Build-Up of Distributed Fuel Cell Value In California: 2011 Update Background and Methodology

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I. EXECUTIVE SUMMARY

This paper examines the value to California residents of a broad introduction of stationary fuel cells into the State of California, based on an updated analysis of a similar study by the California Fuel Cell Manufacturers Initiative published in 2008. This updated analysis examines only stationary fuel cells to be used in distributed electricity generation markets, ranging in size from several hundred kilowatts ("kW") to several 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. A brief summary that compares the results of this updated analysis to those of the original study can be found in Attachment A.

Stationary fuel cells contribute significant value to ratepayers and the State of California by providing on-site combined cooling and/or heating and power ("CCHP") to host customers distributed across the State. This value can be quantified by comparing the attributes of distributed electricity generated using the fuel cell's electrochemical process against the attributes of central station electricity that is generated by combusting fossil fuel at larger plants in more remote locations. This analysis was performed to update the value of distributed fuel cells in California by quantifying many of the benefits attributed to fuel cells through avoided central station electricity generation, avoided transmission and distribution use, added grid support, avoided emissions and related health benefits, and increased job creation potential.

A representative fuel cell 300-1400 kilowatts in size, fueled 100% with natural gas, and operated in CCHP mode 75% of the time ***today*** contributes up to 20.1 cents of value per kilowatt-hour ("kWh") of fuel cell electricity generated based on the ***avoided costs*** of central station electricity generation. This value increases to 27.4 cents per kWh ("cents/kWh") if that same fuel cell is fueled primarily with renewable digester gas, with natural gas as backup fuel only.[1] With only 22 MW of fuel cell capacity installed in California at the end of 2010, out of a total annual peak load of over 50,000 MW, fuel cells currently provide only about 0.06% of California's electricity consumption. With the increased penetration of distributed fuel cells over time, both the amount of electricity

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[1] A variety of fuel cell products are offered in California to address the stationary distributed generation market, ranging in size from 100 kW to 2800 kW in nominal rating. The calculated values in this analysis are based on specific models (ranging from 300 kW to 1400 kW nominal rating and including phosphoric acid and molten carbonate fuel cell technologies) as representative of this range of fuel cell products. Attachment B to this updated analysis provides a brief description of different types of fuel cells and Attachment H provides a summary of the representative fuel cell's assumed operating characteristics.

provided by fuel cells and the cents/kWh value will increase, together dramatically increasing the total value of distributed fuel cells to California.

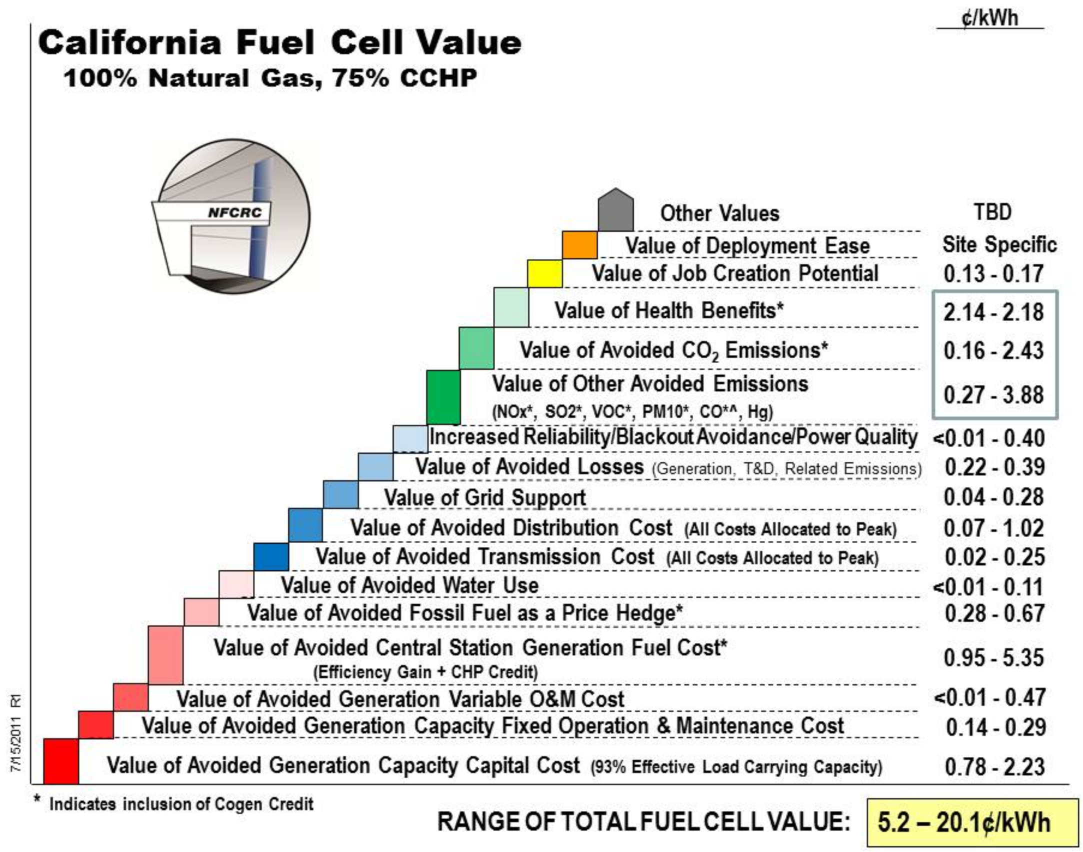

Figure 1. California Fuel Cell Value: 100% Natural Gas, 75% CCHP Mode

As seen in Figure 1, the most significant value in the 100% natural gas use case comes from the value of avoided emissions and related health benefits, which in aggregate contribute 2.57-8.49 cents/kWh of fuel cell electricity generated. This aggregate value is followed in size by the Value of Avoided Central Station Generation Fuel Cost at 0.95-5.35 cents/kWh. This value results from the high overall system efficiency achieved from the capture and use of waste heat when the fuel cells are operating in CCHP mode. Operating in CCHP mode results in the sequential generation of at least two products, typically electricity and thermal energy (in the form of hot water or steam), though the thermal energy may also be used for chilling through the use of absorption chillers.[2]

[2] The CCHP acronym and the term "cogeneration" are used interchangeably throughout this paper; both refer to the capture and use of waste heat to generate another product in addition to generating electricity. Whether the cogenerated product is used for cooling or heating will be application-specific. The CCHP acronym is used rather than the more common CHP acronym to include a broader range of possible uses for the waste heat.

Figure 2 (below) illustrates the build-up of the 6.3-27.4 cents of value contributed by the same representative fuel cell if it is operated 75% of the time on renewable digester gas (25% on natural gas) and in CCHP mode 75% of the time. All of the values in Figure 2 are impacted by the cost of digester gas cleanup equipment and its associated parasitic electric load. Figure 2 clearly shows the 80-90% increase in the Value of Avoided Central Station Generation Fuel Cost to 1.70-10.28 cents/kWh, as renewable digester gas for fuel cell generation displaces much higher cost natural gas for central station generation. Additional value accrues to the aggregate value of avoided emissions and related health benefits (2.93-10.42 cents/kWh) as renewable digester gas is cleaned up and used as fuel for low-emission fuel cell generation, rather than being flared (or vented) to the atmosphere.

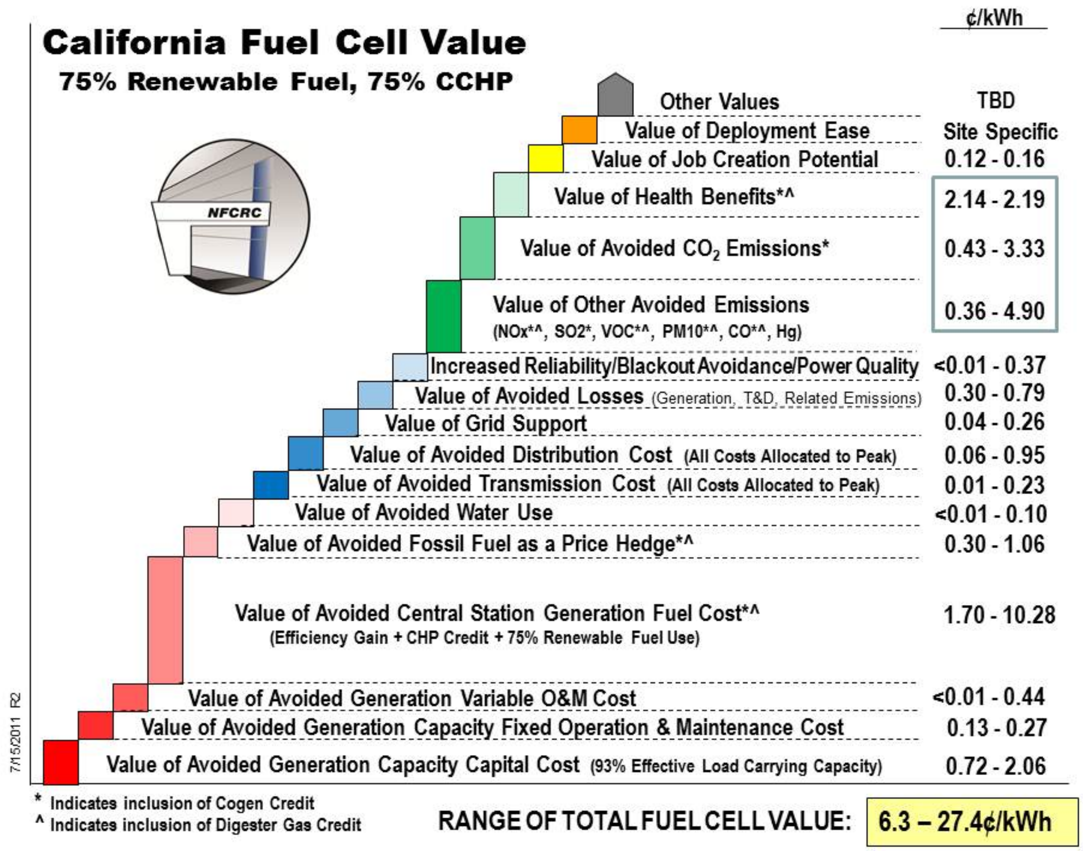

Figure 2. California Fuel Cell Value: 75% Renewable Fuel, 75% CCHP Mode

Figures 1 and 2 present values assuming 75% CCHP mode operation for two different fuels. A sensitivity analysis presented in Section IV.E demonstrates that the total value proposition of stationary fuel cells in California in Figures 1 and 2 would increase by 11-16%, respectively, if the representative fuel cell were to operate in CCHP mode 100% of the time.

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.

The categories of avoided costs in the "California Fuel Cell Value" "waterfall" graphs illustrated in Figures 1 and 2 depict a number of so-called "distributed value elements" that represent distributed generation technology attributes compared to a central electricity generating plant. The actual avoided costs values shown in Figures 1 and 2 reflect fuel cell-specific calculations for each distributed value element included in this study, some of which are quantified based on observable market prices of equipment, services, and other relevant factors, and some of which are quantified based on values derived from a broad-based literature search. Additional data on fuel cell technologies, economics, and underlying assumptions was obtained from the participating organizations. Each distributed value element quantified for fuel cells in Figures 1 and 2 is discussed in some detail later in this paper to enable the reader to understand the derivation of its value.

Some of the quantified attributes would have similar values for other distributed generation technologies, though the specific value of any given attribute may be technology-dependent (*e.g.*, value of avoided emissions). Some of the quantified attributes have higher values due to the technology-specific characteristics of fuel cells. When operating 100% on natural gas, stationary fuel cells provide value through their increased electrical efficiency and CCHP operating characteristics. When operating in CCHP mode, high-quality heat is recovered to displace grid electricity and/or natural gas for boiler fuel, thereby further reducing both significant amounts of fuel use and the concomitant emissions of carbon. This value contribution is significantly enhanced by the ability of stationary fuel cells to utilize renewable digester gas as fuel, thereby also avoiding digester gas flare emissions.

Technology-specific characteristics contributing to higher relative fuel cell value compared to other distributed generation technologies 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 and related health benefits
- Low acoustic signature
- Virtually zero emissions signature

- Low vibration.

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 fuel cell distributed value elements quantified in this study fall into the following four general categories, which are graphed from the bottom up and color coded by category in Figures 1 and 2: (i) Generation-related (avoided fixed and variable costs, including fuel costs), color coded in red hues; (ii) grid-related (increased reliability, avoided transmission and distribution costs), color coded in blue hues; (iii) avoided emissions and related health benefits, color coded in green hues; and, (iv) job creation potential, color coded in yellow. Many fuel cell value components are less affected by fuel choice than are the values associated with avoided fuel costs and avoided emissions and related health benefits discussed above. Working up from the base of each value build-up, these include:

- The avoided costs of the central station generator whose generation is assumed to be displaced by that of the fuel cells. The range of value is determined by the California Public Utilities Commission's 2009 Market Price Referent (”MPR”) proxy plant, which is an in-state, state-of-the-art natural gas combined cycle generator, and by the costs of a representative out-of-state coal-fired generator.

- Fuel cells provide value as a price hedge against the volatility of fossil fuel prices to the extent that fossil fuel use is avoided as a result of (i) the increased electrical efficiency of fuel cells, (ii) the increased use of digester gas, and/or (iii) the displacement of boiler fuel from CCHP operations. Although natural gas prices have come down significantly from their 2008 peak, they still exhibit significant volatility (though off of a lower base in recent years), and coal prices have shown a slow secular increase during the same time period.

- Fuel cells use little or no water, an increasingly important feature in regions of water scarcity and conservation measures, like California. The range of the Value of Avoided Water Use is determined by (i) the type of cooling assumed to be used by the displaced central station generating technologies, and (ii) the highly varied value/cost of water in different regions of the State.

- The 300-1400 kilowatt fuel cells considered in this avoided cost analysis are assumed to be located on-site, for the purpose of serving a host customer's electrical and thermal load. As distributed energy resources, these fuel cells displace grid-provided electricity, contributing additional value by avoiding the need for distribution and transmission capacity upgrades. This value is site specific, and the range of value illustrated in Figures 1 and 2 is based on estimated distribution and transmission costs in various regions served by California's three major investor-owned utilities.

- The Value of Grid Support is based on the fact that distributed energy resources, such as on-site fuel cells, reduce the need for ancillary services as they displace grid-provided electricity.

- The Value of Avoided Losses reflects the estimated 7.8% of grid-related transmission and distribution losses incurred as electricity is delivered to consumers from remote central station generators. These losses are avoided by distributed energy resources providing on-site electricity.

