

Build-Up of Distributed Fuel Cell Value In California: Background and Methodology



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Build-Up of Distributed Fuel Cell Value In California: Background and Methodology

I. EXECUTIVE SUMMARY

This paper presents the findings of a study by the California Fuel Cell Manufacturers Initiative (“CAFCEMI”) that examines the value to California residents of a broad introduction of stationary fuel cells into the state of California. This study examines only stationary fuel cells to be used in distributed generation markets, ranging in size from several hundred kilowatts (“kW”) to tens of megawatts (“MW”). This study does not address the application of fuel cells in other stationary applications (*e.g.*, residential, central station), nor does it address the application of fuel cells in portable or transportation applications.

Figure 1, entitled “Build-Up of Fuel Cell Value in California,” illustrates the results of the study’s step-by-step analysis of the value in cents/kWh of the *avoided costs* of central station electricity generation attributable to fuel cells *today*. This “waterfall” chart shows that distributed fuel cells currently provide 6.6-20.5 cents/kWh of value to California electricity consumers. With only 18 MW of fuel cell capacity in California out of a total annual peak load of over 50,000 MW, fuel cells currently provide less than 0.01% of California’s electricity use. With the increased penetration of distributed fuel cells over time, both the amount of electricity provided by fuel cells and the cents/kWh value will increase, together dramatically increasing the total value of distributed fuel cells to California.

The categories of avoided costs in the “Build-Up of Distributed Fuel Cell Value in California” illustrated in Figure 1 depict a number of so-called “distributed value elements” that represent distributed generation technology attributes vis-à-vis a central electricity generating plant. The actual values shown in Figure 1 reflect fuel cell-specific calculations for each distributed value element included in this study, some of which would be similar to values for other distributed generation technologies and some of which have higher values due to the technology-specific characteristics of fuel cells. Technology-specific characteristics contributing to higher relative fuel cell value include:

- Electricity generation through electrochemical reaction rather than by combustion
 - Higher electrical efficiency, resulting in more efficient fuel use and reduced carbon signature
 - Greater reliability, partially due to fewer moving parts
 - Improved power quality
 - Avoided emissions
- Low acoustic signature
- Virtually zero emissions signature
- Low vibration.

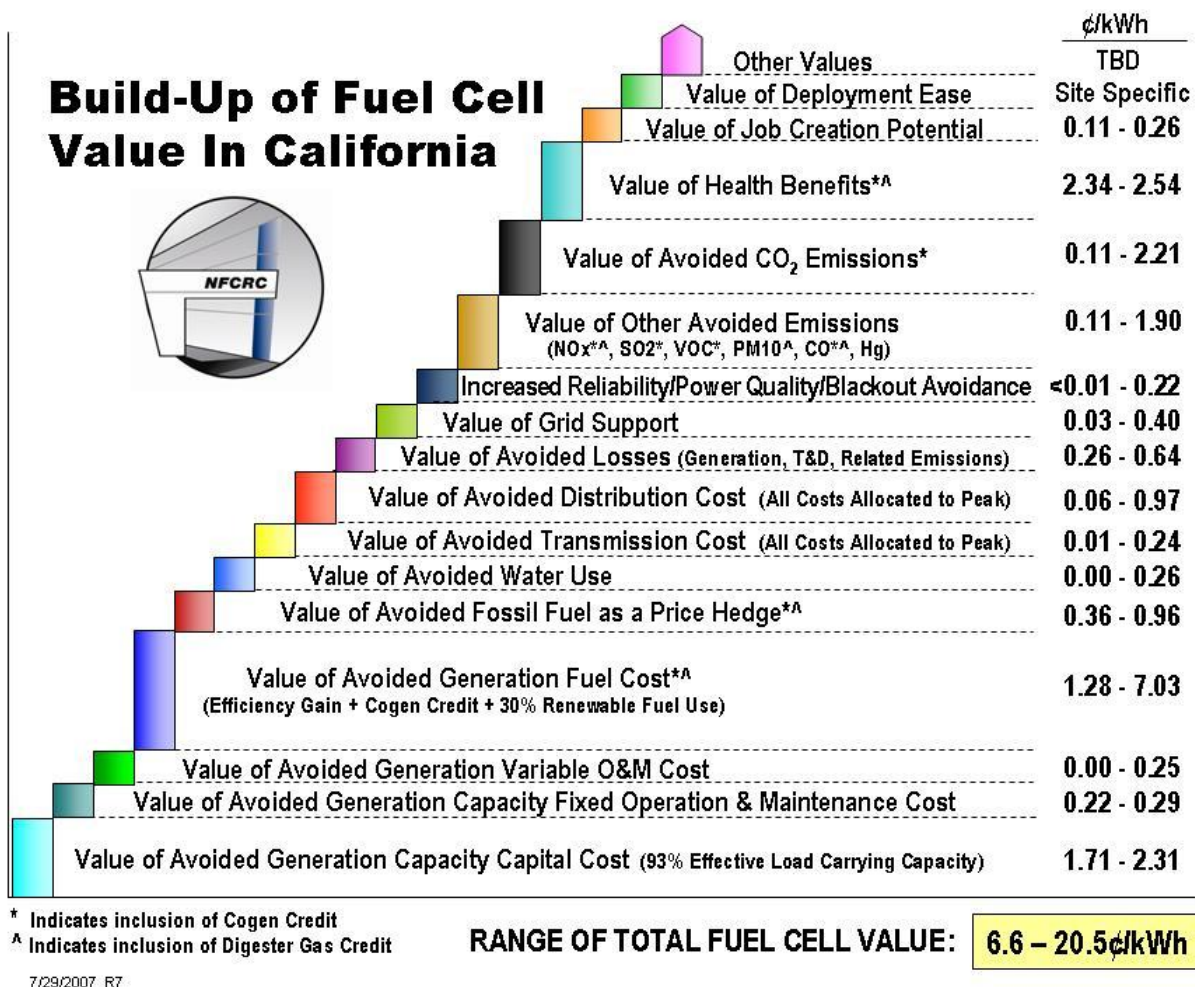


Figure 1. Build-Up of Fuel Cell Value in California

Features that are shared with some but not all distributed generation technologies include:

- Cogeneration potential, resulting in even higher overall system efficiency
- 24/7 baseload operations
- Fuel flexibility
- Well-suited for renewable fuels.

The distributed value elements quantified in this study specifically for fuel cells fall into the following four general categories: (i) Generation-related (avoided fixed and variable costs, including fuel costs); (ii) grid-related (increased reliability, avoided transmission and distribution costs); (iii) avoided emissions and related health benefits; and, (iv) job creation potential.

Each distributed value element quantified for fuel cells in Figure 1 is discussed in some detail in this paper to enable the reader to understand the derivation of its value. Some of

the avoided costs illustrated in Figure 1 are quantified based on observable market prices of equipment, services, and other relevant factors, and some are quantified based on values that are derived from a broad-based literature search. Some attributes would also apply to other distributed generation technologies, though the specific value of any given attribute may be technology-dependent (*e.g.*, value of avoided emissions). Therefore, additional data on fuel cell technologies, economics, and underlying assumptions was obtained from the participating organizations.

The results of the avoided cost analysis illustrated in Figure 1 were incorporated into a full benefit-cost analysis of stationary fuel cells in California. Three of the major benefit-cost tests specified by the California Public Utilities Commission (“CPUC”) in its Standard Practices Manual were performed as part of this study, including:

- The Participant Test
- The Ratepayer Impact Measure Test
- The Societal Test.

The full benefit-cost analysis was based on detailed fuel cell cost and performance data provided by the participating organizations. Figure 2, entitled “Benefit:Cost Ratios for Fuel Cell Baseload Electricity Generation in California, with SGIP Funding” illustrates the capacity weighted-average results, based on benefit-cost ratios calculated for nine separate fuel cell products. Figure 2 clearly demonstrates that: (i) fuel cells provide significant societal benefits to California for each of the four fuel and operating mode combinations analyzed, and (ii) ratepayer funding provided through the CPUC’s Self-Generation Incentive Program (“SGIP”) has moved stationary fuel cells that generate baseload electricity to the point of near cost-effectiveness from the participant’s (*i.e.*, investor’s) perspective, even without federal and state tax credits. Additional details related to the benefit-cost analyses are provided in Section III of this report.

The fuel cells considered in the study operate as a baseload distributed generation technology. Therefore, valuing the avoided costs associated with the deployment of these fuel cells must be based on a comparison with the avoided baseload central station electricity generation technology serving California customers. These avoided baseload central station generation technologies include in-state natural gas-fired generators and out-of-state coal-fired generators from which California imports power. Although coal-fired imports into California will be limited in the future under long-term contracts, it is anticipated that significant volumes of short-term coal-fired electricity imports will continue to make their way into California for the foreseeable future.

Fuel cells generate electricity using an electrochemical process rather than through combustion, and even though most fuel cells use natural gas, fuel cells on average require less natural gas per kWh generated than most central station natural gas-fired generators. As a result, fuel cells have lower carbon dioxide (*i.e.*, greenhouse gas) emissions than the avoided generator, as described in detail in this paper. In addition, the 30% of California’s fuel cells that operate on renewable digester gas from landfills and wastewater treatment plants further reduce emissions by preventing flaring of that digester gas. Emissions are further mitigated by the 60% of all fuel cells that capture

waste heat to produce steam or hot water, thereby avoiding fuel input to natural gas boilers to produce those products. Each of these factors contributes to ever more avoided (*i.e.*, reduced) emissions attributable to fuel cells. Another key advantage that fuel cells have over conventional power generation technologies is that fuel cells emit only small quantities of nitrogen oxides (“NO_x”) and sulfur oxides (“SO_x”) (*i.e.*, acid rain pollutants), in part because their fuel input has to be desulfurized and in part because fuel cells do not employ combustion technology to produce electricity.

Benefit:Cost Ratios for Fuel Cell Baseload Electricity Generation in California, with SGIP Funding

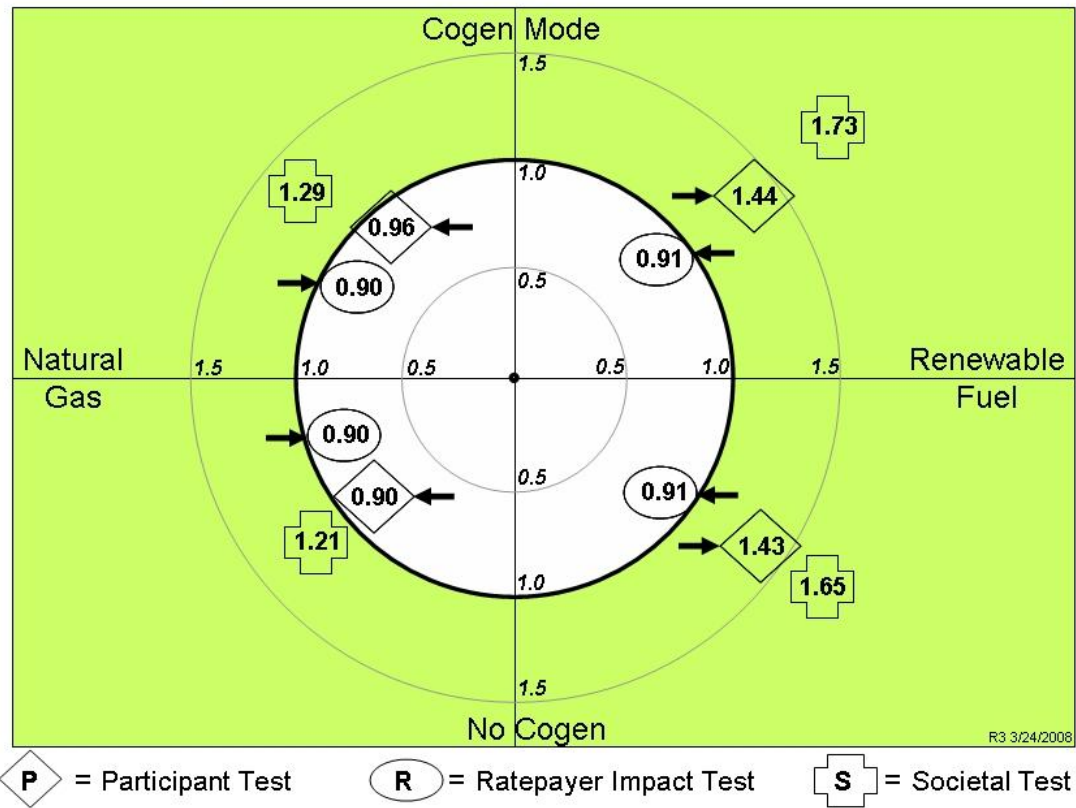


Figure 2. Weighted-Average Benefit-Cost Ratios with SGIP Funding

Fuel cells provide significant value to California’s ratepayers today. As fuel cell installed capacity and penetration rates increase throughout the state, the value provided to California’s ratepayers through cogeneration, digester gas use, avoided central station generation, and the associated avoided emissions will grow significantly. Per MW of installed capacity, fuel cells result in more *avoided* emissions per year than either solar photovoltaics or wind energy; combining the unique operating characteristics of these diverse technologies would further enhance the benefits of fuel cells to the state.

Fuel cells and their resultant lower emissions have the potential to make a significant contribution to achieving the reduced greenhouse gases (“GHG”) emissions goals under the California Global Warming Solutions Act of 2006 (“AB32”). Industry input, supported by California Energy Commission analysis, indicates that stationary fuel cell penetration in California could reach 3200 MW by 2020. This penetration level would reduce carbon dioxide emissions by over 4 million metric tonnes per year and save enough natural gas to generate nearly 15 million MWh of electricity – equivalent to the electricity consumption of 2 million California residences.

II. FUEL CELLS: TECHNOLOGY AND GENERAL ATTRIBUTES

For the reader unfamiliar with fuel cells, Attachment A provides a four-page introduction to fuel cell technology. Attachment A describes the basic operation of a fuel cell, the fundamental differences between the five major fuel cell types, and a number of the general attributes of fuel cells used in stationary applications.

