronts me in a stance so sturdy she seems sprouted from Rocky Mountain granite. As she speaks, her hands fly in formation like two jet fighters, veering as she makes her point: "We sullied this environment, and now we're cleaning it up. A site of this magnitude has never been closed. When we're finished in 2006, all you will see here is grass."

Looking at Rocky's 400 acres (1.6 square kilometer) of buildings and roads, I find this hard to believe. But here and there lie heaps of concrete rubble, remnants of buildings already dismantled.

Mazurowski takes me on a tour of Building 771, a former plutonium fabrication center once described as the "most dangerous building in the U.S." and still a radiation threat despite partial cleanup. We stretch into protective rubber clothing from booties to gloves to bonnets. Only our faces are exposed, because there's little chance of airborne contamination.

We pass scores of glove boxes, whose rubber gloves—mixed with lead to shield technicians from radiation—hang as if still waiting for someone to insert hands, reach inside the steel boxes, and manipulate plutonium into a shape appropriate for a thermonuclear explosion.

Workers use torches to cut the boxes, unused since 1989, into chunks to be placed in drums for transport to the Waste Isolation Pilot Plant near Carlsbad, New Mexico, to be buried permanently in 2,150-foot-deep (655.3-meters-deep) caverns hacked out of ancient salt.

The room is humid and dark, and the torches spit out luminescent sparks. I wipe my bare forehead with my rubber-gloved hand, forgetting I have been forbidden to do so because my glove might have picked up an errant speck of plutonium spewing radiation in the form of billions of alpha particles. This is a big deal. Though alpha can be stopped by a piece of paper, they are particularly dangerous if inhaled or swallowed. I own up. A technician waves a radiation counter close to my face to detect any alpha. Fortunately, I'm clean.

Above is a cat's cradle of miles of pipes, from which radioactive liquid is being drained. Bit by bit, pipe by pipe, glove box piece by piece, Building 771 is returning to grass.

I left Rocky that day fairly impressed with the professionalism and cleanup efforts of manager Mazurowski and her troops. Later, to get another viewpoint, I sought out Len Ackland, director of the Center for Environmental Journalism at the University of Colorado, Boulder, and author of a critical book about the plant, Making a Real Killing. I asked Ackland what he thinks of Rocky Flats going back to grass. He responded with a significant question: "What's beneath the grass?"

The answer: dirt specked with plutonium. Environmentalists would like the plutonium removed; DOE says the radiation will be minuscule, about one millirem a year, adding that it would cost millions to replace the soil.

Rocky flats may be DOE's poster child for cleanup success, but a sister facility, the 586-square-mile (1,517.7-square-kilometer) Hanford Site, in Washington State, is quite another matter. Here reposes the country's greatest volume of high-level nuclear waste.

The Hanford inventory includes 53 million gallons (200 million liters) of waste from plutonium processing stored in underground tanks, nearly 2,300 tons (2,087 metric tons) of spent fuel, four and a half tons (four metric tons) of plutonium, 25 million cubic feet (707,921 cubic meters) of solid waste, and 38 billion cubic feet (1.1 billion cubic meters) of contaminated soil and groundwater. In a storage pool I look at the nation's most lethal single source of radiation excepting reactor cores—1,936 steel cylinders containing cesium and strontium covered by 13 feet (3.9 meters) of water. When a technician switches off the lights, radiation from the cylinders puts on a light show of royal blue.

Hanford reactors made plutonium for the first nuclear explosion, near Alamogordo, New Mexico, in 1945 and for the bomb dropped on Nagasaki (the Hiroshima bomb used uranium). Hanford had produced about 59 tons (53 metric tons) of bomb-grade plutonium by the time it closed in 1989.

From the earliest days, Hanford scientists observed that radionuclides—a catchall term for radioactive atoms—were entering the environment. Iodine 131, a gas by-product of plutonium processing, escaped from unfiltered stacks. Water taken from the nearby Columbia River to cool reactors was returned to the river with a burden of radioactive sodium, zinc, arsenic, even some -ium elements.

Later, waste stored in underground tanks leaked into the soil, and 45 billion gallons (170 billion liters) of contaminated liquids were dumped onsite, some near leaking tanks. Thus contaminated plumes were created underground, some threatening the Columbia. The press began reporting claims of increasing rates of cancer in people and birth defects in people and animals in farm areas near Hanford.

In September 1985 Michael Lawrence, DOE manager of the site, met the farmers to consider their concerns. That radiation causes illness in an individual is virtually impossible to prove; nonetheless Lawrence decided to release previously classified information, beginning with 19,000 pages of documents written by Hanford scientists as far back as 1943. Lawrence was the first DOE official to do such a thing, and his decision "raised some eyebrows," he remembers, back in Washington, D.C.

In Hanford other eyebrows were raising, especially those of Michele Gerber, a housewife, mother, and trained historian who was poring over the released documents. "The scientists didn't believe the texts would be read in their lifetime," Gerber told me. "I was dumbfounded at how shockingly candid they were."

During early releases of iodine 131 in the 1940s, technicians nonchalantly recorded that the radioactive gas was spreading farther than anticipated. "They just enlarged their sampling circles," Gerber said, "to 25, 50, 100, 150 miles (40, 80, 161, 241 kilometers), all the way to Spokane and Walla Walla." Trancelike, Gerber read through the night till sunup. "I was thinking—you did what? Why didn't you stop? Why didn't you change the production process to reduce the emissions?"

Many doubted the data until contamination was found in desert flowers decorating the desk of an official. Concern mounted, but Hanford had plutonium production quotas to meet. Special silver filters finally stopped 99 percent of iodine emissions by 1952.

Gerber's book detailing pollution at Hanford, *On the Home Front*, was published in 1992, a work of history dispassionately told, thoroughly footnoted, the literary equivalent of a nuclear explosion. The fallout: Though Hanford scientists knew they were contaminating the environment, they didn't tell the public about it.

The public felt betrayed. Roy Gephart, a geohydrologist who had been involved with Hanford for 28 years, said Gerber's book taught him "things I never knew. I talked to workers who said they were taken by surprise when they read the book. They felt deceived. That's why many Americans distrust us today."

Gephart is now a program manager in environmental sciences at Pacific Northwest National Laboratory, a federal facility near Hanford. "The important thing is to do the cleanup right and regain the public trust," he says, "but that may take another generation."

They're building a four-billion-dollar plant now at Hanford to vitrify radioactive waste in glass for storage, burying low-level waste in giant pits lined with impervious plastic, finding cesium in the dirt of reactor storage pools, roofing old reactors in steel for a 75-year wait until radioactivity diminishes, and installing hundreds of wells to monitor underground plumes. "If the plumes ever threaten human health," says Gephart, "we plan to intercept them, build barriers, and stabilize the contaminants. However, most plumes will remain untouched because of cost, risk, and the lack of suitable technology."

Michele Gerber looks back: "The Cold War really was a war," she says. "And Hartford was a battlefield with a different kind of destruction, radionuclides pervading the environment. You can't have the production that Hartford did and not have the waste. I'm optimistic we'll clean it up. All I ever wanted was a clean river."

Another Cold War battlefield, the Idaho National Engineering and Environmental Laboratory (INEEL), west of Idaho Falls, began its career as a firing range for battleship guns in World War II. Later this vast expanse of sagebrush and shrub became a research center for nuclear reactors and for a time was used as a permanent repository for some nuclear waste.

INEEL received thousands of barrels of waste by train from Rocky Flats until October 1988, when Idaho Governor Cecil Andrus ordered state troopers to block the shipment. The train motored back to Colorado, among its freight cars a maroon one numbered 6503 that you can still see on a siding at Rocky—the waste long ago removed, of course.

Shipments soon resumed, however. In 1995 INEEL decided to burn the plutonium-contaminated waste in a state-of-the-art incinerator. As explained to me, the machine would separate the plutonium while burning PCBs and other chemicals. An infinitesimal fraction of plutonium might escape, INEEL experts said, but not enough to be harmful.

A hundred miles (160 kilometers) away in Jackson, Wyoming, a cowboy-chic redoubt of the wealthy as well as a way point for tourists bound for Yellowstone, folks did not see it that way. They worried about "a cloud of plutonium particles blowing in our direction," said Angus Thuermer, Jr., editor of the Jackson Hole News. "Alarm bells were ringing from one end of the valley to the other. INEEL said it was safe, but a lot of people here don't trust the government."

One was Gerry Spence, a famed trial lawyer who frequently appears on TV talk shows wearing a deerskin shirt. "INEEL acted as if these nuclear particles would drop the minute they hit the Wyoming border," he said. At a meeting of a thousand Jacksonians in 1999, Spence laid out the plutonium threat. "It was a closing argument before the jury," he remembered, "and the people prevailed." Harrison Ford pledged $50,000 to the cause. Others joined, and in a half hour Spence had raised $500,000. An organization was launched, Keep Yellowstone Nuclear Free.

In an editorial, Powder, a skiing magazine, speculated that Jackson skiers would schuss on "nuclear powder" during a "nuclear winter," leaving headlamps at home, presumably because the night would be lighted by the glow of nuclear material.

Plutonium doesn't glow in the dark, however, and some Jackson citizens were mighty skeptical that plutonium cinders would smudge their town. "There's no evidence, zip, that plutonium or any other radioactive material will descend upon Jackson," said Jerry Fussell, a former professor of nuclear engineering at the University of Tennessee specializing in nuclear systems risk assessment. "Can you imagine a whirlwind in Idaho Falls winding up and pitching nuclear materials to Jackson Hole? Ridiculous.' Fussell, who has served as a U.S. delegate to the International Atomic Energy Agency for discussions of radioactive releases, said, "It will be a disgrace if Jackson prevents operation of that incinerator."

Prevented it was. Gerry Spence sued, and after a year of wrangling, an agreement was struck: INEEL would investigate alternatives to incineration of the plutonium-contaminated waste, which remains on site. Spence agreed not to bring suit questioning the disposition of other waste. One INEEL official told me, "It's not the most pleasant thing, having Gerry Spence on your tail."

I repeated the remark to Spence, and he smiled. We were sitting on the back porch of his ranch north of Dubois, Wyoming, where Spence looks taller and younger—he was 71—then on TV. A chirping gallery of robins and warblers failed to interrupt his gloomy assessment of nuclear waste storage.

"The idea that we could find some safe way to deal with that waste is simply a myth," Spence said. "First you have to haul it. Am I to believe that there will never be any acts of God that will intervene? That's what they said about the Titanic."

Other people on the nuclear waste trail spoke with equal candor—a scientist, an activist, a DOE manager, an environmentalist, and a river guide.