- The Value of Increased Reliability/Blackout Avoidance/Power Quality is based on the ability of distributed fuel cells to displace grid-delivered electricity during on-peak demand periods. This ability is assumed to be proportional to stationary fuel cell market penetration in California, which is (conservatively) expected to grow nearly twenty-fold by 2020, from a 2010 base approaching 22 megawatts MW.[3] Power quality is assumed to be proportional to increased reliability.

- The Value of Job Creation Potential reflects the wages paid for the installation and maintenance of stationary fuel cells in California, converted to cents/kWh based on market penetration. Note that the Value of Job Creation Potential does not assume that any stationary fuel cell manufacturing capacity will be built in California by 2020. The Value of Job Creation Potential could increase significantly if policy initiatives, such as feed-in tariffs, were established at levels high enough to increase the speed of technology deployment and motivate new in-state manufacturing capacity.

- In addition to the value components that are quantified in Figures 1 and 2, there are many other "distributed value elements" that are more difficult to quantify and that are mentioned here only qualitatively. These value components include: (i) Ease of siting and deployment due to the modularity of the 300-1400 kW stationary fuel cells considered in this analysis; (ii) the relatively low acoustic signature of fuel cells; (iii) increased local control of resources; (iv) cleaner and more efficient use of fossil fuels; and (v) achieving environmental justice goals.

The results of the avoided cost analysis illustrated in Figures 1 and 2 have been incorporated into a full benefit-cost analysis of distributed stationary fuel cells in California. Three of the major benefit-cost tests specified by the California Public Utilities Commission ("CPUC") in its Standard Practice Manual[4] were performed as part of the benefit-cost analysis, including:

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[3] The assumed 378 MW of distributed fuel cell capacity to be added by 2020 represents less than 20% of the 2020 Base Case Market Forecast for new combined heat and power capacity additions in California made by ICF International, July 23, 2009, p. 55.

[4] CPUC, October 2001.

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

Each of these three benefit-cost tests relies on measuring a prescribed set of benefits and costs over the lifetime of an asset (such as a fuel cell project). Total lifetime benefits and costs are compared by calculating a benefit-cost ratio. The full benefit-cost analysis is performed both with and without the benefit of ratepayer funding provided through the CPUC's Self-Generation Incentive Program ("SGIP").

The full benefit-cost analysis described in this paper was based on detailed fuel cell cost and performance data provided by the participating organizations. Figure 3 (below), entitled "Stationary Fuel Cells in California: Benefit-Cost Ratios for Baseload Electricity Generation, with SGIP Funding" illustrates the capacity weighted-average results for each of the three tests, based on benefit-cost ratios calculated for eight separate fuel cell products ranging in size from 300 kW to 3.8 MW. The fuel cell products included in the benefit-cost analysis are either commercially available today or will be within the next 3-5 years.

This study assesses four possible combinations of fuel and operating mode for each of the eight 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.

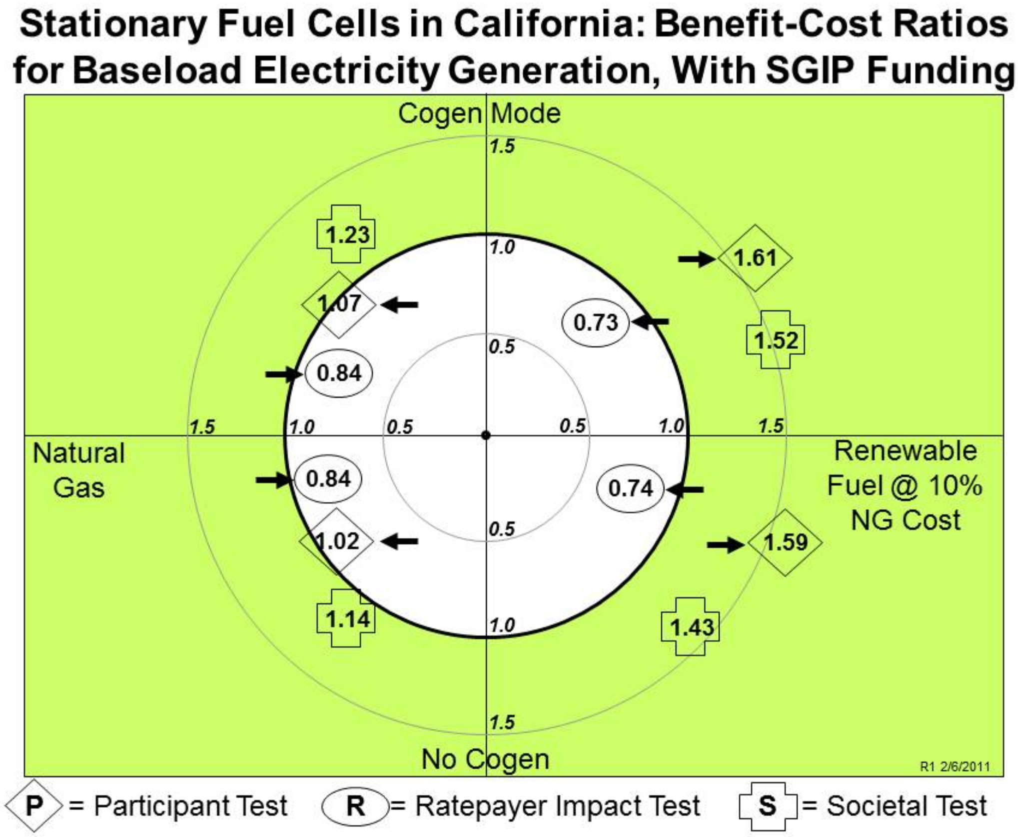

Figure 3. Weighted-Average Benefit-Cost Ratios with SGIP Funding

The results from each of the four spanning scenarios are presented in the following manner:

- The lower left quadrant of Figure 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 Figure 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:
  - o Participant Test benefit-cost ratios are shown within a diamond
  - o RIM Test benefit-cost ratios are shown within an oval
  - o 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.

    - The value of the benefit-cost ratio is significant in only one dimension; the exact placement of its associated shape along the concentric ring representing its value is based solely on ease of presentation.

Figure 3 clearly demonstrates that: (i) Fuel cells provide significant societal benefits[5] to California for each of the four fuel and operating mode combinations analyzed, and (ii) SGIP funding over time effectively moves stationary fuel cells that generate baseload electricity using natural gas to the point of cost-effectiveness from the participant's (*i.e.*, investor's) perspective.

For purposes of the benefit-cost analysis, renewable fuel was assumed to be 10% of the cost of natural gas, resulting in very high levels of cost-effectiveness from the participant's perspective for fuel cells operating either in electric-only mode or with cogeneration. For stationary fuel cells operating on renewable fuel, cost-effectiveness from the participant's perspective is higher when the assumed cost of renewable fuel is lower. Additional details related to the benefit-cost analyses are provided in Section III of this paper.

Fuel cells represent an advanced power generation system that provides significant value to California's ratepayers today. The value provided to California's ratepayers through CCHP, renewable digester gas use, avoided central station generation, and the associated avoided emissions and health benefits will grow significantly as fuel cell installed capacity and penetration rates increase throughout the State.

Solar photovoltaics ("solar PV") and wind energy also represent important and necessary components of advanced power generation systems. The intermittency and constrained capacity factor associated with these renewable resources will require complementary advanced storage technology and robust, 24/7, high efficiency, environmentally sensitive power generation. Fuel cells are well suited as a 24/7 complement to solar PV and wind. In particular, per MW of installed capacity, fuel cells result in more *avoided* emissions per year than either solar PV or wind energy because fuel cells provide round-the-clock baseload generation, regardless of prevailing wind or solar insolation conditions. In

[5] As indicated by a Societal Test benefit-cost ratio significantly greater than 1.0.

addition, the high quality thermal attributes of fuel cells create the ability to operate in CCHP mode through the capture and use of waste heat, which adds appreciably to the level of avoided emissions. Combining the unique operating characteristics of fuel cells, wind, and solar PV enhances the ability of the State to meet the goals of around-the-clock secure, reliable, and environmentally sensitive power generation.

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"). Stationary fuel cell penetration in California could conservatively reach 400 MW by 2020. This penetration level would reduce carbon dioxide ("CO_2") emissions by 540,000 metric tonnes per year (assuming 100% natural gas and 75% CCHP) and save enough natural gas to generate nearly 1.2 million MWh of electricity – equivalent to the electricity consumption of over 185,000 California residences. Use of available renewable digester gas has the potential to reduce CO_2 emissions even further – as much as 3 times more CO_2 could be avoided if 75% of the 400MW is fueled by renewable digester gas. .

II. FUEL CELLS: TECHNOLOGY AND GENERAL ATTRIBUTES

For the reader unfamiliar with fuel cells, Attachment B provides a five-page introduction to fuel cell technology. It 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.

The majority of stationary fuel cells generating baseload electricity in California operate in CCHP mode because the capture and re-use of waste heat significantly improves a project's economics. At the same time, approximately 25% of the installed capacity of stationary fuel cells in California at the end of 2010 was designed to operate in electric-only mode and there may be cases where there is no on-site use for the waste heat. Therefore, 75% of California's fuel cells are assumed to operate in cogeneration mode for the purposes of this study, regardless of fuel type. The changes in value attributed to stationary fuel cells in California assuming 100% CCHP operations are illustrated and discussed in Section IV.E (below) as a sensitivity analysis.

Most large stationary fuel cells operating as baseload electricity generators are fueled with natural gas, and some also operate on renewable fuel. Therefore, this study assessed the value proposition for two separate cases: (i) Fuel cells fueled 100% with natural gas, and (ii) fuel cells fueled with renewable fuel (with 25% natural gas for backup purposes).

Fuel cells generate electricity using an electrochemical process rather than through combustion, and even though most fuel cells use natural gas, larger size fuel cells typically require less natural gas per kWh generated than most central station natural gas-fired generators. As a result, these fuel cells would have lower carbon dioxide (*i.e.*, GHG) emissions than the avoided generator. In addition, fuel cells that operate on renewable digester gas (*e.g.*, from municipal wastewater treatment or food/beverage processing) or on landfill gas reduce other types of emissions by preventing flaring of that methane gas. Emissions are further mitigated by fuel cells that operate in CCHP mode, capturing waste heat to produce steam or hot water, thereby avoiding fuel input to natural gas boilers that would otherwise produce those products. Waste heat can actually also be used for cooling. The waste heat from fuel cells can be supplied to single or double effect absorption chillers (in the form of hot water, steam, or exhaust gas) to produce from 100 to 135 tons cooling per MW of fuel cell capacity. The heat from multiple fuel cells can be combined to drive larger absorbers. While high-grade heat is being used to create chilled water, low-grade heat can simultaneously be used to provide useful heat, allowing for combined cooling, heat and power applications for buildings. Typical applications for chilled water include space cooling and refrigeration sub-cooling.[6]

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.

III. DESCRIPTION OF BENEFIT-COST ANALYSIS METHODOLOGY

As described above, three separate benefit-cost tests are performed for each of four different spanning scenarios. Each scenario reflects a different combination of fuel and operating mode, as follows:

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

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, who is typically 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. As a result, the Societal

6 Useful waste heat that is captured is assumed to be used to displace heat from a natural gas-fired boiler, rather than from an electrical chiller.

Test includes more benefits than either the Participant Test or the RIM Test, incorporating such benefits as the Value of Avoided Emissions, the Value of Health Benefits, and the Value of Job Creation Potential.

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 is provided in Attachment D.

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 eight 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-five 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 in each investor-owned utility "(IOU") franchise area in California for each of the three benefit-cost tests identified above. 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 results of the benefit-cost analysis are presented as the capacity-weighted average of the utility-specific results for each scenario. 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.

Attachment D provides the interested reader with greater detail about the data collected and its use in deriving the benefit-cost ratios for each of the three benefit-cost tests.

C. RESULTS OF BENEFIT-COST ANALYSIS

The previously described data were used to perform the three different benefit-cost tests and to generate the capacity weighted-average benefit-cost ratios presented in Figures 3 and 4. Capacity weighted-average benefit-cost ratios were calculated both with and without the benefit of SGIP funding. Figure 4 shows the weighted-average benefit-cost ratios assuming no SGIP funding, whereas the results previously presented in Figure 3 showed the weighted-average benefit-cost ratios with SGIP funding included.

A benefit-cost ratio equal to one indicates that a project's benefits exactly equal its costs. A benefit-cost ratio greater than one indicates that the benefits of the project outweigh the costs, whereas a benefit cost ratio less than one indicates that the project's costs outweigh its benefits.

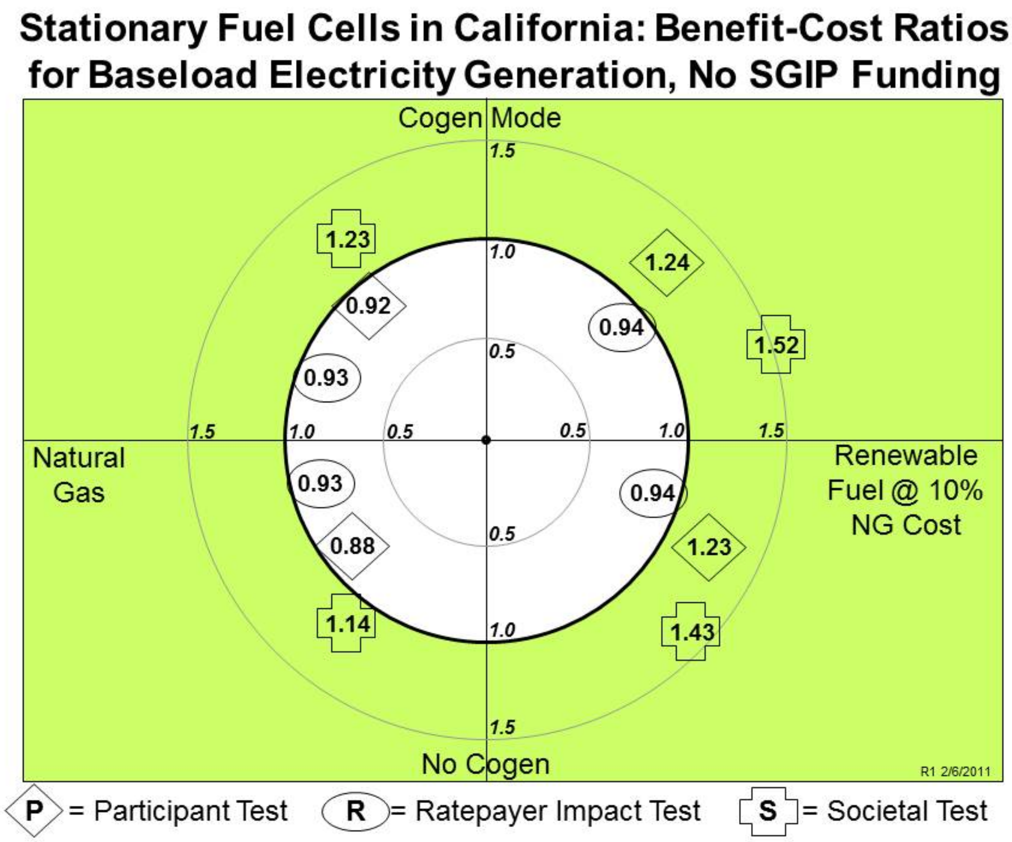

Figure 4. Weighted-Average Benefit-Cost Ratios without SGIP Funding

The results in Figure 4 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 0.92 for the Participant Test and 1.23 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 0.93-0.94, again assuming no SGIP incentives.