III. DESCRIPTION OF BENEFIT-COST ANALYSIS METHODOLOGY

A. BENEFIT-COST TESTS

Each of the three benefit-cost tests performed as part of this study has its own purpose, and each evaluates the benefits and costs of a project or program from a different perspective. The Participant Test measures the benefits and costs from the perspective of the individual participant, that typically being the individual or company owning the project or participating in the program. The Ratepayer Impact Measure (“RIM”) Test measures the benefits and costs of a project or program from the perspective of utility ratepayers. The Societal Test is the broadest of the three benefit-cost tests, measuring the benefits and costs of a project or program from a societal perspective.

While all three tests measure benefits and costs over the life of a project, the Societal Test uses a lower (societal) discount rate than the discount rate used from the Participant Test and the RIM Test. The lower societal discount rate is intended to reflect the fact that society usually takes a longer term perspective than do individual investors or ratepayers. Because all benefits and costs are discounted before the benefit-cost ratio is calculated for each test, there is no relative advantage or disadvantage for fuel cell products that are commercially available today versus products that are still under development. A more detailed discussion of each benefit-cost test will be provided below.

B. DATA USED IN BENEFIT-COST ANALYSIS

The participating fuel cell manufacturers provided detailed cost and performance data for commercially available products and projected cost and performance data for products that are currently under development. A total of nine separate fuel cell products were

included in the benefit-cost analysis; four of the fuel cell products are commercially available today and all are projected to be commercially available within the next three-to-ten years. Data provided by the fuel cell manufacturers was supplemented with benefit and cost data obtained from a broad-based literature review. A separate benefit-cost ratio was calculated for each product for each investor-owned utility “(IOU)” franchise area in California for each of the three benefit-cost tests identified above.

CPUC-approved natural gas and electricity tariff rates in effect as of the end of February, 2008, were used in the benefit-cost analysis for each test for each of the IOUs included in the study, *i.e.*, PG&E, SDG&E, SCE, and SoCal Gas. Natural gas and electricity tariff rates through 2030 were escalated using the average annual rate of change in costs projected for each IOU in a major study and supporting analysis done for the CPUC by Energy and Environmental Economics, Inc. (*See E3 Avoided Cost Study and Updated E3 Electric Avoided Costs Workbook.*) Because the E3 Avoided Cost Study includes cost projections only through the year 2030, tariff rates for the period from 2031-2042 were assumed in this study to escalate at 2% per year. The E3 Avoided Cost Study also includes calculated marginal costs for transmission and distribution, for electricity generation, and for natural gas supplies for each of the IOUs through 2030. As was the case with IOU natural gas and electricity tariff rates, IOU marginal costs beyond 2030 were assumed to escalate at 2% per year.

Most large stationary fuel cells operating as baseload electricity generators are fueled with natural gas and collect the waste heat to cogenerate steam or hot water. However, such fuel cells may also operate on renewable fuel and there may be cases where there is no on-site use for the waste heat. Therefore, this study assessed four possible combinations of fuel and operating mode for each of the nine fuel cell products included in the analysis in order to create a “spanning scenario” for each of the three benefit-cost tests. The four combinations of fuel and operating mode are as follows:

- Natural Gas + No Cogeneration
- Natural Gas + Cogeneration Mode
- Renewable Fuel + No Cogeneration
- Renewable Fuel + Cogeneration Mode.

The renewable fuel considered in this study is anaerobic digester gas, typically derived from wastewater treatment plants, landfills, and manure collection ponds. Use of such digester gas requires removal of impurities and compression before the gas can be used in a fuel cell. The need for an up-front clean-up skid adds capital costs ranging from \$250-1000/kW of installed fuel cell capacity for fuel cells operating on renewable fuel. Additional annual O&M costs associated with the up-front clean-up skid are assumed to be 2% of the additional capital costs. An electrical efficiency loss of 2% is included to reflect the larger volume of (lower Btu) digester gas that must pass through any fuel cell operating on renewable fuel.¹

¹ This efficiency loss does not apply to molten carbonate fuel cells because the carbon dioxide in the digester gas actually enhances the carbonate-based electrochemistry and offsets any efficiency loss.

Another item that must be considered in the benefit-cost analysis with respect to renewable fuel is the cost of the digester gas as compared to the cost of the natural gas that would otherwise be used by the fuel cell. The results presented in Figure 2 (above) and in Figure 3 (below) assume that digester gas is valued at 10% of the utility's tariff cost of natural gas. This assumption recognizes that there may be some competition for renewable fuel, and is more conservative than simply assuming that digester gas is a cost-free fuel that would otherwise be flared. In addition, because digester gas production depends on a number of uncontrollable factors such as ambient temperature and waste composition, a fuel cell project may need to maintain a portion of its natural gas supply and delivery under contract in the event that there is insufficient digester gas available at any given time to maintain fuel cell operations. The results presented in Figures 2 and 3 assume that natural gas is available to replace up to 15% of the project's annual renewable fuel requirements.

Almost all stationary fuel cells generating baseload electricity operate in cogeneration mode because the capture and re-use of waste heat significantly improves a project's economics. Thus, cogeneration mode is considered to be the base case in the benefit-cost tests performed in this study. Fuel cells not operating in cogeneration mode are assumed to have \$70-170/kW less in up-front capital costs and reduced annual O&M costs equal to 2% of the reduced up-front capital costs.

Once the discounted benefit-cost ratios for each fuel cell product, each IOU, and each fuel and operating mode combination were calculated, a capacity weighted-average benefit-cost ratio for all products across all utility franchise areas was calculated for each test and for each fuel and operating mode combination. The ultimate calculation of a capacity weighted-average benefit-cost ratio was deemed necessary in order to maintain the confidentiality of each manufacturer's data.

C. RESULTS OF BENEFIT-COST ANALYSIS

Capacity weighted-average benefit-cost ratios were calculated both with and without the benefit of SGIP funding. Figure 3 (below) shows the weighted-average benefit-cost ratios assuming no SGIP funding, whereas the previously presented Figure 2 showed the weighted-average benefit-cost ratios with SGIP funding included. In each case, the spanning scenarios are reflected in a similar manner:

- The lower left quadrant of Figures 2 and 3 represents the results of each weighted-average benefit-cost test for the "Natural Gas + No Cogeneration" fuel and operating mode combination; the upper left quadrant represents the results for the "Natural Gas + Cogeneration Mode" combination.
- Similarly, the lower right quadrant of Figures 2 and 3 represents the results of each weighted-average benefit-cost test for the "Renewable Fuel + No Cogeneration" combination, and the upper right quadrant represents the results for the "Renewable Fuel + Cogeneration Mode" combination.

- Actual capacity weighted-average benefit-cost ratios for each fuel and operating mode combination are associated with a specific shape for ease of interpretation:
 - Participant Test benefit-cost ratios are shown within a diamond
 - RIM Test benefit-cost ratios are shown within an oval
 - Societal Test benefit-cost ratios are shown within a cross.
- Concentric circles provide a quick reference of the relative value for each of the weighted-average benefit-cost ratios, as indicated along the axis of each quadrant.
 - A benefit-cost ratio less than 1.0 would be located within the white portion of the quadrant for any given fuel and operating mode combination.
 - A benefit-cost ratio greater than 1.0 would be located in the green portion of each quadrant for any given fuel and operating mode combination.

Benefit:Cost Ratios for Fuel Cell Baseload Electricity Generation in California, without SGIP Funding

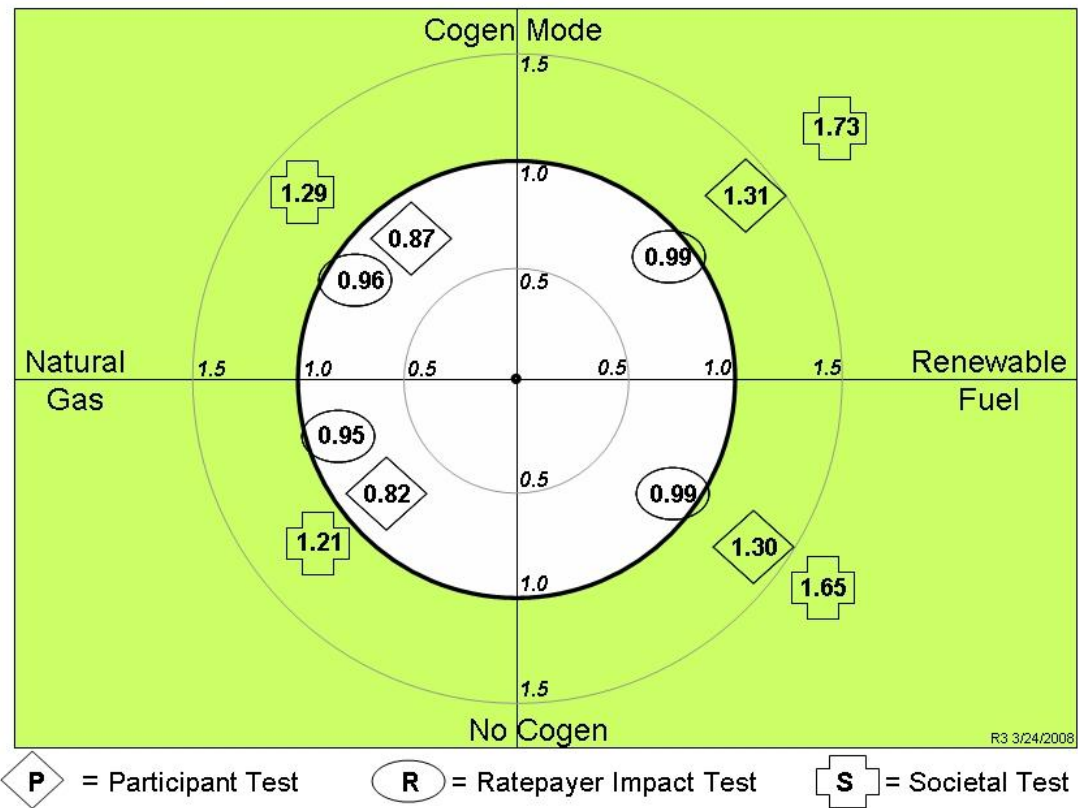


Figure 3. Weighted-Average Benefit-Cost Ratios without SGIP Funding

The results in Figure 3 clearly show that stationary fuel cells in California have the greatest weighted-average benefit-cost ratio when they are operating in cogeneration mode using renewable fuel. Fuel cells operating on natural gas in cogeneration mode

have a weighted-average benefit-cost ratio of 0.87 for the Participant Test and 1.29 for the Societal Test, assuming no SGIP ratepayer-funded incentives. Fuel cells operating on natural gas without cogeneration have more limited benefits, as shown in the associated benefit-cost ratios. Typical benefit-cost ratios for the RIM Test ranged from 0.95-0.99, again assuming no SGIP incentives.

Figure 2 (presented earlier) shows how each of the weighted-average benefit-cost ratio changes when SGIP funding for fuel cell projects is included in the analysis. Of note:

- For each fuel and operating mode combination, the benefit-cost ratio for the Participant Test increases as SGIP funding is provided to the participant.
 - Note that the SGIP funding almost brings the benefit-cost ratio for the Participant Test to 1.0, as intended. Including the benefits of the federal Investment Tax Credit would move that benefit-cost ratio into the green area in most cases.
- Conversely, the benefit-cost ratio for the RIM Test decreases since the SGIP funding is provided by the utility ratepayers.
- No changes result under the Societal Test, since the SGIP funding is seen as an intra-societal transfer that has no net impact from a societal perspective.

The sections below explain the results of each of the weighted-average benefit-cost ratios in greater detail, to provide the reader with an intuitive understanding of the calculated outcomes.

D. PARTICIPANT TEST

The participant (*i.e.*, investor) in a fuel cell project will avoid having to pay electric utility energy and demand rates to the extent that onsite electricity is generated by the fuel cell. With respect to the natural gas utility:

- To the extent that the fuel cell operates on natural gas, the participant's payments to the natural gas utility will increase for the natural gas required to run the fuel cell.
- If the fuel cell operates on renewable fuel, the participant's payments to the natural gas utility will increase only to the extent that natural gas is required to supplement the renewable fuel. The (opportunity) cost of the renewable fuel can range from cost-free to 100% of the cost of utility-supplied natural gas.
- If the fuel cell operates in cogeneration mode (regardless of fuel), the amount of natural gas required by on-site boilers will be reduced in proportion to the amount of useful waste heat.

In the Participant Test, the annual difference between reduced payments to the electric utility and increased payments to the natural gas utility is compared to all of the costs and financial offsets associated with the fuel cell over the project's life, including up-front capital cost, annual O&M costs, and investment incentives and tax credits. The benefit-

cost ratio is calculated as the ratio of the net present value of each year's benefits and costs over the life of the project, using a nominal discount rate of 8.5%.²

E. RIM TEST

The RIM Test reflects the (discounted) aggregate net change in revenues and marginal costs *from the perspective of the electric and/or natural gas utility* affected by the fuel cell project.

The RIM Test reflects the electric utility's lower revenues due to the onsite electricity generated by the fuel cell. Whereas the electric utility's revenues are lower, so too are its marginal costs of transmission and distribution and of electricity generation. Note that the reduction in the electric utility's revenues is independent of whether the fuel cell operates on natural gas or renewable fuel, since electricity is generated by the fuel cell in either case.

Conversely, the natural gas utility benefits from higher revenues only (i) if the fuel cell operates on natural gas or (ii) to the extent that natural gas is required to supplement the fuel cell's renewable fuel use. However, the natural gas utility also faces higher marginal costs to procure and transport whatever additional natural gas is required by the fuel cell. The greater the extent to which the fuel cell operates solely on renewable fuel, the lesser the increase in the natural gas utility's revenues and associated marginal costs. Similarly, the natural gas utility's revenues and associated marginal costs will be reduced in proportion to the amount of useful waste heat that is captured if the fuel cell operates in cogeneration mode on any fuel.³

Changes (up or down) in utility revenues and utility marginal costs are captured in the RIM Test; ratepayer-funded incentives and program administration costs are also included as utility costs. It is primarily the difference between each of the affected utility's (average cost) regulated tariff rates and marginal costs, as adjusted by the "net-to-gross" percentage, that determines the value of the RIM Test benefit-cost ratio for any given project in any given utility franchise area.⁴ The benefit-cost ratio is calculated as the net present value of each year's benefits and costs over the life of the project using an 8.5% annual discount rate.