Arjun Makhijani Smart, informed, thoughtful, this India-born Ph.D. in electrical engineering has critiqued the nuclear scene for 20 years. The most dramatic sideburns I have ever seen hang from his temples like onions—white, bulbous, huge. With eight staffers he runs the Institute for Energy and Environmental Research, a think tank in Takoma Park, Maryland, a suburb of Washington, D.C. Makhijani told me he'd rather do something else, but DOE keeps him busy.

"I am a constructive critic," he says. As an example he offers his detective work on the amount of transuranic waste haphazardly buried in the 1950s and '60s, when trucks simply dumped barrels of plutonium-contaminated waste into pits and trenches. A layer of soil was spread over the waste, then heavy equipment leveled it. The process was repeated.

Trying to gauge the amount of waste in the pits, Makhijani studied government records and concluded that officials were guessing: "They were throwing darts." He sent a critique to DOE, which looked it over for two years and finally agreed with him, admitting there was ten times more radioactivity in plutonium—contaminated waste buried in pits throughout the nuclear weapons establishment than they thought. "There is a ton of plutonium in Idaho alone," says Makhijani. "Some of it is leaching through the soil and threatening the Snake River aquifer."

Makhijani favors the phaseout of nuclear power, replacing it with wind power. "In 12 Midwest states there's enough wind potential to generate three times the U.S. production of electricity," he says.

Marcus Page In Las Vegas, I met this antinuclear, peace activist who was once arrested for protesting Star Wars at Vandenberg Air Force Base in California. He regularly shows up at antinuclear protests, where he unpacks a portable radio station and starts broadcasting for Catholic Worker Kommunity Radio. At our meeting he wore a dimpled, narrow-brimmed, round-topped, black felt hat that seemed a bit too small, exactly the kind of hat, I imagined, that Rumpelstiltskin himself would have worn. I admired it. Page immediately took it off and gave it to me.

Page wants to abolish nuclear weapons and power plants because "they just create more waste. There is no safe way to store it, so it is irresponsible to generate radioactive materials that last for hundreds of generations."

Ines Triay Another of DOE's talented young managers, Triay escaped from Cuba at the age of three with her parents and later earned a Ph.D. in chemistry from the University of Miami. She manages the Waste Isolation Pilot Plant in New Mexico, a repository that expects to receive 850,000 drums of transuranic waste by 2035. "I intend to reduce that by at least 15 years," says Triay, who runs the plant "like a business," despite a plethora of regulations. "There are literally tens of thousands of requirements I have to meet," she says. "Many duplicate and waste time and money." If she succeeds, she will achieve a cost underrun of around eight billion dollars off the original 16-billion-dollar figure.

Joni Arends She's the waste programs director for Concerned Citizens for Nuclear Safety, an environmental group in Santa Fe, New Mexico. Late one afternoon at a Tex-Mex restaurant on Cerrillos Road, we sat at the bar, and I listened as Arends recited a list of government environmental mischief, from alpha particles to omegaton anxieties. After three Dr Peppers I asked, "Joni, is there anything the United States government has done in the past 50 years that you approve of?"

She looked away thoughtfully, and after a time looked back. "Yes," she said, "President Eisenhower built the Interstate Highway System."

David Lyle A river guide, Lyle feels happy when running rapids and "lousy" when looking at a humongous mound of uranium tailings close by the Colorado River near his home in Moab, Utah. Because ammonia leaches from the tailings into the river to threaten endangered fish, because cancer-causing radon wafting from the pile has settled as a radon "fog," and because he's just tired of looking at ten million tons (nine million metric tons) of tailings.

"The citizens of Moab have yelled about this for 25 years," protests Lyle.

The Moab pile is an ugly duckling amid the glorious desert scenery of Arches National Park and the Scott M. Matheson wetlands nearby. DOE is pondering whether to move it—at a cost of 364 million dollars—or to attempt to contain the leaking ammonia and other groundwater pollution.

For Spence, Makhijani, Arends, and many others, the safety of nuclear materials shipped by highway and rail is a prime concern. Near Chugwater, Wyoming, I encountered such a shipment when returning to my home in Denver from a fishing trip. A clutch of military humvees with troops, big Chevy Suburbans wearing "Security Forces" signs, and a circling helicopter rode shotgun around a large white trailer bearing a U.S. Air Force logo—all creeping along at 50 miles an hour (80 kilometers an hour) on an interstate that allowed 75 (121). On the door of the lead vehicle another sign declared, "The United States of America."

How to find out whether this was nuclear waste or just something nuclear?

I decided to create a nuisance, pulling past the convoy and parking by the roadside, holding my cell phone suspiciously, I hoped, with my laptop open. The third time I parked, it was dark. I had given up attracting attention.

Suddenly my door was cracked open by a fit, squarely built man in a blue jumpsuit with cartridge belt who identified himself as a U.S. marshal. "We're wondering why you're doing this," he said. He had sneaked up behind me with his lights off and now shielded his right hand, cupping his sidearm I supposed. The helicopter hovered, its spotlight in my face.

I sputtered that I was a NATIONAL GEOGRAPHIC writer working on a story on nuclear waste. "We know who you are," he replied. Just then the convoy with the trailer passed.

"Is that nuclear waste?" I asked.

"No," he replied.

"Can you tell me what it is?"

"No."

Marshal Douglas Lineen closed my door and departed, and so did the helicopter, leaving me resolved to stop annoying these people and to try to find out if the suspect cargo might be a nuclear warhead.

"With all that security, probably a complete weapon," said Douglas Ammerman, an engineer at Sandia National Laboratories in Albuquerque, New Mexico, when I asked him later. Ammerman makes a living banging up one-quarter- to one-half-scale steel containers designed to carry nuclear waste.

His technicians drop, burn, immerse, try to puncture, and otherwise torture such containers to test their integrity. In one spectacular instance, they rammed a locomotive at 81 miles an hour (130 kilometers an hour) into an obsolete, full-size cask mounted on a flatbed, damaging the locomotive but not the cask.

Ammerman told me he couldn't think of a situation that might rupture a cask. "Perhaps if you were going past Mount St. Helens when it blew," he offered.

Don Hancock, the nuclear waste program director for the Southwest Research and Information Center in Albuquerque, challenged Ammerman's statement. Hancock noted that a freight train carrying hazardous waste wrecked last year in a tunnel in Baltimore, causing a fire that burned for five days. "They had to close the tunnel. Suppose that had been a spent fuel shipment?" he asked.

Hancock observed that a propane fire burns at 2,000 degrees Fahrenheit (1,093.3 degree Celsius). The Nuclear Regulatory Commission specifies that casks be tested by burning them in fuel for a half hour at a temperature of 1,475 degrees Fahrenheit (801.7 degree Celsius).

At the offices of the NRC in Rockville, Maryland, I put the question to E. William Brach, director of the Spent Fuel Project Office. Why 1,475 degrees Fahrenheit (801.7 degree Celsius)? Brach looked at me, then turned a quizzical expression toward Mark Delligatti, senior project manager, who shrugged.

It turns out the NRC adopted the standard in 1965, taking it and other canons from International Atomic Energy Agency requirements published in 1961. Hancock regards these 40-year-old standards as obsolete.

"I would like to see full-size containers tested to failure," he says, "as automobiles are. We need to know what kind of crash or fire will rupture a cask."

An important consideration, it would seem, because shipments of high-level waste on the nation's highways and railroads could eventually deliver tens of thousands of tons of spent fuel, from nuclear power plants and Navy ships, and other dangerous waste to a repository. Spent fuel from power plants alone increases at the rate of 2,000 tons (1.8 metric tons) a year. Already some plant water-storage pools are filled, and the overflow spent fuel is stored above ground in casks that can be licensed as safe for at least 20 years. Some say store the stuff above ground and maybe new technology will come along and solve the problem.

If the government has its way, shipments will head for Yucca Mountain, 90 miles (145 kilometers) northwest of Las Vegas, chosen by Congress in 1987 as a potential resting place for the nation's spent fuel rods and other high-level waste. DOE has invested four billion dollars testing and tunneling Yucca amid controversy as thick as the compacted volcanic ash that comprises the 1,500-foot-high (457-meter-high) ridge.

Adamantly, the state of Nevada finds "significant and unacceptable risks" just about everywhere it looks in Yucca Mountain, from geology to groundwater to nickel alloy containers (for the spent fuel) that DOE says will last at least 10,000 years. More like 500, says Nevada, and many environmentalists agree.

In January, Spencer Abraham, Secretary of Energy, declared the site "scientifically sound" and "technically suitable" for development, forwarding the matter to the President as the law requires, while firing a shot across the bow of battleship Nevada.

Nevada fired back. Senator John Ensign retorted, "The Department of Energy has been hell-bent on building Yucca Mountain no matter what the science, what the ethics, what the cost." Governor Kenny Quinn threatened to bring suit all the way to the Supreme Court.

After President Bush approved the site on February 15, Nevada filed a notice of disapproval on April 8, sending the matter to Congress, which can override Nevada's veto by a majority vote. Pending state lawsuits and approval of DOE's license application to the NRC, DOE will proceed to build the site, which could be in operation as early as 2010.

The Environmental Protection Agency has ruled that DOE must demonstrate that Yucca Mountain can meet EPA standards for public and environmental health for 10,000 years. Does that mean radioactivity won't be a threat after 10,000 years? Nope. The peak radiation dose to the environment will occur after 400,000 years, according to DOE.

Nevertheless, and despite objections from many scientists, EPA decided on 10,000 years because of "tremendous uncertainties" beyond that period.

"Do you think we will still have a Department of Energy 300,000 years from now?" I was asked by Steve Page, director of EPA's Office of Radiation and Indoor Air.

I don't know. But there's no uncertainty about how long it takes radioactivity to subside, about ten half-lives. For plutonium 239, this is 240,000 years.

There are no textbook solutions. Some environmentalists would settle for a compliance period of 250,000 to 500,000 years. The Swedes are shooting for a lot longer. To store their high-level waste, they plan to use steel containers coated with copper, which won't corrode in the absence of oxygen, imbedded 1,800 feet (549 meters) in granite (an option rejected in the U.S.) and surrounded by impervious clay to inhibit moisture transport. They expect this architecture to contain radioactivity for a million years.

That's plenty of time for *Homo sapiens* to experience evolutionary changes. Perhaps to a species we might call *Homo furioso*, wondering loudly—what were those ancient Americans thinking when they put that hot stuff in the earth and decided 10,000 years was time enough to contain it?

There may be a better way, according to Yoon Chang, associate director of Argonne National Laboratory near Chicago and an expert in reactor technology. Today's inefficient reactors burn only 3 percent of the fuel. The other 97 percent is declared "spent," fit only for Yucca Mountain.

