Application: R.20-11-003
Exhibit No.:
Date:  September 1, 2021
Witness(es): Detrio

Prepared Direct Testimony of Allie Detrio
on behalf of
the Microgrid Resources Coalition

## I. Introduction

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

**A:** My name is Allie Detrio.

**Q: Was this material prepared by you or under your supervision?**

**A.** Yes, it was.

**Q: Insofar as this material is factual in nature, do you believe it to be correct?**

**A.** Yes, I do.

**Q: Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?**

**A:** Yes, it does.

**Q: Do you adopt this testimony as your sworn testimony in this proceeding?**

**A:** Yes, I do.

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

**A:** I have 13 years of work experience in clean energy and sustainability. For the past 6 years, I have been working directly in California legislative and regulatory affairs on a variety of energy policy issues related to Distributed Energy Resources (DERs) and microgrids. Before starting my own firm and joining the MRC as Senior Advisor, I was the Manager of Policy & Strategy at ENGIE, one of the largest independent power producers and a global leader in microgrid development worldwide. I hold a Bachelor of Science in Sustainability from the Global Institute of Sustainability at Arizona State University, as well as minors in History, Philosophy, and Economics. My expertise lies in bridging the gap between energy policy and project development. Throughout my career, I have held a variety of positions in the energy industry, including engineering, procurement, and construction ("EPC"), business development, project management, and market research. Over the past several years, I have consulted or provided regulatory support to various entities for the interconnection and market access of numerous distributed energy projects utilizing a variety of different technologies. My portfolio spans microgrids, advanced software, controls, PV solar, battery storage, bioenergy, and other clean generation technologies, as well as higher level strategic policy development in sustainability and resiliency.

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

**A:** Yes. I have recently submitted testimony before this Commission in Rulemaking 20-08-020 concerning development of net energy metering successor tariffs on behalf of Ivy Energy. I remain actively involved in that docket.

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

**A:** I am testifying on behalf of the Microgrid Resources Coalition ("MRC"). The MRC is a consortium of leading microgrid owners, operators, developers, suppliers, and investors formed to advance microgrids through advocacy for laws, regulations and tariffs that support their access to markets, compensate them for their services, and provide a level playing field for their deployment and operations. In pursuing this objective, MRC intends to remain neutral as to the technologies deployed in microgrids and the ownership of the assets that form microgrids. MRC's members are actively engaged in developing microgrids in many regions of the United States including many who are actively engaged in microgrid development in California.[1] MRC's members have extensive

[1] Members of the MRC include Bloom Energy, eco(n)law, Emory University, Engie, Icetec, Mainspring Energy, Princeton University, Reimagine Power, Resilience Plus, Scale Microgrid Solutions, Schneider Electric, University of Missouri and the University of Texas at Austin. The

experience operating sophisticated microgrids -- some for over 30 years. Collectively, they represent the cutting edge of microgrid technology and microgrid contributions to a reliable, resilient energy system overall, including the provision of net benefits to all energy system customers, whether participating in microgrids or not.[2] The Microgrid Resources Coalition was a leading contributor to Hawaii's microgrid services tariff, the first of its kind in the nation, as well as many other market and rate design activities across the U.S., including the development of the District of Columbia's MEDSIS ("Modernizing the Energy Delivery System for Increased Sustainability") program, New York's REV ("Reforming the Energy Vision") program, and FERC Order 2222, just to name a few.

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

**A:** My testimony responds to the Commission's request for program proposals that would reduce demand or increase supply at net peak summers in 2022 and 2023. In response to this request, my testimony proposes an Emergency Capacity Services Tariff ("ECST") as a new tariffed program to both reduce demand and increase capacity to supply the electricity grid, particularly during emergency capacity events. As discussed herein, a well-designed ECST can incentivize and support end consumer reductions in demand and

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MRC's comments represent the perspective of the coalition and should not be construed as speaking for individual members.

[2] The mission of MRC is to promote microgrids as energy resources by advocating for policy and regulatory reforms that recognize and appropriately value the services that microgrids offer, while assuring non-discriminatory access to the grid for various microgrid configurations and business models. MRC generally supports disaggregated, fair pricing for well-defined services both from the grid to microgrids as well as from microgrids to the grid. MRC promotes community-based resilience standards and support utilities that are working toward new business models that value resilient distributed resources. MRC works for the empowerment of energy customers and communities.

increases in capacity provide net benefits and enable the grid to address increasing stresses, especially during the net peak period or during extreme weather events. The proposal I outline in this testimony builds upon currently approved programs by taking some elements of existing tariffs like the Rule 21 tariff, AB 1613 tariff, and the recently approved Emergency Load Reduction Program ("ELRP") to form the basis of the ECST. A summary of the ECST is included in this testimony as Attachment A.