² For the nine fuel cell projects included in this benefit-cost analysis, project life ranged from 15 to 25 years.

³ This assumes that the useful waste heat that is captured is being used to displace heat from a natural gas-fired boiler, rather than from an electrical chiller.

⁴ The "net-to-gross" percentage is a measure of how the utility's electric or natural gas load would have changed even in the absence of an incentive program. If no other empirical data are available, the standard net-to-gross percentage used in California is 85%. The implication is that 15% of the load shift (up or down) would have occurred even without a ratepayer-funded incentive program. Therefore, the utility's revenue impact (positive or negative) due to the incentive program is not 100% of the revenue impact of the load shift, but is rather only the 85% of the load shift that can be attributed to the incentive program.

F. SOCIETAL TEST

The Societal Test in effect combines the benefits and costs from the Participant Test and the RIM Test, but excludes investment incentives and tax credits because these items are a wash (*i.e.*, zero out) from a societal perspective. In addition, the value of externalities—considered in neither the Participant Test nor the RIM Test—is explicitly included in the Societal Test. The analysis underlying the waterfall chart in Figure 1 is used to determine the value of those externalities (*i.e.*, project attributes) to be included in the Societal Test for each individual fuel cell product and for each fuel and operating mode combination.⁵ Quantified values for the following externalities were included in the Societal Test benefit-cost ratio calculations:

- Value of Avoided Emissions
- Value of Related Health Benefits
- Value of Avoided Fossil Fuel as a Price Hedge
- Value of Grid Support
- Value of Increased Reliability, Blackout Avoidance and Improved Power Quality
- Value of Job Creation Potential.

As was the case in the RIM Test, actual increases or decreases in the participant's payments to the natural gas or electric utility by the investor are fully included in the Societal Test. However, the actual impact of those revenue changes on the natural gas and/or electric utility is reduced by applying the “net-to-gross” percentage to all utility revenues and marginal costs to reflect the fact that a certain percentage of the load shift attributable to fuel cells would have occurred even in the absence of a ratepayer-funded incentive program. The benefit-cost ratio for the Societal Test is calculated as the ratio of the net present value of each year's benefits and costs over the life of the project, using a societal discount rate of 5.0%.

G. COST OF AVOIDED EMISSIONS

The first step in calculating the Value of Avoided Emissions for inclusion in the Societal Test was to determine the annual physical units of avoided emissions for each fuel cell product as compared to the average California natural gas-fired fleet of electricity generators.⁶ Calculation of physical units of avoided emissions was performed for several types of emissions, including carbon dioxide (“CO₂”), NO_x, SO_x, carbon monoxide (“CO”), particulate matter, and volatile organic compounds (“VOC”).

⁵ Note that the value of many of the distributed value elements included in Figure 1's waterfall chart (e.g., avoided generation capital and O&M costs) is captured in the utility tariffs and marginal costs underlying the Participant Test and the RIM Test. To avoid double counting, only the value of those distributed value elements not already captured in the Participant Test and the RIM Test is included in the Societal Test.

⁶ Additional detail on the calculation of the Value of Avoided Emissions is provided below in Section IV F.

To calculate the cost per unit of avoided emissions, the annual avoided physical emissions for each fuel cell product were multiplied by the project life and then divided by the net present value (“NPV”) of the project’s total costs, including initial capital cost, stack change out costs, and lifetime O&M costs.⁷

Similar to the benefit-cost ratio calculations, the cost of avoided emissions for each of the nine fuel cell products was aggregated into a capacity weighted-average cost measure to maintain the confidentiality of product-specific data.⁸ The following results were calculated assuming that 50% of the NPV of the project’s total costs was assigned to avoided CO₂ emissions and 50% to cumulative avoided NO_x, SO_x, CO, VOC and particulate matter emissions.

- The weighted-average NPV cost of avoided CO₂ emissions was \$192/metric tonne for “natural gas + cogeneration mode” and \$737/metric tonne for “natural gas + no cogeneration.”
- For renewable fuel, the weighted-average NPV cost of avoided CO₂ emissions was \$130/metric tonne with cogeneration and \$479/metric tonne without cogeneration.
- The weighted-average NPV cost of avoided NO_x, SO_x, CO, VOC and particulate matter emissions was \$20/pound for “natural gas + cogeneration mode” and \$25/pound for “natural gas + no cogeneration.”
- For renewable fuel, the weighted-average NPV cost of avoided NO_x, SO_x, CO, VOC and particulate matter emissions was \$13/pound with cogeneration and \$15/pound without cogeneration.

As noted, these results are based on a comparison of emissions from fuel cells generating baseload electricity in California and average emissions from the existing in-state natural gas-fired generating fleet. Additional efforts are underway to calculate the costs per unit of avoided emissions for fuel cells when compared to new, technology-specific projects.

H. BENEFIT-COST CONCLUSIONS

The societal benefits of stationary fuel cells generating baseload electricity outweigh the societal costs for each of the four spanning scenarios (*i.e.*, fuel and operating modes) examined in this benefit-cost analysis. As illustrated in Figures 2 and 3, this holds true with or without SGIP funding. However, the SGIP funding remains important from an investor’s viewpoint, as seen in the shift of the benefit-cost ratio for the Participant Test

⁷ The NPV was calculated using the nominal discount rate of 8.5% that was also used to calculate the benefit-cost ratios for the Participant Test and the RIM Test.

⁸ Note that the cost of avoided CO₂ emissions is expressed in \$/metric tonne. A metric tonne (or, more formally, a “megagram”) is 1000 kilograms. At the equivalent of 2205 pounds, a metric tonne is 10.25% heavier than the 2000 pound ton commonly used in the U.S. Therefore, to obtain the cost of avoided CO₂ emissions in \$/ton, simply divide the cost in \$/metric tonne by 1.1025,

from less than 1.0 in Figure 3 to nearly 1.0 in Figure 2 for the most common “natural gas + cogeneration mode” scenario (upper left-hand quadrant). As explained above, the federal ITC has provided the final push towards cost-effectiveness from the participant’s perspective.

The RIM Test benefit-cost ratio moves counter to the Participant Test benefit-cost ratio since the SGIP funding is provided by the ratepayers to the fuel cell project investors. The RIM Test reflects the ratepayers’ perspective, based solely on changes in utility revenues and marginal costs. To the extent that the ratepayers and the society are one and the same, the results of the RIM Test must be considered in conjunction with the results of the Societal Test. In California, IOU ratepayers represent over two-thirds of the state’s total electricity use⁹ and over three-fourths of the state’s total natural gas use.¹⁰ Therefore, the substantial benefits reflected in the Societal Test accrue predominantly to those ratepayers providing SGIP funding and spill over the consumers of the state’s remaining electricity and natural gas deliveries.

In terms of the cost of avoided emissions, fuel cells reduce CO₂ emissions at a weighted-average NPV cost of \$130-737/metric tonne and cumulative NO_x, SO_x, CO, VOC and particulate matter emissions at a weighted-average NPV cost of \$13-25/pound, depending on the underlying fuel and operating mode combination.

IV. INTRODUCTION TO AVOIDED COST VALUATION METHODOLOGY

This section will describe the details and assumptions behind the cents per kWh (“cents/kWh”) avoided cost values derived in the “Build-Up of Distributed Fuel Cell Value in California” waterfall chart, as illustrated above in Figure 1. Some of the avoided costs are quantified based on observable market prices equipment, service, and other relevant factors, and some are quantified based values that are derived from a broad-based literature search. For the benefit of the reader, descriptions of the underlying assumptions are provided below for each calculated cents/kWh value range, starting at the bottom of the waterfall, continuing up through each value range toward the top of the waterfall.

The *categories* of avoided costs quantified in Figure 1 relate to a number of so-called “distributed value elements,” which represent attributes of distributed generation technology vis-à-vis a central generating plant; the *values* derived in this study are specific to distributed fuel cells. Distributed value elements are categorized as being Political, Locational, Environmental, Antidotal, Security-related, or Efficiency-related.¹¹ Taking the first letter of each category, the “PLEASE” matrix is developed to summarize the potential distributed value elements in each category, as shown in Attachment B. The

⁹ See CPUC, “Annual Report 2007,” p. 17.

¹⁰ See California Gas Utilities, “2006 California Gas Report,” p. 19.

¹¹ The PLEASE Matrix was first presented on April 13, 2005, in testimony before the CPUC on behalf of the Americans for Solar Power by Lori Smith Schell, Ph.D. in proceeding R.04-03-107.

quantified values in Figure 1 are not all-inclusive, and do not include many of the distributed value elements identified in the PLEASE matrix. Those distributed value elements that are featured in the “Build-Up of Fuel Cell Value in California” waterfall chart are marked with an asterisk (*) on the PLEASE matrix in Attachment B.

The fuel cells being considered in this analysis operate as a baseload distributed generation technology, generating electricity through an electrochemical process rather than through combustion. The resultant lower CO₂ emissions have the potential to make a significant contribution to achieving reduced GHG emissions goals under AB32. Fuel cells are also essentially free of particulates and unburned hydrocarbons, and have very low NO_x and SO_x emissions (both of which are acid rain pollutants that contribute to secondary particulate formation).

As a baseload technology, valuing the avoided costs associated with the deployment of fuel cells must be based on a comparison with the avoided baseload central station electricity generation technology serving California customers.

- For baseload central stations located in California, many of the avoided costs are derived from the natural gas combined cycle parameters that the CPUC defined as the 2006 Market Price Referent (“MPR”) proxy plant in its Resolution E-4049. Additional avoided costs specific to California are taken from the E3 Avoided Cost Study.
- For baseload central stations located outside of California serving California markets, avoided costs are based on repowering existing coal-fired generators, based on the assumption that California’s resource planning and AB32 requirements will result in no new coal-fired generators being built to serve California’s electricity demand. Despite California’s pending reduced reliance on coal-fired electricity imports purchased under long-term contracts, it is anticipated that a significant portion of California’s imported electricity will continue to be from coal-fired generation, albeit purchased under short-term or spot market contracts.

Avoided costs related to these two baseload generation technologies establish the range of values for each of the distributed value elements included in the “Build-Up of Distributed Fuel Cell Value in California.” The cumulative range of value is calculated to be 6.6-20.5 cents/kWh for fuel cells currently installed in California, with the value expected to increase significantly over time as the penetration of fuel cells throughout the state increases.

A. AVOIDED GENERATION COSTS

The avoided generation costs include separate estimates for avoided capacity costs and avoided energy/generation costs.

Capacity: Fuel cells achieve their highest electrical efficiency when operated as a baseload electricity generating technology. Fuel cells currently operating in California

have an estimated annual capacity factor of 91%, and also have high availability during periods of peak electric demand. (See Itron, SGIP Fourth Year Impact Report, pp. 8-15.)

Value of Avoided Generation Capacity Capital Cost – The range of the Value of Avoided Generation Capacity Capital Cost is calculated here based on the annualized capacity value of a repowered subcritical pulverized coal generator (low end of range) and a combined cycle natural gas-fired generator (high end of range). The avoided capacity capital cost is calculated as the annual capacity charge rate (15% from Duke, *et al.*, p. 9) times the capital cost for the technology (\$770 per kW-yr for repowering a baseload coal plant,¹² and \$980 per kW-yr for a combined cycle gas generator for the CPUC 2006 MPR proxy plant).

Value of Avoided Generation Capacity Fixed Operation & Maintenance (“O&M”) Cost – This is an additional avoided capacity cost, with an unadjusted range of \$13.94/kW-yr for a combined-cycle gas turbine and \$19.60/kW-yr for a repowered baseload coal generator, derived from the same sources as above.

However, electrical grid peak loads are predominantly driven by air conditioning demand on sunny days. The capacity credit (avoided cost) for any distributed generation technology should be set based on the effective load carrying capacity (“ELCC”) of that technology at a certain area within the system. The ELCC is the capacity of any electricity generator, whether distributed or conventional, to contribute effectively to a utility’s capacity to meet its peak load. (See Herig, p. 2.)

Based on the performance of fuel cells participating in the SGIP, the average ELCC for fuel cells in California is 93%. (See Itron, SGIP Fourth Year Impact Report, pp. 8-15.) Although the fuel cells in this study operate as a baseload technology, their on-peak performance effectively reduces peak load due to their distributed nature. Therefore, a 93% ELCC is used to adjust both the Avoided Generation Capacity Capital Cost and the Avoided Generation Capacity Fixed O&M Cost. ***Note that for any given fuel cell project, the capacity-related avoided costs should reflect the localized system average ELCC.***

To recognize the dispersion value of distributed fuel cells, the generation-related avoided capacity costs have been multiplied by 1.14, the California electric generation reserve margin that is not applied to distributed generation projects.

To convert \$/kW-yr capacity values to cents/kWh, it is necessary to divide the \$/kW-yr capacity value by the number of hours per year during which a fuel cell project is expected to generate electricity; this number is derived from the annual capacity factor

¹² The repowering-related capital and O&M costs used in this analysis are derived from repowering costs used by the U.S. Environmental Protection Agency (“EPA”) in its Base Case 2004 Integrated Planning Model (Exhibit 4-21). EPA’s repowering costs are inflated to 2007\$ and escalated by the ratio of applicable costs from: (i) U.S. Department of Energy, Energy Information Administration (“EIA”), Assumptions to the Annual Energy Outlook 2007 (“AEO 2007”) (p. 77), and (ii) EPA (Exhibit 4-9) for a new conventional pulverized coal plant. Application of such a ratio is necessary because EIA does not include cost estimates for repowering in its Assumptions to the AEO 2007.

for fuel cells. With 91% being the average annual capacity factor for fuel cells in California, there are 7,972 hours of expected fuel cell generation per year (*i.e.*, 8760 hours/year x 0.91). The resultant Value of Avoided Generation Capacity Capital Cost is 0.171-0.231 cents/kWh.