In an ambitious recycling project, Chang wants to use that fuel in an advanced "fast" reactor that, on paper, promises to burn 99.9 percent of the fuel, including all but 0.1 percent of the plutonium and its -ium friends requiring long-term storage. "Most of the waste will be an ashlike residue of fission products that will be harmless"—now hear this—"in only 300 years," Chang predicts, though some disagree.

Not even Homer Simpson could melt down a fast reactor, says Chang. Its sodium coolant has a high boiling point—today's reactors use water—and would absorb excess heat. Meanwhile, the fuel elements would expand and separate, stopping the chain reaction "without human intervention." Basic fast-reactor technology has been demonstrated, says Chang, and the next step is to get it working smoothly in one advanced design, an enormous project that would take "around ten years and two billion dollars in federal funds."

Fast reactor sounds too good to be true, and may be. Skeptics question whether its promise can be realized, noting, for example, that sodium catches fire easily. But Chang is optimistic.

Would you like to make a two-billion-dollar bet to settle this? Or would you rather build a Yucca Mountain every 50 years or so and make *Homo furioso* really mad? Perhaps you want to chuck everything nuclear and put your money on power from wind or solar sources.

These are questions the country will have to face, along with garbage problems still unsolved. One that haunts me concerns five plutonium-processing plants at Hanford. Three of these dingy gray hulks sprawl about a thousand feet (304.8 meters) long with walls of reinforced concrete up to eight feet thick. Tear these monsters down, and where do you put that rubble?

Some people are suggesting, don't tear 'em down. Fill 'em up with low-level waste and cover everything with the good earth. I like that, a harmonious conclusion to a contentious chapter in the nation's history-radioactivity returned to the womb that bore it.

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High-level radioactive waste management

From Wikipedia, the free encyclopedia

High-level radioactive waste management concerns how radioactive materials created during production of nuclear power and nuclear weapons are dealt with. Radioactive waste contains a mixture of short-lived and long-lived nuclides, as well as non-radioactive nuclides.[1] There was reported some 47,000 tonnes of high-level nuclear waste stored in the USA in 2002.

Spent nuclear fuel stored underwater and uncapped at the Hanford site in Washington, USA.

The most troublesome transuranic elements in spent fuel are neptunium-237 (half-life two million years) and plutonium-239 (half-life 24,000 years).[2] Consequently, high-level radioactive waste requires sophisticated treatment and management to successfully isolate it from the biosphere. This usually necessitates treatment, followed by a long-term management strategy involving permanent storage, disposal or transformation of the waste into a non-toxic form.[3] Radioactive decay follows the half-life rule, which means that the rate of decay is inversely proportional to the duration of decay. In other words, the radiation from a long-lived isotope like iodine-129 will be much less intense than that of short-lived isotope like iodine-131.[4]

Governments around the world are considering a range of waste management and disposal options, usually involving deep-geologic placement, although there has been limited progress toward implementing long-term waste management solutions.[5] This is partly because the timeframes in question when dealing with radioactive waste range from 10,000 to millions of years,[6][7] according to studies based on the effect of estimated radiation doses.[8]

Thus, Alfvén identified two fundamental prerequisites for effective management of high-level radioactive waste: (1) stable geological formations, and (2) stable human institutions over hundreds of thousands of years. As Alfvén suggests, no known human civilization has ever endured for so long, and no geologic formation of adequate size for a permanent radioactive waste repository has yet been discovered that has been stable for so long a period.[9] Nevertheless, avoiding confronting the risks associated with managing radioactive wastes may create countervailing risks of greater magnitude. Radioactive waste management is an example of policy analysis that requires special attention to ethical concerns, examined in the light of uncertainty and *futurity*: consideration of 'the impacts of practices and technologies on future generations'.[10]

There is a debate over what should constitute an acceptable scientific and engineering foundation for proceeding with radioactive waste disposal strategies. There are those who have argued, on the basis of complex geochemical simulation models, that relinquishing control over radioactive materials to geohydrologic processes at repository closure is an acceptable risk. They maintain that so-called "natural analogues" inhibit subterranean movement of radionuclides, making disposal of radioactive wastes in stable geologic formations unnecessary.[11] However, existing models of these processes are empirically underdetermined:[12] due to the subterranean nature of such processes in solid geologic formations, the accuracy of computer simulation models has not been verified by empirical observation, certainly not over periods of time equivalent to the lethal half-lives of high-level radioactive waste.[13][14] On the other hand, some insist deep geologic repositories in stable geologic formations are necessary. National management plans of various countries display a variety of approaches to resolving this debate.

Researchers suggest that forecasts of health detriment for such long periods *should be examined critically*.[15] Practical studies only consider up to 100 years as far as effective planning[16] and cost evaluations[17] are concerned. Long term behaviour of radioactive wastes remains a subject for ongoing research.[18] Management strategies and implementation plans of several representative national governments are described below.

Contents

Geologic disposal

The International Panel on Fissile Materials has said:

> It is widely accepted that spent nuclear fuel and high-level reprocessing and plutonium wastes require well-designed storage for periods ranging from tens of thousands to a million years, to minimize releases of the contained radioactivity into the environment. Safeguards are also required to ensure that neither plutonium nor highly enriched uranium is diverted to weapon use. There is general agreement that placing spent nuclear fuel in repositories hundreds of meters below the surface would be safer than indefinite storage of spent fuel on the surface.[19]

The process of selecting appropriate permanent repositories for high level waste and spent fuel is now under way in several countries with the first expected to be commissioned some time after 2017.[20] The basic concept is to locate a large, stable geologic formation and use mining technology to excavate a tunnel, or large-bore tunnel boring machines (similar to those used to drill the Chunnel from England to France) to drill a shaft 500–1,000 meters below the surface where rooms or vaults can be excavated for disposal of high-level radioactive waste. The goal is to permanently isolate nuclear waste from the human environment. However, many people remain uncomfortable with the immediate stewardship cessation of this disposal system, suggesting perpetual management and monitoring would be more prudent.

Because some radioactive species have half-lives longer than one million years, even very low container leakage and radionuclide migration rates must be taken into account.[21] Moreover, it may require more than one half-life until some nuclear materials lose enough radioactivity to no longer be lethal to living organisms. A 1983 review of the Swedish radioactive waste disposal program by the National Academy of Sciences found that country’s estimate of several hundred thousand years—perhaps up to one million years—being necessary for waste isolation "fully justified."[22]

The proposed land-based subductive waste disposal method would dispose of nuclear waste in a subduction zone accessed from land,[23] and therefore is not prohibited by international agreement. This method has been described as a viable means of disposing of radioactive waste,[24] and as a state-of-the-art nuclear waste disposal technology.[25]

In nature, sixteen repositories were discovered at the Oklo mine in Gabon where natural nuclear fission reactions took place 1.7 billion years ago.[26] The fission products in these natural formations were found to have moved less than 10 ft (3 m) over this period,[27] though the lack of movement may be due more to retention in the uraninite structure than to insolubility and sorption from moving ground water; uraninite crystals are better preserved here than those in spent fuel rods because of a less complete nuclear reaction, so that reaction products would be less accessible to groundwater attack.[28]

Materials for geological disposal

In order to store the high level radioactive waste in long-term geological depositories, specific waste forms need to be used which will allow the radioactivity to decay away while the materials retain their integrity for thousands of years.[29] The materials being used can be broken down into a few classes: glass waste forms, ceramic waste forms, and nanostructured materials.

The glass forms include borosilicate glasses and phosphate glasses. Borosilicate nuclear waste glasses are used on an industrial scale to immobilize high level radioactive waste in many countries which are producers of nuclear energy or have nuclear weaponry. The glass waste forms have the advantage of being able to accommodate a wide variety of waste-stream compositions, they are easy to scale up to industrial processing, and they are stable against thermal, radiative, and chemical perturbations. These glasses function by binding radioactive elements to nonradioactive glass-forming elements.[30] Phosphate glasses while not being used industrially have much lower dissolution rates than borosilicate glasses, which make them a more favorable option. However, no single phosphate material has the ability to accommodate all of the radioactive products so phosphate storage requires more reprocessing to separate the waste into distinct fractions.[31] Both glasses have to be processed at elevated temperatures making them unusable for some of the more volatile radiotoxic elements.

The ceramic waste forms offer higher waste loadings than the glass options because ceramics have crystalline structure. Also, mineral analogues of the ceramic waste forms provide evidence for long term durability.[32] Due to this fact and the fact that they can be processed at lower temperatures, ceramics are often considered the next generation in high level radioactive waste forms.[33] Ceramic waste forms offer great potential, but a lot of research remains to be done.

National management plans

Finland, the United States and Sweden are the most advanced in developing a deep repository for high-level radioactive waste disposal. Countries vary in their plans on disposing used fuel directly or after reprocessing, with France and Japan having an extensive commitment to reprocessing. The country-specific status of high-level waste management plans are described below.

In many European countries (e.g., Britain, Finland, the Netherlands, Sweden and Switzerland) the risk or dose limit for a member of the public exposed to radiation from a future high-level nuclear waste facility is considerably more stringent than that suggested by the International Commission on Radiation Protection or proposed in the United States. European limits are often more stringent than the standard suggested in 1990 by the International Commission on Radiation Protection by a factor of 20, and more stringent by a factor of ten than the standard proposed by the U.S. Environmental Protection Agency (EPA) for Yucca Mountain nuclear waste repository for the first 10,000 years after closure. Moreover, the U.S. EPA's proposed standard for greater than 10,000 years is 250 times more permissive than the European limit.[34]

The countries that have made the most progress towards a repository for high-level radioactive waste have typically started with public consultations and made voluntary siting a necessary condition. This consensus seeking approach is believed to have a greater chance of success than top-down modes of decision making, but the process is necessarily slow, and there is "inadequate experience around the world to know if it will succeed in all existing and aspiring nuclear nations".[35]

Moreover, most communities do not want to host a nuclear waste repository as they are "concerned about their community becoming a de facto site for waste for thousands of years, the health and environmental consequences of an accident, and lower property values".[36]

Asia

People's Republic of China

In the Peoples Republic of China, ten reactors provide about 2% of electricity and five more are under construction.[37] China made a commitment to reprocessing in the 1980s; a pilot plant is under construction at Lanzhou, where a temporary spent fuel storage facility has been constructed. Geological disposal has been studied since 1985, and a permanent deep geological repository was required by law in 2003. Sites in Gansu Province near the Gobi desert in northwestern China are under investigation, with a final site expected to be selected by 2020, and actual disposal by about 2050.[38][39]

Republic of China

In the Republic of China, nuclear waste storage facility was built at the Southern tip of Orchid Island in Taitung County, offshore of Taiwan Island. The facility was built in 1982 and it is owned and operated by Taipower. The facility receives nuclear waste from Taipower's current three nuclear power plants. However, due to the strong resistance from local community in the island, the nuclear waste has to be stored at the power plant facilities themselves.[40][41]