## II. Elements of the Emergency Capacity Services Tariff

**Q: Could you describe the general program design for MRC's ECST proposal?**

**A:** I'd be delighted to do so. I propose to use the Rule 21 tariff[3] for the basis of the ECST. This would permit customers who are looking to install new DERs to provide support to the grid, whether as exported energy or as demand response particularly during emergency capacity shortfalls. At present, I propose equivalent value for exported electrons and reduction of electrons for simplicity and ease of valuation. Over time, more sophisticated services and corresponding values could be added to the ECST. I suggest that the tariff be available to customers that individually or through an aggregation can commit to provide a minimum of 200 kW of as-available capacity to the utility for a minimum specified period. In the interconnection agreement, a customer taking service under the ECST will elect a non-zero emergency capacity value that it is prepared to provide to the distribution system during specified hours agreed upon by the utility and customer. This would require a simple modification of the Rule 21 export tariffs or addendum that outlines the final terms and conditions for providing capacity. Some elements of the pro forma AB 1613 Combined Heat and Power ("CHP") Power Purchase

[3] Electric Rule 21 https://www.cpuc.ca.gov/Rule21/

and Sale Agreement (the "CHP PPA"), such as the election of the as-available capacity, could be integrated into the Rule 21 export agreement.[4] ECST resources would be compensated at the standard retail generation rate under normal conditions coupled with a waiver of standby and departing load charges. Combined, these two elements remove barriers to adoption and entice customers to provide capacity that could provide substantial assistance in addressing emergency capacity shortfalls while minimizing overall customer rate impacts. During emergency capacity events called by the utility, which could be called for a variety of reasons like strained net peak hours, a red flag warning, or CAISO flex alert, a specified emergency purchase price for energy delivered during an event will be paid by the utility to ECST customers in the amount of $2.00/kWh which was the amount specified in the Governor's Emergency Proclamation issued on July 30, 2021 (the "Emergency Proclamation"[5]). I find this amount to be reasonable because of the immediate value that is generated for the energy system. Given the state's systemwide reliability challenges, there is an urgent need to provide power, especially in the age of a global pandemic. All customers with DERs participating in the ECST will be required to otherwise be on a time of use ("TOU") rate.

**Q: What are the other core elements of the ECST?**

**A:** There are a few other key elements of the ECST. First, all DERs enrolled under this program and not already interconnected would be eligible for expedited interconnection. The utilities should be required to meet the Rule 21 timelines currently in place or be

[4] AB 1613 Tariff: https://www.pge.com/pge_global/common/pdfs/for-our-business-partners/energy-supply/standard-contracts-for-multiple-facilities-pursuant-to-ab-1613/79-1121_March2019.pdf

[5] Governor Newsom Emergency Proclamation, July 30, 2021; https://www.gov.ca.gov/wp-content/uploads/2021/07/Energy-Emergency-Proc-7-30-21.pdf

permitted to expedite review of ECST projects given the state of emergency. The MRC suggests that Rule 2 special facilities should not be required or applied to ECST customers, helping to reduce the cost and timelines for interconnection.[6] I further propose that the utilities be encouraged to dramatically expand their interconnection resources (both personnel and IT) to accommodate the processing of ECST applications on an expedited basis. Any DERs interconnected under this tariff would be permitted to charge energy storage devices from the grid in non-emergency conditions. Grid charging during capacity shortfall conditions would be prohibited for ECST customers. Lastly, DERs interconnected under this tariff must agree to perform all scheduled maintenance outside of the April-October months, as those tend to be when supply is limited, and extreme weather is most likely to strain California's grid.[7] The MRC is open to utility suggestions of a different window. DER systems must have a defined period by which they are and are not allowed to conduct maintenance, so that they may be online and ready to serve during the agreed upon capacity shortfall risk period.