Energy/Generation: Energy should be valued at the avoided real-time cost on at least an hourly basis. Avoided energy/generation costs include the avoided cost of central generating station fuel and the central station avoided variable O&M costs.

Value of Avoided Generation Variable O&M Cost - The Value of Avoided Generation Variable O&M Cost range of 0-0.25 cents/kWh is determined by the 2006 MPR proxy plant on the low side and by the adjusted EPA repowering costs on the high side, with the Value of Avoided Water Use subtracted out as a separate variable that sets an upper limit on the avoided variable O&M costs, as discussed below.

Value of Avoided Generation Fuel Cost – Although most fuel cells use natural gas to fuel the chemical reaction through which the fuel cell generates electricity, fuel cells have a higher electrical efficiency than the average California natural gas-fired generator. Thus, the Value of Avoided Generation Fuel Cost in this analysis reflects this efficiency gain for fuel cells that rely on natural gas. In addition, fuel cells may also be fueled with waste hydrogen from industrial processes, digester gas from landfills, waste water treatment plants, or other “renewable” sources. Electricity generated by these fuel cells contributes to the Value of Avoided Generation Fuel Cost in proportion to the renewable share of total installed fuel cell capacity in California, as described below. Similarly, the proportion of fuel cells that capture waste heat that is used to displace steam or hot water production from a natural gas-fired boiler also contributes to the Value of Avoided Generation Fuel Cost, as described below.

The Avoided Generation Capacity Cost parameters described above serve as a starting point for calculating the Avoided Generation Fuel Cost for fuel cells. The range of the avoided costs of central station generating fuel is set by the avoided baseload coal generation plant on the low side and by the average California avoided natural gas-fired plant on the high side.¹³

The range of avoided natural gas prices is based on the range of daily settlement prices for prompt-month natural gas futures contract prices on the New York Mercantile Exchange (“NYMEX”).¹⁴ Since the beginning of calendar year 2004, this range has been

¹³ With respect to the avoided natural gas plant, the natural gas-fired 2006 MPR proxy plant is used as a point of comparison only for avoided capital capacity costs and avoided O&M costs; the average California avoided natural gas-fired plant is used as a point of comparison for all other calculations.

¹⁴ The term “prompt month” refers to the earliest month for which futures contracts are trading. Trading of futures contracts for any given delivery month ends prior to the end of immediately previous month. Therefore, “the prompt month” in mid-April would be May, but by the end of April, after trading for the May futures contract closes, the prompt month becomes June.

\$4.20-15.40/MMBtu, for natural gas located at the Henry Hub, onshore Louisiana.¹⁵ The NYMEX natural gas price is converted to cents per kWh by multiplying it times the range of heat rates assumed for (i) the average California avoided natural gas-fired plant (*i.e.*, 8,087-9,100 Btu/kWh)¹⁶ and (ii) the average fuel cell (*i.e.*, 8,060-8,343 Btu/kWh).

The range of avoided coal prices is based on the monthly national average cost of coal delivered to electric utilities, as reported on FERC Form 423. Since the beginning of 2004, this monthly average coal price has ranged from \$1.27-1.71/MMBtu. (*See* EIA, November 19, 2006, Table 4.2.) The coal price is converted to cents per kWh by multiplying it times the range of heat rates assumed for the baseload coal generation plant (*i.e.*, 8,844-10,875 Btu/kWh).

The Avoided Generation Fuel Cost values calculated using the above methodology yields a range of 1.12-1.86 cents/kWh for coal and 3.40-14.01 cents/kWh for natural gas (but only if the avoided natural gas-fired generation was 100% avoided). However, since only 30% of all installed fuel cell capacity in California is assumed to use “renewable” digester gas instead of natural gas, the Avoided Generation Fuel Cost attributed to fuel cells in this analysis is only 30% of the absolute range of values, *i.e.*, 0.34-4.20 cents/kWh.¹⁷ The higher efficiency of fuel cells contributes an additional 0.01-0.82 cents/kWh to the Avoided Generation Fuel Cost for those 70% of California fuel cells assumed to be operating on natural gas. The avoided coal price of 0.34 cents/kWh sets the lower end of the range, and the combined avoided natural gas price of 5.02 cents/kWh sets the upper end of the range for the electric-only Avoided Generation Fuel Cost, *i.e.*, prior to recognition of the Cogen(eration) Credit. As explained below, the Cogen(eration) Credit adds another 0.94-2.01 cents/kWh of Value of Avoided Generation Fuel Cost, making the total Value of Avoided Generation Fuel Cost 1.28-7.03 cents/kWh.

Value of Avoided Fossil Fuel as a Price Hedge – Fossil fuel price volatility can wreak havoc with personal and corporate budgets. Fossil fuel input that is avoided by fuel cells using renewable fuel and/or using captured waste heat, therefore, provides a type of price hedging mechanism that protects electricity consumers from unpredictable fossil fuel price volatility.

The range of estimates for the Value of Avoided Fossil Fuel as a Price Hedge is based on applying the heat rate end-points of 8,087 Btu/kWh and 10,875 Btu/kWh (discussed above) to the estimates derived by Bolinger, *et al.* (January 2004, p. 8). As was the case for the Avoided Generation Fuel Cost, the attributed Value of Avoided Fossil Fuel as a

¹⁵ No cost adjustment has been made to reflect the value of transportation from the Henry Hub to California, since this transportation value (known as the “basis”) is highly volatile, varies seasonally, and may be either positive or negative.

¹⁶ The average California avoided natural gas-fired plant had a five-year weighted-average heat rate for 2001-2005 that was approximately 21% less efficient than that of the 2006 proxy plant, based on state-specific electricity generation and fuel consumption values as reported by EIA (June 2007; March 2007c).

¹⁷ It is assumed that all power generated fuel cells using such renewable fuel will continue to be used on-site, as is currently the case.

Price Hedge reflects in part the 30% of total California fuel cell capacity that is assumed to operate using renewable digester gas rather than natural gas. The electric-only hedge value range of 0.02-0.36 cents/kWh attributed to these renewable fuel-based fuel cells reflects the fact that their generated electricity requires no fossil fuel input, thereby avoiding the financial impact of fossil fuel price volatility (*e.g.*, budget uncertainty, uneconomic projects). Similarly, an additional Value of Avoided Fossil Fuel as a Price Hedge of 0.34-0.60 cents/kWh is attributed to the 60% of total California fuel cell capacity that captures waste heat for cogeneration and combined cooling, heating, and power (“CCHP”) applications, thereby avoiding natural gas input to the avoided boiler. Combined, these two components have a total hedge value range of 0.36-0.96 cents/kWh.

B. AVOIDED WATER USE

Value of Avoided Water Use – Some fuel cells consume water for the electrochemical reaction than generates electricity and for the water purification required to meet fuel cell input requirements.¹⁸ Other fuel cells either produce a net output of water or use no water during normal operations, and only a nominal amount during startup and shutdown.

The Value of Avoided Water Use that electricity generated by fuel cells provides is calculated based on avoided water consumption relative to a central station generating station. The combined cycle, natural gas-fired 2006 MPR proxy plant uses dry cooling; CEC data for a similar plant indicates that only 0.02 gallons of raw water are required per kWh of generation (CEC, April 2006, p. 36).¹⁹ The existing fleet of baseload coal generators serving California is assumed to use closed recirculating cooling, which requires 1.12 gallons of raw water per kWh of generation (National Energy Technology Laboratory (“NETL”), August 2005, p. 68).²⁰ These values compare to an estimated range of raw water use per kWh for fuel cells of 0-0.17 gallons. These values indicate that even the minimal water use by the dry-cooled proxy plant may be avoided by fuel cells, and that the avoided water use compared to the baseload coal plant is significant at 0.95 gallons per kWh. The range of water costs applied to the avoided coal-fired central station water use is \$0.557-\$3.636 per hundred cubic feet of metered water, based on tariff rates as of March 2007 for Class A water companies located throughout California.

The calculated (unadjusted) range of Value of Avoided Water Use is 0.001-0.461 cents/kWh. However, since the cost of water usage is typically included in the Value of Avoided Generation Variable O&M Cost,²¹ the (adjusted) Value of Avoided Water Use

¹⁸ This water, as well as other water generated by some fuel cells, may be recovered and used for non-potable purposes such as irrigation.

¹⁹ All water usage quantities have been adjusted by a scaling factor such that the underlying plant size is 500 MW, which is the size of the 2006 proxy plant.

²⁰ The CEC dry-cooled water usage for a natural gas combined cycle plant represents a 95% reduction from the NETL recirculating cooling water usage for a similar plant. This is in line with the 90% reduction discussed in the March-April 2002 University of Arizona publication *Arizona Water Resource*.

²¹ See CEC, online “California Distributed Energy Resource Guide.”

cannot exceed the Value of the Avoided Generation Variable O&M Cost. In our study, the (adjusted) Value of Avoided Water Use of 0.00-0.26 cents/kWh has been subtracted from the values derived in the Value of Avoided Generation Variable O&M Cost category to avoid double counting.

Note that the Value of Avoided Water Use varies significantly depending on location. In addition, commercial prices for water will underestimate the Value of Avoided Water Use to the extent that those prices do not fully reflect the societal cost of the water used.

C. AVOIDED TRANSMISSION & DISTRIBUTION COSTS

Because fuel cells are distributed energy resources that are typically located close to the point of use, fuel cells require much less transmission and distribution (“T&D”) infrastructure than does conventional central station generation. The value of avoided T&D is very much dependent on location and on the adequacy of T&D infrastructure relative to load growth in that location. Fuel cell installations in “load pockets” where transmission capacity is constrained will provide maximum value. The same applies to areas located within a constrained distribution grid, or in a new housing development where marginal investment can be directly avoided.

Avoided transmission costs are separate and distinct from avoided distribution costs; both are taken from the E3 Avoided Cost Study, and have been (i) adjusted to reflect the assumed 93% California average ELCC of fuel cells in California and (ii) converted to cents/kWh using the assumed 91% annual fuel cell capacity factor. The ELCC is applied here (as it was earlier) on the assumption that the on-peak performance of baseload fuel cells effectively reduces peak load due to the distributed nature of those fuel cells.

Value of Avoided Transmission Cost – The (adjusted) Value of Avoided Transmission Cost ranges from a low of 0.01 cents/kWh into the service territory of Pacific Gas & Electric (“PG&E”) to a high of 0.24 cents/kWh into the service territory of Southern California Edison (“SCE”).

Value of Avoided Distribution Cost – The (adjusted) Value of Avoided Distribution Cost ranges from a low of 0.06 cents/kWh in the Dominguez Hills area within SCE’s service territory to a high of 0.97 cents/kWh within the service territory of San Diego Gas & Electric (“SDG&E”). When avoided T&D costs for a specific area are combined, the minimum value of 0.11 cents/kWh occurs in the East Bay region within PG&E’s service territory, and the maximum value of 1.10 cents/kWh occurs within SDG&E’s service territory.

Value of Avoided Losses – This category of avoided cost accounts for the fact that distributed generation from fuel cells does not have to pass through the electrical grid and thus does not incur the associated T&D line losses. This means that 6% less electricity has to be generated by central generating stations, with an equivalent percentage

reduction in generation-related capacity requirements, O&M costs, fuel input, and emissions output.²²

Value of Grid Support – The estimated Value of Grid Support reflects the avoided ancillary services costs associated with the electricity load displaced by fuel cell generation. The value is based on 2.84% of the range of (unadjusted) Avoided Generation Fuel Cost, since fuel cost is assumed to be a major driver of wholesale electricity prices in California. Note that 2.84% is the same value that the E3 Avoided Cost Study applies to the avoided market price of electricity to estimate avoided ancillary services (pp. 146-147).

Value of Improved Reliability and Blackout Avoidance – Electricity generated by distributed fuel cells reduces the amount of electricity generated at central stations that must pass through the electric grid, thereby relieving potential overloading of many grid components (*e.g.*, transformers). To the extent that reduced overloading reduces the likelihood of load loss, distributed fuel cells have additional value in improved grid reliability and blackout avoidance.

The calculated Value of Improved Reliability and Blackout Avoidance for distributed fuel cells in California is based on the following five factors:

- The percentage of the state’s population affected by a blackout.
- The duration of a blackout.
- The penetration of distributed fuel cells.²³
- California’s daily per capita Gross State Product (“GSP”), as a surrogate measure of the direct costs of a blackout.
- An assumption that indirect costs related to a blackout are 60% as large as the direct costs.²⁴

The current calculated range of the Value of Improved Reliability and Blackout Avoidance is 0.002-0.192 cents/kWh, using 2005 values for GSP and fuel cell penetration.²⁵ The lower end of the range is based on a 1-hour blackout that affects 10%

²² This value approximates the 5.52% volume-weighted average for California’s three investor-owned utilities as agreed to by Working Group for use in 2007 market price benchmark calculation (CPUC, January 25, 2007, p.7).

²³ The penetration of distributed fuel cells is calculated as the ratio of fuel-cell generated MWh to total California retail electricity sales in MWh. For 2006, this ratio was estimated to be 0.04%.

²⁴ ICF Consulting, Summer 2003, estimates “Aggregate Indirect Costs” as 63% of “Aggregate Direct Costs” in its modeling of “Economic Costs of a Simulated Attack on the California Electric Grid.”

²⁵ The Value of Increased Reliability/Power Quality/Blackout Avoidance of <0.01-0.24 cents/kWh shown in the “Build-Up of Fuel Cell Value in California” waterfall chart illustrated in Figure 1 combines the Value of Increased Reliability and Blackout Avoidance with the Value of Increased Power Quality (discussed below).

of the state's population; the upper end is based on a 24-hour blackout affecting 50% of the state's population.

Results calculated using the methodology described above were compared to estimated losses derived by others for both California (in whole or in part) and for the Northeastern U.S. August 2003 blackout (as it affected New York City).²⁶ Although not identical, the results were such that the methodology used here was deemed to be a reasonable means of valuing the improved reliability and blackout avoidance attributable to distributed fuel cells in California.