India

Sixteen nuclear reactors produce about 3% of India's electricity, and seven more are under construction.[37] Spent fuel is processed at facilities in Trombay near Mumbai, at Tarapur on the west coast north of Mumbai, and at Kalpakkam on the southeast coast of India. Plutonium will be used in a fast breeder reactor (under construction) to produce more fuel, and other waste vitrified at Tarapur and Trombay.[42][43] Interim storage for 30 years is expected, with eventual disposal in a deep geological repository in crystalline rock near Kalpakkam.[44]

Japan

In 2000, a Specified Radioactive Waste Final Disposal Act called for creation of a new organization to manage high level radioactive waste, and later that year the Nuclear Waste Management Organization of Japan (NUMO) was established under the jurisdiction of the Ministry of Economy, Trade and Industry. NUMO is responsible for selecting a permanent deep geological repository site, construction, operation and closure of the facility for waste emplacement by 2040.[45][46] Site selection began in 2002 and application information was sent to 3,239 municipalities, but by 2006, no local government had volunteered to host the facility.[47] Kōchi Prefecture showed interest in 2007, but its mayor resigned due to local opposition. In December 2013 the government decided to identify suitable candidate areas before approaching municipalities.[48]

The head of the Science Council of Japan's expert panel has said Japan's seismic conditions makes it difficult to predict ground conditions over the necessary 100,000 years, so it will be impossible to convince the public of the safety of deep geological disposal.[48]

Europe

Belgium

Belgium has seven nuclear reactors that provide about 52% of its electricity.[37] Belgian spent nuclear fuel was initially sent for reprocessing in France. In 1993, reprocessing was suspended following a resolution of the Belgian parliament;[49] spent fuel is since being stored on the sites of the nuclear power plants. The deep disposal of high-level radioactive waste (HLW) has been studied in Belgium for more than 30 years. Boom Clay is studied as a reference host formation for HLW disposal. The Hades underground research laboratory (URL) is located at −223 m in the Boom Formation at the Mol site. The Belgian URL is operated by the Euridice Economic Interest Group, a joint organisation between SCK•CEN, the Belgian Nuclear Research Centre which initiated the research on waste disposal in Belgium in the 1970s and 1980s and ONDRAF/NIRAS, the Belgian agency for radioactive waste management. In Belgium, the regulatory body in charge of guidance and licensing approval is the Federal Agency of Nuclear Control, created in 2001.[50]

Finland

In 1983, the government decided to select a site for permanent repository by 2010. With four nuclear reactors providing 29% of its electricity,[37] Finland in 1987 enacted a Nuclear Energy Act making the producers of radioactive waste responsible for its disposal, subject to requirements of its Radiation and Nuclear Safety Authority and an absolute veto given to local governments in which a proposed repository would be located. Producers of nuclear waste organized the company Posiva, with responsibility for site selection, construction and operation of a permanent repository. A 1994 amendment to the Act required final disposal of spent fuel in Finland, prohibiting the import or export of radioactive waste.

Environmental assessment of four sites occurred in 1997–98, Posiva chose the Olkiluoto site near two existing reactors, and the local government approved it in 2000. The Finnish Parliament approved a deep geologic repository there in igneous bedrock at a depth of about 500 meters in 2001. The repository concept is similar to the Swedish model, with containers to be clad in copper and buried below the water table beginning in 2020.[51] An underground characterization facility, Onkalo spent nuclear fuel repository, was under construction at the site in 2012.[52]

France

With 58 nuclear reactors contributing about 75% of its electricity,[37] the highest percentage of any country, France has been reprocessing its spent reactor fuel since the introduction of nuclear power there. Some reprocessed plutonium is used to make fuel, but more is being produced than is being recycled as reactor fuel.[53] France also reprocesses spent fuel for other countries, but the nuclear waste is returned to the country of origin. Radioactive waste from reprocessing French spent fuel is expected to be disposed of in a geological repository, pursuant to legislation enacted in 1991 that established a 15-year period for conducting radioactive waste management research. Under this legislation, partition and transmutation of long-lived elements, immobilization and conditioning processes, and long-term near surface storage are being investigated by the Commissariat à l'Energie Atomique (CEA). Disposal in deep geological formations is being studied by the French agency for radioactive waste management, L'Agence Nationale pour la Gestion des Déchets Radioactifs, in underground research labs.[54]

Three sites were identified for possible deep geologic disposal in clay near the border of Meuse and Haute-Marne, near Gard, and at Vienne. In 1998 the government approved the Meuse/Haute Marne Underground Research Laboratory, a site near Meuse/Haute-Marne and dropped the others from further consideration.[55] Legislation was proposed in 2006 to license a repository by 2015, with operations expected in 2025.[56]

Germany

Nuclear waste policy in Germany is in flux. German planning for a permanent geologic repository began in 1974, focused on salt dome Gorleben, a salt mine near Gorleben about 100 kilometers northeast of Braunschweig. The site was announced in 1977 with plans for a reprocessing plant, spent fuel management, and permanent disposal facilities at a single site. Plans for the reprocessing plant were dropped in 1979. In 2000, the federal government and utilities agreed to suspend underground investigations for three to ten years, and the government committed to ending its use of nuclear power, closing one reactor in 2003.[57]

Within days of the March 2011 Fukushima Daiichi nuclear disaster, Chancellor Angela Merkel "imposed a three-month moratorium on previously announced extensions for Germany's existing nuclear power plants, while shutting seven of the 17 reactors that had been operating since 1981". Protests continued and, on 29 May 2011, Merkel's government announced that it would close all of its nuclear power plants by 2022.[58][59]

Meanwhile, electric utilities have been transporting spent fuel to interim storage facilities at Gorleben, Lubmin and Ahaus until temporary storage facilities can be built near reactor sites. Previously, spent fuel was sent to France or the United Kingdom for reprocessing, but this practice was ended in July 2005.[60]

Netherlands

COVRA (*Centrale Organisatie Voor Radioactief Afval*) is the Dutch interim nuclear waste processing and storage company in Vlissingen,[61] which stores the waste produced in their only remaining nuclear power plant after it is reprocessed by Areva NC[62] in La Hague, Manche, Normandy, France. Until the Dutch government decides what to do with the waste, it will stay at COVRA, which currently has a license to operate for one hundred years. As of early 2017, there are no plans for a permanent disposal facility.

Russia

In Russia, the Ministry of Atomic Energy (Minatom) is responsible for 31 nuclear reactors which generate about 16% of its electricity.[37] Minatom is also responsible for reprocessing and radioactive waste disposal, including over 25,000 tons of spent nuclear fuel in temporary storage in 2001.

Russia has a long history of reprocessing spent fuel for military purposes, and previously planned to reprocess imported spent fuel, possibly including some of the 33,000 metric tons of spent fuel accumulated at sites in other countries who received fuel from the U.S., which the U.S. originally pledged to take back, such as Brazil, the Czech Republic, India, Japan, Mexico, Slovenia, South Korea, Switzerland, Taiwan, and the European Union.[63][64]

An Environmental Protection Act in 1991 prohibited importing radioactive material for long-term storage or burial in Russia, but controversial legislation to allow imports for permanent storage was passed by the Russian Parliament and signed by President Putin in 2001.[63] In the long term, the Russian plan is for deep geologic disposal.[65] Most attention has been paid to locations where waste has accumulated in temporary storage at Mayak, near Chelyabinsk in the Ural Mountains, and in granite at Krasnoyarsk in Siberia.

Spain

Spain has five active nuclear plants with seven reactors which produced 21% of the country's electricity in 2013. Furthermore, there is legacy high-level waste from another two older, closed plants. Between 2004 and 2011, a bipartisan initiative of the Spanish Government promoted the construction of an interim centralized storage facility (ATC, *Almacén Temporal Centralizado*), similar to the Dutch COVRA concept. In late 2011 and early 2012 the final green light was given, preliminary studies were being completed and land was purchased near Villar de Cañas (Cuenca) after a competitive tender process. The facility would be initially licensed for 60 years.

However, soon before groundbreaking was slated to begin in 2015, the project was stopped because of a mix of geological, technical, political and ecological problems. By late 2015, the Regional Government considered it "obsolete" and effectively "paralyzed." As of early 2017, the project has not been shelved but it stays frozen and no further action is expected anytime soon. Meanwhile, the spent nuclear fuel and other high-level waste is being kept in the plants' pools, as well as on-site dry cask storage (*almacenes temporales individualizados*) in Garoña and Trillo.

As of early 2017, there are no plans for a permanent high-level disposal facility either. Low- and medium-level waste is stored in the El Cabril facility (Province of Cordoba.)

Sweden

In Sweden, as of 2007 there are ten operating nuclear reactors that produce about 45% of its electricity.[37] Two other reactors in Barsebäck were shut down in 1999 and 2005.[66] When these reactors were built, it was expected their nuclear fuel would be reprocessed in a foreign country, and the reprocessing waste would not be returned to Sweden.[67] Later, construction of a domestic reprocessing plant was contemplated, but has not been built.

Passage of the Stipulation Act of 1977 transferred responsibility for nuclear waste management from the government to the nuclear industry, requiring reactor operators to present an acceptable plan for waste management with "absolute safety" in order to obtain an operating license.[68][69] In early 1980, after the Three Mile Island meltdown in the United States, a referendum was held on the future use of nuclear power in Sweden. In late 1980, after a three-question referendum produced mixed results, the Swedish Parliament decided to phase out existing reactors by 2010.[70] In 2010, the Swedish government opened up for construction of new nuclear reactors. The new units can only be built at the existing nuclear power sites, Oskarshamn, Ringhals or Forsmark, and only to replace one of the existing reactors, that will have to be shut down for the new one to be able to start up.

The Swedish Nuclear Fuel and Waste Management Company. (Svensk Kärnbränslehantering AB, known as SKB) was created in 1980 and is responsible for final disposal of nuclear waste there. This includes operation of a monitored retrievable storage facility, the Central Interim Storage Facility for Spent Nuclear Fuel at Oskarshamn, about 150 miles south of Stockholm on the Baltic coast; transportation of spent fuel; and construction of a permanent repository.[71] Swedish utilities store spent fuel at the reactor site for one year before transporting it to the facility at Oskarshamn, where it will be stored in excavated caverns filled with water for about 30 years before removal to a permanent repository.

