Application: R.20-11-003

Exhibit No.:

Witness(es): Faruqui

PREPARED DIRECT TESTIMONY OF

# DR. AHMAD FARUQUI

ON BEHALF OF

# BLOOM ENERGY CORPORATION

**SEPTEMBER 10, 2021**

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# I. Introduction

**Q: Please state your name for the record.**

A: My name is Ahmad Faruqui.

**Q: Please describe your qualifications and experience.**

A: I am a Principal with The Brattle Group based in San Francisco, where I have been employed since 2006. I have previously worked at Charles River Associates and four other consulting firms. I have testified on rate design matters, including net energy metering, in several jurisdictions and also on matters involving energy efficiency, demand response, advanced metering infrastructure, and load forecasting in several jurisdictions. I hold a doctoral degree in economics from the University of California at Davis, a master's degree in agricultural economics also from the same university, and master's and bachelor's degrees in economics from the University of Karachi, Pakistan. I began my career at the California Energy Commission in the Assessments Division. Later, I worked at the Electric Power Research Institute for 11 years.

In my career, I have advised some 150 clients in 12 countries on 5 continents and appeared before regulatory bodies, governments, and legislative councils in Alberta (Canada), Arizona, Arkansas, California, Colorado, Connecticut, Delaware, District of Columbia, Egypt, FERC, Georgia, Illinois, Indiana, Iowa, Jamaica, Kansas, Kentucky, Michigan, Maryland, Minnesota, Missouri, Nevada, New Brunswick (Canada), Nova Scotia (Canada), Ohio, Oklahoma, Ontario (Canada), Pennsylvania, the Philippines, Saudi Arabia (ECRA), Texas, and Washington.

I serve on the editorial board of The Electricity Journal and have authored or coauthored more than 150 papers in peer-reviewed and trade journals dealing with various aspects of rate design, demand side management, energy efficiency, demand response, load forecasting, decarbonization and electrification. I have also co-edited 5 books on industrial structural change, customer choice, and electricity pricing. My work has been cited in *Bloomberg*, *Businessweek*, *The Economist*, *Forbes*, and *National Geographic*, in addition to news outlets including the *Los Angeles Times*, *The New York Times*, *San Francisco Chronicle*, *San Jose Mercury News*, and the *Washington Post*. I have also appeared on Fox Business News and NPR.

I have also taught economics at San Jose State University, the University of California, Davis, and the University of Karachi and delivered guest lectures at universities such as Carnegie Mellon, Harvard, Idaho, MIT, New York University, Northwestern, Rutgers, Stanford, UC Berkeley, and UC Davis.

**Q: Q. What is your expertise in matters related to Demand-Side Management?**

A: I was working at the Electric Power Research Institute ("EPRI") in the early 1980s where the term "demand-side management" was coined at a meeting at the Chicago O'Hare airport between EPRI and the Edison Electric Institute. I managed EPRI's multi-year project on Demand-Side Management ("DSM") that produced several reports on the subject. I organized several conferences on the topic with investor-owned utilities ("IOUs"), publicly owned utilities, and cooperatives and spoke at several others. As a consultant, I worked on DSM plans for utilities in several jurisdictions.

**Q: What is your expertise related to Cost-Benefit Tests related to Demand-Side Management?**

A: I used the five Standard Practice tests in my DSM planning studies. I also used the three-pronged test that was developed for fuel switching programs to evaluate a suite of electrification programs directed at commercial and industrial customers at a large California utility. More recently, I worked on a project for EPRI in which we developed a new test for evaluating electrification programs. This test was developed in consultation with several leading experts including a former president of the California Public Utilities Commission ("CPUC") and a leading analyst at the Natural Resources Defense Council ("NRDC"). It is called the Total Value Test.

**Q: Have you testified before the Commission previously?**

A: Yes, I have testified on behalf of Pacific Gas & Electric Company ("PG&E") and Southern California Edison ("SCE") on matters related to dynamic pricing in the context of advanced metering infrastructure and on behalf of the Joint Utilities on rate design matters related to fixed charges and inclining block rates.