Figure 3 (presented earlier) includes directional arrows to show 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 moves the benefit-cost ratio for the Participant Test to 1.0 over time, as intended. Including the benefits of the federal Investment Tax Credit would move that benefit-cost ratio further into the green area for those able to take advantage of this tax credit.
    - The impact of SGIP funding for fuel cells operating on renewable fuel is very sensitive to the assumed cost of the renewable fuel. As the assumed cost of the renewable fuel increases from the assumed 10% of natural gas cost, the benefit-cost ratios for each operating mode would move toward the respective results for the 100% natural gas-fuelled operating mode.
- Conversely, the benefit-cost ratio for the RIM Test decreases with SGIP funding since the SGIP funding is provided by 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 derivation of the weighted-average benefit-cost ratios for the Participant Test, the RIM Test, and the Societal Test are described in greater detail in Attachment D, to provide the reader with an intuitive understanding of the calculated outcomes.

D. VALUE VERSUS COST OF AVOIDED EMISSIONS

The virtually zero emissions signature of fuel cells results in avoided emissions as compared to electricity generated by the average California natural gas-fired fleet of generators. Societal benefits are created as a result of these avoided emissions and are included in the calculation of the Societal Test benefit-cost ratios.

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.[7] Calculation of physical units of avoided emissions was performed for each fuel cell product for several types of emissions, including CO_2, NO_x, SO_x, carbon monoxide ("CO"), particulate matter, and volatile organic compounds ("VOC").

[7] Additional detail on the calculation of the Value of Avoided Emissions is provided in Attachment G.

The second step in calculating the ***Value*** of Avoided Emissions was to value the physical units of avoided emissions. This was done by setting a range of prices based on market prices observed over the past several years. The high end of the range is typically set by emissions reduction credit ("ERC") prices in the South Coast Air Quality Management District, which can have ERC prices for particulate matter and VOC more than three times higher than prices in other air quality management districts. This variance in ERC prices is seen in the broad range calculated for the Value of Avoided Emissions in Figures 1 and 2. This broad range has a much smaller impact on the benefit-cost ratios calculated for the Societal Test, where reducing ERC prices for particulate matter and VOC by two-thirds reduces the Societal Test results by no more than 0.01.

The ***cost*** per unit of avoided emissions is a completely separate metric whose purpose is to calculate how much investment is required to reduce one unit of emissions (typically one metric tonne). 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 operating and maintenance ("O&M") costs.[8] Note that the cost per unit of avoided emissions depends on the cost and performance of installed generating equipment rather than on the cost of emissions allowances.

Similar to the benefit-cost ratio calculations, the unit cost of avoided emissions for each of the eight fuel cell products was aggregated into a capacity weighted-average cost measure to maintain the confidentiality of product-specific data.[9] The results were calculated by assuming that the NPV of each project's total costs was equally split between the project's avoided CO_2 emissions and all other avoided emissions. This means that 50% of the NPV of the project's total costs was assigned to calculating the unit cost of avoided CO_2 emissions and 50% to calculating the unit cost of the cumulative avoided NO_x, SO_x, CO, VOC and particulate matter emissions. Applying a different percentage split to the NPV of each project's total costs would result in a proportionate shift of the unit cost between avoided CO_2 emissions and all other avoided emissions, the two categories of avoided emissions examined here.

The following results (based on the 50:50 cost split described above) make clear the unit cost of avoided emissions associated with both cogeneration and the use of renewable fuel by distributed fuel cells in California. Such unit costs can be useful in ranking fuel cells and other distributed generating technologies in terms of their cost effectiveness in reducing various types of emissions.

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8 The NPV was calculated using the nominal discount rate of 8.25% that was also used to calculate the benefit-cost ratios for the Participant Test and the RIM Test.

9 Note that the cost of avoided CO_2 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 CO_2 emissions in $/ton, one divides the cost in $/metric tonne by 1.1025.

- The weighted-average NPV cost of avoided CO_2 emissions was $136/metric tonne for “natural gas + cogeneration mode;” the weighted-average NPV cost of avoided CO_2 emissions was negative for “natural gas + no cogeneration” due to the significant impact of several higher cost, smaller capacity fuel cell products that did not result in avoided CO_2 emissions when producing only electricity.

- For renewable fuel, the weighted-average NPV cost of avoided CO_2 emissions was $47/metric tonne with cogeneration; the weighted-average NPV cost of avoided CO_2 emissions was $70/metric ton for “renewable fuel + no cogeneration.” Note that the CO_2 emissions associated with renewable fuel use are generally assumed to be part of the natural CO_2 cycle, thereby netting to zero with the CO_2 being taken up to create the renewable fuel.

- The weighted-average NPV cost of avoided NO_x, SO_x, CO, VOC and particulate matter emissions was $16/pound for “natural gas + cogeneration mode” and $24/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 $9/pound with cogeneration and $11/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.

E. 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 3 and 4, 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 from less than 1.0 in Figure 3 to slightly greater than 1.0 in Figure 3 for the most predominant “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 70% of the State’s total electricity use and 99% of the State's total natural gas use.[10] Therefore, the substantial benefits reflected in the Societal Test accrue predominantly to those IOU ratepayers providing SGIP funding and spill over to the consumers of the State's remaining electricity and natural gas deliveries.

In terms of the cost of avoided emissions, fuel cells reduce CO_2 emissions at a weighted-average NPV cost of $47-136/metric tonne when operating in cogeneration mode, depending on the underlying fuel. Fuel cells reduce cumulative NO_x, SO_x, CO, VOC and particulate matter emissions at a weighted-average NPV cost of $9-24/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/kWh avoided cost values derived in the "California Fuel Cell Value" waterfall charts, as illustrated above in Figures 1 and 2. Some of the avoided costs are quantified based on observable market prices equipment, service, and other relevant factors, and some are quantified based on values that are derived from a broad-based literature search. For the benefit of the reader, detailed descriptions of the underlying assumptions are provided by category in Attachments E, F, and G for each calculated cents/kWh value range, starting with the generation-related values at the bottom of the waterfall, continuing up through each category of values toward the top of the waterfall.

The ***categories*** of avoided costs quantified in Figures 1 and 2 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 C. The quantified values in Figures 1 and 2 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 "California Fuel Cell Value" waterfall charts are marked with an asterisk (*) on the PLEASE matrix in Attachment C.

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. Depending on the point of comparison (*i.e.*, the avoided central station generating technology), fuel cells have the potential to make a significant contribution to achieving reduced GHG emissions goals under AB32 due to the relatively low CO_2 emissions resulting from their electrochemical process. In all cases, fuel cells

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[10] *See* CPUC, "2010 Annual Report," p. 11.

[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.

are 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 2009 MPR proxy plant in its Resolution E-4298. 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.[12]

Avoided costs related to these two baseload generation technologies establish the range of values for each of the distributed value elements included in the "California Fuel Cell Value" waterfall graphs. The cumulative range of value is calculated to be 5.2-20.1 cents/kWh for fuel cells currently installed in California and running on 100% natural gas. For fuel cells running on renewable fuel, the cumulative range of value is calculated to be 6.3-27.4 cents/kWh, due largely to the increased avoided fuel costs and the value of the avoided emissions from digester gas that would otherwise be flared. The value in both cases is expected to increase significantly over time as the penetration of fuel cells throughout the State increases.

[12] Replacing the representative out-of-state coal-fired baseload generator with, for instance, an in-state natural gas-fired peaking generator as the second avoided electricity generation technology would actually increase the value proposition of fuel cells in California. The increase results mainly from the higher cost of natural gas compared to coal, the higher heat rate and resultant emissions from the natural gas-fired peaking generator versus the 2009 MPR proxy plant, and the higher cost of in-state versus out-of-state emissions reduction credits.

A. AVOIDED GENERATION COSTS

The avoided generation costs are color-coded in red in Figures 1 and 2 and include separate estimates for avoided capacity-related costs and avoided energy-related costs. Attachment E provides a detailed description of how the value range is derived for each category of avoided generation costs, including:

- Value of Avoided Generation Capacity Capital Cost
- Value of Avoided Generation Capacity Fixed O&M Cost
- Value of Avoided Generation Variable O&M Cost
- Value of Avoided Central Station Generation Fuel Cost
- Value of Avoided Fossil Fuel as a Price Hedge
- Value of Avoided Water Use.

The first two categories of avoided generation costs are capacity-related costs and the other four categories are energy-related costs.

Fuel cells achieve their highest electrical efficiency when operated as a baseload electricity generating technology. The representative fuel cell, sized between 300 and1400 kW, is used as the basis for this avoided cost valuation and is assumed to have an annual capacity factor of 92.5%, based on input from the participating organizations. This level of capacity factor for fuel cells was demonstrated in the early years of the SGIP, though capacity factors for fuel cells participating in the SGIP and operating on natural gas have more recently been in the 60-75% range.[13] Since the avoided cost values are reported in cents/kWh of electricity generated by fuel cells, use of a higher capacity factor will actually result in more conservative values.

Fuel cells currently operating in California have high availability during periods of peak electric demand.[14] The reported performance of fuel cells participating in the SGIP during the coincident peak for the California Independent System Operation ("CAISO") varies widely from year to year within a broad range of uncertainty due to calculations based on a mix of measured and estimated data. On-peak fuel cell performance in recent years has ranged from a high of 98% in 2005[15] to a low of 64.4% in 2008.[16] Given the range of on-peak fuel cell performance, the average on-peak availability factor for fuel cells in California has been kept at 93%, the same value that was used in the original study in 2008.[17] The on-peak availability factor is used in conjunction with the annual

[13] Itron, SGIP Ninth-Year Impact Report, pp. 5-6 – 5-12 and Appendix A.

[14] Itron, SGIP Ninth-Year Impact Report, pp. 5-24.

[15] Itron, SGIP Fifth-Year Impact Report7, p. 1-7.

[16] Itron, SGIP Eighth-Year Impact Report, p. 5-9.

[17] Itron, SGIP Fourth-Year Impact Report, pp. 8-15.

capacity factor to convert capacity-related costs expressed in $/kW into equivalent energy-related costs expressed in $/kWh.

B. 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.

The avoided T&D costs are color-coded in blue in Figures 1 and 2 and include the following categories of avoided costs and grid-related value:

- Value of Avoided Transmission Cost
- Value of Avoided Distribution Cost
- Value of Grid Support
- Value of Avoided Losses
- Value of Increased Reliability/Blackout Avoidance/Power Quality.

Attachment F provides a detailed description of how the value range is derived for each category of avoided T&D costs.

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 on-peak availability factor of fuel cells in California and (ii) converted to cents/kWh using the assumed 92.5% annual capacity factor for the representative fuel cell. The on-peak availability factor is applied to avoided T&D costs in the same manner as it was applied to avoided generation costs on the assumption that the on-peak performance of baseload fuel cells effectively reduces peak load T&D congestion due to the distributed nature of the electricity generated by those fuel cells.

C. 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, sulfur dioxide ("SO_2"), and particulate matter less than 10 microns in diameter ("PM10"). However, due to the decision made in this analysis to separate capacity-related value from energy-related 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, historical natural gas futures contract prices from the New York Mercantile Exchange ("NYMEX") 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.

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 endpoints of a range of emissions allowance prices either observed in the marketplace or derived from the literature.[18] Details explaining the derivation of each type of avoided emissions included in this updated analysis can be found in Attachment G.

Attachment H contains two tables, one that summarizes the underlying assumptions used to calculate the range of value for the avoided emissions and related health benefits and another that summarizes the results. The Value of Avoided CO_2 Emissions for distributed fuel cells in California operating 100% on natural gas is calculated at 0.16-2.43 cents/kWh; the combined Value of Other Avoided Emissions is 0.27-3.88 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 2.14-2.18 cents/kWh. For fuel cells operating on renewable fuel, the Value of Value of Avoided CO_2 Emissions is 0.43-3.33 cents/kWh; the combined Value of Other Avoided Emissions is 0.36-4.90 cents/kWh due to the added value for avoided flare gas emissions; and, the additional Value of Health Benefits is 2.14-2.19 cents/kWh. Specific details for each avoided pollutant and related health benefits are discussed in Attachment G.

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[18] Emissions allowance prices observed in the marketplace are based on the Market Price Indices for emissions as reported by CantorCO2e for the two-year time period of November 1, 2008-October 31, 2010.

D. DIGESTER GAS CREDIT

The renewable fuel considered in this study is anaerobic digester gas, typically derived from wastewater treatment plants, landfills, and manure collection ponds. Biomethane is considered a renewable fuel source, with technically feasible for use digester gas levels (conservatively) estimated to reach 75 trillion British thermal units ("Btu") in California by 2020.[19] This level of biomethane availability could support the State's entire potential 2020 installed fuel cell capacity of 400 MW more than three times over, given the assumption that fuel cells operating on renewable fuel will use natural gas as backup fuel 25% of the time.

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 is assumed to add capital costs of $490/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. Based on the representative fuel cell operations, the additional capacity and O&M costs associated with renewable fuel result in a renewable fuel "cost" of approximately 0.45 cents/kWh. 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.

A fuel cell operating on digester gas 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. This may occur because digester gas production depends on a number of uncontrollable factors such as ambient temperature and waste composition; this analysis assumes 25% natural gas for backup purposes. In addition, a parasitic electrical load of 10% is included to reflect the larger volume of (lower Btu) digester gas that must pass through any fuel cell operating on renewable fuel and the cost of operating the anaerobic digester gas cleanup.

Digester gas is assumed to be approximately one-half biogenic CO_2 [20] and one-half methane (CH_4) [21], with small amounts of N_2, O_2, hydrogen sulfide (H_2S), and PM10; average heat content is about 600 Btu/ft^3 on a higher heating value ("HHV") basis. 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.

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[19] CEC, December 2006, p. 12, Figure 1.6.

[20] Biogenic carbon dioxide is considered to be part of the natural carbon cycle, and is not generally included in CO_2 emissions inventories.

[21] 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.

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 3.23-12.19 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 = 0.75-4.92 cents/kWh.
- Value of Fossil Fuel Price Hedge = 0.02-0.38 cents/kWh.
- Value of Health Benefits of Avoided In-State Emissions = 2.04-2.07 cents/kWh.
- Value of Avoided Emissions = 0.42-4.82 cents/kWh.