Conceptual design of a permanent repository was determined by 1983, calling for placement of copper-clad iron canisters in granite bedrock about 500 metres underground, below the water table in what is known as the KBS-3 method. Space around the canisters will be filled with bentonite clay.[71] After examining six possible locations for a permanent repository, three were nominated for further investigation, at Osthammar, Oskarshamn, and Tierp. On 3 June 2009, Swedish Nuclear Fuel and Waste Co. chose a location for a deep-level waste site at Östhammar, near Forsmark Nuclear Power plant. The application to build the repository was handed in by SKB 2011.

Switzerland

Switzerland has five nuclear reactors that provide about 43% of its electricity around 2007 (34% in 2015).[37] Some Swiss spent nuclear fuel has been sent for reprocessing in France and the United Kingdom; most fuel is being stored without reprocessing. An industry-owned organization, ZWILAG, built and operates a central interim storage facility for spent nuclear fuel and high-level radioactive waste, and for conditioning low-level radioactive waste and for incinerating wastes. Other interim storage facilities predating ZWILAG continue to operate in Switzerland.

The Swiss program is considering options for the siting of a deep repository for high-level radioactive waste disposal, and for low & intermediate level wastes. Construction of a repository is not foreseen until well into this century. Research on sedimentary rock (especially Opalinus Clay) is carried out at the Swiss Mont Terri rock laboratory; the Grimsel Test Site, an older facility in crystalline rock is also still active.[72]

United Kingdom

Great Britain has 19 operating reactors, producing about 20% of its electricity.[37] It processes much of its spent fuel at Sellafield on the northwest coast across from Ireland, where nuclear waste is vitrified and sealed in stainless steel canisters for dry storage above ground for at least 50 years before eventual deep geologic disposal. Sellafield has a history of environmental and safety problems, including a fire in a nuclear plant in Windscale, and a significant incident in 2005 at the main reprocessing plant (THORP).[73]

In 1982 the Nuclear Industry Radioactive Waste Management Executive (NIREX) was established with responsibility for disposing of long-lived nuclear waste[74] and in 2006 a Committee on Radioactive Waste Management (CoRWM) of the Department of Environment, Food and Rural Affairs recommended geologic disposal 200–1,000 meters underground.[75] NIREX developed a generic repository concept based on the Swedish model[76] but has not yet selected a site. A Nuclear Decommissioning Authority is responsible for packaging waste from reprocessing and will eventually relieve British Nuclear Fuels Ltd. of responsibility for power reactors and the Sellafield reprocessing plant.[77]

North America

Canada

The 18 operating nuclear power plants in Canada generated about 16% of its electricity in 2006.[78] A national Nuclear Fuel Waste Act was enacted by the Canadian Parliament in 2002, requiring nuclear energy corporations to create a waste management organization to propose to the Government of Canada approaches for management of nuclear waste, and implementation of an approach subsequently selected by the government. The Act defined management as "long term management by means of storage or disposal, including handling, treatment, conditioning or transport for the purpose of storage or disposal."[79]

The resulting Nuclear Waste Management Organization (NWMO) conducted an extensive three-year study and consultation with Canadians. In 2005, they recommended Adaptive Phased Management, an approach that emphasized both technical and management methods. The technical method included centralized isolation and containment of spent nuclear fuel in a deep geologic repository in a suitable rock formation, such as the granite of the Canadian Shield or Ordovician sedimentary rocks.[80] Also recommended was a phased decision making process supported by a program of continuous learning, research and development.

In 2007, the Canadian government accepted this recommendation, and NWMO was tasked with implementing the recommendation. No specific timeframe was defined for the process. In 2009, the NWMO was designing the process for site selection; siting was expected to take 10 years or more.[81]

United States

The Nuclear Waste Policy Act of 1982 established a timetable and procedure for constructing a permanent, underground repository for high-level radioactive waste by the mid-1990s, and provided for some temporary storage of waste, including spent fuel from 104 civilian nuclear reactors that produce about 19.4% of electricity there.[37] The United States in April 2008 had about 56,000 metric tons of spent fuel and 20,000 canisters of solid defense-related waste, and this is expected to increase to 119,000 metric tons by 2035.[82] The U.S. opted for Yucca Mountain nuclear waste repository, a final repository at Yucca Mountain in Nevada, but this project was widely opposed, with some of the main concerns being long distance transportation of waste from across the United States to this site, the possibility of accidents, and the uncertainty of success in isolating nuclear waste from the human environment in perpetuity. Yucca Mountain, with capacity for 70,000 metric tons of radioactive waste, was expected to open in 2017. However, the Obama Administration rejected use of the site in the 2009 United States Federal Budget proposal, which eliminated all funding except that needed to answer inquiries from the Nuclear Regulatory Commission, "while the Administration devises a new strategy toward nuclear waste disposal."[83] On March 5, 2009, Energy Secretary Steven Chu told a Senate hearing "the Yucca Mountain site no longer was viewed as an option for storing reactor waste."[82][84] Starting in 1999, military-generated nuclear waste is being entombed at the Waste Isolation Pilot Plant in New Mexico.

In a Presidential Memorandum dated January 29, 2010, President Obama established the Blue Ribbon Commission on America's Nuclear Future (the Commission).[85] The Commission, composed of fifteen members, conducted an extensive two-year study of nuclear waste disposal, what is referred to as the "back end" of the nuclear energy process.[85] The Commission established three subcommittees: Reactor and Fuel Cycle Technology, Transportation and Storage, and Disposal.[85] On January 26, 2012, the Commission submitted its final report to Energy Secretary Steven Chu.[86] In the Disposal Subcommittee's final report the Commission does not issue recommendations for a specific site but rather presents a comprehensive recommendation for disposal strategies. During their research the Commission visited Finland, France, Japan, Russia, Sweden, and the UK.[87] In their final report the Commission put forth seven recommendations for developing a comprehensive strategy to pursue:[87]

Recommendation #1
: The United States should undertake an integrated nuclear waste management program that leads to the timely development of one or more permanent deep geological facilities for the safe disposal of spent fuel and high-level nuclear waste.[87]

Recommendation #2
: A new, single-purpose organization is needed to develop and implement a focused, integrated program for the transportation, storage, and disposal of nuclear waste in the United States.[87]

Recommendation #3
: Assured access to the balance in the Nuclear Waste Fund (NWF) and to the revenues generated by annual nuclear waste fee payments from utility ratepayers is absolutely essential and must be provided to the new nuclear waste management organization.[87]

Recommendation #4
: A new approach is needed to site and develop nuclear waste facilities in the United States in the future. We believe that these processes are most likely to succeed if they are:

- Adaptive—in the sense that process itself is flexible and produces decisions that are responsive to new information and new technical, social, or political developments.
- Staged—in the sense that key decisions are revisited and modified as necessary along the way rather than being pre-determined in advance.
- Consent-based—in the sense that affected communities have an opportunity to decide whether to accept facility siting decisions and retain significant local control.
- Transparent—in the sense that all stakeholders have an opportunity to understand key decisions and engage in the process in a meaningful way.
- Standards- and science-based—in the sense that the public can have confidence that all facilities meet rigorous, objective, and consistently-applied standards of safety and environmental protection.
- Governed by partnership arrangements or legally-enforceable agreements with host states, tribes and local communities.[87]

Recommendation #5
: The current division of regulatory responsibilities for long-term repository performance between the NRC and the EPA is appropriate and should continue. The two agencies should develop new, site-independent safety standards in a formally coordinated joint process that actively engages and solicits input from all the relevant constituencies.[87]

Recommendation #6
: The roles, responsibilities, and authorities of local, state, and tribal governments (with respect to facility siting and other aspects of nuclear waste disposal) must be an element of the negotiation between the federal government and the other affected units of government in establishing a disposal facility. In addition to legally-binding agreements, as discussed in Recommendation #4, all affected levels of government (local, state, tribal, etc.) must have, at a minimum, a meaningful consultative role in all other important decisions. Additionally, states and tribes should retain—or where appropriate, be delegated—direct authority over aspects of regulation, permitting, and operations where oversight below the federal level can be exercised effectively and in a way that is helpful in protecting the interests and gaining the confidence of affected communities and citizens.[87]

Recommendation #7
: The Nuclear Waste Technical Review Board (NWTRB) should be retained as a valuable source of independent technical advice and review.[87]

International repository

Although Australia does not have any nuclear power reactors, Pangea Resources considered siting an international repository in the outback of South Australia or Western Australia in 1998, but this stimulated legislative opposition in both states and the Australian national Senate during the following year.[88] Thereafter, Pangea ceased operations in Australia but reemerged as Pangea International Association, and in 2002 evolved into the Association for Regional and International Underground Storage with support from Belgium, Bulgaria, Hungary, Japan and Switzerland.[89] A general concept for an international repository has been advanced by one of the principals in all three ventures.[90] Russia has expressed interest in serving as a repository for other countries, but does not envision sponsorship or control by an international body or group of other countries. South Africa, Argentina and western China have also been mentioned as possible locations.[55][91]

In the EU, COVRA is negotiating a European-wide waste disposal system with single disposal sites that can be used by several EU-countries. This EU-wide storage possibility is being researched under the SAPIERR-2 program.[92]

See also

- Radioactive waste
- Economics of new nuclear power plants
- List of nuclear waste treatment technologies
- Deep geological repository
- Nuclear reprocessing
- Decommissioning of Russian nuclear-powered vessels
- *Into Eternity*, a 2010 documentary about the construction of a Finnish waste depository
- *Journey to the Safest Place on Earth*, a 2013 documentary about the urgent need for safe depositories

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External links

- International Atomic Energy Agency – Internet Directory of Nuclear Resources (http://www.iaea.org/inis/ws/subjects/nuclear_facilities.html) (links)
- Nuclear Regulatory Commission – Radioactive Waste (http://www.nrc.gov/waste.html) (documents)
- Radwaste Solutions (http://www.ans.org/pubs/magazines/rs/) (magazine)
- "Radioactive Waste (documents and links)" (http://earthwatch.unep.net/radioactivewaste/index.php). UNEP Earthwatch.
- World Nuclear Association – Radioactive (http://world-nuclear.org/info/info.htm#radioactivewastes)

Categories: Radioactive waste

TAXPAYERS FOR COMMONSENSE
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Policy Briefs

Taxpayer Subsidies for Small Modular Reactors

February 27, 2013 > **Updated: September 30, 2013**
Programs: Energy

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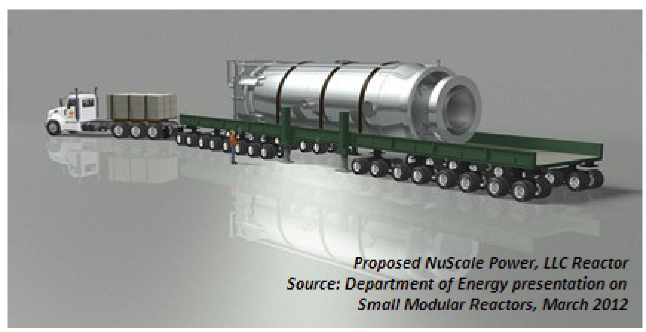
The Department of Energy (DOE) is asking Congress to provide hundreds of millions in subsidies to commercialize small modular nuclear reactors (SMR). First proposed in the 2011 budget, the Administration has committed to providing more than $500 million for licensing support and research and development for these downsized reactors. A fraction of the size of commercial scale reactors, SMRs would be manufactured by assembly line and transported by truck, ship, or rail to their destinations. With designs ranging in size from one-third the size of a large-scale plant down to the size of a hot tub, SMRs will also produce significantly less power: 300 megawatts electrical (MWe) or less compared to 1,000 MWe for a typical commercial scale reactor.