**Q: On whose behalf are you testifying today in this proceeding?**

A: I am testifying on behalf of Bloom Energy.

**Q: What is the purpose of your testimony?**

A: I will comment on the proposed Emergency Capacity Services Tariff ("ECST") offered by Witness Detrio based on my independent analysis and discuss how fuel cells powered by natural gas participating in such a tariff can play a vital in enhancing system reliability during the emergency conditions that are the focus of this proceeding.

# II. Potential Impacts of the Proposed ECST if Used for Fuel Cell Deployment

**Q: Have you reviewed the revised scoping memo for this proceeding?**

A: Yes, I have the read the revised scoping memo.

**Q: Do you understand the Commission's objectives for this proceeding?**

A: Yes, I believe I do. I have also read the Governor's Emergency Proclamation. The state is experiencing an unusual energy emergency. The large-scale outages that took place last August are on everyone's mind. No one wants a repetition of those large-scale outages. The energy and capacity shortages are not going away any time soon. They may even get worse next year.

**Q: Have you reviewed the outline of the ECST proposal provided in the testimony of Ms. Detrio?**

A: Yes, I have reviewed it.

**Q: Have you undertaken any research or analyses that bear on the potential for the ECST proposal to further the objectives of this proceeding, as you understand them?**

A: Yes, I have undertaken such an analysis.

**Q: Could you provide a general description of the analysis that you conducted?**

A: The process involved several steps. First, we developed a methodology for predicting the number of customers that are likely to be interested in installing fuel cells, calibrated the methodology with the appropriate date on electric rates, gas prices and the cost of installing and operating the fuel cells and developed a predictive model. Second, we used the resulting model to predict likely fuel cell adoption rates for several customer types across the three investor-owned utilities in the state. Third, we used the number of participating fuel cell customers to assess the costs and benefits of fuel cells to California. We conducted the cost-benefit analysis under three sets of conditions: a reference case in which departing load and standby charges are imposed on customers with fuel cells, a case in which these customers are given credits to offset these two charges, and a case in which these customers are provided an emergency capacity payment of $2/kWh for energy provided to the grid under emergency conditions.

**Q: Could you provide a general description of how the analysis that you conducted bears on the potential value of the ECST to further the objectives of this proceeding, as you understand them?**

A: As stated above, we modeled the impact that providing a credit equivalent to the standby and departing load charges ("ECST credit") as well as an emergency capacity payment ("ECST emergency payment") would have on the economics of customers who are thinking of adopting fuel cells.

**Q: Can you briefly describe the cost effectiveness tests used in your analysis?**

A: I used two widely used cost effectiveness tests to evaluate the benefit of fuel cell technology. First, I used the Participant Cost Test ("PCT") to predict the number of fuel cell customers. Second, I compute the net benefits under the Total Resource Cost test ("TRC").[1] I use results from these two tests to estimate the total benefits that fuel cell deployment brings to California.

The PCT considers the net quantifiable benefits from the perspective of the participant. This test can be used to determine if a customer would adopt a particular measure by accounting for the reduction in electric bills that would accrue to the participant as well as accounting for any utility incentives that may be provided to the participant and comparing those benefits with the cost of adopting and installing the measure. As an example, if a utility offers a rebate to install an efficient central air conditioning system, the PCT would consider the reduction in the customer's electric bill and the rebate the utility pays to the customer against the incremental costs of buying and installing the more efficient air conditioner. This test is particularly useful in determining the attractiveness of the program to customers who are in the market to replace their existing equipment with more efficient equipment. However, the test does have a narrow scope given that it only assesses the program effectiveness from the perspective of the participating customer. Also, it only factors in quantifiable costs and benefits and does not account for intangible costs (e.g., noise and space intrusion) and benefits (e.g., enhanced comfort).