**Q: Do you propose any other elements for the ECST such as performance standards?**

**A:** Yes. To be eligible for the ECST, a customer must: (1) have verified capacity to deliver firm emergency service; and (2) have an availability factor greater than 95 percent. The customer must submit the following information to the utility for compliance and certification purposes: (1) independently verified, reputable third-party bench test data

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[6] Electric Rule 2 https://www.pge.com/tariffs/assets/pdf/tariffbook/ELEC_RULES_2.pdf

[7] Powerplants that were supposed to provide firm capacity were offline during summer months when capacity was already strained. See also: Politico news coverage https://www.politico.com/states/california/story/2021/06/30/old-clunkers-california-power-plants-break-down-during-heat-wave-1387507 New York Times news overage https://www.nytimes.com/2020/08/20/business/energy-environment/california-blackout-electric-grid.html

over a reasonable period of time, that when extrapolated, would meet the performance standards adopted by this decision; or (2) actual, real-time operating performance data from its own prior operations or substantially similar equipment meeting the performance standards.[8] Distributed energy resources under this order must also comply with the emissions standards adopted by the State Air Resources Board pursuant to the distributed generation certification program requirements of Section 94203 of Title 17 of the California Code of Regulations, or any successor regulation.[9]

**Q: What does MRC propose for a participating customer's minimum capacity election?**

A: Customers participating in the ECST must designate in the interconnection agreement the As-Available Capacity that the customer intends to provide during emergency capacity conditions by utilizing their DERs. I suggest that the customer be required to elect at least 200 kW of capacity or, if aggregations are permitted, the minimum aggregated capacity of multiple customers should be at least 200 kW. Without sizing restrictions or "blue sky" charging constraints, DER projects interconnected under the ECST will be built to a size that can comfortably meet their contractual obligations to the grid while also optimizing for customer energy needs. A key feature that the ECST would unlock is the ability of DERs to respond more flexibly during emergency capacity conditions due to the ability to integrate it into the DER system design. During the August 2020 grid stress periods, DERs contributed hundreds of MW of capacity, averting power

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[8] D.21-07-011 articulates this requirement to demonstrate performance which could be repurposed for the ECST https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M393/K334/393334241.PDF

[9] California Air Resources Board, Distributed Generation Certification, https://ww2.arb.ca.gov/our-work/programs/dgcert

disruptions and minimizing the scope and extent of those that did occur.[10] These contributions were made on a voluntary basis,[11]without either compensation or a tariff structure that enabled planning or operational visibility into what they could, or would provide. These resources offer critically needed benefits to a highly stressed energy system that is likely to grow even more so in the near future. A tariff structure is essential to incent, and make effective use of, their potential to help provide a reliable, resilient and cost-effective energy system.

**Q: Why does MRC propose to use Rule 21's interconnection tariff as a key element of the ECST?**

**A:** The Rule 21 tariff allows for DERs to follow a well-established interconnection process that does not require integration to the CAISO wholesale market and its currently high barriers to participation. That said, Rule 21 interconnection can still be a time-consuming and administratively fraught process that can take as long as 12-18 months. The MRC suggests that the utilities be required to expedite the utility review process so that interconnection can be completed in 6-9 months and that these resources can effectively contribute to a more resilient and reliable energy system in time to address anticipated near-term reliability challenges in 2022 and 2023.

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[10] Cohn, Lisa " California Microgrid Flex Their Skills During Blackouts (Microgrid Knowledge, August 25, 2020), available at https://microgridknowledge.com/california-blackouts-microgrids-flexible-load/

[11] St. John, "Consumers are Playing a Big Role in Keeping the Lights on in California This Week" (GreenTech Media, Aug. 19, 2020), *available at* https://www.greentechmedia.com/articles/read/how-california-has-escaped-more-rolling-blackouts-this-week

**Q: Why is waiving standby and departing load charges reasonable within the context of the ECST?**

**A:** The ECST is designed to meet emergency grid capacity needs identified by the Commission as looming concerns during Summer 2022 and 2023. If the Commission wishes to encourage customers to be on call to reduce load or provide exports as a service during capacity shortfalls, it needs to remove disincentives to invest in these facilities and to hold them ready to serve the grid. Both departing load and standby charges operate as strong disincentives to provide services that are desperately needed at this time. Accordingly, they should not apply under the ECST. On a certain level, this element is really as simple as a matter of reason and common sense. If you want customers to take an action, do not penalize them for doing so.