SMRs will likely never be a good investment, but in the current fiscal climate taxpayers must be especially concerned with any dollars DOE doles out. High-risk, high-cost, and highly questionable, small modular reactors don't just look like a bad investment they are a ridiculous waste. For a range of reasons, subsidies for SMRs equal nothing more than another handout for the nuclear power industry.

Appendix One: Company Profiles | Appendix Two: Legislation

SMRs: High-risk, Unknown Costs



Proposed NuScale Power, LLC Reactor
Source: Department of Energy presentation on Small Modular Reactors, March 2012

To date, there are no reliable cost estimates for SMRs. Nuclear vendors are notorious for underestimating costs, and there is no actual experience manufacturing or building SMRs. Since the 1950s, the nuclear industry worldwide has consistently pushed for larger reactors on the theory the economics would improve if the high fixed costs of building nuclear plants could be spread over more kilowatt hours. SMRs represent a reversal of this reasoning and call into question the extensive federal support now being offered to promote a "nuclear renaissance" based on standardizing and sticking to a few large reactor designs. While commercial scale reactors of 1,000 MWe or greater could cost at least $8 billion, DOE officials have projected the first SMRs will cost approximately $1 billion per 100-150 MWe. When asked about operation and maintenance costs compared to commercial scale reactors, the federally-owned Tennessee Valley Authority (TVA) said it expects it to be higher. The Department of Energy has already provided nearly $200 million for these so-called mini reactors while their commercial viability remains in question. DOE has committed up to $452 million over the next five years to support the licensing and deployment of up to two SMR reactor designs by the Nuclear Regulatory Commission (NRC).

Federal Subsidies for Small Modular Reactors

Federal support for SMRs is provided through a subsidy program for commercial nuclear power that can be traced back to the 1950s when federal subsidies for nuclear power reached astronomical levels. Not only did the government develop reactor and enrichment technology for the private sector, it also assumed legal responsibility for nuclear waste disposal, something never done for any other industry. In addition, the government issued multimillion-dollar development grants for many reactor technologies (most since abandoned) and distributed research reactors around the world.

At the same time, the U.S. Navy started developing smaller nuclear reactors for naval ships and the Army's Nuclear Power Program constructed eight experimental mini-reactors for use in rural operations. Since then, interest in using SMRs within the military and for domestic energy applications has grown. From 1999 to 2004, DOE's Nuclear Energy Research Initiative awarded research and development grants to public, private, and non-profit entities in support of SMR development.

Two federal initiatives currently provide support for the commercialization of SMRs: the recently created DOE Small Modular Reactor Program and the private-public partnership program at DOE's Savannah River site in South Carolina. To date, nearly $200 million in federal funds have been provided for SMRs through the Small Modular Reactor Program. Congress approved more than $90 million for DOE's SMR program in FY2012 and nearly the same for FY2013 (See Table 1). The President's FY2014 budget proposal of $735 million for the Office of Nuclear Energy included another $90 million for SMRs.

Below are brief descriptions of the DOE SMR Program and the Private-Public partnership program at DOE's Savannah River site.

DOE's Small Modular Reactor Program

The SMR Program is funded through two separate annual budget lines including: "SMR Licensing Technical Support" and "Reactor Concepts Research, Development, and Demonstration." The Licensing Technical Support (LTS) program "provide[s] support for design, certification, standards, and licensing." Moreover, the Advanced Concepts R&D program provides taxpayer support to the nuclear industry through free reactor design and technological development.

Table 1: DOE Small Modular Reactor Program Funding (millions)

Sub-Program:	FY2011 (ACTUAL)	FY2012 (ACTUAL)	FY2013 (ENACTED)	FY2014 (REQUESTED)
Licensing Support	-	67	67.410	70
Advanced R&D	3.105	24.529	~24.529*	20
TOTAL SMR Program	$3.105	$91.529	$91.939	$90

Source: Consolidated and Further Continuing Appropriations Act, 2013 (P.L. 113-6) & Congressional Budget Requests
*Final appropriations under the FY13 Continuing Resolution have yet to be determined.

In March 2012, the Department of Energy announced a public-private funding opportunity aimed at commercializing SMR technologies through the Licensing Technical Support program. Within the announcement, DOE stated it would select up to two SMR proposals to receive up to $452 million in cost-share funding for reactor licensing support, dependent on Congressional appropriations. The funds are intended to help the SMR designs reach a commercial operation date before 2022. The award period would span five years from 2012 and 2016 and require taxpayers to provide up to 50% of project costs. In response to the funding opportunity announcement, four companies applied: Westinghouse Electric Company, Generation mPower LLC (subsidiary of Babcock & Wilcox and Bechtel Power Corp.), SMR LLC (subsidiary of Holtec International Corp.), and NuScale Power LLC (subsidiary of Fluor Power Corp.) (See Table 2 or Appendix One for more information on individual applicants).

In November 2012, DOE selected Babcock & Wilcox's (B&W) 180 MWe SMR design and its utility partner, the Tennessee Valley Authority as the first applicant to be awarded cost-share funding. DOE announced that B&W would be awarded at least $150 million over the lifetime of the program. Yet, the final award amount could reach the full $226 million—if appropriated. Babcock & Wilcox announced it had signed a contract with TVA to start preparing an NRC construction permit application for its four proposed reactors at TVA's Clinch River site in February 2013. Yet, according to the Nuclear Regulatory Commission, TVA initially intended to submit its application in late 2012. A B&W-TVA press release says the companies plan to submit an application in 2015—three years behind schedule.

Due to selecting only one applicant after the first solicitation and lower than expected appropriations, DOE announced a second solicitation in March 2013. The second solicitation would amount to the second half of the total $452 million committed by DOE for the Licensing Technical Support program. In response to the second funding opportunity announcement, all three of the SMR developers that did not get selected under the first solicitation reapplied. As of September 1, 2013, three additional companies have also announced submitting applications: Hybrid Power Technologies, General Atomics (subsidiary of General Dynamics), and National Project Management Corp. (See Table 2 or Appendix One for more information on individual applicants). DOE is expected to announce its selections for the second solicitation in early 2014.

While the first and second solicitations both have the potential to reach a final award of up to $226 million each, stark differences exist between the objectives of the two solicitations. Under the first round, the selected SMR design was required to possess a utility partner and reach a commercialization date before 2022. DOE would support both the SMR design owner and utility partner in gaining both reactor design certification and a combined operating and construction license from the NRC. By contrast, the second round is intended to support only the reactor design certification and does not require the SMR design owner to possess a utility partner for later deployment. The second round also extends the program until 2017 and targets a commercial operation date of approximately 2025.

Savannah River Nuclear Development Site

In March 2012, DOE's Savannah River site and Savannah River National Laboratory (SRS) signed three Memorandums of Agreement (MOA) for public-private partnerships with small modular reactor companies to commercialize SMR technologies. Located in South Carolina, DOE's SRS provides support ranging from technology demonstration to design certification and licensing assistance. This support is in addition to the SMR program.

> *In one Memorandum of Agreement, SRS plans to invite the National Nuclear Security Administration (NNSA) to discuss incorporating mixed oxide fuels (MOX) into SMR LLC's design. When soliciting proposals for public-private partnerships, SRS said it intends to develop SMR designs that are capable of using fuel based from surplus plutonium and spent reactor fuel as a potential alternative to storing spent nuclear fuel at Yucca mountain.*

Created in 1950, the federally-owned, privately-managed Savannah River complex was established to manufacture materials needed for nuclear weapons development during the Cold War. Since then, the 310-square mile complex has ceased producing weapons materials and housed much of DOE's experimental nuclear research and development including mixed oxide fuels, environmental management, and waste storage technologies to the benefit of private industry. Savannah River has an annual budget of approximately $2.5 billion.

Current Applicants Seeking Federal Subsidies

Eight small modular reactor companies have applied for support from DOE to date, but none of the different reactor designs have been licensed by the NRC. NRC and DOE aim to award the first design certification license by 2018 and final combined construction and operating license by the early 2020s. Currently, all companies are in the pre-application phase with NRC working towards initial design certification.

The majority of the SMR designs would develop an integral pressurized light water reactor (iPWR) while others would develop a fast neutron reactor (FNR), combined FNR and high-temperature reactor (HTR), or a hybrid helium gas reactor with a fossil fuel-fired combustion turbine (Hybrid). (See Table 2 or Appendix One for more information on individual applicants)

Table 2: Active Small Modular Reactor Projects at the Department of Energy

Company Name	Reactor Capacity (MWe)	Reactor Type	DOE Licensing Technical Support: 1st Solicitation Applicant	1st Solicitation Recipient*	DOE Licensing Technical Support: 2nd Solicitation Applicant	Savannah River Site Partnership Recipient	Location
Westinghouse Electric Company	225	iPWR	X		X		Ameren Power's Callaway Site, MO
The Babcock & Wilcox Company	180	iPWR	X	X			Tennessee Valley Authority's Clinch River Site, TN
Holtec International Incorporated	145	iPWR	X		X	X	Department of Energy Savannah River Site, SC
Fluor Power Corporation	45	iPWR	X		X	X	Department of Energy Savannah River Site, SC

Table 2: Active Small Modular Reactor Projects at the Department of Energy

Gen4 Energy	25	FNR				X	Department of Energy Savannah River Site, SC
Hybrid Power Technologies	300	Hybrid			X		Kansas City, KS
General Atomics	265	FNR, HTR			X		Idaho National Laboratory, ID
National Project Management Corporation	165	HTR			X		Oswego, NY
*Announced in November 2012							

NRC Not Ready For SMRs

The United States Nuclear Regulatory Commission has stated it is not fully prepared to license SMRs. In 2008, NRC estimated it would have a regulatory review process in place to license the first SMRs within five years. However, in May 2012 the NRC stated “If an appreciable fraction of total SMR initiatives materialized, it would create an untenable situation for the NRC.”