In addition, I also use TRC test, which compares the incremental costs of a new technology (excluding any transfer payments such as utility rebates) to the incremental benefits to the power system (mostly in the form of reduced use of the bulk power system). This test focuses on the question: is this program resulting in a net benefit to the system? To continue using the example from above, in the TRC test, the marginal costs of replacing inefficient air conditioners with more efficient air conditioners is compared against the net

[1] These tests were originally developed to evaluate energy efficiency programs. Since then, they have been applied to evaluate a number of programs, including demand response programs.

benefits (in the form of avoided costs or cost reductions) to the overall grid. If the reduction in overall grid costs is greater than the marginal cost to upgrade to more efficient air conditioners, the program would pass the TRC test. I note that this test does not account for any rebate the customer may receive from the utility nor does it consider the value of any lost revenue the utility may experience from reduced electric usage. The TRC test ignores these incentives and potentially lost utility revenues, not because they are not important to specific parties, but because they represent transfer payments between the parties, rather than the economic efficiency of the energy system as a whole.

Of the CPUC-approved cost-effectiveness tests, the TRC test has a wide scope and seems to most closely align with the CPUC's goal of pursuing policies that maximize long-term net benefits to the California energy system.

**Q: There are other cost-benefit analysis tests besides the PCT and the TRC. Why did you just focus on the PCT and the TRC tests in your analysis?**

Yes, besides the PCT and the TRC tests, three additional tests cost-effectiveness tests are included in the California Standard Practice Manual: the Program Administrator ("PAC") test, the Ratepayer Impact Measure ("RIM") test, and the Societal test.

The Societal test is a variant of the TRC test which uses a societal discount rate and includes externalities. To avoid the complex, fractious and largely unsettled discussion of what the right societal rate should be, including the issues associated with seeking to quantify externalities, I do not use the Societal Test.

The Program Administrator Cost Test uses a similar set of benefits to the TRC, but the costs are more narrowly defined as the costs incurred by the utility including any incentives paid to customers, program administration, among others. Given its similarity to the TRC but with the reduced scope of costs, I do not focus on this test.

The RIM test considers the shift in revenues between customers who participate in a program and customers who do not participate. The test considers the impact of the program on all ratepayers when assessing net benefits of a program. It considers the revenue and cost impacts from the perspective of the utility. If utility revenues decrease by less than utility costs, the utility gains in net revenue and can share these benefits with all ratepayers resulting in an overall reduction in rates for all ratepayers. Most energy efficiency programs do not pass the RIM test. But because they pass the TRC test and create value for the state as a whole, the state still spends $1.5 billion annually on energy efficiency programs.[2] Most electrification programs pass the RIM test but fail the TRC test. Most load management programs pass both the RIM and TRC tests.

Even though the RIM test can be easily applied to all DSM programs, this test too has a somewhat narrow scope and significant drawbacks. The RIM test is very sensitive to long-term projections of marginal costs and rates and is sensitive to assumptions about the financing of a given program. Most importantly, because the test only looks at utility costs, this test does not identify least-cost opportunities from an economic efficiency perspective,[3] nor does it capture a set of broader environmental and societal implications that have become ever more important in the age of decarbonization.

For these reasons, the PCT and TRC are the most appropriate cost-effectiveness tests to evaluate the net benefits of fuel cell technology.

**Q: Please describe how you analyze effects of the proposed ECST on fuel cell adoption using the PCT.**

A: I use the PCT to determine the impacts that standby and departing load charges would have on customer adoption of fuel cells. First, I create different customer profiles using the following key factors: utility-specific rate schedules (for the three IOUs), natural gas price (low, medium, and high), customer load profile (six profiles), and fuel cell costs (low,

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[2] Berg, W., S. Vaidyanathan, B. Jennings, E. Cooper, C. Perry, M. DiMascio, and J. Singletary. 2020. *The 2020 State Energy Efficiency Scorecard*, page 38. Washington, DC: ACEEE. aceee.org/research-report/u2011.

[3] See Decision 09-08-026 Decision Adopting Cost-Benefit Methodology For Distributed Generation

medium, and high). Together, I create 162 prototypical customer profiles to represent the California fuel cell market (see Figure 1 below).