Besides the direct benefits of renewable digester gas use, there are some additional costs associated with the additional equipment for the cleanup skip required to clean and condition the digester gas before it can be used in the fuel cell. Based on cost estimates derived from the literature and from data provided by the participating organizations, renewable fuel is charged a cost of 0.45 cents/kWh in the avoided cost analysis. In addition, the 10% parasitic electric load required to operate all of the equipment associated with the cleanup skid reduces the overall avoided cost value for fuel cells operating on renewable fuel; this impact is reflected in the values above, as well as in all other values illustrated in the "California Fuel Cell Value" illustrated in Figure 2.

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 70% of the representative fuel cell's waste heat is captured as useful energy,[22] and that this useful energy replaces the output from an 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 in Attachment G for each relevant type of emissions). All values are adjusted to reflect the 75% of fuel cell capacity that is assumed to operate in a cogeneration (*i.e.*, CCHP) mode.

[22] This value is significantly larger than the 46% value used in the original study in 2008 because of improvements in finding ways to use the lowest grade waste heat when operating in CCHP mode, thereby improving the total thermal efficiency of the fuel cell units.

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, SO_2, VOC, CO, and CO_2. The cumulative Value of Cogen Credit across all value components is 1.70-9.43 cents/kWh, regardless of the type of fuel being used by the fuel cell.

The following components contribute to the total Value of Cogen Credit and the corresponding values (for 75% CCHP operations) are included in the total range of values for the appropriate category in the "California Fuel Cell Value" waterfall charts illustrated in Figures 1 and 2:

- Value of Avoided Natural Gas = 0.95-5.35 cents/kWh.
- Value of Fossil Fuel Price Hedge = 0.28-0.68 cents/kWh.
- Value of Health Benefits of Avoided In-State Emissions = 0.11-0.13 cents/kWh.[23]
- Value of Avoided Emissions = 0.36-3.27 cents/kWh.[24]

Figures 5 and 6 below restate the results shown in Figures 1 and 2 for a sensitivity case that assumes that all stationary fuel cells operate in CCHP mode 100% of the time. The red ovals highlight the avoided cost components that increase in value due to the assumed 25% increase in CCHP mode operations; all other value components are unaffected by the increase.

[23] Details regarding the Value of Health Benefits of Avoided In-State Emissions related to cogeneration are provided in Attachment G, Section I.H. Value of Health Benefits of Avoided In-State Emissions.

[24] Avoided NO_x, SO_2, and CO_2 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 tables provided by Johnson Boiler Company.

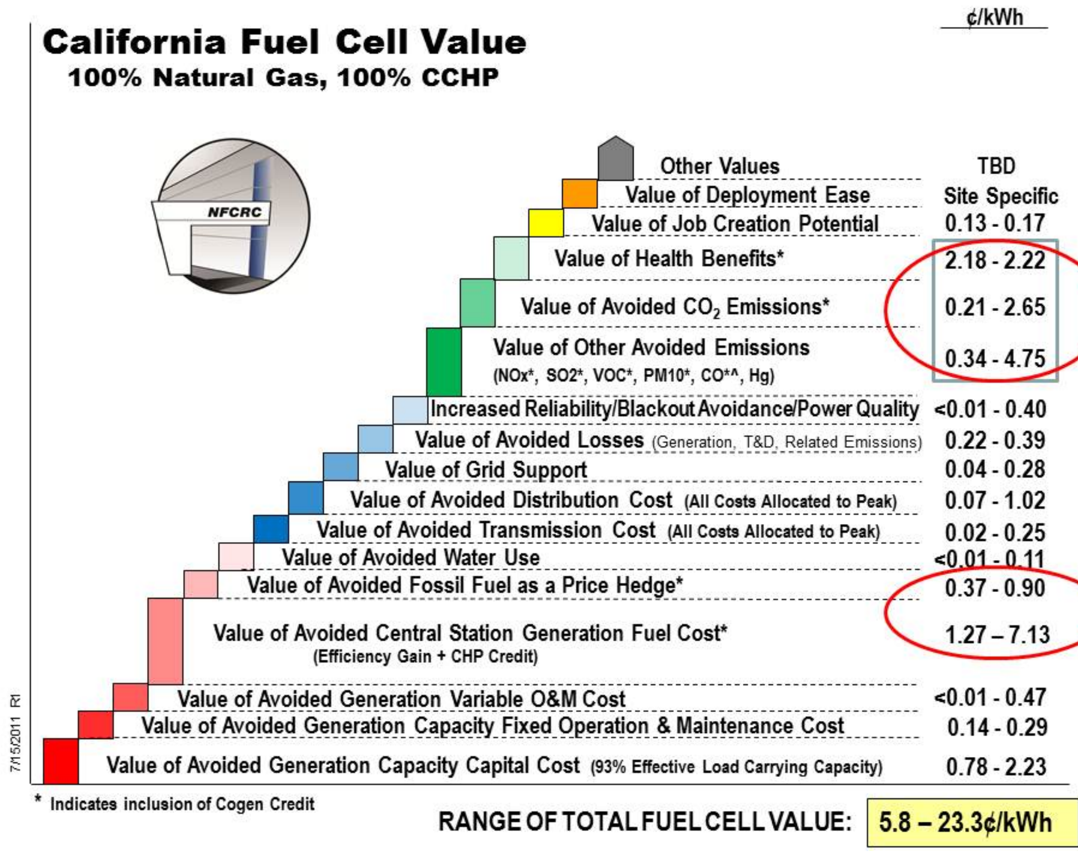


Figure 5. California Fuel Cell Value: 100% Natural Gas, 100% CCHP Mode

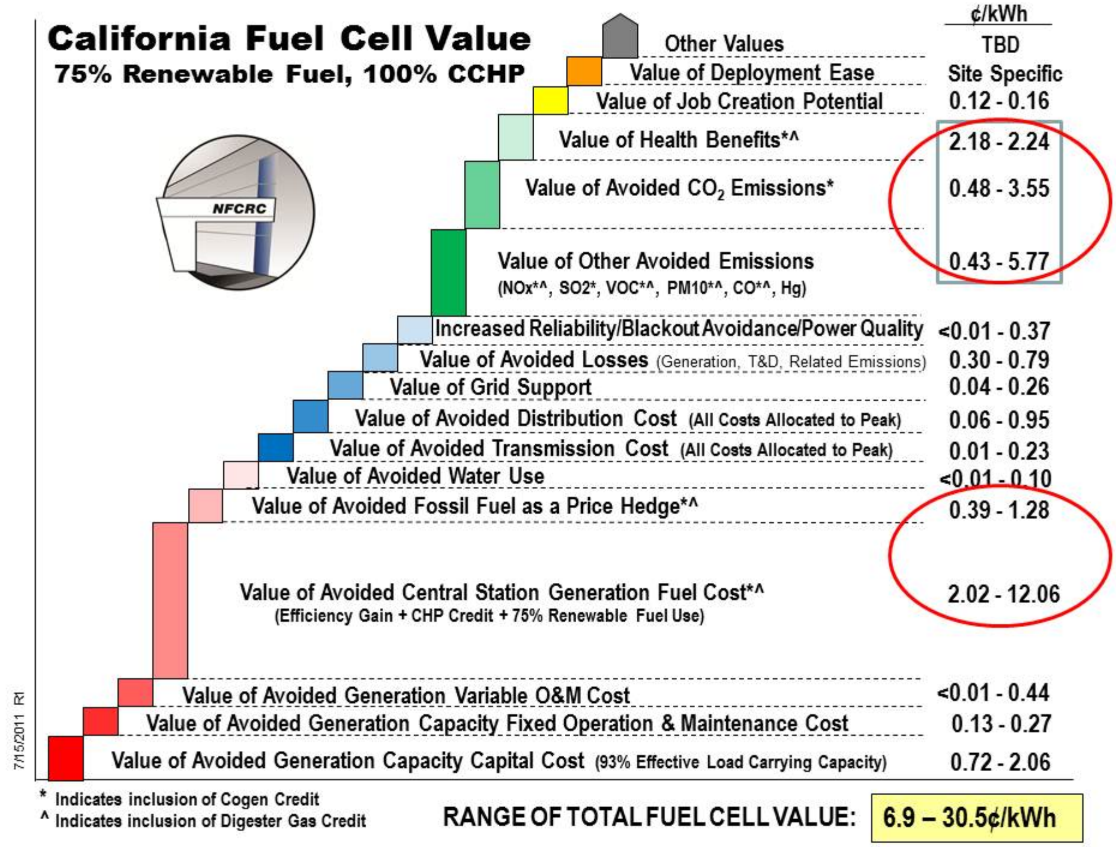


Figure 6. California Fuel Cell Value: 75% Renewable Fuel, 100% CCHP Mode

Comparing the results of Figures 3 and 4 to the results of Figures 1 and 2, respectively, it can be seen that the 25% increase in assumed CCHP operations increases the total value proposition of stationary fuel cells in California by 16% for fuel cells operating on natural gas and by 11% for fuel cells operating on renewable fuel. This increase in value roughly translates to a 5% increase in value for every 10% increase in assumed CCHP operations.

F. 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 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 0.13-0.17 cents/kWh for fuel cells operating 100% on natural gas; the impact of the 10% parasitic electric load for fuel cells operating on renewable fuel reduces the Value of Job Creation Potential to 0.12-0.16 cents/kWh. This range is based on the following set of assumptions:

- Installed fuel cell capacity in California will grow from its 2010 level of nearly 22 MW to 400 MW by 2020.
- Installation of a representative 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 $1/4^{th}$ as much labor as the initial installation (90 hours per year).
- The average labor cost for fuel cell installation and maintenance is $75/hour.

The additional Value of Job Creation Potential due to fuel cell companies building manufacturing capacity in California could be significant in the longer term if policies were put into place to increase the assumed penetration level of fuel cells. For purposes of this updated analysis, a conservative assumption was made that no additional fuel cell manufacturing capacity will be needed in California to support the assumed 2020 installed capacity of 400 MW.

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.

G. ADDITIONAL VALUES

Value of Deployment Ease – 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 in Attachment G) 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, 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.

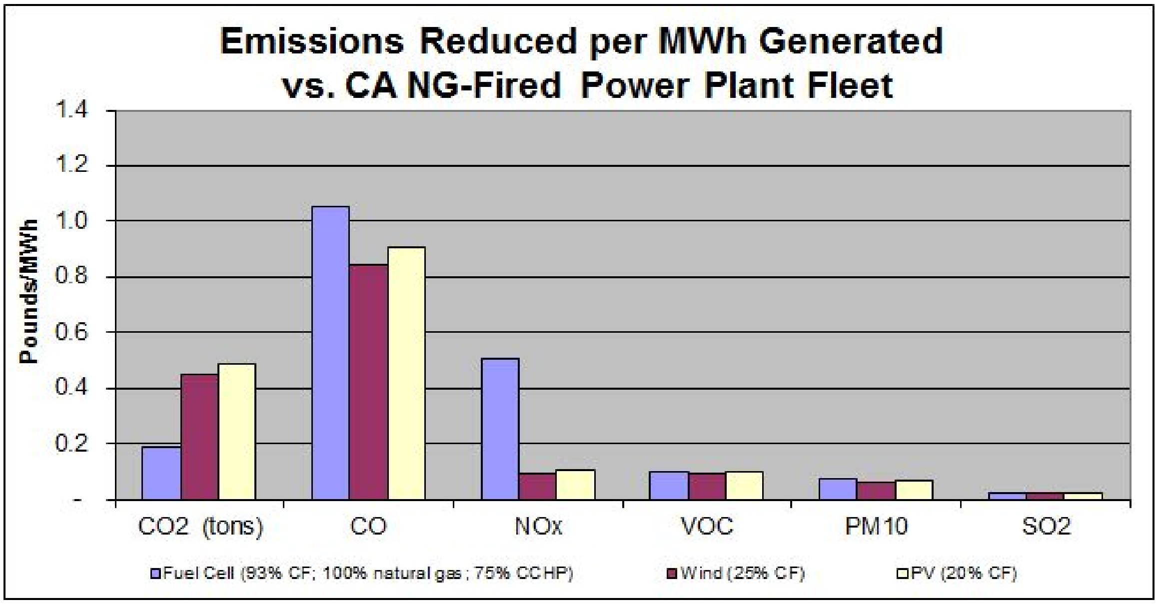
Other Values - The estimated values in the "California Fuel Cell Value" waterfall charts shown in Figures 1 and 2 are not all-inclusive, and do not reflect many of the distributed value elements identified in the PLEASE matrix in Attachment C. Among those distributed value elements not included because they are difficult to quantify are the positive visibility impact due to reduced emissions, the positive impact on local control of resources, the positive impact on responsiveness to load growth due to the modularity of distributed stationary fuel cells, and the positive impact on achieving environmental justice goals.

V. COMPARISON OF ANNUAL AVOIDED EMISSIONS ACROSS TECHNOLOGIES: PER MWH VERSUS PER INSTALLED MW

Avoided in-state emissions for the representative fuel cells in this analysis (assuming the average California natural gas-fired generating fleet as the avoided central station generator) are compared against the avoided emissions for electricity generated using solar PV and wind. Solar PV and wind have no fuel input and, consequently, no emissions; all emissions from the average California natural gas-fired generating fleet are avoided by these two generating technologies. The same lack of fuel input also means that solar 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 the representative fuel cell in this analysis, solar 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 solar PV than for wind by the percentage of grid-related losses (assumed to be 7.8% in this analysis).

Figures 7 and 8 each include two sets of graphs that compare *avoided* emissions for fuel cells, solar PV, and wind. The graphs in Figure 7 are for fuel cells operating 100% on natural gas and 75% of the time in CCHP mode. The graphs in Figure 8 are for fuel cells operating predominantly on renewable digester gas (with 25% natural gas backup) and 75% of the time in CCHP mode.