This is because the regulatory framework for licensing SMRs does not fully exist. It has yet to be determined whether many of the proposed qualities of SMRs, such as generation capacity, modularity, and security features, are covered under the current licensing process for new nuclear reactors. Most of all, NRC hasn’t decided whether it will license individual reactors or issue a combined license for a multi-reactor facility—for example General Atomics' ’four pack’ or NuScale’s ’twelve-pack.’ In December 2012, NRC projected to complete certification for B&W, NuScale, and Westinghouse’s reactor designs in 2017, however, as of July 2013, the timelines for those certifications are listed as ‘Under Review.’

There are questions whether NRC will uphold current regulatory standards for SMRs. The Nuclear Energy Institute (NEI) argues NRC should reduce decommissioning cost assurances (i.e. funds set aside for cleanup after the reactor is shut down); annual fees paid to NRC; the number of control room operators on site; and insurance requirements in the event of a nuclear accident.

> *“The current insurance and indemnity requirements … for multiple reactor modules that collectively exceed 100 MWe may not provide adequate assurance to the public that all claims resulting from a nuclear incident at such a facility would be compensated.”*
>
> *– Michael Johnson, Director of Office of Nuclear Reactors, NRC. SECY-11-0178. December 2011.*

Under current law, SMR operators would provide the same decommissioning cost assurances as all other U.S. reactors. NEI proposes SMR operators apply for a short-term exemption and ultimately change the law in the long term. Under the Omnibus Budget Reconciliation Act of 1990, all nuclear reactor licensees are also required to pay an annual fee that makes up the majority of NRC’s budget authority. This fee is divided equally among the nation’s 100 nuclear reactors. NEI proposes changing this requirement and linking annual fees to output levels, which would significantly reduce rates for SMR operators.

Questions about safety and security requirements have also been raised. Since many of the SMR designs being developed include “passive safety” features, industry is in discussions with NRC about adjusting requirements. Proposals include reducing the required number of plant operators on site and decreasing the size of the emergency planning zone. Reducing security checkpoints at SMR plants is also being considered as a cost-cutting effort.

Although significantly smaller than traditional reactors, SMRs will still require significant insurance in the event of an accident. New nuclear reactors are currently covered by the Price-Anderson Act for accidents valued at more than $12.6 billion. Price-Anderson may fall dramatically short in the case of SMRs, however. Under the Act, reactors that produce 100 MWe or greater must hold the maximum amount of private insurance available ($375 million) as well as a “retrospective insurance plan.” Smaller reactors producing less than 100 MWe must also hold the maximum amount of private insurance (between $4.5 and $75 million), but are not required to hold the additional plan. Multi-reactor facilities consisting of reactors between 100 MWe and 300 MWe that produce less than 1300 MWe are treated as a single entity for insurance purposes. The Act does not address combinations of reactors under 100 MWe, such as Gen4 or

Fluor's reactor designs, or potential combinations of reactors with fossil fuel-fired facilities.

Summary: Taxpayer Concerns

In these tight budget times, federal taxpayers cannot afford yet another giveaway to the heavily-subsidized nuclear power industry. Continued taxpayer support for SMR licensing in addition to R&D giveaways amounts to just another subsidy in a suite of federal supports for the nuclear industry. More than 100 reactors operated by 30 companies exist in the United States; the nuclear industry, not federal taxpayers, must lead the way if SMRs are to reach commercial viability.

> *Even the nuclear industry has said they can move forward without subsidies. Senior Vice President of Holtec International Pierre Oneid said his company aims to commercialize its SMR design whether or not it receives a federal cost-share subsidy.*
>
> *- James Hammond. "Holtec, NuHub to Partner on Small Reactor Grant." GSA Business. April 2012.*

In the Department of Energy's materials on SMRs, the agency argues there is a "need and a market" in the United States for SMRs. In reality, no one is clamoring to buy an SMR because there is no assurance the electricity will be remotely competitive with power from other sources. New nuclear power today is uncompetitive by a very wide margin. To compete with today's natural gas prices, SMRs would have to produce electricity at half the projected cost of conventional reactors. There is not the slightest indication they can do so.

During times of economic stress, the nuclear industry has a tradition of rushing forth to proclaim a new technology just around the corner that will sweep current problems aside. Unfortunately, these visions have an equally long tradition of expensive failure, most often at taxpayers' expense. The Department of Energy's efforts to spend taxpayer dollars on small modular reactors will simply continue this legacy of failure and must be rejected.

For more information, please contact Autumn Hanna at (202) 546-8500 x112 or autumn[at]taxpayer.net

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Appendix One: Company Profiles

Babcock and Wilcox Company

Generation mPower, LLC (GmP) is a jointly-owned subsidiary of Babcock & Wilcox Nuclear Energy Inc. (B&W) and Bechtel Power Corporation. Established in 1867, B&W is a public utility component manufacturer and government contractor based in Charlotte, NC with more than 12,000 employees. B&W made nearly $170 million in net profits in 2011. Bechtel is one of the largest engineering and construction companies in the United States with more than 50,000 employees. Founded in 1898, Bechtel Power Corporation is headquartered in San Francisco, CA.

GmP was founded in 2010 and intends to commercialize its 180 MWe small modular reactor by October 2021. GmP is partnering with the federally-owned Tennessee Valley Authority (TVA) which aims to construct a 'four pack' of SMRs at TVA's Clinch River site in Tennessee. Prior to these plans, GmP had intended to construct up to six reactors the TVA site and reach a commercial operation date by 2018, however Gmp altered it plans in 2012—dependent on plant licensing from NRC. GmP's reactor is proposed to be 83 feet tall by 13 feet wide, have a four-year refueling lifecycle, and construction period of three years. As of May 2012, more than $200 million has been spent on the development of GmP's SMR design. Most recently, GmP signed a contract with TVA to start preparing the NRC construction permit application for the proposed reactors at TVA's Clinch River site. GmP aims to submit its design certification application in 2014.

Babcock & Wilcox has designed and built seven of the 100 current operating nuclear reactors in the United States. TVA currently operates six commercial reactors and will advise GmP throughout the NRC licensing process. According to a recent presentation, TVA has been working on the commercialization of SMRs since 2009. GmP's plans are backed by the Generation mPower Industry Consortium and advisory council—a collection of more than a dozen public utility suppliers.

Fluor Power Corporation

NuScale Power, LLC is a majority-owned subsidiary of Fluor Power Corporation with close ties to the Idaho National Engineering and Environmental Laboratory (INEEL) and Oregon State University (OSU). Founded in 1912, Fluor is a global engineering and construction company headquartered in Irving, TX. Fluor has more than 43,000 employees worldwide and net profits of nearly $600 million in 2011. Overall, Fluor's largest contribution to the project has been providing $30 million to NuScale (simultaneously becoming a majority owner) for continued research and development in 2011. Fluor itself has little or no experience designing nuclear reactors.

Founded in 2007, NuScale Power LLC aims to commercialize its 45 MWe reactor by 2024 —five years later than initially proposed. NuScale's SMR design is a product of a more than decade long partnership between the federally-managed Idaho National Engineering and Environmental Laboratory and Oregon State University—dating back to 2000. Soon after the company was founded, NuScale was awarded exclusive rights to the SMR design which had been developed through this partnership with funding from DOE. Soon after, NuScale signed a memorandum of understanding with Kiewit Contractors Company that Kiewit will provide construction services once NuScale's SMR design has been approved by NRC. As of February 2012, approximately $130 million has been spent on the development of NuScale's SMR design.

NuScale is one of three companies awarded a public-private partnership to commercialize its SMR design at DOE's Savannah River site in South Carolina. Once NuScale has demonstrated its 45 MWe reactor, it intends to build a 'twelve pack' to produce a total of 540 MWe at one facility. In one 2008 presentation, NuScale proposed combining up to 30 reactors at one facility. NuScale's 45 MWe SMR design is proposed to be 65 feet high by 14 wide, last up to 60 years, and have a two-year refueling interval.

NuScale's plans are backed by a Customer Advisory Board, a collection of more than a dozen public utility suppliers and organizations, and the Western Initiative for Nuclear, a coalition of Western Governors, Energy Northwest, and the Utah Association of Municipal Power Systems. Recently, Rolls-Royce announced its support for NuScale's SMR design as well.

*Noteworthy: Fluor Corporation is a joint-owner of the corporation (Savannah River Nuclear Solutions, LLC) that manages and operates the Savannah River site facilities.

Gen4 Energy Incorporated

Founded in 2007 and headquartered in Denver, Colorado, Gen4 Energy Inc. (formerly Hyperion Power Generation Incorporated) is a private company focused on commercializing its 25 MWe small modular reactor design. A participant in DOE's Technology Transfer Program, Gen4 SMR design is the sole product of the federal Los Alamos National Laboratory (LANL). Exclusive rights to the 25 MWe reactor design developed by LANL were awarded to Gen4 soon after it was founded and nearly a dozen LANL employees continue to work on SMR design today.

Gen4 is one of three companies with a public-private partnership agreement with DOE's Savannah River Site to commercialize its small modular reactor design. Gen4's design is the smallest of the federally supported SMR designs, describing its reactor as "about the size of a typical backyard hot tub."

Unlike the other four applicants, Gen4 announced in early 2012 it would not pursue DOE's SMR cost-share funding opportunity. "While we will not pursue the Licensing [public-private partnership], we are excited to continue our work under our Memorandum of Agreement with DOE to deploy our advanced reactor at Savannah River," stated David Carlson, Gen4 Energy's Chief Operating Officer. Gen4's reactor design is proposed to last ten years after which the entire reactor module must be replaced.

Holtec International Incorporated

SMR, LLC is a wholly-owned subsidiary of Holtec International Incorporated. Established in 1986 and headquartered in Jupiter, FL, Holtec is a public utility components manufacturer specializing in waste storage facilities with operations worldwide. While Holtec is a global leader in power plant waste management and has supported the construction of nuclear reactors in the past, it has little to no experience designing nuclear reactors.

Founded in 2011, SMR LLC aims to apply for design certification in 2016 and commercialize its 160 MWe reactor in the mid-2020s. In addition to the cost-share funding opportunity, SMR LLC is one of three companies awarded a public-private partnership to further develop its reactor design at DOE's Savannah River site in South Carolina. Notably, within SMR LLC's memorandum of agreement with DOE, the company agrees to discuss incorporating MOX fuel into its design with the National Nuclear Security Administration. SMR LLC's reactor is proposed to have a four-year refueling cycle and last up to 80 years. Most recently, Holtec altered its reactor design to decrease generation capacity to 145 MWe and refueling intervals of three years.