**FIGURE 1: VARIABLES USED TO GENERATE 162 CUSTOMER PROFILES**

| Utilities & Rates | Gas Price at Henry Hub* ($/MMBtu) | Customer Load Profile | Bloom Cost ($/kWh) |
|---|---|---|---|
| PG&E – B-20 Rate | Low ($1.92) | Tech Campus | Low (-15% at $0.077) |
| SCE – TOU-8 Rate | Medium ($2.58) | Grocery Store | Medium ($0.091) |
| SDG&E – AL-TOU Rate | High ($2.97) | Hospital | High (+15% at $0.105) |
| | | Biotech | |
| | | Food Processing | |
| | | Office | |

Next, I run the PCT on a set of 162 prototypical potential customers twice. First, the PCT determines a customer's decision to adopt a fuel cell without any credit against the customer's rates (with standby and departing load charges applied). In this scenario, I compare current electric bills to the costs a customer would incur if they switched to a Bloom fuel cell. Switching to a Bloom fuel cell would mean a customer pays a Bloom per kWh charge and pays for fuel (whether biogas, hydrogen or natural gas), but would avoid a portion of their prior utility electric bill. I assume that a fuel cell passes the PCT if a customer's costs decrease under the fuel cell scenario. Aggregating the results from all prototypical customers gives a baseline fuel cell market. Although there are additional benefits of using a fuel cell such as no longer needing to run a diesel generator during outages, it is my understanding that customers generally need a net cost reduction as well as additional reliability benefits to invest in deploying a fuel cell.

Second, I evaluate a customer's decision to adopt a fuel cell system if a credit like the ECST credit is instituted. The credit amount is equivalent to the standby and departing load charges. After recalculating customer bills with the ECST credit, I again calculate the potential fuel cell market size by aggregating all customers who would experience a reduction in costs switching over to a fuel cell. I obtain an estimate for market size expansion by comparing these two estimates.

**Q: What are your findings?**

A: Overall, I find that providing fuel cell systems a credit equivalent to the standby and departing load charges results in a net system benefit and can greatly encourage the adoption of this technology. In the first scenario, where fuel cell systems receive no credit, only 19 percent of the potential customers were able to reduce their electric bills by adopting a fuel cell system (compared to having no fuel cell at all). For the entire group, their average energy cost increased by 9 percent. Applying a credit equivalent to the value of standby and departing load charges makes it significantly more attractive for customers to purchase fuel cell systems. Across the 162 simulations, 74 percent of potential customers can reduce their electric bills by adopting a fuel cell system, with the average savings of around 8 percent. Put differently, the credit leads to bill savings for a majority of customers. Without the credit, as many as 75 percent of the customers who historically would have adopted fuel cells now would not adopt.

**Q: What are the implications of your findings?**

A: Without a credit, I expect that there would be less fuel cell capacity deployed in the future relative to a scenario where a credit exists. To estimate what that difference may be, I construct a future projection of fuel cell deployment based on historical deployment. Between 2021 and 2030, I estimate that Bloom's fuel cell fleet will increase from about 300MW to about 700MW, with an average growth of 42 MW per year. Applying the 75 percent reduction would result in a potential loss 312 MW of fuel cell capacity in California by 2030. To put this in context, during the August 2020 events, California relied on between 756 and 910 MW of emergency capacity through demand response on August 14 and August 15.[4]

[4] California Independent System Operator, California Public Utilities Commission & California Energy Commission, "Final Root Cause Analysis, Mid-August 2020 Extreme Heat Wave," at pg. 108 (Jan. 13, 2021). available at: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf

**Q: Next, let us discuss the Total Resource Cost test. Please describe how you apply the TRC to estimate the net benefit of fuel cell technology.**

A: The TRC compares the marginal costs of using a new technology to the marginal benefits of using the new technology. In my analysis, I estimate the marginal costs of a Bloom fuel cell system as the capital and operational cost to operate a Bloom fuel cell minus the capital and operational costs of a diesel backup generation system providing comparable customer resilience. This is because when selecting their resilience options, many customers choose behind-the-meter diesel generators for their relatively low installation and operation costs. A typical Bloom customer places a relatively high value on a reliable source of power. This intangible benefit is traditionally captured in a model as the value of lost load ("VOLL"); however, it is challenging to determine an exact value on overall customer VOLL and VOLL estimates vary widely.[5] Rather than include a VOLL estimate that could distort actual system benefits and unduly influence the conclusions of this study, I assume a typical Bloom customer to have already addressed their need for resilience through the use of a diesel generator. Therefore, the incremental cost of using a fuel cell is the total cost of running a fuel cell less the cost of maintaining a diesel generator year-round and operating the generator during grid outages.[6] Bloom system costs are estimated using Bloom financial models while diesel generation costs are estimated using relevant data from PG&E's microgrid testimony.[7]