The calculated range of the Value of Improved Reliability and Blackout Avoidance is anticipated to increase significantly as the penetration of fuel cells throughout the state increases. Assuming the goal of 3200 MW of installed fuel cell capacity is achieved by 2020 (as described below), fuel cell penetration would increase 200-fold from today's level, potentially generating nearly 8% of the total MWh consumed in California, providing up to 45 cents/kWh (in 2007\$) in Value of Improved Reliability and Blackout Avoidance.

Value of Improved Power Quality – The Value of Improved Power Quality is calculated as being 15% of the Value of Reliability and Blackout Avoidance.²⁷ This percentage is based on an analysis done for the New York State Energy Research and Development Authority (“NYSERDA”) that provided separate estimates of the total U.S. cost of outages and of power quality problems. As defined in the NYSERDA report:

- “The ability of the electric system to deliver electric power without interruption is termed 100% *reliability*.
- The ability to deliver a clean signal without variations in the nominal voltage or current characteristics is termed high *power quality*.” (Emphasis in original.)

(See Energy and Environmental Analysis, Inc., and Pace Energy Project, December 2005, pp. ES1 and ES3.)

The calculated range for the current Value of Improved Power Quality is 0.0002-0.0288 cents/kWh. As was the case for the Value of Increased Reliability and Blackout Avoidance, this value is expected to increase significantly as the penetration of fuel cells in California increases.

²⁶ See, for instance, Anderson Economic Group, August 19, 2003; Consortium for Electric Infrastructure to Support a Digital Society (“CEIDS”), June 2001; Clean Power Research, LLC, March 17, 2006; Center for Risk and Economic Analysis of Terrorism Events (“CREATE”), May 31, 2005; Electricity Consumers Resource Council (“ELCON”), February 9, 2004; ICF Consulting, August 21, 2003; ICF Consulting, Summer 2003; Rose, *et al.*, October 14, 2005.

²⁷ Because of its relationship with the Value of Increased Reliability and Blackout Avoidance, the Value of Improved Power Quality is added to the Value of Increased Reliability and Blackout Avoidance under the category of Increased Reliability/Power Quality/Blackout Avoidance in Figure 1.

D. DIGESTER GAS CREDIT

Biomethane is considered a renewable fuel source, with technically feasible for use digester gas levels (conservatively) estimated to reach 75 trillion Btu in California by 2020 (CEC, December 2006, p. 12, Figure 1.6). This level of biomethane availability could support nearly 40% of the state's potential 2020 installed fuel cell capacity of 3200 MW. The analysis underlying this valuation assumes that 30% of the state's installed fuel cell capacity operates using digester gas, which is based on an industry estimate.

Digester gas is assumed to be approximately half biogenic CO₂²⁸ and half methane (CH₄),²⁹ with small amounts of N₂, O₂, hydrogen sulfide (H₂S), and PM10; average heat content is about 600 Btu/ft³ (HHV). Use of digester gas by fuel cells has several benefits. First, such use means that the digester gas will not be flared, thereby avoiding flare-related emissions of NO_x, CO, and PM10. Second, use of digester gas by fuel cells directly displaces natural gas use, resulting in natural gas savings.

The direct benefits of natural gas cost savings and avoided emissions from digester gas use, as well as the indirect health-related benefits of those avoided emissions, contribute a total value ranging from 0.75-1.81 cents/kWh. This range of values is included in the values illustrated in Figure 1 and can be broken down as follows:

- Value of Avoided Natural Gas = 0.34-1.03 cents/kWh.
- Value of Fossil Fuel Price Hedge = 0.02-0.36 cents/kWh.
- Value of Health Benefits of Avoided In-State Emissions = 0.39-0.41 cents/kWh.
- Value of Avoided Emissions = 0.003-0.015 cents/kWh.

E. COGEN(ERATION) CREDIT

Fuel cells typically capture the waste heat from the electrochemical reaction process that produces electricity. The waste heat is then used to cogenerate another useful product such as hot water, steam, process heat, or cooling (*e.g.*, through the use of an absorption chiller). As a result, whatever process would otherwise have been used to provide the cogenerated product(s) is avoided, reducing the amount of input fuel required for that process and the amount of output emissions.

The Value of Cogen Credit is calculated using a format similar to that used by the CPUC in calculating avoided greenhouse gas emissions. (*See* CPUC, December 13, 2006, Attachment 5.) It is assumed that approximately 46% of the fuel cell's captured waste heat is available as useful energy, and that this useful energy replaces the output from an

²⁸ Biogenic carbon dioxide is considered to be part of the natural carbon cycle, and is not generally included in CO₂ emissions inventories.

²⁹ Both carbon dioxide and methane are greenhouse gases, though methane is 20 times more damaging as a greenhouse gas than is carbon dioxide according to the U.S. Climate Change Science Program.

in-state natural gas-fired boiler operating at 80% efficiency. The avoided natural gas is priced using the same range of NYMEX futures prices that was used for the Value of Avoided Generation Fuel Cost, averaged over a six-month period to reflect a more conservative (seasonal) fuel procurement practice. The avoided emissions are valued at in-state emissions prices (as discussed below for each relevant type of emissions). All values are adjusted to reflect the 60% of fuel cell capacity that is assumed to operate in a cogeneration or CCHP mode.

Values related to cogeneration and CCHP are calculated over the range of fuel cell heat rates for the avoided natural gas boiler fuel, for the corresponding fossil fuel price hedge, and for avoided emissions of NO_x, SO₂, and CO₂. The cumulative Value of Cogen Credit for fuel cells across all categories is 1.42-3.61 cents/kWh.

The following Value of Cogen Credit values are included in the total range of values for the appropriate category in the “Build-Up of Fuel Cell Value in California” waterfall chart illustrated in Figure 1:

- Value of Avoided Natural Gas = 0.94-2.01 cents/kWh.
- Value of Fossil Fuel Price Hedge = 0.34-0.60 cents/kWh.
- Value of Health Benefits of Avoided In-State Emissions = ~0.02 cents/kWh.³⁰
- Value of Avoided Emissions = 0.12-0.98 cents/kWh.³¹

F. AVOIDED EMISSIONS AND RELATED HEALTH BENEFITS

The E3 Avoided Cost Study assumes that the cost of regulated emissions is captured in the market price of electricity. The category of regulated emissions includes only generation-related emissions for which emissions allowances are currently mandated, including NO_x, SO₂, and PM10. However, due to the decision made in this analysis to separate capacity value from a derived energy value, it is necessary to consider separately those values captured in the market value of electricity in California that are neither capacity- nor fuel-related.

Natural gas is typically the marginal fuel source that sets the market price of electricity in California. In this analysis, natural gas prices set the upper bound on the Avoided Generation Fuel Cost, and coal prices (as a component of the electricity import price) set the lower bound. Natural gas as the Avoided Generation Fuel Cost thus acts (in part) as a surrogate for the market price of electricity. However, since NYMEX natural gas futures contract prices do not include the cost of emissions allowances, the value of avoided emissions must be calculated as a separate distributed value element for each of the avoided emissions identified.

³⁰ Details regarding the Value of Health Benefits of Avoided In-State Emissions related to cogeneration are provided below in the Value of Health Benefits section.

³¹ Avoided NO_x, SO₂, and CO₂ emissions from the natural gas-fired boiler are calculated using the “CHP Emissions Calculator” developed by EPA’s Combined Heat and Power Partnership. Avoided CO and VOC emissions are calculated using results derived by the Scottish Executive (2006).

To calculate the value of avoided emissions related to fuel cells, it is first necessary to identify *for each pollutant* (i) the emissions rate applicable to the avoided baseload technology and (ii) the resultant emissions over the assumed heat rate range for both the average California avoided natural gas-fired plant and the existing fleet of baseload coal generating plants serving California. The resultant emissions rate range for each baseload generating technology is then compared to the emissions rate for fuel cells to identify the quantity (if any) of avoided emissions in lb/MWh. The minimum and maximum avoided emissions are then valued at the end points of a range of emissions allowance prices either observed in the marketplace or derived from the literature.

The underlying assumptions and results for the avoided emissions and related health benefits are summarized in Attachment C. The Value of Avoided CO₂ Emissions attributed to distributed fuel cells in California is calculated at 0.11-2.21 cents/kWh; the combined Value of Other Avoided Emissions is 0.11-1.90 cents/kWh. Assuming that the Value of Health Benefits associated with avoided emissions is not reflected in emissions allowance prices, the additional Value of Health Benefits is calculated to be 2.34-2.54 cents/kWh. Specific details for each avoided pollutant and related health benefits are discussed below.

Value of Avoided NO_x Emissions – For the average avoided California natural gas-fired plant, the NO_x emissions rate is calculated using the updated E3 Electric Avoided Costs workbook. Using the average natural gas-fired plant’s assumed heat rate range of 8,087-9,100 Btu/kWh, the resultant NO_x emissions rate is 0.11-0.14 lb/MWh. For the typical avoided baseload coal generating plant serving California, the assumed NO_x emissions rate is 0.074 lb/MMBtu, as identified by the Center for Energy Efficiency and Renewable Technologies (“CEERT”) for a subcritical pulverized coal plant burning bituminous coal without carbon capture (CEERT, p. 31). For the assumed heat rate range of 8,844-10,875 Btu/kWh, the resultant NO_x emissions rate is 0.69-0.85 lb/MWh. The estimated NO_x emissions rate for fuel cells ranges from 0.01-0.06 lb/MWh.

For the average avoided natural gas-fired plant, the value of the avoided NO_x emissions is based on observed prices for Emissions Reduction Credits (“ERCs”) bought and sold in California. These NO_x ERCs are bought once for the life of the emissions permit, and are priced in \$/lb/day. The range of prices used in this analysis is \$25,000-\$356,164/lb/day. For the baseload coal plant, which is assumed to be located outside of California, the value of avoided NO_x emissions is based on observed prices for annual NO_x emissions allowances in markets outside of California. The range of prices used in this analysis is \$500-\$7,500/ton, where the NO_x emissions allowances must be purchased separately for each year.

Combining the calculated range of avoided NO_x emissions and the applicable range of prices for each of the baseload technologies considered in this analysis yields a range of values of avoided NO_x emissions from 0.06-0.99 cents/kWh.³²

³² All reported values for avoided emissions in this section of the report include (i) the value of avoided emissions (where applicable) for avoided digester gas flaring for that 30% of fuel cells assumed to use

Value of Avoided SO₂ Emissions – The Updated E3 Electric Avoided Costs Workbook does not include calculations of SO₂ emissions, and the NETL indicates that target SO₂ emissions from a new natural gas combined cycle plant are negligible. However, the California Environmental Protection Agency (“Cal EPA”) in its California Hydrogen Blueprint estimates SO₂ emissions from a natural gas combined cycle plant at 0.0026 lb/MMBtu of natural gas, and it is this value that is used here for the average avoided natural gas-fired plant. For the baseload coal generator, the CEERT-equivalent SO₂ emissions rate of 0.15 lb/MMBtu of coal is used in the valuation of Avoided SO₂ Emissions.

For the assumed heat rate range of 8,087-9,100 Btu/kWh for the average avoided natural gas-fired plant, the resultant SO₂ emissions rate is 0.022-0.025 lb/MWh. For the avoided baseload coal generating plant at the assumed heat rate range of 8,844-10,875 Btu/kWh, the resultant SO₂ emissions rate is 1.41-1.73 lb/MWh. The SO₂ emissions rate for fuel cells is assumed to be 0.001-0.005 lb/MWh.

As was the case for NO_x emissions, the value of the avoided SO₂ emissions for the average avoided natural gas-fired plant is based on observed prices for one-time ERCs bought and sold in California, which are priced in \$/lb/day. The range of prices for SO₂ ERCs used in this analysis is \$40,000-\$163,014/lb/day. For the baseload coal plant, the value of avoided SO₂ emissions is again based on observed prices for annual SO₂ emissions allowances in markets outside of California. The range of prices used in this analysis is \$100-\$1,650/ton, where SO₂ emissions allowances (like NO_x allowances) must be purchased separately for each year.

Combining the calculated range of avoided SO₂ emissions and the applicable range of prices for each of the baseload technologies yields a range of Value of Avoided SO₂ Emissions of 0.01-0.14 cents/kWh.

Value of Avoided VOC Emissions – The VOC emissions rate for both the average avoided natural gas-fired plant and the baseload coal plant is taken from Abt Associates, and is estimated to be 0.0120 lb/MMBtu for the average avoided natural gas-fired plant and 0.0023 lb/MMBtu for the baseload coal plant. Applying the applicable heat rate range to each baseload technology, the resultant range of VOC emissions is 0.10-0.12 lb/MWh for the average natural gas-fired plant and 0.02-0.03 lb/MWh for the baseload coal plant.

The Value of Avoided VOC Emissions uses observed California VOC ERC prices for the proxy plant emissions, and the Cantor-Fitzgerald VOC ERC index for the Houston-Galveston Area for the outside-of-California baseload coal plant VOC emissions.³³ The range of Value of Avoided VOC Emissions is 0.002-0.345 cents/kWh.

digester gas as reported above (in Section D) and (ii) the value of avoided emissions for cogeneration and CCHP as reported above (in Section E).

³³ These were the only VOC emissions allowance prices found for outside-of-California.

Value of Avoided PM10 Emissions – The methodology and data sources for calculating avoided PM10 emissions are the same as those used for valuing avoided NO_x emissions. The PM10 emissions rate for the average avoided natural gas-fired plant of 0.067-0.074 lb/MWh is calculated using the parameters in the updated E3 Electric Avoided Costs workbook and the heat rate range of 8,087-9,100 Btu/kWh. The PM10 emissions rate range for the baseload coal plant of 0.28-0.35 lb/MWh is calculating using the CEERT-equivalent 0.03 lb/MMBtu emissions rate and the heat rate range of 8,844-10,875 Btu/kWh. As a rule, fuel cells have no solid emissions, so the PM10 emissions rate for fuel cells is nil.