SMR LLC's plans are supported by the State of South Carolina, NuHub, URS Corporation, CB&I, SCE&G, PSEG Power, Exelon, Entergy, and First Energy which have agreed to share operation responsibilities if and when the demonstration project is constructed.

Westinghouse Electric Company

Formed in 1886, Westinghouse Electric Company is a service provider to nearly every corner of the nuclear power industry. Westinghouse is a subsidiary of Toshiba Nuclear Energy Holdings Inc. with more than 14,000 employees and is headquartered in Monroeville, PA with operations worldwide. Westinghouse has significant experience designing and building nuclear reactors. Currently, 48 of the 104 operating nuclear reactors in the United States have been designed and built by Westinghouse with another 14 proposed reactors under consideration.

Westinghouse announced plans in February 2011 to commercialize its 225 MWe small modular reactor by 2021. The design is largely based off Westinghouse's AP1000 reactor design which was approved by the Nuclear Regulatory Commission in December 2011. Westinghouse's SMR design is proposed to be 89 feet tall by 39 feet wide, have a refueling period of two years, and a lifespan of 60 years. In addition to power generation for public utilities, Westinghouse envisions its SMRs to supply on-site power for coal-to-liquid operations, as well as tar sands and oil shale development operations. Prior to current plans, Westinghouse had initially planned develop a 200 MWe reactor design. Westinghouse aims to submit its design certification application in September 2013.

Westinghouse intends to build its first SMR in partnership with public service utility Ameren Missouri, at Ameren's Callaway Energy Center. Westinghouse's plans are also backed by Burns & McDonnell, General Dynamics Electric Boat, and the "NexStart SMR Alliance"—a coalition of more than a dozen public utility suppliers.

In May 2013, Westinghouse announced plans to partner with China's State Nuclear Power Technology Corporation (SNPTC) to accelerate deployment of its SMR design in the U.S. and China. SNPTC will lead efforts to license Westinghouse's SMR design in China.

Hybrid Power Technologies

Since its formation in 2005, this private company based in the Kansas City, KS has been developing the technology and design for hybrid power plants that use both nuclear and fossil fuel sources.

In its SMR design, Hybrid Power Technologies (HBT) proposes using a 600 MWt graphite-cooled thermal reactor to power a 1000 MWt integrated combined cycle gas turbine (CCGT). HBT's design aims to improve the efficiency of a traditional CCGT by mitigating the energy normally lost by the process of running a gas turbine. The entire unit is expected to have 52% net efficiency and generate 850 MWe of power —300 MWe of which would be generated from the small modular reactor.

The size of HBT's SMR design makes it considerably less 'modular' than others. As a result, the company proposes using barges, compared to rail or truck delivery systems, to transport the parts needed to construct its 170 ft. tall unit. The SMR is estimated to cost $1.388 billion and have a life span of 40 years.

General Dynamics Corporation

Established in 1955 and based in San Diego, CA, General Atomics (GA) is a subdivision of General Dynamics, one of the world's largest technology developers. General Dynamics has averaged more than $1.9 billion in profits over the past five years.

Since the 1980s, General Atomics has attempted to commercialize a gas-turbine modular helium reactor with a generation capacity of approximately 240 MWe to no success. GA has also proposed a smaller version of this reactor called the remote-site modular helium reactor with a generation capacity of 10-25 MWe, but the design remains in the research and development phase. Lastly, GA is well known within the nuclear power industry for its 16 MWe research reactor that has operated at many sites around the world for nearly 50 years.

In February 2010, General Atomics announced a modified version of its long researched gas-turbine modular helium reactor. With the new design, estimated at $1.7 billion, GA applied for the second round of DOE SMR licensing support. Approximately the "size of a school bus," the reactor would generate 265 MWe with the option of combining four reactors at a single facility to potentially produce 1060 MWe. The reactor proposes to use reprocessed nuclear waste, such as depleted uranium, and plutonium to power its reactor.

GA is partnering with Chicago Bridge and Iron Company, Mitsubishi Heavy Industries, and the Idaho National Laboratory to commercialize its small modular reactor design. GA's SMR design would have a 42 month construction timeline and a 30 year refueling period.

National Project Management Corporation

Recently formed and headquartered in Oswego, NY, National Project Management Corporation (NPMC) is a private company that proposes to commercialize its 165 MWe small modular reactor design with the support of multiple domestic and international entities. Acting as a U.S. representative for an international consortium, NPMC announced in late July 2013 that it had applied for the maximum DOE cost-share subsidy.

NMPC proposes to commercialize a gas-turbine modular helium reactor (GT-MHR). Similar to the General Atomics' proposed GT-MHR design, NMPC's SMR design proposes to use nuclear waste to power its reactor.

From the early 1990s through the 2000s, South Africa and several industry partners attempted to commercialize the pebble bed modular reactor, but the project was cancelled in 2010. The project lacked a customer, consistently missed deadlines, and would have cost an estimated $4.2 billion more to complete on top of the $1.3 billion the partners had already spent.

NPMC is partnering up with Pebble Bed Modular Reactor Company (subsidiary of Eskom), National Grid Plc based in the United Kingdom, the New York state government, the City of Oswego, the Port Authority of Oswego, Empire State Development, and the New York State Energy Research and Development Authority. NMPC's SMR would be constructed in Oswego, NY where it could be transported by rail or ship across the U.S. and worldwide. In addition to federal support, New York State has committed nearly $300 million to the development of NPMC's SMR design.

Appendix 2: Legislation

In the 112th Congress, six pieces of legislation were introduced in order to provide federal support for small modular reactors. Most notably, Senator Mark Udall (D-CO) introduced the Nuclear Energy Research Initiative Improvement Act of 2011 (S. 1067) that would have earmarked $250 million to SMRs between 2012 and 2016. Furthermore, three of the six bills call for public-private cost-share agreements as the main funding mechanism for a small modular reactor program. Below are brief summaries of each piece of legislation.

November 1, 2011 – Rep. Thomas Rooney (R-FL) – H.R. 3302: Restore America Act of 2011
Rep. Rooney's bill would require the Nuclear Regulatory Commission (NRC) to provide a report to Congress with policy recommendations for streamlining licensing of SMRs and then administer those recommendations within one year. The bill had no cosponsors.
June 16, 2011 – Sen. Kent Conrad (D-ND) – S. 1220: Fulfilling U.S. Energy Leadership Act of 2011
Sen. Conrad's bill would require NRC to establish a program to streamline the licensing of a standard SMR design through public-private cost-share agreements within ten years. The bill had no cosponsors.
June 3, 2011 – Rep. Jim Matheson (D-UT) – H.R. 2133: FUEL Act
Rep. Matheson's bill would require DOE to carry out a SMR RD&D program to support the commercialization of SMRs through public-private cost-share agreements. The bill had no cosponsors.
May 25, 2011 – Sen. Mark Udall (D-CO) – S. 1067: Nuclear Energy Research Initiative Improvement Act of 2011
Sen. Udall's bill would require DOE to carry out a nuclear RD&D program including SMRs with annual appropriations of $50 million for five years, totaling $250 million. The bill had three cosponsors: Sens. Jeff Bingaman (D-NM), Lisa Murkowski (R-AK), and Amy Klobauchar (D-MN).
March 8, 2011 – Sen. Jeff Bingaman (D-NM) – S. 512: Nuclear Power 2021 Act
Sen. Bingaman's bill would require DOE to carry out a SMR RD&D program to support the commercialization of two SMR reactor designs through public-private cost-share agreements so industry can obtain a design certification NRC by January 1, 2018. The bill had seven cosponsors: Sens. Mary Landrieu (D-LA), Lisa Murkowski (R-AK), Mark Pryor (D-AR), Mark Udall (D-CO), Michael Crapo (D-ID), James Risch (R-ID), and Roy Blunt (R-MO).
March 3, 2011 – Rep. Devin Nunes (R-CA) – H.R. 909: Roadmap for America's Energy Future
Rep. Nunes' bill—similar to Rep. Rooney's bill—would require NRC to provide a report to Congress with policy recommendations for streamlining licensing of SMRs and then administer those recommendations within one year. The bill had 73 Republican cosponsors.

Filed under: Stop Waste, Eliminate Corporate Welfare, Rein in Deficits

3 Comments

THE VERGE

TECH ENERGY CARS

Tesla unveils residential 'solar roof' with updated battery storage system

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by Jordan Golson | @jlgolson | Oct 28, 2016, 8:49pm EDT

Tesla will build and sell its own line of solar panels to combine with its battery storage system, the company announced at a press event at Universal Studios in LA, today. The system will allow residential homeowners to replace their entire roof with solar panels connected to an updated Powerwall 2 battery pack, making it much simpler for homes to be entirely powered by solar power.

The roof is made of a textured glass tile with integrated solar cells. The roofs look "as good or better" than conventional roofs, according to Musk. They look like normal roofing tiles from the ground, but are completely transparent to the sun. The tiles are hydrographically printed, which, Musk says, makes each one a "special snowflake tile," and no two roofs will be the same. "You can take any two roofs that look like that and they will be different — because they are different," said Musk.

There are a number of different versions of solar panels: Textured Glass Tile, Slate Glass Tile, Tuscan Glass Tile, and Smooth Glass Tile. Tesla says its glass tiles are much more durable than conventional roof tile — something that's important in areas with risk of hail.

"CHECK OUT THIS SWEET ROOF." - ELON MUSK

The products are a "joint collaboration" between SolarCity and Tesla, according to SolarCity CEO Lyndon Rive. Tesla is attempting to acquire SolarCity for $2.6 billion and shareholders of both companies will vote on the proposed acquisition in the middle of November.

The Powerwall 2 can store 14 kWh of energy, with a 5 kW continuous power draw, and 7 kW peak. The battery is warranted for unlimited power cycles for up to 10 years. It can be floor or wall mounted, inside or outside. It can be used for load shifting or back-up power.

Musk says there are three parts to the solar energy solution: generation (solar panels), storage (batteries), and transportation (electric cars). Musk's plan is to sell all three of those products through Tesla.

Those wishing to go entirely solar, with minimal draw off the electrical grid, would need to buy solar panels from a separate company (like SolarCity) as well as Powerwall batteries from Tesla. Now, customers will be able to buy both products from Tesla directly.

Musk says there are four to five million new roofs built each year in the US, and the solar roof product will be price competitive with more traditional roofs with solar added to it. However, existing roofs which do not need to be replaced will be better candidates for more traditional roof-mounted solar solutions.

Tesla CEO Elon Musk, who announced the Powerwall 2 in the California sunshine, had previously teased the product in a series of tweets as well as the Tesla Motors "Master Plan, Part Deux," earlier this summer.

Availability and pricing of the solar roof — not to mention how the thing is actually installed and works — was not announced. The Powerwall is $5,500.

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