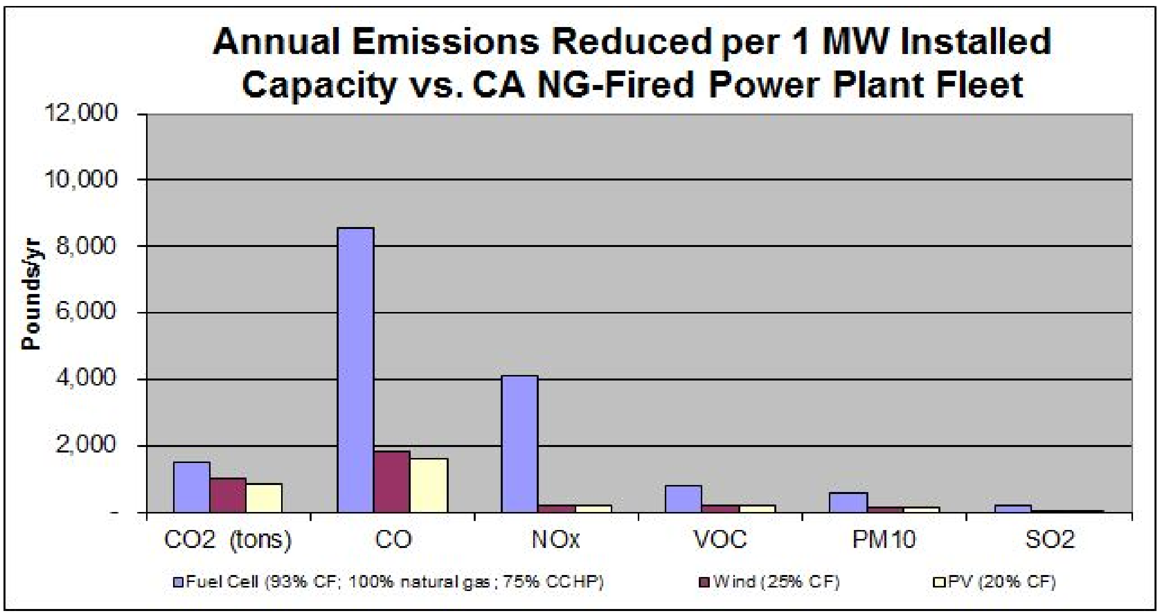
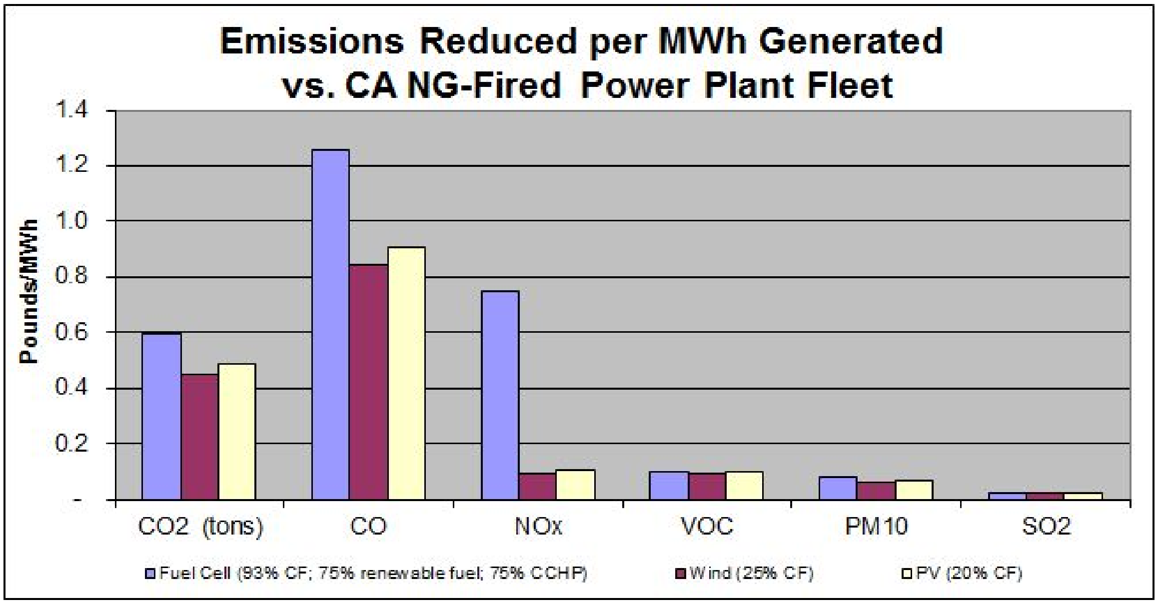


Figure 7: Case 1 - Fuel Cells Operating on Natural Gas, 75% CCHP



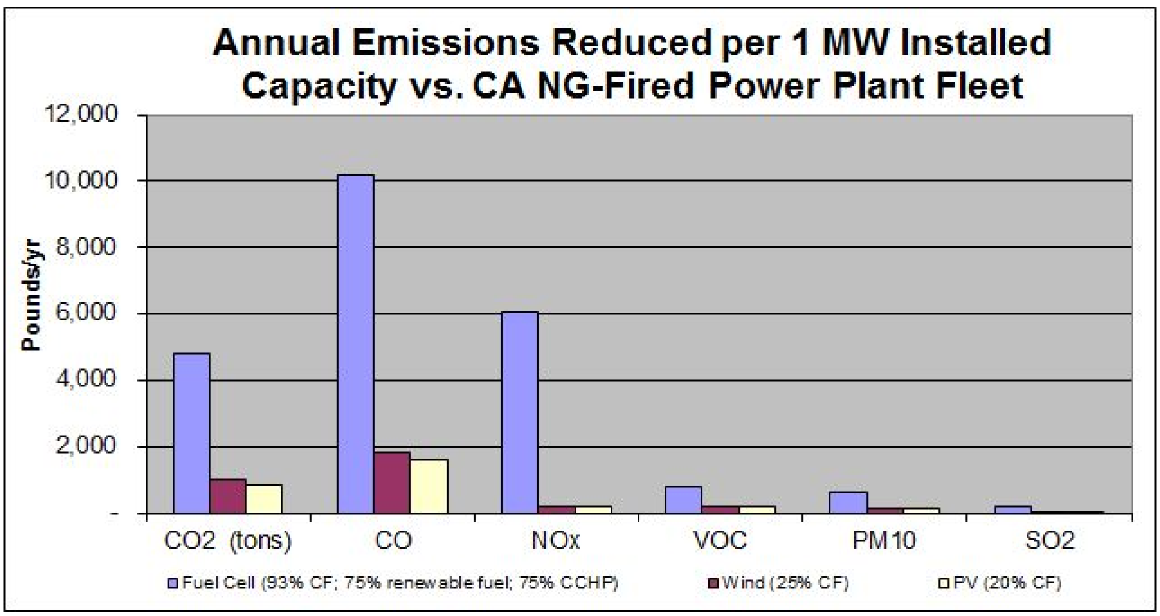


Figure 8: Case 2 - Fuel Cells Operating on Renewable Fuel, 75% CCHP

The top graph in Figures 7 and 8 compares the avoided emissions per MWh of electricity generated by each of the three technologies. As expected, *avoided* emissions are greater for distributed solar PV than for wind in all cases. However, *avoided* emissions of all pollutants (other than CO_2 in the 100% natural gas case) are greatest for fuel cells because of (i) avoided boiler fuel emissions due to fuel cell cogeneration through capture of high quality waste heat and/or (ii) avoided emissions due to fuel cell use of digester gas. The combined influence of cogeneration and renewable fuel use can be seen in the comparison of avoided CO_2 per MWh. Fuel cells operating on 75% renewable fuel achieve greater avoided emissions of CO_2 per MWh than solar PV when they operate more than 42% of the time in CCHP mode.

The bottom graph in Figures 7 and 8 compares the annual avoided emissions for the three technologies per MW of installed capacity. As discussed previously, the representative fuel cells in this analysis are a baseload generating technology with an annual capacity factor of 92.5% (and operating 75% of the time in CCHP mode). Conversely, solar 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 solar PV[25] and 25% for wind resources[26] in California. Based on the assumed annual capacity factors, a 1 MW fuel cell project would generate 8,103 MWh of electricity per year, plus significant cogenerated products. A 1 MW wind project would generate 2,190 MWH of electricity per year, and a 1 MW solar PV project would generate 1,752 MWh of electricity per year. *The significant difference in annual electricity generated results in a somewhat counterintuitive outcome:* ***Per installed MW of capacity, fuel cells operating in CCHP mode have greater avoided emissions per year across the board than either wind or solar PV.***

VI. NATURAL GAS SAVINGS

As described above, this avoided cost analysis has presented results for two different scenarios. The first scenario assumed that fuel cells operate 100% on natural gas and capture waste heat for CCHP applications 75% of the time. In this first scenario, if 400 MW of installed stationary fuel cell capacity in California is achieved by 2020:

- The maximum natural gas savings for California would be nearly 9,400,000 million Btu per year. This is:

    - ✓ Enough natural gas to generate 1,200,000 MWh of electricity.
    - ✓ Enough electricity to satisfy over 185,000 homes in California.
    - ✓ Equivalent to 1.5 million barrels of oil.

- Total CO_2 reductions would be nearly 540,000 metric tonnes.

    - ✓ Equivalent to nearly 89,000 acres of forest.

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[25] Itron's 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%." Itron's SGIP Ninth-Year Impact Report showed (p. 1-10) annual solar PV capacity factors ranging from about 15% to slightly over 19%.

[26] The 25% capacity factor is taken from the most recent years reported in 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.) Itron's SGIP Ninth-Year Impact Report did not report wind capacity factors, but did reference (p. 5-25) CEC data reporting average annual wind capacity factors ranging from 14% to 26%.

- ✓ Equivalent to removing 100,000 cars from the road.

The second scenario assumed that fuel cells operate 75% on digester gas (with 25% natural gas backup) and capture waste heat for CCHP applications 75% of the time. In this second scenario, for the same 400 MW of installed stationary fuel cell capacity in 2020:

- The maximum natural gas savings for California would be nearly 37,000,000 million Btu per year. This is:

    - ✓ Enough natural gas to generate 4,800,000 MWh of electricity.
    - ✓ Enough electricity to satisfy nearly 740,000 homes in California.
    - ✓ Equivalent to 6.4 million barrels of oil.

- Total CO_2 reductions would be nearly 1,720,000 metric tonnes.

    - ✓ Equivalent to nearly 283,000 acres of forest.
    - ✓ Equivalent to removing over 425,000 cars from the road.

VII. 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. Benefit-cost ratios show that SGIP funding has been successful in moving distributed fuel cells towards increased cost effectiveness. Avoided cost analysis shows that the current fleet of distributed fuel cells contributes value to the State of California of up to 27.4 cents/kWh of electricity generated. 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. Distributed fuel cells operating in CCHP mode avoid more emissions per year per unit of installed capacity than either solar or wind generation, thanks to significantly higher operating hours and the ability to avoid boiler emissions for cogenerated products. In short, 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.

VIII. ACKNOWLEDGEMENTS

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Analyses of the data, meetings to discuss assumptions and overall approach, and reporting were wholly the responsibility of the NFCRC.

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Attachment A

California Distributed Fuel Cell Value: Comparison of 2011 Update with 2008 Results

Figure A-1 presents the results of the 2008 analysis entitled "Build-Up of Distributed Fuel Cell Value in California: Background and Methodology." The 2011 update is based on the characteristics of a representative 300 – 1400 kilowatt ("kW") stationary fuel cell, whereas the 2008 analysis was based on a representative 1.2 megawatt ("MW") stationary fuel cell. This change in the 2011 update reflects the wider range of sizes and different types of fuel cell being now being installed in California, as evident in the populations of deployed and pending fuel cell projects.

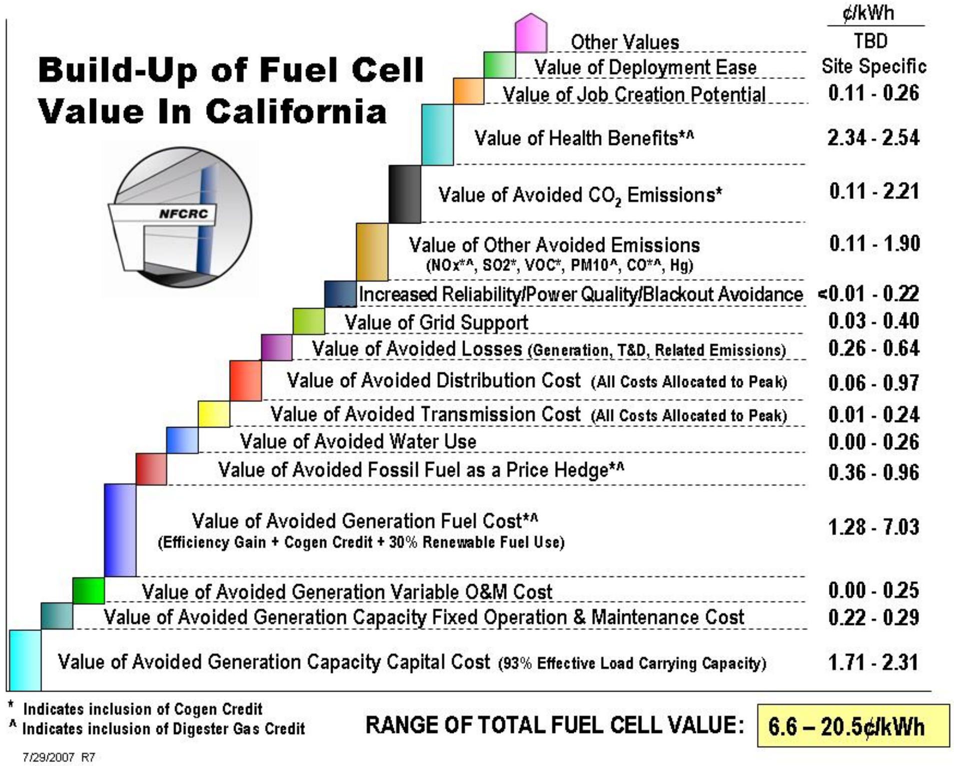

Figure A-1. 2008 California Fuel Cell Value: 60% Natural Gas, 30% CCHP Mode

Other factors contributing to differences in the value proposition for the 2011 update compared to the value proposition in the 2008 analysis include:

- Changes in the assumed operating characteristics of the representative stationary fuel cell:

- o The 2008 results assumed 30% digester gas use and 60% operating in combined cooling, heating and power ("CCHP") mode

- o The 2011 update presents results for two separate base cases:

  - ➢ 100% natural gas use and 75% operating in CCHP mode

  - ➢ 75% digester gas use (with 25% natural gas backup) and 75% CCHP mode

- Higher avoided costs associated with the 2009 Market Price Referent ("MPR") proxy plant versus the 2007 MPR proxy plant

- Lower natural gas prices and higher coal prices; higher emissions reduction credit ("ERC") prices

- More complete emissions profiles for flared digester gas and avoided boiler emissions

- More complete costs and operating impact assessment for digester gas cleanup equipment

- Reduced the CO_2 emissions rate proportional to the amount of time the representative fuel cell operates on renewable fuel to recognize those CO_2 emissions as part of the natural (*i.e.*, non-fossil) carbon cycle

- Lower projected 2020 California installed fuel cell capacity (400 MW versus former 3200 MW).

Attachment B

Fuel Cells: Technology and General Attributes

I. 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 and it requires no recharging. 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. It should be noted that 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, depending on the context.