**Q: What compensation structure you propose for the ECST?**

**A:** In addition to compensation at the generation rate component of a participating customer's otherwise applicable time-varying retail rate, during certain grid events, the ECST would provide compensation for the value of reliability services the customer's load reduction or increased exports provide. This compensation is derived using a "value stack framework" that provides compensation for emergency reliability services that are rendered during specified grid conditions or extreme weather events.

**Q: What compensation are you proposing during a Capacity Shortfall?**

**A:** If the utility calls a Capacity Emergency, customers under the ECST would follow utility directives to reduce demand or deliver exported energy. For taking either of these actions, consistent with the approach taken in the Governor's emergency proclamation, customers shall be compensated at $2.00/kWh for delivering energy. If the Commission wanted to put some bounds on this payment structure, it could designate a certain number of hours that would be eligible for this higher incentive, such as the top 200 hours of system need. This compensation structure provides a higher value payment to customers that are ready to respond to a potential outage. In any event the customers should be provided with the full value to the system of delivering energy in these circumstances.

**Q: Are there any other values or services that could be added to the ECST framework?**

**A:** In addition to the basic emergency capacity service that this tariff seeks to procure from customers, the Commission could also consider providing additional payments to customers who provide emergency services to members of the public that may be in need. This would serve as a further incentive to support vulnerable communities during adverse weather or grid conditions. The ADL Ventures Report on diesel alternatives derived an avoided cost of diesel: *$182/kW-yr + $0.30/kWh.* [12] This valuation does not include the Value of Lost Load ("VOLL") that would otherwise occur from an outage.[13] The MRC believes that an added value for public entities that includes the VOLL as well as the avoided cost of diesel generation should be added to the ECST to incentivize these customers to serve as emergency shelter or safe gathering place for community members. While the current avoided cost calculation of diesel generation remains a crude number that has not been fully vetted by stakeholders, it nonetheless provides a valuable data

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[12] ADL Ventures Report at pg. 2
https://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M348/K580/348580460.PDF

[13] Manhattan Institute Report on California PSPS and Wildfire Risk pegs a VOLL at $160-$320 per customer per day. See: Lesser & Feinstein *"Playing with Fire: California's Approach to Managing Wildfire Risks";* April 7, 2020 https://www.manhattan-institute.org/managing-california-wildfire-risk

point that the Commission should consider when evaluating the need for emergency reliability services, and a starting point for further analyses and determinations.

**Q: Why do you believe the compensation provided for Emergency Capacity Response is reasonable?**

**A:** A compensation structure is clearly needed to achieve the stated policy goals of the Governor's emergency proclamation quickly and effectively: Emergency reliability now. Given how important electricity is to modern life, particularly under COVID conditions and the need to increasingly rely on data and communications systems. I believe it is reasonable for the Commission to take a "no regrets" policy regarding adoption of this program. The State of California faces a serious and immediate capacity shortfall that will last at least for the next several years. The best way to meet this challenge head on, achieving reliability while minimizing rate impacts, is for the Commission to leverage customer investments through a simple, straightforward incentive to customer action. Resources that can be brought to bear to solve this problem in the timeframes identified should be compensated for the value they provide to the system. For the sake of simplicity and time, the Governor's Emergency Proclamation establishes a compensation value that is appropriate as a starting point. If the Commission wanted to put bounds on the compensation, it could incorporate that into the tariff design. As noted above, behind the meter resources played a crucial role in helping to address the August 2020 reliability challenges, but could have provided far more, and need a reasonable, programmatic structure to incent and dependably provide that support in the future.[14] This does not

[14] St. John, "Consumers are Playing a Big Role in Keeping the Lights on in California This Week" (GreenTech Media, Aug. 19, 2020), *available at*

have to be complicated. Set the prices right, remove the regulatory barriers, and let customers respond.

## III. ECST Program Administration, Measurement & Evaluation, Implementation, and Budget

**Q: Who do you propose should manage the ECST?**

A: The IOUs would administer the ECST for their respective service territories. Each would be responsible for enrollment of participants, verification of customer eligibility for enrollment in the tariff, calling of Capacity Emergency Events, consistent with tariff parameters, and other implementation details.

**Q: How would enrollment of participants occur?**

A: The MRC suggests creating an ECST rate schedule under the Rule 21 tariff that is open to customers with at least 200 kW of capacity that can be provided during the capacity shortfall. This would be a voluntary program that customers could enroll in like any other rate schedule under Rule 21.