The marginal benefits of using a Bloom fuel cell include the reduced costs of running the California electric grid and additional environmental benefits**.** Since Bloom fuel cells generally run constantly, there is a quantifiable reduction in load on the electrical grid thereby reducing the need for infrastructure to support this load. This includes the reduction in costs from energy generation, generation capacity, ancillary services, losses, and transmission and distribution infrastructure. Environmental benefits include reduced impacts on $CO_2$ emissions, methane leakage, $SO_2$ emissions, and $NO_X$ emissions. I rely on

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[5] LBNL's Interruption Cost Calculator suggests a VOLL of $1,300 per kWh while ERCOT uses a VOLL of $9/kWh

[6] I assume that a diesel generator is used for 96 hours of the year based on PG&E's PSPS analysis

[7] See PG&E Prepared Testimony in CPUC Rulemaking 19-09-009, Exhibit No. PG&E-1, Workpaper Table 3-2

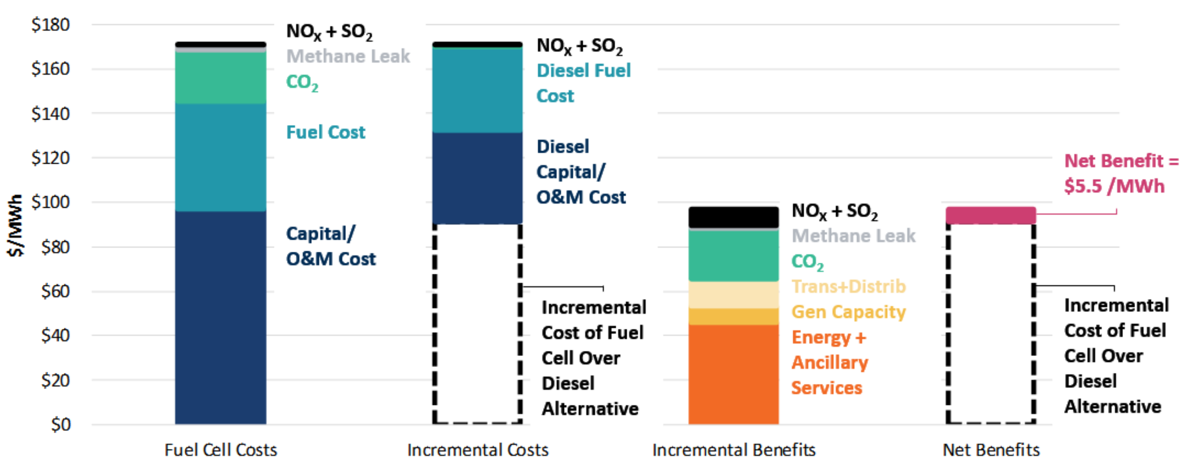
the 2021 Avoided Cost Calculator, Bloom's internal cost data, and data from the U.S. Environmental Protection Agency for major assumptions in my analysis.

**Q: What are your TRC test findings?**

A: Overall, I find that fuel cell systems across all three IOUs lead to positive net system benefits, calculated as the cost of the fuel cell less avoided costs of diesel backup generation and grid power. For instance, a fuel cell customer in San Diego Gas and Electric's ("SDG&E") service territory brings $5.5 per MWh of net system benefits. Figure 2 below shows a full breakdown of costs and benefits. The first bar includes the total cost of a Bloom fuel cell on the system. The second bar shows the costs to a diesel generator and the incremental costs incurred when switching to a Bloom fuel cell. The third bar shows the system benefits from adopting a fuel cell. The incremental costs and the net benefits are shown in the final bar.