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^{o}C); (2) Proton Exchange Membrane ("PEMFC," ~80^{o}C); (3) Phosphoric Acid ("PAFC," ~200^{o}C); (4) Molten Carbonate ("MCFC," ~650^{o}C); and, (5) Solid Oxide ("SOFC," 800-1000^{o}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.

II. 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.

III. 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 ("H_2O"), or a CO molecule to form carbon dioxide ("CO_2"). 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 B-1.

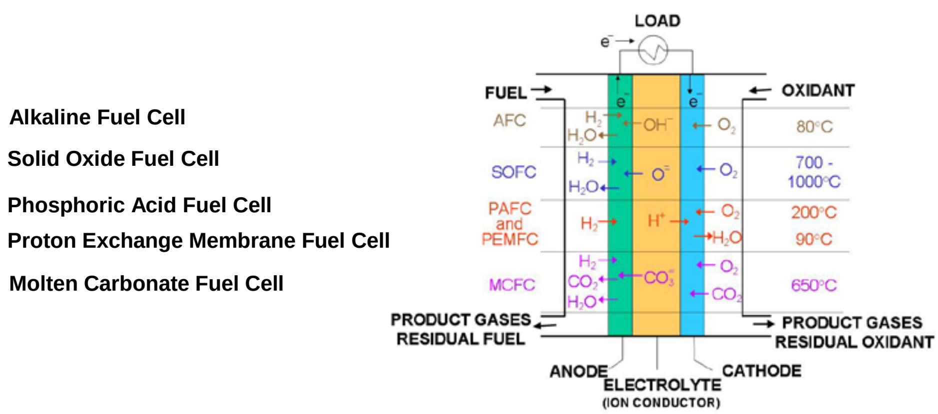

Figure B-1. Types of Fuel Cells

IV. 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 58% (LHV) when operated as hybrids in combination with other systems such as gas turbines.[27] 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 CO_2 generated ***per kWh of electricity produced*** is inversely proportional to the electrical efficiency, fuel cells with their higher electrical efficiency emit less CO_2 (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 CO_2 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).[28] 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 CO_2 emissions, criteria pollutant emissions, and the demand on fuel resources.

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[27] Electrical efficiency can 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.

[28] The waste heat from fuel cells can be supplied to single or double effect absorption chillers (in the form of hot water, steam, or exhaust gas) to product from 100 to 135 tons cooling per megawatt of fuel cell capacity. The heat from multiple fuel cells can be combined to drive larger absorbers. While high-grade heat is being used to create chilled water, low-grade heat can simultaneously be used to provide useful heat, allowing for combined cooling, heat and power applications for buildings. Typical applications for chilled water include space cooling and refrigeration sub-cooling.

V. 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 nitrogen oxides (“NO_x”). Because fuel cells are intolerant of sulfur, the fuels used have to be desulfurized, and thus fuel cells emit essentially no SOx. 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 CO_2 is also generated. As explained above, because of the high electrical efficiency of fuel cells, the amount of CO_2 emitted per kWh of electricity generated is lower than from conventional power 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 CO_2 emitted.

VI. 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, some need limited water during normal operation, and some operate in water balance and therefore consume no water
- 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.[29] Figure B-2 includes photos of several types of stationary fuel cells used for baseload generation.

400 kW PAFC
(Courtesy UTC Power, Inc.)

1400 kW MCFC
(Courtesy FuelCell Energy, Inc.)

Figure B-2. Types of Stationary Fuel Cells

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[29] This updated analysis assumes that 75% of installed fuel cell capacity in California captures waste heat for cogeneration (*e.g.*, CCHP use). Results for a sensitivity analysis assuming that 100% of California fuel cells operated in CCHP mode are presented in Section IV.E.

Attachment C

"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 achieving environmental justice goals	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, NO_x and SO_x emissions levels*	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.*, VOC, 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 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 remedia-tion 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 D

Benefit-Cost Analysis Data and Tests: Details

This attachment provides greater detail on the data used in the derivation of the benefit-cost results and also provides more background and detail on the three benefit-cost tests performed, including the:

- Societal Test
- Ratepayer Impact Measure ("RIM") Test
- Participant Test.

The full benefit-cost analysis is performed both with and without the benefit of ratepayer funding provided through the CPUC's Self-Generation Incentive Program ("SGIP").

Each of these three benefit-cost tests relies on measuring a prescribed set of benefits and costs over the lifetime of an asset (such as a fuel cell project). Total lifetime benefits and costs are compared by calculating a benefit-cost ratio. A benefit-cost ratio equal to one indicates that a project's benefits exactly equal its costs. A benefit-cost ratio greater than one indicates that the benefits of the project outweigh the costs, whereas a benefit cost ratio less than one indicates that the project's costs outweigh its benefits.

I. DATA USED IN BENEFIT-COST ANALYSIS

Natural gas and electricity tariff rates as approved by the California Public Utilities Commission ("CPUC") and in effect as of the end of January, 2011, were used in the benefit-cost analysis for each test for each of the IOUs included in the study, *i.e.*, Pacific Gas & Electric ("PG&E"), San Diego Gas & Electric ("SDG&E"), Southern California Edison ("SCE"), and Southern California Gas ("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, though marginal costs for natural gas supplies were adjusted downward through 2014 to better reflect current forward market conditions. 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.

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 operating and maintenance ("O&M") costs associated with the up-front clean-up skid are assumed to be 2% of the additional capital costs. The total amount of electricity generated by fuel cells operating on renewable digester gas is reduced by 10% to reflect the parasitic electric load required to operate the equipment associated with the up-front clean-up skid.

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 Figures 3 and 4 of the main report 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 3 and 4 of the main report assume that natural gas is available to replace up to 25% of the fuel cell 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 the 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 $20-167/kW less in up-front capital costs and reduced annual O&M costs equal to 2% of the reduced up-front capital costs.

II. 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:

- For fuel cells that operate 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, and is assumed to be 10% of the natural gas cost in the results presented in Figures 3 and 4 of the main report.

- 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 captured from the fuel cell.

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 (if applicable). 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 8.25%.[30]

III. 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.[31]

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-

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[30] For the eight fuel cell projects included in this benefit-cost analysis, project life was typically 20 years. The 8.25% nominal discount rate is equivalent to the 20-year Weighted Average Cost of Capital used in the 2009 Market Price Referent ("MPR").

[31] 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.

to-gross" percentage, that determines the value of the RIM Test benefit-cost ratio for any given project in any given utility franchise area.[32] 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.

IV. 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–which were not considered in either the Participant Test or the RIM Test–is explicitly included in the Societal Test. The analysis underlying the waterfall chart in Figures 1 and 2 of the main report 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.[33] 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 monetary payments to the natural gas or electric utility 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

[32] 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%. This analysis takes a somewhat more conservative approach and uses a net-to-gross percentage of 90% due to the contentiousness of the debate surrounding the appropriate calculation of the net-to-gross percentage. The implication is that 10% of the load shift attributable to the Self Generation Incentive Program (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 90% of the load shift that can be attributed to the incentive program.

[33] Note that the value of many of the distributed value elements included in the main report in Figure 1 and 2's waterfall charts (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.

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%.

Attachment E

Generation-Related Avoided Costs: Details

Generation-related avoided costs account for the lion's share of the value provided to the State of California by stationary fuel cells, followed closely by the value of avoided emissions and related health benefits. This attachment describes the derivation of value for each of the following categories of generation-related avoided costs, which are color-coded in blue in Figures 1 and 2 of the main report:

- Value of Avoided Generation Capacity Capital Cost
- Value of Avoided Generation Capacity Fixed Operating and Maintenance ("O&M") Cost
- Value of Avoided Generation Variable O&M Cost
- Value of Avoided Generation Fuel Cost
- Value of Avoided Fossil Fuel as a Price Hedge
- Value of Avoided Water Use.

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 California Public Utilities Commission ("CPUC") defined as the 2009 Market Price Referent ("MPR") proxy plant in its Resolution E-4298. 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 greenhouse reduction 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.

I. 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 550 megawatt ("MW") repowered subcritical pulverized coal generator (low end of range) and a 500 MW 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 ($353 per kW-yr for repowering a baseload coal plant,[34] and $1098 per kW-yr for a combined cycle gas generator for the CPUC 2009 MPR proxy plant).

II. VALUE OF AVOIDED GENERATION CAPACITY FIXED O&M COST

This is an additional avoided capacity cost, with an unadjusted range of $10.25/kW-yr for a combined-cycle gas turbine and $19.38/kW-yr for a repowered baseload coal generator, derived from the same sources as above.[35]

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 on-peak availability factor or 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.)

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.***

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[34] The repowering-related capital and O&M costs used in this analysis are derived from life extension costs for existing units used by the U.S. Environmental Protection Agency ("EPA") in its Base Case 2010 Integrated Planning Model (Exhibit 4-21). EPA's repowering costs are inflated to 2010$ from 2007$ using an inflation factor of 1.05 from the U.S. Bureau of Labor Statistics. See additional explanation in next footnote.

[35] EPA, August 2010, Chapter 4, Table 4-9, p. 4-12. The value of $19.38/kW-yr is for a 30-40 year old coal-fired steam turbine unit, unscrubbed (given the level of SO2 emissions assumed),with no nitrogen oxides ("NOx") or mercury control equipment. The EPA Base Case value of $45.80/kW-yr in 2007$ was inflated to 2010$ by multiplying by 1.05. $28.71/kW-yr was subsequently converted into $/kW and added to capital cost to avoid overstating value due to what was considered a too-high a coal plant fixed O&M value; the fixed O&M value was set equal to the new scrubbed coal plant fixed O&M in the 2009 Annual Energy Outlook and the balance of the cost was transferred to the repowering capital cost, on the rationale that the life extension investment would make the fixed O&M value "nearly new."

To recognize the dispersion value of distributed fuel cells, the generation-related avoided capacity costs have been multiplied by 1.17, 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 for fuel cells. Using 92.5% as the average annual capacity factor for the representative fuel cell in California, there are 8,103 hours of expected fuel cell generation per year (*i.e.*, 8760 hours/year x 0.925). The resultant Value of Avoided Generation Capacity Capital Cost is 0.78-2.23 cents per kilowatt-hour ("cents/kWh") for fuel cells operating 100% on natural gas and 0.72-2.06 cents/kWh for fuel cells operating on renewable fuel. The lower avoided cost value for fuel cells operating on renewable fuel reflects the impact of the 10% parasitic electric losses during the 75% of the time that renewable fuel is assumed to be used; natural gas is used the other 25% of the time. A similar impact will be evident in all of the avoided cost values calculated for fuel cells operating on renewable fuel.

III. VALUE OF AVOIDED GENERATION VARIABLE O&M COST

The Value of Avoided Generation Variable O&M Cost range of 0.14-0.29 cents/kWh for fuel cells operating 100% on natural gas is determined by the 2009 MPR proxy plant on the low side and by the adjusted EPA coal life extension costs on the high side.[36] The same is true for the Value of Avoided Generation Variable O&M Cost range of 0.13-0.27 cents/kWh for fuel cells operating on renewable fuel. In both cases, the Value of Avoided Water Use is subtracted out as a separate variable that sets an upper limit on the avoided variable O&M costs, as discussed below.

IV. VALUE OF AVOIDED GENERATION FUEL COST

Because fuel cells use an electrochemical reaction rather than combustion to generate electricity, fuel cells generally have a higher electrical efficiency than combustion-based distributed generation technologies of similar size. The representative fuel cell in this avoided cost analysis is based on the operational parameters of 300-1400 kW fuel cells, based on products currently available for distributed baseload power generation. The representative fuel cell reflects a variety of fuel cell technologies with different efficiencies. As a consequence, the (average) representative fuel cell has a relatively high heat rate compared to the average fleet of California natural gas-fired generators. The average fleet of California natural gas-fired generators has a relatively low assumed heat

[36] EPA, August 2010, Chapter 4, Table 4-8, p. 4-9. The value of 0.1082 cents/kWh is the mid-point variable O&M cost for an unscrubbed coal steam plant with no NOx or mercury control equipment, inflated to 2010$ from 2007$ using an inflation factor of 1.05 from the U.S. Bureau of Labor Statistics.

rate of 7,633-7,692 Btu/kWh,[37] which is actually lower than the assumed 8,759-9,717 Btu/kWh heat rate of the representative fuel cell before taking into account the efficiency benefit of operating in combined cooling, heating and power ("CCHP") mode (the value of which is calculated separately and discussed in Section IV.E of the main report).[38] Thus, the Value of Avoided Generation Fuel Cost in this analysis is derived only from the use of renewable fuels (where applicable) and from avoided natural gas boiler fuel as a result of cogeneration; there is no Value of Avoided Generation Fuel Cost attributed to electricity generation when the representative fuel cell is assumed to be operating 100% on natural gas.

Fuel flexibility is an important attribute of stationary fuel cells that is not explicitly quantified in this avoided cost analysis. Fuel cells may 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.[39]

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").[40] Since the beginning of calendar year 2007, this range has been

[37] The average California avoided natural gas-fired plant had a five-year weighted-average heat rate for 2003-2007 that was approximately 11% less efficient than that of the 2009 MPR proxy plant, based on state-specific electricity generation and fuel consumption values as reported by EIA (March 2010; February 2011). The five-year weighted-average heat rate for 2003-2007 is used as a point of comparison to the 2009 MPR proxy plant because the 2003-2007 time period reflects data from a time period ending at roughly the same time that the 2009 MPR was being set, given the two-year lag in EIA data availability.

[38] All heat rates are expressed in terms of higher heating value ("HHV") in this paper, as described in greater detail in Attachment B.

[39] With respect to the avoided natural gas plant, the natural gas-fired 2009 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.

[40] 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.

$2.51-13.58/MMBtu, for natural gas located at the Henry Hub, onshore Louisiana.[41] Natural gas prices have dropped significantly in the past several years due to the combined impact of reduced demand starting with the economic downturn in 2008 and increased production from shale gas. Historical rather than forecast NYMEX prices are used in this updated analysis, given the uncertainties associated with forecasting future economic activity, natural gas demand, and shale gas development. Changes to the assumed range of fuel costs underlying the fuel-related values calculated in this analysis would result in directionally proportionate changes to those values.