The Value of Avoided PM10 Emissions uses observed California PM10 ERC prices for the average natural gas-fired plant emissions, and the Cantor-Fitzgerald VOC ERC index for the Houston-Galveston Area as a surrogate for an outside-of-California PM10 emissions allowance price. The rationale behind the latter assumption is based on (i) a lack of pricing data for PM10 emissions allowances outside of California’s ERC markets and (ii) a similarity in the maximum price of California PM10 and VOC ERC prices. The range of Value of Avoided PM10 Emissions is 0.03-0.22 cents/kWh.

Value of Avoided CO Emissions – The CO emissions rate for both the average natural gas-fired plant and the baseload coal plant is taken from Abt Associates, and is estimated to be 0.1095 lb/MMBtu for the average natural gas-fired plant and 0.0192 lb/MMBtu for the baseload coal plant. Applying the applicable heat rate range to each baseload technology, the resultant range of CO emissions is 0.94-1.06 lb/MWh for the average natural gas-fired plant and 0.18-0.22 lb/MWh for the baseload coal plant. These emissions rates are all higher than the CO emissions rate from fuel cells, which is estimated to be 0.10 lb/MWh.

The Value of Avoided CO Emissions is based on observed California CO ERC prices for both the average natural gas-fired plant and the baseload coal plant CO emissions, as no outside-of-California CO emissions allowance prices were found in the literature. The range of observed California CO ERC prices is \$4,214-\$8,337/lb/day of CO emissions. Multiplying the endpoints of these prices times the end-points of the avoided CO emissions results in a Value of Avoided CO Emissions of 0.01-0.10 cents/kWh.

Value of Avoided Mercury Emissions – EPA’s Clean Air Mercury Rule (“CAMR”) became effective on May 18, 2006. However, compliance with the new regulations is not required until 2008, so observable market pricing is not yet available. As a result, the assumed range of value for mercury emissions allowances is based on estimated technological costs of capturing mercury from flue gas, as found in the literature. These costs range from \$5,000-\$35,000/lb of mercury removed. (*See Krotz, p. 3.*)

Neither fuel cells nor the average natural gas-fired plant have any mercury emissions, which means that the lower end of the Value of Avoided Mercury Emissions is zero. The mercury emissions rate from the baseload coal plant is assumed to be the CEERT-equivalent average value of 2.94 lb/TBtu.³⁴ At the baseload coal plant’s assumed heat

³⁴ “TBtu” stands for “trillion Btu,” which is equal to a million MMBtu.

rate range, the range of mercury emissions is 2.76E-05 lb/MWh to 3.39E-05 lb/MWh; all of these mercury emissions would be avoided by electricity generated by fuel cells.³⁵

It is assumed that the maximum price for mercury emissions allowances will be limited by the \$35,000/lb technical cost of mercury removal. Multiplying this \$35,000/lb maximum value by the 3.39E-05 lb/MWh upper limit on baseload coal generator mercury emissions yields a maximum Value of Avoided Mercury Emissions of 0.12 cents/kWh.

Based on previous findings by the U.S. EPA, Lutter, *et al.*, adopt the position (p. 4) that “mercury controls on utility emissions are likely to have ‘little effect’ on sulfur dioxide and oxides of nitrogen.” This would indicate that there is little to no double-counting of avoided emissions values, at least as it concerns mercury, SO₂, and NO_x.

Value of Avoided CO₂ Emissions – Although CO₂ and other GHG emissions are not yet subject to mandatory regulation in the United States, there is increasing pressure for the implementation of some type of carbon tax, particularly on the transportation and electric utility sectors of the economy. The CPUC now requires the investor-owned utilities that it regulates to “penalize” potential new generation resources with an \$8/ton CO₂ cost as part of its Integrated Resource Planning process, and CO₂ markets in Europe have traded anywhere from €2-€35/metric tonne since October 2005 (Chicago Climate Exchange, various dates).

For a natural gas-fired plant, the E3 Avoided Cost Study (pp. 74-75) estimates a linear relationship between CO₂ emissions and heat rate between a heat rate floor of 6,240 Btu/kWh and a heat rate ceiling of 14,000 Btu/kWh, with a carbon intensity of natural gas of 117 pounds CO₂ per MMBtu. (See Update E3 Electric Avoided Costs Workbook supporting file cpucAvoided26-1_update3-20-06.xls for detailed derivation.) Based on the 8,087-9,100 Btu/kWh heat rate range assumed for the average California avoided natural gas-fired plant in this analysis, the associated CO₂ emissions rate would be 0.50-0.56 ton/MWh. The CO₂ emissions rate for fuel cells is 0.46-0.49 ton/MWh, resulting in a range of avoided CO₂ emissions compared to the average California natural gas-fired plant of 0.04-0.07 ton/MWh; the avoided 0.04 ton/MWh will set the lower end of the range of avoided CO₂ emissions attributable to fuel cells.

The CO₂ emissions rate for the baseload coal generator is estimated to range from 0.97-1.20 ton/MWh, using the CEERT-equivalent average CO₂ emissions rate of 208 lb/MMBtu over the assumed heat rate range of 8,844-10,875 Btu/kWh.³⁶ Thus, the avoided CO₂ emissions from the baseload coal generator range from 0.51-0.71 ton/MWh, and the 0.71 ton/MWh avoided CO₂ emissions sets the upper end of the range of avoided CO₂ emissions attributable to fuel cells.

³⁵ 1.0E-05 is scientific notation for 0.00001.

³⁶ This is similar to the range of 0.91-1.12 ton/MWh calculated using the CO₂ emissions rate of 206.7 lb/MMBtu for Southwest mid-sulfur bituminous coal, as reported in EIA’s Assumptions to AEO2007 (p. 138).

The CPUC's assumed \$8.00/ton CO₂ is used to establish the minimum Value of Avoided CO₂ Emissions.³⁷ The maximum price per ton of CO₂ is more difficult to assess, with the European prices mentioned above being the only real source of existing market data. If the maximum European price of €35/metric tonne is converted to \$/ton using a historical range of \$0.85-\$1.35/€, the resultant range of CO₂ emissions allowance prices is \$27.00-\$41.87/ton CO₂.

In terms of carbon, rather than of CO₂, the CPUC's required use of \$8/ton of CO₂ in the IRP process is the equivalent of \$29.33/ton of carbon. This is in contrast to the \$100/ton of carbon assumed in Duke, *et al.*, p. 9, which is the equivalent of \$27.27/ton of CO₂. If a cost of \$100/ton of carbon is applied to range of avoided CO₂ emissions of 0.04-0.71 ton/MWh, the associated Value of Avoided CO₂ Emissions ranges from \$1.09-\$19.36/MWh, equivalent to 0.109-1.936 cents/kWh. Multiplying the \$8/ton CO₂ times the same range of avoided CO₂ emissions results in a range of Value of Avoided CO₂ Emissions from \$0.32-\$5.68/MWh, equivalent to 0.032-0.568 cents/kWh. Combining these results yields a range of electric-only value of 0.032-1.936 cents/kWh. Adding the range of Value of Avoided CO₂ Emissions from fuel cell cogeneration of 0.08-0.27 cents/kWh yields a total Value of Avoided CO₂ Emissions of 0.11-2.21 cents/kWh.

Value of Health Benefits of Avoided In-State Emissions – Lutter, *et al.*, conclude (p. 11) that “[a]vailable data suggest that cutting power plants’ mercury emissions may reduce cases of subtle and mostly imperceptible neurological effects among children at a cost on the order of \$150,000 per case avoided. Other health and environmental benefits appear negligible.” No attempt is made to estimate a California-specific health benefit from mercury emissions reductions in this analysis for two reasons. First, the estimate made by Lutter, *et al.*, is a national average estimate, with no state-specific breakdown of data provided. Second, the avoided baseload coal generator is assumed to be located outside of California, so any health benefits related to mercury removal would benefit Californians only indirectly.

By far the largest contributor to the Value of Health Benefits of Avoided In-State Emissions is reductions in particulate matter, particularly reductions in particulate matter less than 2.5 microns in diameter (“PM2.5”). PM2.5 emissions are a subset of particulate matter less than 10 microns in diameter (“PM10”), but PM2.5 emissions are more damaging to health because they lodge deeper in the lungs, and cannot readily be coughed out.

PM2.5 emissions are estimated at 90% of PM10 emissions in the electricity generation sector, based on the statewide estimated annual average emissions published by the California Air Resources Board (“CA ARB”) for calendar year 2000 for electric generation and cogeneration (*See* CA ARB, 2001). Calendar year 2000 emissions levels were used to correspond to California-specific calculations of the health-related economic value of reducing PM2.5 and PM10 emissions. (*See* Hall, 2006; Cal EPA/CA ARB,

³⁷ The E3 Avoided Cost Study (p. 79) uses a cost estimate of \$0.004/lb of CO₂, which is the equivalent of the \$8/ton of CO₂ penalty applied in the CPUC's Integrated Resource Planning process.

2002; Cal EPA/CA ARB, 2003; Cal EPA/CA ARB, 2006.) Combining results from these sources, the Value of Health Benefits of Avoided In-State Emissions for PM_{2.5} ranges from 1.91-2.09 cents/kWh and the additional value for avoided >PM_{2.5}-PM₁₀ emissions is 0.40-0.41 cents/kWh, including the health benefits of avoided digester gas flare emissions.

The health benefits of reduced NO_x and SO₂ power plant emissions on a cents/kWh basis are derived using the results of an extensive study by Abt Associates (Abt Associates, October 2000).³⁸ The Abt Associates study provides both nationwide and state-specific estimates of health benefits in terms of avoided incidences of mortality, hospitalizations, and various categories of illness. These estimates were used to calculate the value of California-specific benefits based on the proportion of California-specific avoided health-related incidences to nationwide totals. (See Abt Associates, Exhibits 6-2 and 6-7.) The California-specific estimates here are derived using a methodology similar to that used to estimate the health benefits of avoided emissions due to distributed solar photovoltaics in New Jersey (Hoff and Margolis, 2003).

Total California health benefits as derived from the Abt Associates study were divided by 75% of California's total 1997 NO_x and SO₂ power plant reductions to arrive at a value of \$1.02/lb (1999\$) of reduced emissions.³⁹ The \$1.02/lb (1999\$) of reduced emissions was inflated to 2007\$ and then converted to cents/kWh using estimated NO_x and SO₂ emissions rates from the Updated E3 Electric Avoided Costs Workbook for the heat rate range of 8,087-9,100 Btu/kWh for the average California natural gas-fired plant. Estimated NO_x and SO₂ emissions rates for the baseload coal-fired generator plant were obtained from the literature, and applied to the heat rate range of 8,844-10,875 Btu/kWh. The Value of Health Benefits of Avoided In-State Emissions for avoided NO_x and SO₂ emissions ranges from 0.034-0.037 cents/kWh, including the health benefits of avoided digester gas flare emissions and avoided boiler emissions in the appropriate proportions.

The Total Value of Health Benefits is 2.34-2.54 cents/kWh, which includes the values for avoided PM_{2.5}, PM₁₀, NO_x and SO₂.

G. JOB CREATION POTENTIAL

Value of Job Creation Potential – Every megawatt of installed fuel cell capacity generates immediate local employment opportunities for the initial installation of the fuel cells and for the ongoing maintenance and service requirements. In addition, because fuel cells are costly to ship, as the market for fuel cells in California grows, at some point

³⁸ A summary of the Abt Associates study can be found in the October 2000 Clean Air Task Force report.

³⁹ A 75% reduction in NO_x and SO₂ was the underlying assumption in the health benefits calculated in the Abt Associates study. A 75% reduction in total 1997 California electricity utility emissions as reported by EIA was used to calculate the \$/lb value, based on the total California-specific health benefits derived from the Abt Associates study. (See EIA, Electric Power Annual, Table 5.1.)

it will likely become economic for fuel cell manufacturing, assembly, and remanufacturing facilities to be built in California.

The Value of Job Creation Potential related to installation and ongoing maintenance of fuel cells in California is estimated to range from 0.11-0.26 cents/kWh. This range is based on the following set of assumptions:

- California represents 1/3rd of the total U.S. market for fuel cells.
- Labor represents 25% of the total installed cost of fuel cells.
- Installation of a fuel cell requires three full-time workers to work for three weeks, for a total of 360 hours.
- Ongoing maintenance of a fuel cell requires 1/4th as much labor as the initial installation (90 hours per year).
- The average labor cost is \$90/hour.

Although more speculative, the additional Value of Job Creation Potential due to fuel cell companies building manufacturing capacity in California could in the longer term add another 1.93 cents/kWh (in 2007\$), based on the following assumptions:

- Manufacturing plants with 40 MW per year of manufacturing capacity will be added once the annual volume of fuel cells installed in California reaches twice that size.
- Each MW of manufacturing capacity adds 8 new jobs (direct job creation; no estimate of new jobs created as an indirect result of the new manufacturing capacity has been made).⁴⁰
- The average labor cost for manufacturing production workers is \$45/hour.

The value of these economic benefits is purposefully conservative. The Value of Job Creation Potential could be significantly higher, given its dependence on the specific types of jobs created, local wage rates, and the actual growth of the fuel cell market in California.

H. ADDITIONAL VALUES

Value of Deployment Ease and Speed – Fuel cell systems can be sited and installed in a relatively short period of time given available land and equipment. The carrying costs associated with the lead times necessary for siting, permitting and constructing a central generating station are largely avoided. Low emissions (as discussed in detail above) and quiet operation mean that fuel cell systems can be rapidly deployed with minimal to no “greenfield” or unmanageable “NIMBY” impact. The value created through fuel cell modularity is especially dependent on the localized circumstances and difficult to quantify in average terms. In much of California, as is true in much of the United States,

⁴⁰ Based on a March 7, 2006 press release by the Ohio Department of Development related to Governor Taft’s Third Frontier Fuel Cell Program (TFFCP) indicating the creation of 200 new jobs for a 25 MW fuel cell manufacturing facility.

opposition to new infrastructure usually results in opponents availing themselves of the full suite of administrative remedies to thwart or delay investment. No specific estimate of this value is provided since the Value of Deployment Ease and Speed may vary significantly for each fuel cell project site.