The net benefits from customers in PG&E and SCE $1 per MWh and $15 per MWh, respectively. The differences in benefits between the three major California utilities stem from slightly different assumptions made in the ACC about their costs. Broadly speaking, three major factors influence the observed net benefits: reduced system costs, reduced greenhouse gas emissions, and high fuel and capital costs for diesel.

**FIGURE 2: FUEL CELL COSTS AND BENEFITS FOR AN SDG&E CUSTOMER**



**Q: Please elaborate on the main factors that are responsible for the net benefits?**

**A:** A Bloom fuel cell customer removes a significant portion of their load from the California electric grid, and thereby reducing the amount each utility needs to pay to produce energy. Unlike other microgrid technologies such as solar that run only intermittently, fuel cells generally operate constantly, meaning that the load served by a fuel cell is essentially removed from the grid. This means that the grid now supports less load, which in turn reduces transmission and generation capacity needs.

Second, Bloom fuel cells also have less carbon emissions than the marginal emissions rate of the California grid. There are slight increases in methane leakage as a fuel cell runs exclusively on biogas or natural gas at present, but the benefit of overall reduction in $CO_2$, $SO_2$, and $NO_X$ more than offset the cost of this leakage.

Third, the *incremental* cost of a fuel cell in my model is much lower than the full cost of a fuel cell because I assume that the options for a customer who would like to address their reliability needs are a diesel generator or a fuel cell system. Despite only operating for a limited number of hours in a year, the diesel generator has significant capital and fuel costs that are no longer incurred after the conversion to a fuel cell.

**Q: What is the range of values for the net system benefit of the fuel cell fleet currently operating in California?**

A: Assuming a fleet size of 275 MW, and an availability of 96 percent, the current fuel cell fleet in California generates about 2.3 million MWh per year. Using the net system benefit of $5.5 per MWh for SDG&E, the total net system benefit is around $12.7 million per year, with a range of $2.4 million to $34.8 million if using the net benefits for PG&E and SCE, respectively.

**Q: What is the net system benefit from the new ECST credit?**

A: As I describe above, the new credit can help bring as much as 312 MW of new fuel cell capacity online. Using the net levelized system benefit of $1 to $15 per MWh, I estimate that instituting the credit could result in $2.7 - $40 million of annual net system benefits by 2030. These benefit estimates are conservative as they do not include the resiliency value of fuel cells. If the frequency of emergency power shutoff events increases, which is likely given the state of the California electric system and the continuing challenges of large wildfires, the net benefits will only increase as expensive diesel generation is used more frequently and as the unmeasured resiliency benefits become more apparent.

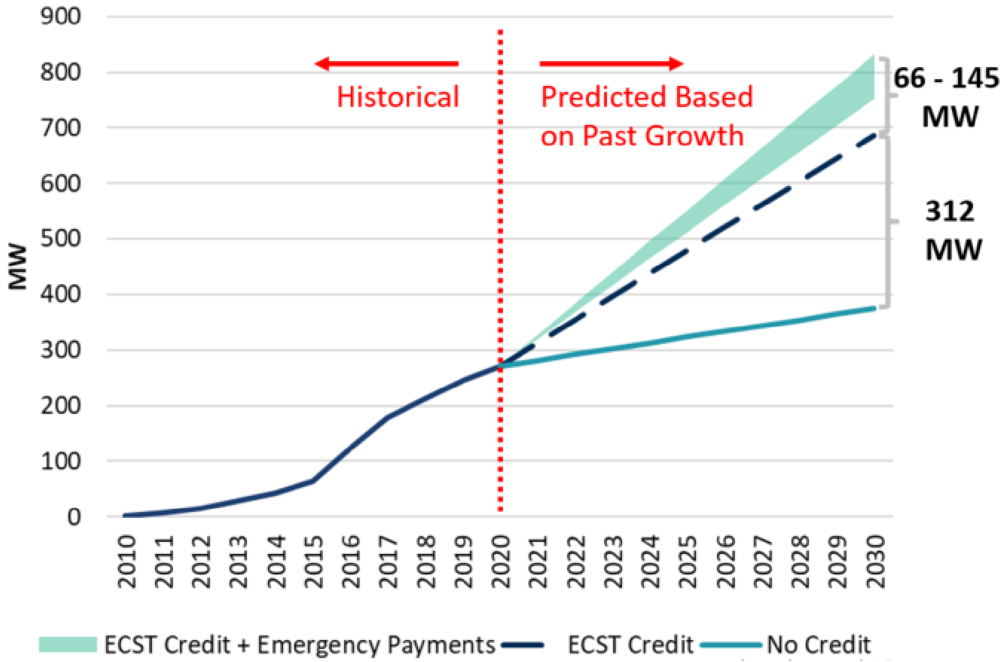
**Q: If fuel cells were eligible for the emergency capacity payment of $2 per kWh as outlined in the ECST program, how would the adoption rate change?**