**Q: Do you have any recommendations regarding implementation of the ECST?**

**A:** Yes. No later than 10 days after the date of any order approving the ECST and providing the IOUs with authority to implement and administer the ECST, each large electrical corporation shall file with the Commission a Tier 2 Advice Letter that presents a tariff for staff review and approval.

**Q: What budget do you propose for IOU Program Marketing, Outreach and Evaluation?**

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https://www.greentechmedia.com/articles/read/how-california-has-escaped-more-rolling-blackouts-this-week

**A:** I do not believe IOU marketing is necessary for the ECST if it is implemented as described in my testimony, as customers and the market will respond to the opportunity. The basic compensation structure of the ECST will provide a signal to the market to act expeditiously, in response to the value generated by this program. The simplicity of the ECST compensation framework makes the opportunity easily understandable to potential ECST customers. The IOUs will need funding to provide modest updates to their websites in support of the program, but I do not have the insight into utility costs to present a budget for this effort. However, the cost should be modest as the utilities regularly update their websites to provide customers with information on programs they offer. Similarly, program evaluation costs should also be modest as the program is relatively simple and the IOU will have all information regarding customer participation, program impacts, and program payments. Thus, evaluation of the program should be relatively straightforward. Details on program evaluation costs would need to be developed once the overall structure of the program is approved by the Commission based on consultation with each IOU so that their internal capacities can be understood better.

**Q:** **Are there program costs that are unique to the ECST that the IOUs would incur?**

**A:** Yes, there are unique program costs for the ECST – namely, interconnection costs. The IOUs should be encouraged to dramatically expand their interconnection teams to handle the new workload of processing interconnection applications and performing all safety inspections and testing so that Permission to Operate (“PTO”) can be granted within 6-9 months, before Summer 2022.

**Q: How do you propose grid upgrade costs are handled within the ECST?**

**A:** Any grid upgrades (including distribution system upgrades) that are required should be the cost responsibility of the IOUs in this interim emergency program, and they may seek cost recovery in their next GRC for the costs of interconnection. Rule 2 special facilities costs should not apply to facilities interconnected under the ECST. In my view, ECST resources are special facilities – special in that they are desperately needed for an emergency. As such, the Commission and IOUs should acknowledge that these are *necessary* facilities that provide an urgently needed net benefit to the grid and all customers, and therefore not subject to the costs and fees usually invoked by Rule 2. Rule 2 is for added or special facilities that are deemed above what is required to provide safe and reliable electric service. Since the Governor has declared an emergency because of California's inability to provide safe and reliable electric service, these costs shall not be borne by the customers who are helping to solve this emergency.

**Q: What do you propose for a program budget for incentive payments?**

**A:** The MRC is unable to provide a detailed estimated program budget at this time but would estimate that procuring 1,000 MW of as-available capacity through this tariff would cost approximately $8 million per event. Assuming 10 events were called per year, the program would cost a total of $80 million. This is based on the following calculation and assuming that a typical event would be 4 hours in duration:

- 1000 MW (program size) X 1000 KW/MW = 1,000,000 KW
- 4 hour event x 1,000,000 KW = 4,000,0000 kWh
- 4 million kWh x $2/kWh = $8 million per event
- 10 events = $80 million

Additional costs for expedited interconnection and distribution network upgrades would also be a part of the overall program budget.  Interconnection costs are not known until midway through the interconnection process, so it is not possible at this time to estimate the total costs of the program.

**Q:** **How do you see the ECST interacting with existing Commission-approved programs?**

**A:** The ECST would be a brand-new program, authorized via emergency order.  No other technology incentives are needed; the ECST is designed to provide enough value for services rendered that the DERs can be monetized without upfront incentives.  To the extent any SGIP funds remain, or new incentives are offered through the Energy Commission via EPIC or other grant, the MRC would consider allowing customers that receive that funding to still take service on the ECST.  The two Commissions could coordinate to ensure that any technology incentives given to customers after the creation of the ECST are those that are clearly identified in the Environmental & Social Justice Action Plan or serve other public policy goal.[15]

**Q:** **Are you aware of any prior experiences with programs like the ECST?**

**A:** The Commission can take note of its own SGIP Equity Resilience Budget and the market's pace of uptake from the time that program opened with a value incentive ($1.00/Wh in the case of SGIP). SGIP had been expanded with the passage of SB 700 in 2018, which resulted in a new infusion of more than $800 million dollars.[16] The funding

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[15] CPUC Environmental & Social Justice Action Plan https://www.cpuc.ca.gov/news-and-updates/newsroom/environmental-and-social-justice-action-plan

[16] SB 700 (Wiener, 2018) https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201720180SB700 The SGIP

was supposed to last through 2024. After the opening of the Equity Resiliency Budget ("ERB"), the incentives were subscribed faster than anyone expected and the ERB was waitlisted within a year of the program opening. If the value proposition is high enough, customers and the market will respond quickly.