Other Values - The estimated values in the “Build-Up of Fuel Cell Value in California” are not all-inclusive, and do not reflect many of the distributed value elements identified in the PLEASE matrix in Attachment B. Among those distributed value elements not included because they are difficult to quantify are the visibility impact due to reduced emissions, the impact on local control of resources, and the impact on responsiveness to load growth due to their modularity.

V. COMPARISON OF AVOIDED EMISSIONS ACROSS TECHNOLOGIES

The avoided proxy plant emissions for fuel cells (as calculated above) are compared against the avoided emissions for electricity generated using solar photovoltaics (“PV”) and wind. PV and wind have no fuel input and, consequently, no emissions; all proxy plant emissions are avoided by these two generating technologies. For the same reason, however, PV and wind receive no emissions-related credit for either digester gas use (*i.e.*, avoided flare emissions) or cogeneration (*i.e.*, avoided boiler fuel).

Wind generation typically occurs in remote locations that require full use of the grid, with all of the related losses. As is the case for fuel cells, PV tends to be a distributed energy resource that avoids the losses related to use of the electrical grid. Thus, the avoided emissions per kWh will be higher for PV than for wind by the percentage of grid-related losses (assumed to be 6% in this analysis).

Attachment D presents two graphical comparisons of *avoided* emissions for fuel cells, PV, and wind. The top graph compares the avoided emissions per MWh of electricity generated by each of the three technologies. As expected, *avoided* emissions are greater for distributed PV than for wind in all cases. However, *avoided* emissions of NO_x and PM10 are greatest for fuel cells because of (i) fuel cell use of digester gas and (ii) cogeneration.

The bottom graph in Attachment D compares the annual avoided emissions for the three technologies per MW of installed capacity. As discussed previously, fuel cells are a baseload technology with an annual capacity factor of 91%. Conversely, PV generates electricity only when the sun is shining and wind, when the wind is blowing. Such intermittent resources have a much lower annual capacity factor than that of fuel cells, averaging 20% for PV⁴¹ and 25% for wind resources⁴² in California. *The significant*

⁴¹ The SGIP Fifth-Year Impact Report reported (p. 5-5) that: “Level 1 PV projects had capacity factors that ranged from approximately 12% to slightly over 20%.”

⁴² The 25% capacity factor is taken from the CEC’s “Wind Performance Summary 2002-2003” (Fig. 5-3, p. 21). Monthly capacity factors for wind as reported in the SGIP Fifth-Year Impact Report were less than 25% in all months (Fig. 5-2, p. 5-5.)

difference in capacity factors results in a somewhat counterintuitive outcome: Per installed MW of capacity, fuel cells have greater avoided emissions per year across the board than either PV or wind.

VI. INDUSTRY DATA INPUT

In addition to the detailed cost and performance data, data on projected fuel cell penetration in California for the next 15 years was obtained from four of the five participating organizations actively manufacturing or developing stationary fuel cells for baseload electricity generation. In addition, each company provided information on its anticipated level of participation in each of the following five market segments:

- Distributed Generation with Waste Heat Recovery: Customer-sited, with waste heat recovery for cogeneration or CCHP applications.
- 24/7 Renewable Fuel Power Generation with Waste Heat Recovery: Baseload electricity generation using renewable fuel, with waste heat recovery for cogeneration or CCHP applications.
- Cogeneration of Hydrogen: Sited at or near locations needing hydrogen feedstock (e.g., refineries, chemical facilities, refueling stations), with the ability to change the ratio of electricity and hydrogen generated as dictated by demand.
- Advanced Fuel Cell/Gas Turbine Power Generation: Large-scale “hybrid” generation systems that combine fuel cells and gas turbines to maximize the efficiency of electricity-only generation.
- Utility Procurement: Relatively larger-scale installations, with targeted locations at utility substations.

Projections of future installed MW of fuel cells for each company were aggregated year-by-year and market segment-by-market segment. The five companies in aggregate projected that the total installed MW of stationary fuel cell capacity in California would grow from its current level of 18 MW to over 3200 MW by 2020, assuming that current incentive levels were continued over the long term. This penetration level is in line with estimates provided in the CEC’s November 2005 Staff Report entitled “Assessment of California Combined Heat and Power Market and Policy Options of Increased Penetration,” as shown in the calculations provided in Attachment E.

VII. MARKET SEGMENT VALUATION DETAIL

The 18 MW of stationary fuel cells currently installed in California serve the first two market segments (described in Section V above) in an approximate 3:1 ratio. Over time, because of the value of their exhaust heat, distributed fuel cells with cogeneration will continue to dominate the market over time, fueled up to 30% with renewable digester gas.

As the Advanced Fuel Cell/Gas Turbine Power Generation hybrid technology approaches commercialization, its focus will be on using the energy in the exhaust heat to generate increased amounts of electricity only, thus achieving even greater electrical efficiencies. These hybrid units will tend to be larger scale, with capacities ranging upward from 1 MW; their 2020 market share is anticipated to exceed 5%. Electric-only fuel cell units of all types will increasingly target utility customers, with the Utility Procurement market segment anticipated to grow to over 15% of the total California market for stationary fuel cells by 2020.

The Cogeneration of Hydrogen market segment will develop in parallel with the other market segments, with its ultimate market share dependent on the speed at which California's "Hydrogen Highway" develops. Refinery and other industrial demand alone would limit the Cogeneration of Hydrogen market share in 2020 to less than 5% of California's total stationary fuel cell market.

Attachment F illustrates what percentage of the total value of fuel cells in California each of the five market segments identified above could contribute by 2020, based on input from fuel cell manufacturers.

VIII. NATURAL GAS SAVINGS

The dominance of the Distributed Generation with Waste Heat Recovery market segment, approximately half of which is fueled using digester gas, creates the added benefit of reducing California's natural gas consumption.

As described above, this analysis assumes that 30% of fuel cells operate using digester gas and that 60% of fuel cells capture waste heat for cogeneration or CCHP applications.⁴³ Assuming that 3200 MW of installed stationary fuel cell capacity in California is achieved by 2020:

- The total annual natural gas savings for California would be 136,000,000 MMBtu.
 - Enough natural gas to generate 15,000 GWh of electricity.
 - Enough electricity to satisfy 2.3 million homes in California.
 - Equivalent to 23 million barrels of oil.
- Total CO₂ reductions would be 4.1 million metric tonnes.
 - Equivalent to 674,000 acres of forest.

⁴³ Note that these percentages may overlap and thus are not additive, since fuel cells that operate on digester gas typically also cogenerate heat or steam.

IX. CONCLUSIONS

As demonstrated throughout this paper, fuel cells provide significant value to California's ratepayers today, as measured in terms of both benefit-cost ratios and avoided costs. As fuel cell installed capacity and penetration rates increase throughout the state, the value provided to California's ratepayers through cogeneration, digester gas use, avoided central station generation, and the associated avoided emissions will grow significantly. Fuel cells have the potential to make a significant contribution to meeting the state's AB32 GHG reduction goals while adding ratepayer value in many different respects.

X. ACKNOWLEDGEMENTS

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Attachment A

FUEL CELLS: TECHNOLOGY AND GENERAL ATTRIBUTES

INTRODUCTION

Fuel cells can be made to suit a wide variety of applications or market sectors, including stationary, transportation and portable applications. This study addresses fuel cells for stationary applications. Stationary applications include baseload power for the needs of utilities, commercial buildings, government and military complexes, large institutional, medical and industrial centers and a host of others. To serve these applications, systems ranging in capacity from several hundred kilowatts to multi-megawatts are now available and larger systems are being developed.

In its most basic form a fuel cell is an electrochemical device in which a fuel and an oxidant are combined to produce electricity and heat. With two electrodes separated by an electrolyte, a fuel cell is similar to a battery, except that it will not run down as long as fuel and air are supplied. To generate useful quantities of electricity, individual cells must be connected together in series to build voltage, and the size and number of cells in a cell stack or module will determine its electric generating capacity. Because the conversion of the fuel to electrical energy takes place electrochemically, without combustion, the process is highly efficient, clean and quiet. Perhaps confusingly, the term “fuel cell” can refer to an individual cell itself, to a cell stack, to a module consisting of a number of cells, or to the entire electrical system.

While the basic principles of all fuel cells are the same, the electrolytes, conducting ions and operating temperatures differ greatly between fuel cell types. Five major types of fuel cells have been (or are being) developed, generally identified according to the type of electrolyte used. In ascending order of operating temperature, the five major types of fuel cells are: (1) Alkaline (“AFC,” ~70°C); (2) Proton Exchange Membrane (“PEMFC,” ~80°C); (3) Phosphoric Acid (“PAFC,” ~200°C); (4) Molten Carbonate (“MCFC,” ~650°C); and, (5) Solid Oxide (“SOFC,” 800-1000°C). With some exceptions, higher temperature fuel cells (*i.e.*, PAFC, MCFC, and SOFC) tend to be better suited to larger applications, while lower temperature systems (*i.e.*, AFC and PEMFC) are considered better suited to smaller applications.

FUEL FLEXIBILITY

While the ideal fuel for a fuel cell is a simple molecule such as hydrogen, hydrogen is not widely available, especially in amounts suitable for power generation. Consequently, natural gas is the most widely used fuel for fuel cells, given its wide availability and the fact that hydrogen can be extracted from it with relative ease. Renewable fuels such as digester gas from wastewater treatment plants, landfill gas, and biofuels in general are also attractive fuels for fuel cells, as is propane; these fuels extend the range of fuel cells

to areas where natural gas is not available. Fuel cells having higher operating temperatures thrive on these less hydrogen-rich fuels and thus have an advantage with respect to fuel flexibility over fuel cells that require very pure hydrogen.

HOW A FUEL CELL OPERATES

Typically hydrogen, or in the case of some fuel cells, a mixture of hydrogen and carbon monoxide (“CO”), is fed into the anode of the fuel cell. Air carrying the oxygen enters the fuel cell at the cathode. In a high temperature fuel cell, the oxygen easily splits into two streams: oxygen ions and electrons. (Low-temperature fuel cells usually require a platinum-based catalyst to encourage formation of the oxygen ions.) The oxygen ion stream passes through the electrolyte and seeks a hydrogen molecule to form water (“H₂O”), or a CO molecule to form carbon dioxide (“CO₂”). The electron stream is the useful stream, and is created once an external circuit is provided, forming an electric current. This electric current can be utilized before the electrons return to the cathode to keep the fuel cell’s electrochemical process going. An overview of the entire electrochemical process is illustrated below in Figure A-1.

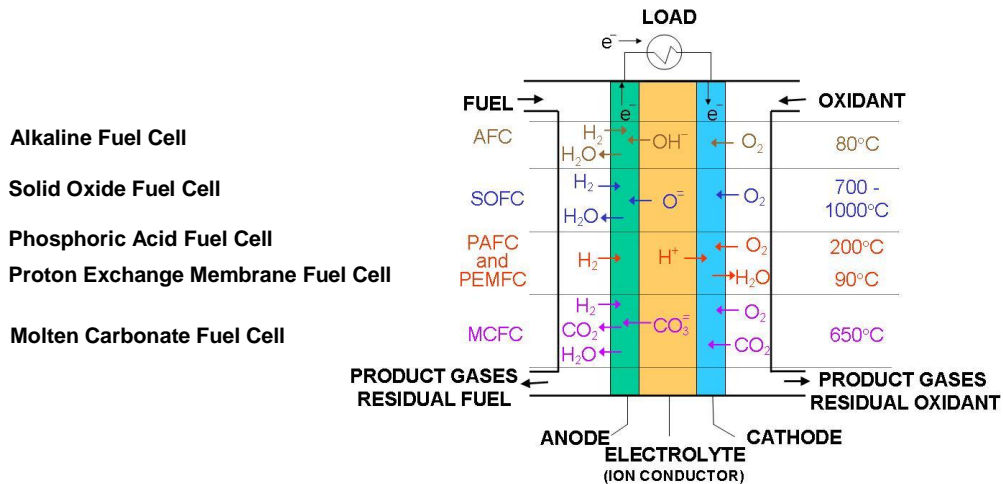


Figure A-1. Types of Fuel Cells

EFFICIENCY

The efficiency of stationary fuel cells encompasses both the generation of electrical power and the cogeneration of a thermal product. The thermal product can be used for either heating or cooling. This attribute is referred to as “Combined Cooling, Heating, and Power” or “CCHP.”

Electrical Efficiency – Electrical efficiency is a measure of how well fuel input is converted to electrical power. The higher the electrical efficiency, the lower the amount of fuel input required per kilowatt-hour (“kWh”) of electricity generated. High electrical efficiency is an important benefit of fuel cells from the viewpoints of both the cost of operation and environmental impact.

Fuel cells have demonstrated lower heating value (“LHV”) electrical efficiencies as high as 48% when operating as simple cycle systems, and as high as 55% (LHV) when operated as hybrids in combination with other systems such as gas turbines.¹ Now in the early stages of development, fuel cell hybrids have the potential to achieve an electrical efficiency in excess of 70% (LHV), a level that is impossible to achieve by conventional electricity generating technologies. Since the amount of CO₂ generated *per kWh of electricity produced* is inversely proportional to the electrical efficiency, fuel cells with their higher electrical efficiency emit less CO₂ (a greenhouse gas) than other electricity generating technologies using the same fuel. Further, with the ability of fuel cells to achieve such a high electrical efficiency, the ability to further reduce CO₂ emissions from electricity generation is inevitably tied to the development of fuel cell hybrids.

CCHP Efficiency – In addition to generating electrical power, the stationary fuel cell can cogenerate a thermal product. The strategy is to capture and utilize the heat produced by the fuel cell for the provision of heat, hot water, steam, or cooling (using, for example, an absorption chiller). This will result in the fuel cell’s overall efficiency (electrical power generation and use of the captured thermal energy) reaching and exceeding 80% (LHV). This attribute displaces the fuel and emissions that would be associated with boilers (in the case of using the thermal energy as heat), and the displacement of electricity to drive chillers (in the case of using the thermal energy for cooling). The resultant effect is to dramatically reduce CO₂ emissions, criteria pollutant emissions, and the demand on fuel resources.