**A:** If new fuel cell systems were eligible for the emergency capacity payment, I would expect to more customers to consider fuel cell technology for their resilience needs. To the extent that their energy demand and profile allow, a fuel cell customer can reduce their energy usage, and export what they would have consumed from their fuel cell system to the grid. Depending on the specific circumstances, the customer could potentially export some or all of the generation from their fuel cell system. For this analysis, I assume three scenarios:

- Scenario 1: the customer exports all generation from their fuel cell system during capacity shortfall periods (equivalent to 200 hours per year)
- Scenario 2: half of generation is exported
- Scenario 3: 25 percent of generation is exported

I reran the PCT model for these three scenarios. As expected, customers across all three scenarios would experience bill reductions. Specifically, in Scenario 1, Scenario 2, and Scenario 3, the electric bills would decrease for 100 percent, 94 percent, and 86 percent of customers, respectively. This translates into a gain of 66-145 MW of fuel capacity by 2030. This is in addition to the 312 MW of capacity addition that occur in response to the credit for standby and departing load charges. Figure 3 below shows the incremental capacity addition across the scenarios that I analyze.

**FIGURE 3: BLOOM FUEL CELL GROWTH IN CALIFORNIA**




**Q: How would the emergency capacity payment encourage *existing* fuel cell owners to curtail their energy consumption during periods of high grid stress?**

**A:** The emergency capacity payments, if extended to cover existing fuel cell owners, would provide a real and strong economic signal for fuel cell customers to provide energy back to the grid in times of need. That will lead to additional societal gains. Currently fuel cell systems are not eligible for these emergency payments. Even so, it is my understanding that many fuel cell customers voluntarily reduced their own load and exported energy to the grid without compensation in August 2020 of last year, when the state was experiencing rolling blackouts.[8] I expect that with appropriate compensation, more of the existing fuel cell systems in the state can provide energy resources during emergency periods. It is certainly an economically appealing proposition for the state: these fuel cell systems have already been installed and are paid for.

[8] https://www.bloomenergy.com/blog/overcoming-an-energy-crisis-innovating-during-a-blackout/

# III. Conclusion

**Q: Please summarize your opinion and recommendations.**

A: First, my analysis indicates that providing a credit for fuel cell customers that would offset standby and departing load charges will substantially boost customer adoption of the technology. Specifically, the credit can incentivize as much as 312 MW of new fuel cell capacity by 2030. Second, the adoption rate would be even higher if fuel cells are allowed to participate in the emergency capacity payment program. Depending on the customer's needs and circumstance, as much as 66-145 MW of additional capacity can be added to the California fleet. Finally, making the emergency capacity payments available to the existing fuel cell systems creates an immediate pathway for the 275 MW of fuel cell capacity in California to support the state's electricity system during energy emergencies. More importantly, the state can leverage this energy resource immediately because these fuel cell systems are already installed and online.

**Q: Does this conclude your testimony?**

A: Yes.

**VERIFICATION [Pursuant to Rule 13.7(e)]**

I, Ahmad Faruqui, state that I am authorized to make this verification on behalf of Bloom Energy. I declare under penalty of perjury that the statements in the foregoing document are true of my own knowledge, except as to matters which are therein stated on information or belief, and as to those matters, I believe them to be true.

Executed on September 10, 2021, at San Francisco, California.

/s/Ahmad Faruqui
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