The NYMEX natural gas price is converted to cents per kWh by adding the implied transportation cost between California and the Henry Hub and multiplying the result times the range of heat rates assumed for (i) the average California avoided natural gas-fired plant (*i.e.*, 7,633-7,692 Btu/kWh) and (ii) the representative fuel cell (*i.e.*, 8,759-9,717 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 2007, this monthly average coal price has ranged from $1.75-2.32/MMBtu. (*See* EIA, January 4, 2011a, 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.*, 8,740-10,744 Btu/kWh).[42]

The Avoided Generation Fuel Cost calculated using the above methodology yields no value for the electricity produced by fuel cells operating on 100% natural gas due to the fact that the heat rate range of the average fleet of California natural gas-fired generators is lower than that of the representative fuel cell. However, fuel cells operating on renewable digester gas are assumed to use natural gas only 25% of the time, contributing to the Avoided Generation Fuel Cost for the 75% of the time that they operate using renewable fuel.[43] The 75% renewable fuel use contributes 0.75-4.93 cents/kWh to the Value of Avoided Generation Fuel Cost in the "California Fuel Cell Value" shown in Figure 2 of the main report. The additional 0.95-5.35 cents/kWh making up the range of the Value of Avoided Generation Fuel Cost in Figure 2 comes from the avoided natural gas boiler fuel for the 75% of the time that the representative fuel cell is operating in cogeneration mode, regardless of fuel type. For fuel cells operating 100% on natural gas,

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[41] A cost adjustment of ($0.21)/MMBtu has been included to reflect the (negative) value of natural gas in California relative to the value at the Henry Hub. This "basis" value is taken from the front years of the 2009 MPR, thought the basis tends to be highly volatile, varies seasonally, and has historically been either positive or negative, depending largely on pipeline capacity restraints between California and the Henry Hub .

[42] EIA, April 2010, Table 8.2. The minimum heat rate for the repowered coal plant is assumed to be equal to the new-and-clean heat rate for a new scrubbed coal plant, nth of a kind. The maximum heat rate is based on six years of 3.5% annual heat rate degradation.

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

the contribution to the Value of Avoided Generation Fuel Cost stems entirely from cogeneration. The avoided coal price of 1.15 cents/kWh is the basis of the lower end of the range, and the basis-adjusted avoided natural gas price of 5.66 cents/kWh is the basis of the upper end of the range for the Avoided Generation Fuel Cost component attributable to the electricity generated using 75% renewable fuel, *i.e.*, prior to recognition of the Cogen(eration) Credit. As explained in Section IV.E of the main report , the Cogen(eration) Credit of 0.9-5.35 cents/kWh of Value of Avoided Generation Fuel Cost makes up the total Value of Avoided Generation Fuel Cost for fuel cells operating 100% on natural gas and slightly more than half of the total of 1.70-10.28 cents/kWh for fuel cells operating on renewable fuel with 25% natural gas backup.

V. VALUE OF AVOIDED FOSSIL FUEL AS A PRICE HEDGE

As explained in the previous section, the representative fuel cell operating 100% on natural gas contributes fuel-related avoided cost value only for the products that it cogenerates, not for the electricity that it produces. The representative fuel cell operating on renewable fuel contributes fuel-related avoided cost value for the products that it cogenerates and for the electricity that it generates using renewable fuel. Avoiding fossil fuel use in important because it also avoids fossil fuel price volatility, which can wreak havoc with personal and corporate budgets. Fossil fuel input that is avoided by fuel cells using renewable fuel and/or capturing and using the high quality waste heat, therefore, provides a type of price hedging mechanism that protects electricity consumers from unpredictable fossil fuel price volatility.

Deriving the range of estimates for the Value of Avoided Fossil Fuel as a Price Hedge is based on a two-step process. First, the cost of locking in a long-term fuel contract is estimated based on a methodology derived by Bolinger, *et al.* that is updated annually.[44] Based on the much lower cost in Bolinger and Wiser's 2010 update,[45] an equivalent cost of 25-30 cents/kWh to lock in a long-term fuel contract is used in this analysis. The heat rate end-points of the two potential avoided central station generators (*i.e.*, 7,633 Btu/kWh and 10,744 Btu/kWh) are then applied to this cost range to derive a Value of Avoided Fossil Fuel as a Price Hedge in the event that 100% of the central station generator fuel cost was avoided.

As was the case for the Avoided Generation Fuel Cost, the attributed Value of Avoided Fossil Fuel as a Price Hedge for the electricity generated by the representative fuel cell only applies for the proportion of that electricity that is generated using renewable fuel. The electric-only hedge value range of 0.02-0.38 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 0.28-0.67 cents/kWh is attributed to the cogenerated products from

[44] Bolinger, *et al.*, January 2004, p. 8.

[45] Bolinger and Wiser, January 4, 2010, pp. 8-9.

the 75% of representative fuel cell assumed to operate in CCHP mode. Capturing and using waste heat for cogeneration and CCHP applications avoids natural gas input to the avoided boiler regardless of the fuel type used by the fuel cell. For fuel cells operating on renewable fuel, these two components combined have a total Value of Avoided Fossil Fuel as a Price Hedge of 0.30-1.06 cents/kWh. For fuel cells operating 100% on natural gas, only the 0.28-0.67 cents/kWh value attributed to the cogenerated products applies.

F. VALUE OF AVOIDED WATER USE

Some fuel cells consume water for the electrochemical reaction that generates electricity and for the water purification to meet fuel cell input requirements.[46] Other fuel cells either have 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 2009 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).[47] The existing fleet of baseload coal generators serving California is assumed to use closed recirculating cooling, which requires 0.702 gallons of raw water per kWh of generation (National Energy Technology Laboratory ("NETL"), May 2007, p. 71).[48] These values compare to an estimated range of raw water use per kWh for the representative fuel cell of 0-0.045 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 0.657 gallons per kWh. The range of water costs applied to the avoided central station generator water use is $0.7913-$7.8527 per hundred cubic feet of metered water, based on tariff rates as of December 2010 for Class A water companies located throughout California.

The calculated (unadjusted) range of Value of Avoided Water Use is 0.002-0.426 cents/kWh. However, since the cost of water usage is typically included in the Value of Avoided Generation Variable O&M Cost,[49] the (adjusted) Value of Avoided Water Use cannot exceed the Value of the Avoided Generation Variable O&M Cost. In our study, the (adjusted) Value of Avoided Water Use of 0.002-0.108 cents/kWh has been

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

[47] 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 2009 proxy plant.

[48] 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*.

[49] *See* CEC, online "California Distributed Energy Resource Guide."

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 may significantly underestimate the Value of Avoided Water Use since those prices do not fully reflect the societal cost of the water used.

Attachment F

Grid-Related Avoided Costs: Details

Avoided T&D cost and other grid-related avoided costs account for up to 12% of the total value proposition of distributed fuel cells in California in this updated analysis. This attachment describes the derivation of value for each of the following categories of grid-related avoided costs, which are color-coded in blue in Figures 1 and 2 of the main report:

- Value of Avoided Transmission Cost
- Value of Avoided Distribution Cost
- Value of Grid Support
- Value of Avoided Losses
- Value of Increased Reliability and Blackout Avoidance
- Value of Improved Power Quality.

I. VALUE OF AVOIDED TRANSMISSION COST

The (adjusted) Value of Avoided Transmission Cost in 2010 ranged from a low of 0.02 cents per kilowatt-hour ("cents/kWh") for transmission into the service territory of Pacific Gas & Electric ("PG&E") to a high of 0.25 cents/kWh for transmission into the service territory of Southern California Edison ("SCE").

II. VALUE OF AVOIDED DISTRIBUTION COST

The (adjusted) Value of Avoided Distribution Cost in 2010 ranged from a low of 0.07 cents/kWh in the Dominguez Hills area within SCE's service territory to a high of 1.02 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 0.12 cents/kWh occurs in the East Bay region within PG&E's service territory, and the maximum value of 1.16 cents/kWh occurs within SDG&E's service territory.

III. 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 7.8% less electricity has to be generated by central generating stations, with an equivalent percentage reduction in generation-related capacity requirements, operating and maintenance costs, fuel input, and emissions output.[50]

IV. 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).

V. 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. In addition, fuel cells can also maintain power in the event of a grid outage, in effect providing backup power.

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.[51]
- 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.[52]

The range of the Value of Improved Reliability and Blackout Avoidance of 0.003-0.351 cents/kWh for fuel cells operating on 100% natural gas is calculated using 2007 values

[50] California Public Utilities Commission, September 30, 2010, Staff Proposal (September 2010), p. 58. The 7.8% value for avoided line losses is the most recent value found and has been used by all parties to the CPUC proceeding regarding prospective modifications to the Self Generation Incentive Program.

[51] 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 2008, the most recent year for which California retail electricity sales data are available, this ratio was estimated to be 0.06%.

[52] 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."

for GSP (the latest available) and 2010 fuel cell penetration.[53] (The range of value for fuel cells operating on renewable fuel is slightly lower due to the impact of the parasitic electric load required to run the digester gas cleanup equipment.) The lower end of the range is based on a 1-hour blackout that affects 10% 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).[54] 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 400 megawatts ("MW") of installed fuel cell capacity is achieved by 2020, fuel cell penetration would increase nearly 17-fold from today's level, potentially generating more than 1% of the total MWh consumed in California, providing up to 7.36 cents/kWh (in 2010$) in Value of Improved Reliability and Blackout Avoidance.

VI. VALUE OF IMPROVED POWER QUALITY

The Value of Improved Power Quality is calculated as being 15% of the Value of Reliability and Blackout Avoidance.[55] 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:[56]

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53 The Value of Increased Reliability/Power Quality/Blackout Avoidance range of <0.01-0.40 cents/kWh shown in the main report's Figure 1 in the "California Fuel Cell Value" waterfall chart and the range of <0.01-0.37 shown in the main report's Figure 2 waterfall chart combines the Value of Increased Reliability and Blackout Avoidance with the Value of Increased Power Quality (discussed below).

54 *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.

55 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 Figures 1 and 2 of the main report.

56 Energy and Environmental Analysis, Inc., and Pace Energy Project, December 2005, pp. ES1 and ES3.

- “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.)

The calculated range for the current Value of Improved Power Quality is 0.0004-0.053 cents/kWh for fuel cells operating 100% on natural gas case and slightly lower for the renewable fuel case. 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.

Attachment G

Avoided Emissions and Related Health Benefits: Details

The avoided emissions and related health benefits attributable to distributed fuel cells in California contribute nearly as much value as do generation-related avoided costs. This attachment provides a detailed description of how the range of value is calculated for each of the following types of avoided emissions:

- Nitrogen oxides ("NO_x")
- Sulfur dioxide ("SO_2")
- Volatile organic compounds ("VOC")
- Carbon monoxide ("CO")
- Particulate matter less than 10 microns in diameter ("PM10")
- Mercury
- Carbon dioxide ("CO_2").

The derivation of the Value of Health Benefits of Avoided In-State Emissions can be found immediately following the detailed descriptions of the avoided emissions.

I. 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 7,633-7,962 Btu/kWh, the resultant NO_x emissions rate is 0.101-0.103 lb/MWh. For the typical avoided baseload coal generating plant serving California, the assumed NO_x emissions rate is 0.07 lb/MMBtu, the mid-point of the emissions rate identified by the Center for Energy Efficiency and Renewable Technologies ("CEERT") for a subcritical pulverized coal plant burning bituminous coal without carbon capture.[57] For the assumed heat rate range of 8,740-10,774 Btu/kWh, the resultant NO_x emissions rate is 0.66-0.81 lb/MWh. The estimated NO_x emissions rate for the representative fuel cell is 0.015 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 is this analysis is \$50,000-\$547,945/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 \$7.80-\$650/ton, where the NO_x emissions allowances must be purchased separately for each year.

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57 CEERT, *et al.*, 2005, p. 31.

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 0.18-3.04 cents per kilowatt-hour ("cents/kWh") for fuel cells operating 100% on natural gas and 0.26-4.01 cents/kWh for fuel cells operating on renewable fuel, with the added value due to the value of the avoided flare gas emissions.[58]

II. VALUE OF AVOIDED SO_2 EMISSIONS

The Updated E3 Electric Avoided Costs Workbook does not include calculations of SO_2 emissions, and the National Energy Technology Laboratory ("NETL") indicates that target SO_2 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 SO_2 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 SO_2 emissions rate of 0.15 lb/MMBtu of coal is used in the valuation of Avoided SO_2 Emissions.

For the assumed heat rate range of 7,633-7,962 Btu/kWh for the average avoided natural gas-fired plant, the resultant SO_2 emissions rate is 0.021-0.022 lb/MWh. For the avoided baseload coal generating plant at the assumed heat rate range of 8,740-10,744 Btu/kWh, the resultant SO_2 emissions rate is 1.41-1.74 lb/MWh. The SO_2 emissions rate for fuel cells is assumed to be <0.001 lb/MWh.

As was the case for NO_x emissions, the value of the avoided SO_2 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 SO_2 ERCs used is this analysis is $40,275-$140,205/lb/day. For the baseload coal plant, the value of avoided SO_2 emissions is again based on observed prices for annual SO_2 emissions allowances in markets outside of California. The range of prices used in this analysis is $52.80-$170.92/ton, where SO_2 emissions allowances (like NO_x allowances) must be purchased separately for each year.

Combining the calculated range of avoided SO_2 emissions and the applicable range of prices for each of the baseload technologies yields a range of Value of Avoided SO_2

[58] All reported values for avoided emissions in this Attachment G include (i) the value of avoided emissions (where applicable) for avoided digester gas flaring for fuel cells operating on digester gas as reported in Section IV.D of the main report and (ii) the value of avoided emissions for cogeneration and CCHP as reported in Section IV.E of the main report. In addition, all reported values for avoided emissions are grossed up by 7.8% to reflect the value of avoided T&D losses. To avoid double counting, the latter values are not included in the Value of Avoided Losses.

Emissions of <0.01-0.04 cents/kWh, regardless of which fuel the representative fuel cell uses since no SO_2 emissions rate was found in the literature for flared digester gas.

III. VALUE OF AVOIDED VOC EMISSIONS

The VOC emissions rate for both the average avoided natural gas-fired plant and the avoided 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 avoided central station generating technology, the resultant range of VOC emissions is about 0.10 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 CantorCO2e VOC ERC index for the Houston-Galveston Area for the outside-of-California baseload coal plant VOC emissions.[59] The range of Value of Avoided VOC Emissions is <0.01-0.29 cents/kWh for fuel cells operating 100% on natural gas and <0.01-0.35 cents/kWh for fuel cells operating on renewable fuel, with the added value due to the value of the avoided flare gas emissions.

IV. 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 0.065-0.066 lb/MWh is calculated using the parameters in the updated E3 Electric Avoided Costs workbook and the heat rate range of 7,633-7,962 Btu/kWh. The PM10 emissions rate range for the baseload coal plant of 0.26-0.32 lb/MWh is calculating using the CEERT-equivalent 0.028 lb/MMBtu emissions rate and the heat rate range of 8,740-10,744 Btu/kWh. As a rule, fuel cells have virtually no solid emissions, so the PM10 emissions rate for fuel cells is considered to be nil.