**Q: How do you propose program costs be recovered?**

**A:** Costs for the ECST program should be recovered from all customers on an equal cents per kilowatt hour basis, as all customers benefit from the reliability services provided by participants in the ECST generated by participants load reductions or exports. As noted previously, the Commission would not have to expend any marketing budget for this effort. Customers and the private sector will respond to this program based on the policy decision alone. Other program costs will include the cost of interconnection resources. The MRC proposes that the IOUs increase their interconnection team capacity so the IOUs can quickly and easily interconnect DERs participating in the tariff. The IOUs should be authorized to recover all interconnection costs for this program, including any IT and personnel resources necessary to facilitate timely interconnection. Any distribution network upgrades that are required by the IOUs should also be eligible for cost recovery and socialized, not borne by the DER customers themselves who are investing in the solution.

**Q: What duration do you propose for the ECST?**

**A:** This ECST would remain open for new enrollments so long as a capacity shortfall exists. Resources will be eligible to remain on the tariff throughout the life of project. If the

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Equity Resiliency Budget has a waitlist (accessed August 31, 2021) https://www.selfgenca.com/home/program_metrics/

Commission determines that a program duration needs to be established, the MRC suggests that any customers be able to stay on the tariff for 25 years, as that is the typical useful lifespan for most DER projects.  Stability is necessary in the value proposition to incentivize private sector investment.

**Q: What are your views on potential risks of the ECST if adopted?**

**A:** I do not envision any significant risks if the ECST is adopted, particularly if compared to the status quo.  The power has gone out.  Fires are raging. Public Safety Power Shutoff events have already been called this year, affecting thousands of customers.[17] The Commission has identified a significant near-term capacity shortfall which instant testimony is seeking to address.  In the face of these collective challenges, I believe it is reasonable for the Commission to adopt a no-regrets policy in this proceeding and approve the ECST through at least the end of 2023, or when the capacity shortfall no longer exists.  The ECST provides not only grid supportive capacity but does so in a way that allows for resiliency.  New projects could be designed to both ensure the grid capacity requirements could be met while also providing backup power to customers. The tariff proposal allows for this design flexibility.

**Q: Do you have any other recommendations for the Commission to consider as part of development of the ECST?**

**A:** Yes, I do.

## IV. Deployment of an Emergency Capacity Services Tariff Will Support Reduction in Energy Use or Increased Energy Exports during Net Peak in Summer 2022 and Onward

[17] PG&E initiated Public Safety Power Shutoffs (PSPS) in August that resulted in more than 50,000 customers in 13 counties losing power. https://www.pgecurrents.com/2021/08/19/psps-update-power-restored-for-essentially-all-affected-customers-after-dry-offshore-wind-event-and-exceptional-drought-conditions-prompt-safety-shutoff/

**Q: Do you have an estimate of the potential impact of the ECST in regard to load reduction or increased exports?**

A: The MRC anticipates that *within its own membership alone*, it could provide several hundred megawatts of capacity to support grid reliability by the end of 2023. Given the short timeframe for proposals, the MRC was only able to solicit informal input from its members on this estimated figure. Extrapolating our membership to assess the serviceable addressable market, the MRC expects that the market response to the ECST would be overwhelmingly positive. Potentially, if the ECST is designed as proposed in my testimony, it is my professional belief that at least 1,000 MW could be brought to bear on the capacity shortfall identified by the Commission by the end of 2023 if the ECST is implemented in a timely fashion. It is important to note that these resources would leverage customer investments, with minimal impacts on overall customer rates, and provide significant net benefits to non-ESCT customers. The elimination of uncertain departing load and standby charges that usually destroy project economics coupled with payment for performance incentive ($2/kWh) consistent with the Governor's Emergency Proclamation and a <1 year interconnection process would send a clear, effective, and necessary signal to the DER market that the Commission is serious about brining DERs to bear on the current situation. I'm confident industry would respond to the need with this proposal.