ENVIRONMENTAL IMPACT

A second major benefit of fuel cells is their low environmental signature. This is due in part to the reaction chemistry. Fuel cells are driven by electrochemistry versus high-temperature combustion chemistry. As a result, fuel cells emit only trace amounts of NO_x. Because fuel cells are intolerant of sulfur, the fuels used have to be desulfurized, and thus fuel cells emit essentially no SO_x. Thus fuel cells produce essentially no acid rain pollutants, a key advantage over conventional power generation technologies. Additionally, because fuel cells use gaseous fuels, they emit no particulates, and because they completely oxidize the fuel, there are no unburned hydrocarbons. If the fuel input is hydrogen, then only water vapor is generated in the exhaust. On the other hand, if the fuel is natural gas or another hydrocarbon fuel, then carbon dioxide is also generated. As explained above, because of the high electrical efficiency of fuel cells, the amount of CO₂ emitted per kWh of electricity generated is lower than from conventional power

¹ Electrical efficiency can be reported relative to either the LHV or higher heating value (“HHV”) of the fuel. LHV is standard for natural gas-fueled systems and represents the typical case where the water in the effluent is exhausted in the gaseous state. In contrast, HHV corresponds to the case where the water in the exhaust is condensed and the latent heat of vaporization is retained in the cycle. As a result, a fuel’s heat content expressed in HHV units exceeds its heat content expressed in LHV units. Conversely, for any given fossil fuel, efficiency expressed in LHV units exceeds efficiency expressed in HHV units. For natural gas, efficiency expressed in LHV units is approximately 10% greater than electrical efficiency expressed in HHV units.

generation technologies of comparable size. In addition to electric power generation, the ability of fuel cells to capture and use the thermal energy further reduces the amount of CO₂ emitted.

FUEL CELLS FOR STATIONARY APPLICATIONS

Within the stationary power market, different types of fuel cells are better suited to serve different market segments, based on size and customer needs (especially for heat and/or cooling), fuel availability, *etc.*

PAFCs, MCFCs, and SOFCs are well suited for continuous, baseload generation of electricity and heat for the following reasons:

- Highest electrical efficiency of any comparable-sized system
- Lowest environmental impact of any power generation system using similar fuels
- Amenable to operation on natural gas, industrial waste hydrogen, digester gas and other biofuels fuels; do not need pure hydrogen
- High quality power produced
- Ease of siting at or near the point of use
- Unattended operation, low maintenance, high availability
- Minimal licensing, permitting and installation time
- Some are air-cooled, most need limited water during normal operation
- Cogeneration (with options for chilled water, steam) or electric-only options.

PEMFCs are well suited for backup power and intermittent power demand (*e.g.*, peak load shaving) for the following reasons:

- Lowest environmental impact of any power generation system using similar fuels
- High quality power produced
- Ease of siting at or near the point of use
- Unattended operation, low maintenance, high availability
- Readily turned on and off as required on demand
- Minimal licensing, permitting and installation time.

The heat available from fuel cells for cogeneration or CCHP applications is an important aspect of fuel cell economic viability, and most stationary fuel cells will have a cogeneration or CCHP application.²

² The study assumes that 60% of installed fuel cell capacity in California captures waste heat for cogeneration (*e.g.*, CCHP use).

Attachment B

“PLEASE” MATRIX OF DISTRIBUTED VALUE ELEMENTS

(* Indicates inclusion in “Build-Up of Fuel Cell Value in California”)

POLITICAL	LOCATIONAL	ENVIRONMENTAL	ANTIDOTAL Hedge against:	SECURITY	EFFICIENCY (Market, Technical)
Impact on local control of resources	Impact on local tax base	“Renewable energy credits” and “green certificates” impact	Fossil fuel price volatility*	Impact on likelihood of system outages*	Impact due to combined cooling, heating & power (CCHP) configuration*
Impact on “political capital”	Land use impact (e.g., T&D line rights of way)	Impact on NO _x and SO _x emissions levels*	Future electricity price volatility	Impact on supply diversity	Impacts on competition & market power mitigation
Impact on achieving RPS goals	Impact on local property values	Impact on PM10 emissions level*	Utility power outages*	Impact on power quality*	Impact on project carrying cost
	Noise level impact	Impact on CO ₂ emissions level	Utility load forecast uncertainty	Impact on utility grid VAR support*	Impact on decision making time required
	Impact on NIMBY-BANANA-NOPE-attitudes	Impact on other emissions levels (e.g., VOCs, mercury)*	Uncertain reserve % requirements	Impact on likelihood & severity of terrorist attacks	Impact on project installation time (due to modularity)
	Impact on local economic activity (e.g., job creation)*	Impact on material input (e.g., solar panels replace some roofing)	Wheeling costs	Impact on domestic fossil fuel use*	Impact on # of available supply options (as DG markets & technologies mature)
	Ability to impact urban load pockets	Healthcare cost impact related to emissions level changes*	Future changes in environmental regulations	Impact on fossil fuel import reliance	Impact on responsiveness to load growth (due to modularity)
	Ability to impact suburban load pockets	Visibility impact due to emissions impact	Site remediation costs (current and future)		Impact on permitting time and cost
	Ability to impact rural or remote loads	Impact on urban “heat islands” (e.g., shading ability)			Impact on operating life of grid components
	Impact of DG fuel delivery system	Impact on consumptive water use*			Impact on resale or salvage value of equipment
	Visual impact	Impact on water & soil pollution levels			

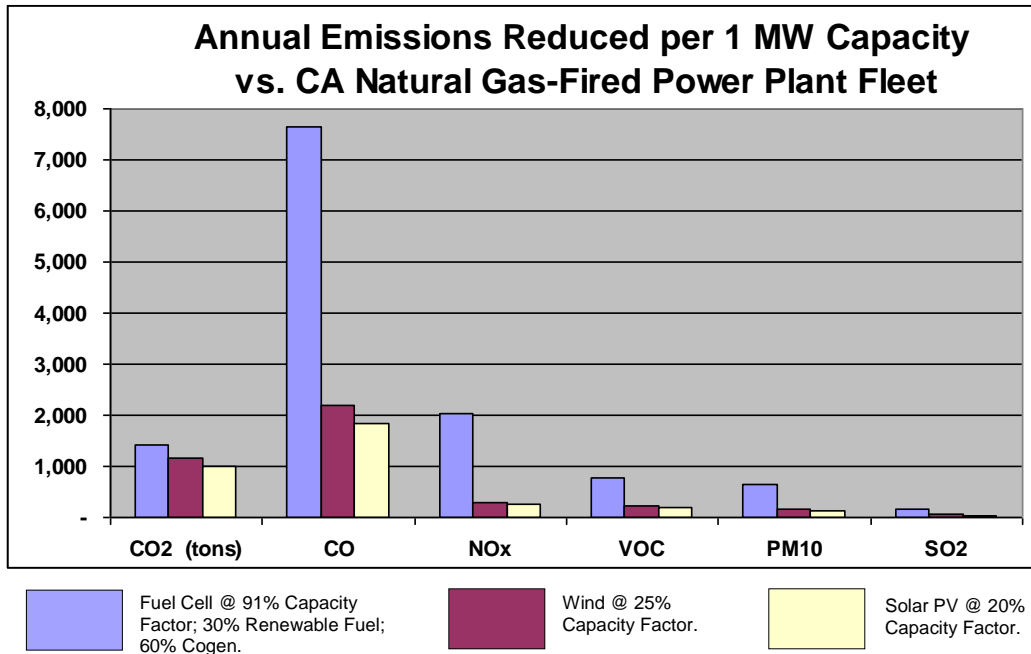
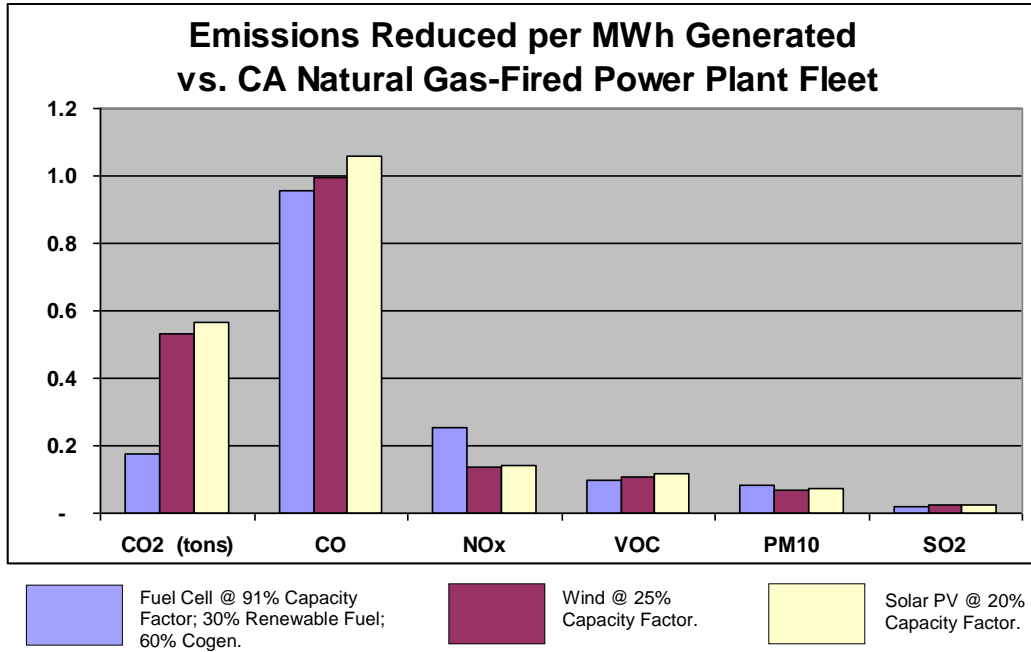
Attachment C

ASSUMPTIONS AND RESULTS FOR AVOIDED EMISSIONS AND RELATED VALUE OF HEALTH BENEFITS

	Heat Rate Range (Btu/kWh)	Emissions Rate (CO ₂ in tons/MWh; all others in lb/MWh)						
		NO _x	SO ₂	PM10	CO	VOC	Mercury	CO ₂
Fuel Cells	8,343	0.06	0.005	-	0.10	0.02	-	0.49
	8,060	0.01	0.001	-	0.10	0.02	-	0.46
Average CA Natural Gas-Fired Generator	9,100	0.14	0.025	0.074	1.06	0.12	-	0.56
	8,087	0.11	0.022	0.067	0.94	0.10	-	0.50
Pulverized Coal-Fired Generator	10,875	0.85	1.730	0.350	0.22	0.03	3.39E-05	1.20
	8,844	0.69	1.406	0.280	0.18	0.02	2.76E-05	0.97
Emissions Prices								
		NO _x	SO ₂	PM10	CO	VOC	Mercury	CO ₂
	In-State:	(\$/lb/day)	(\$/lb/day)	(\$/lb/day)	(\$/lb/day)	(\$/lb/day)	(\$/lb)	(\$/ton)
	Maximum	\$356,164	\$163,014	\$261,189	\$8,337	\$295,890	\$35,000	\$27.27
	Minimum	\$ 25,000	\$ 40,000	\$ 80,000	\$4,214	\$ 5,000	\$ 5,000	\$ 8.00
	Out-of-State:	(\$/ton)	(\$/ton)	(\$/ton)	(\$/ton)	(\$/ton)	(\$/lb)	(\$/ton)
	Maximum	\$ 7,500	\$ 1,650	\$ 2,000	n/a	\$ 2,000	\$35,000	\$27.27
	Minimum	\$ 500	\$ 100	\$ 2,000	n/a	\$ 2,000	\$ 5,000	\$ 8.00
Fuel Cells: Value of Avoided Emissions (cents/kWh)								
		NO _x	SO ₂	PM10	CO	VOC	Mercury	CO ₂
	Maximum	0.99	0.14	0.22	0.10	0.345	0.12	2.21
	Minimum	0.06	0.01	0.03	0.01	0.002	-	0.11
Fuel Cells: Value of Health Benefits of Avoided Emissions								
		NO _x & SO ₂	PM10	PM2.5*	* PM2.5 emissions make up 98% of the PM10 emissions category by weight, per California Air Resources Board 2000 Emissions Inventory.			
	Maximum	0.037 ¢/kWh	0.41 ¢/kWh	2.09 ¢/kWh				
	Minimum	0.034 ¢/kWh	0.40¢/kWh	1.91 ¢/kWh				

Attachment D

COMPARISON OF AVOIDED EMISSIONS FOR FUEL CELLS, SOLAR PV, AND WIND: PER MWH vs. ANNUAL PER INSTALLED MW



Attachment E

ALTERNATE DERIVATION OF 3200 MW OF INSTALLED FUEL CELL CAPACITY IN CALIFORNIA IN 2020

CEC Aggressive Market Access Scenario, Total On-Site CHP MW:	4,471	MW		
CEC Aggressive Market Access Scenario, Total Export CHP MW:	<u>2,869</u>	MW	64%	= Export as % of On-Site CHP
CEC TOTAL On-Site and Export CHP MW (All Technologies):	7,340	MW		
CEC Aggressive Mkt Access Scenario, Total On-Site CHP MW (Fuel Cells Only):	1,101	MW		
Industry Estimate, Total Export CCHP MW (Fuel Cells Only):	<u>551</u>	MW	50%	= Export as % of On-Site CCHP
TOTAL CEC On-Site and Industry Estimate Export CHP MW (Fuel Cells Only):	1,652	MW		
% CCHP of Total Fuel Cell Installed MW in California (Industry Estimate):	60%			
Grossed Up for All Fuel Cell Installed MW (CCHP and Non-CCHP):	2,753	MW		
# of Projects >5 MW (Industry Estimate; "0" in CEC Report):	98	Projects		
Installed Capacity Assuming 5 MW for Each Project >5 MW:	490	MW		
TOTAL On-Site and Export CCHP and Non-CCHP MW (Fuel Cells Only):	3,243	MW		

Sources of Data:

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Attachment F

**2020: CONTRIBUTION TO FUEL CELL VALUE IN CALIFORNIA,
BY MARKET SEGMENT**