The Value of Avoided PM10 Emissions uses observed California PM10 ERC prices for the average natural gas-fired plant emissions, and the CantorCO2e 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 0.07-0.29 cents/kWh for fuel cells operating 100% on natural gas and 0.07-0.30 cents/kWh for fuel cells operating on renewable fuel, with the added value due to the value of the avoided flare gas emissions.

[59] These were the only VOC emissions allowance prices found for outside-of-California.

V. 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 0.90-0.91 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 the representative fuel cell, which is estimated to be 0.02 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. By multiplying the end-points of these prices times the end-points of the avoided CO emissions, the Value of Avoided CO Emissions of 0.01-0.10 cents/kWh for fuel cells operating 100% on natural gas and 0.02-0.10 cents/kWh for fuel cells operating on renewable fuel is calculated, with the added value due to the value of the avoided flare gas emissions.

VI. VALUE OF AVOIDED MERCURY EMISSIONS

The U.S. Environmental Protection Agency ("EPA") issued the Clean Air Mercury Rule ("CAMR") on May 15, 2005. The District of Columbia Circuit Court of Appeals vacated the CAMR on February 8, 2009, and the U.S. Supreme Court refused to hear EPA's request for review of the Court of Appeals decision, effectively invalidating the CAMR. As a result, there are no federal regulations to control mercury emissions and no related market prices. 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.[60]

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.[61] At the baseload coal plant's assumed heat rate range, the range of mercury emissions is 2.77E-05 lb/MWh to 3.41E-05 lb/MWh; all of these mercury emissions would be avoided by electricity generated by fuel cells.[62]

[60] Krotz, October 26, 2006, p. 3.

[61] "TBtu" stands for "trillion Btu," which is equal to a million MMBtu.

[62] 1.0E-05 is scientific notation for 0.00001.

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 3.41E-05 lb/MWh upper limit on baseload coal generator mercury emissions yields a maximum Value of Avoided Mercury Emissions of 0.12 cents/kWh for fuel cells operating 100% on natural gas; this value drops to 0.12 cents/kWh for fuel cells operating on digester gas due to the influence of the 10% parasitic electric load.

Based on previous findings by 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, SO_2, and NO_x.

VII. VALUE OF AVOIDED CO_2 EMISSIONS

For natural gas-fired generators, the E3 Avoided Cost Study (pp. 74-75) estimates a linear relationship between CO_2 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 CO_2 per MMBtu. (*See* Updated E3 Electric Avoided Costs Workbook supporting file cpucAvoided26-1_update3-20-06.xls for detailed derivation.) Based on the 7,633-7,962 Btu/kWh heat rate range assumed for the average California avoided natural gas-fired plant in this analysis, the associated CO_2 emissions rate would be 0.48-0.49 ton/MWh.

The CO_2 emissions rate for the avoided baseload coal generator is estimated to range from 0.97-1.19 ton/MWh, using the CO_2 emissions rate of 205.573 lb/MMBtu from EIA's 2009 Electric Power Annual over the assumed heat rate range of 8,740-10,744 Btu/kWh.[63]

The electric-only CO_2 emissions rate for the representative fuel cell operating 100% on natural gas is 0.49-0.544 ton/MWh. This electric-only CO_2 emissions rate for fuel cells operating on 100% natural gas is offset by two factors: (1) The use of renewable fuel; and (2) avoided natural gas boiler fuel resulting from the use of waste heat in combined cooling, heating and power ("CCHP") mode.

The use of renewable fuel by the representative fuel cell offsets the electric-only CO_2 emissions rate in direct proportion to the proportion of renewable fuel used. The avoided natural gas boiler fuel emissions increase in direct proportion to the proportion of time the fuel cell operates in CCHP model, resulting in another offset to the fuel cell's electric-only CO_2 emissions rate.

The electric-only range of fuel cell CO_2 emissions is compared to a combined CO_2 emissions rate range of 0.48-1.19 ton/MWh for the avoided central station generators,

[63] EIA, January 2011, Table A-3, p. 97. This more recent estimate is lower than the average 208 lb/MMBtu CO2 emissions rate derived in CEERT, *et al*., 2005.

with the avoided average natural gas-fired plant setting the lower end of the range and the avoided baseload coal generator setting the upper end of the rage. The avoided central station CO_2 emissions attributable to the electricity generated by fuel cells operating 100% on natural gas thus range from 0-0.646 ton/MWh. The avoided central station CO_2 emissions attributable to the electricity generated by fuel cells operating predominantly on renewable fuel (with only 25% natural gas for backup) thus range from 0.36-1.05 ton/MWh. Cogeneration from waste heat capture from the representative fuel cell contributes an additional 0.20-0.25 ton/MWh of avoided CO_2 emissions as an offset against the electric-only CO_2 emissions, regardless of fuel type.

Although CO_2 and other greenhouse gas emissions are not yet subject to mandatory regulation in the United States, California's Air Resources Board ("CARB") has proposed regulations for a cap-and-trade program under AB32, to be implemented on January 1, 2012 (unless postponed due to several pending lawsuits).[64] Alternate data sources to estimate potential future CO_2 prices in California could be (i) the \$8/ton CO_2 cost that the California Public Utilities Commission ("CPUC") has required IOUs to apply to "penalize" potential new generation resources as part of its Integrated Resource Planning process, or (ii) CO_2 emissions prices in Europe, which since the European Union's Emissions Trading System ("ETS") began in October 2005 have traded anywhere up to €35/metric tonne, most recently trading at or below half the peak price.[65]

The CPUC's assumed \$8.00/ton CO_2 is used to establish the minimum Value of Avoided CO_2 Emissions.[66] The maximum price per ton of CO_2 is more difficult to assess, with the European ETS prices being perhaps the best 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-\$1.40/€, the resultant range of CO_2 emissions allowance prices is \$29.75-\$49.00/ton CO_2.

In terms of carbon, rather than of CO_2, the CPUC's required use of \$8/ton of CO_2 in the Integrated Resource Planning 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 CO_2. If the CO2-equivalent cost of \$100/ton of carbon (*i.e.*, \$27.27/ton of CO_2) is applied to the electric-only, 100% natural gas fuel cell range of avoided CO_2 emissions of 0-0.646 ton/MWh, the associated Value of Avoided CO_2 Emissions ranges from zero up to \$17.61/MWh, equivalent to 0-1.76 cents/kWh. Multiplying the \$8/ton CO_2 times the same range of avoided CO_2 emissions results in a range of Value of Avoided CO_2 Emissions from zero up to \$5.17/MWh, equivalent to 0-0.52 cents/kWh. Combining these results yields a range of electric-only value of 0-1.76 cents/kWh. Adding the range of Value of Avoided CO_2 Emissions from fuel cell cogeneration of

[64] CARB, October 28, 2010.

[65] Chicago Climate Exchange, various dates.

[66] The E3 Avoided Cost Study (p. 79) uses a cost estimate of \$0.004/lb of CO_2, which is the equivalent of the \$8/ton of CO_2 penalty applied in the CPUC's Integrated Resource Planning process.

0.16-0.67 cents/kWh yields a total Value of Avoided CO_2 Emissions of 0.16-2.43 cents/kWh for fuel cells operating 100% on natural gas.

If the CO2-equivalent cost of $100/ton of carbon (*i.e.*, $27.27/ton of CO_2) is applied to the electric-only, 75% renewable fuel range of avoided CO_2 emissions of 0.36-1.054 ton/MWh, the associated Value of Avoided CO_2 Emissions ranges from $9.82-28.74/MWh, equivalent to 0.98-2.87 cents/kWh. Multiplying the $8/ton CO_2 times the same range of avoided CO_2 emissions results in a range of Value of Avoided CO_2 Emissions from $2.88-8.40/MWh, equivalent to 0.29-0.84 cents/kWh. Combining these results yields a range of electric-only value of 0.29-2.87 cents/kWh. Adding the range of Value of Avoided CO_2 Emissions from fuel cell cogeneration of 0.16-0.67 cents/kWh yields a total Value of Avoided CO_2 Emissions of 0.45-3.54 cents/kWh for fuel cells operating on renewable fuel, which is reduced to a total adjusted Value of Avoided CO_2 Emissions of 0.43-3.33 cents/kWh due to the impact of the 10% parasitic electric load when operating on renewable fuel.

VIII. 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 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 CARB for calendar year 2000 for electric generation and cogeneration (*See* CARB, 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/CARB, May 3, 2002; Cal EPA/CARB, May 31, 2003; Cal EPA/BTHA, January 2007.) Combining results from these sources, the Value of Health Benefits of Avoided In-State Emissions for PM2.5 is 2.01-2.03 cents/kWh in Figure 1 of the main report (for fuel cells operating 100% on natural gas) and 1.86-1.87 cents/kWh in Figure 2 of the main report (75% renewable fuel; 25% natural gas use), with the latter value reflecting the offsetting impact of avoided digester gas flare emissions and the 10% parasitic electric load for digester gas cleanup. Similarly, the additional value of health benefits for avoided >PM2.5-PM10 emissions is 0.07-0.08 cents/kWh in Figure 1 and 0.19-0.22 cents/kWh in Figure 2, the latter of which is driven by the significant health benefits of avoided digester gas flare emissions.

The health benefits of reduced NO_x and SO_2 power plant emissions on a cents/kWh basis are derived using the results of an extensive study by Abt Associates (Abt Associates, October 2000). [67] 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.[68] 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 PV 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 SO_2 power plant reductions to arrive at a value of $1.02/lb (1999$) of reduced emissions.[69] The $1.02/lb (1999$) of reduced emissions was inflated to 2010$ and then converted to cents/kWh using estimated NO_x and SO_2 emissions rates from the Updated E3 Electric Avoided Costs Workbook for the heat rate range of 7,633-7,962 Btu/kWh for the average California natural gas-fired plant. Estimated NO_x and SO_2 emissions rates for the baseload coal-fired generator plant were obtained from the literature, and applied to the heat rate range of 8,740-10,744 Btu/kWh. The Value of Health Benefits of Avoided In-State Emissions for avoided NO_x and SO_2 emissions ranges from 0.06-0.07 cents/kWh for fuel cells operating 100% on natural gas; the range for fuel cells operating on renewable fuel is 0.09-0.10 cents/kWh, including the health benefits of avoided digester gas flare emissions. Both ranges of value include the value of health benefits attributable to avoided boiler emissions for the 75% of fuel cells assumed to be operating in cogeneration mode.

The Total Value of Health Benefits (includes values for avoided PM2.5, PM10, NO_x and SO_2) is 2.14-2.18 cents/kWh for fuel cells operating 100% on natural gas and 2.14-2.19 cents/kWh for fuel cells operating on renewable fuel.

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

[68] The Abt Associates study includes avoided incidences of Work Loss Days among its categories of health benefits of reduced NO_x and SO_2 power plan emissions. The value of Work Loss Days makes up only 0.04% of the calculated California-specific health benefits.

[69] A 75% reduction in NO_x and SO_2 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, January 4, 2011b.)

Attachment H

Input Assumptions and Results

Table H-1. Input Assumptions

	Heat Rate Range (Btu/kWh, HHV)	Emissions Rate (CO_2 in tons/MWh; all others in lb/MWh)						
		NO_x	SO_2	PM10	CO	VOC	Mercury	CO_2
Representative Fuel Cell	8,759	0.015	<0.001	-	0.02	0.02	-	0.544*
	9,717	0.015	<0.001	-	0.02	0.02	-	0.490*
Average CA Natural Gas-Fired Generator	7,962	0.10	0.022	0.066	0.91	0.10	-	0.49
	7,633	0.10	0.021	0.065	0.90	0.10	-	0.48
Pulverized Coal-Fired Generator	10,744	0.81	1.740	0.320	0.22	0.03	3.41E-05	1.19
	8,740	0.66	1.413	0.260	0.18	0.02	2.77E-05	0.97
Boiler Emissions (at 100% Natural Gas)		0.57	0.003	0.006	0.228	0.023	-	0.33
ADG Flare Emissions (at 100% ADG)		0.324	-	0.012	0.272	0.052	-	-

		NO_x	SO_2	PM10	CO	VOC	Mercury	CO_2
Emissions Prices	In-State:	($/lb/day)	($/lb/day)	($/lb/day)	($/lb/day)	($/lb/day)	($/lb)	($/ton)
	Maximum	$547,945	$145,205	$379,452	$8,337	$273,973	$35,000	$27.27
	Minimum	$ 50,000	$ 40,275	$107,500	$4,214	$ 4,450	$ 5,000	$ 8.00
	Out-of-State:	($/ton)	($/ton)	($/ton)	($/ton)	($/ton)	($/lb)	($/ton)
	Maximum	$ 650.00	$ 170.92	$ 5,000	n/a	$ 5,000	$35,000	$27.27
	Minimum	$ 7.80	$ 52.80	$ 4,850	n/a	$ 4,850	$ 5,000	$ 8.00

* For 100% natural gas; reduced in proportion to the % of renewable fuel used.

Table H-2. Results: Value of Avoided Emissions and Health Benefits

Value of Avoided Emissions (¢/kWh)		NO_x	SO_2	PM10	CO	VOC	Mercury	CO_2
Case 1: 100% NG, 75% Cogen Mode	Maximum	3.05	0.04	0.29	0.10	0.29	0.12	2.43
	Minimum	0.18	<0.01	0.07	0.01	<0.01	-	0.16
Case 2: 75% ADG, 75% Cogen Mode	Maximum	4.00	0.04	0.30	0.10	0.35	0.11	3.33
	Minimum	0.27	<0.01	0.07	0.02	<0.01	-	0.43
Case 3: 100% NG, 100% Cogen Mode	Maximum	3.88	0.04	0.30	0.10	0.31	0.12	2.65
	Minimum	0.25	<0.01	0.07	0.02	<0.01	-	0.21
Case 4: 75% ADG, 100% Cogen Mode	Maximum	4.84	0.04	0.30	0.11	0.37	0.11	3.55
	Minimum	0.33	<0.01	0.07	0.02	0.01	-	0.48

Value of Health Benefits (¢/kWh)		NO_x & SO_2	PM10	PM2.5*
Case 1: 100% NG, 75% Cogen Mode	Maximum	0.07	0.08	2.03
	Minimum	0.06	0.07	2.01
Case 2: 75% ADG, 75% Cogen Mode	Maximum	0.10	0.22	1.87
	Minimum	0.09	0.19	1.86
Case 3: 100% NG, 100% Cogen Mode	Maximum	0.09	0.10	2.03
	Minimum	0.08	0.09	2.01
Case 4: 75% ADG, 100% Cogen Mode	Maximum	0.12	0.25	1.87
	Minimum	0.10	0.22	1.86

* *PM2.5 emissions make up 98% of the PM10 emissions category by weight, per California Air Resources Board 2000 Emissions Inventory.*