**Q: What evidence does MRC have that development of the ECST will result in the outcomes desired by the Commission – reduction in load or an increase in exports during the summer net peak?**

A: The Miramar Marine Corps Air Station voluntarily curtailed its load during last August's flex alerts, resulting in 6 MW of capacity reduction, relieving the strain on the grid and reducing risk of further outages that may have impacted other customers.[18] On August 30, 2021, SDG&E filed an Advice Letter outlining its intent to enter into an agreement with the Miramar Marine Corps Air Station regarding a Summer Generation Availability Incentive.[19] SDG&E acknowledged the value that this action had on the grid by waiving departing load charges that otherwise would have been charged to Miramar. The Generation Availability Incentive will compensate Miramar for 6 MW of generation exported or reduced demand during the 4:00-9:00pm, per event, with up to 5 events authorized per month.[20] I commend SDG&E for being proactive and soliciting support from the Miramar project in this time of grid stress. This one-off agreement between Miramar and SDG&E showcases the lack of specific market mechanisms in place today that could be more widely expanded upon to address the systemwide capacity shortfall. The Commission could harness the capacity and other services that sophisticated DERs can provide, extending their energy optimization benefits beyond the customer meter and support the grid for all ratepayers' benefit. The MRC's proposal provides a more robust value proposition, but several elements of the Miramar agreement align with our proposal.

**Q: Do you have any other information that you believe is useful in considering the potential for customer-sited resources to meet resource adequacy needs?**

**A:** I do. First, a recent study, Gigawatt-Scale Customer-Sited Potential: Achieving California Energy Policy Goals, Grid Reliability and Local Resilience, prepared by Station A for

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[18] SDG&E Advice Letter 3838-E; served on August 30, 2021
http://regarchive.sdge.com/tm2/pdf/3838-E.pdf
See also: https://microgridknowledge.com/california-blackouts-microgrids-flexible-load/

[19] Id pg. 1-2

[20] Id.

SunRun and Stem, is instructive on the ability of distributed energy resources to meet grid needs.[21] I have attached this study to this testimony as Attachment B so that it can be reviewed by stakeholders in this docket in a timely fashion. The study found that there is over 6.7 GW of resource adequacy potential across the service territories of the state's three largest IOUs when customer load needs are considered. For example, the study found over 1.2 GW of resource potential for the Greater Bay Area. The study also identified significant resource adequacy potential in various local and sub-local areas across the state. The ECST I am proposing in this testimony is designed to unlock these resources so that they can be brought to bear on the current crisis facing California. After review of the study, I find it to be a reasonable reflection of the potential resource availability that could be unlocked by the ECST. This study provides additional context regarding the opportunity the ECST presents to California that is in addition to my understanding of what MRC's membership can bring to bear on this problem and that Miramar already has demonstrated is possible.

Second, I also believe that California's recent experience during the August 2020 heat storm is illustrative of the level of customer response that can be brought bear on the California's current capacity shortfall. As the Commission is aware, during the August 2020 heat storm, customers stepped up to the plate to significantly reduce their loads through voluntary action and through target exports to the grid. In response to calls by the ISO for conservation and calls from the Commission to operators of customer-sited generation, preliminary analyses indicated that up to 1.3 GW of customer response from

[21] "Gigawatt-Scale Customer-Sited Potential: Achieving California Energy Policy Goals, Grid Reliability and Local Resilience"; Prepared by Station A for SunRun and Stem; https://files.stationa.com/docs/Gigawatt-Scale%20Customer-Sited%20Potential.pdf

resources counted against Resource Adequacy obligations contributed to meeting reliability needs on the days those rolling blackouts occurred.[22] Subsequent analysis showed that the reduction in demand, based on settlement quality meter data, was significantly less: 910 MW on August 14, and 756 MW on August 15. However, these responses – 756 MW and 910 MW – are both significant contributions to maintaining reliability.[23] Moreover, it is my understanding that stakeholders have argued that if the appropriate processes were in place, these stakeholders could have provided significantly more response. Some 30,000 batteries that contributed to August 2020 reliability during the reliability events provided up to 310 MW of support to the grid, the California Solar & Storage Association estimates that up to 530 MW could have been made available from existing resources if appropriate processes were in place.[24] One BTM storage company alone, Stem, provided 50 MW—but it could have provided up to two or three times as much.[25] I find the actual experience of how customers responded to ad hoc calls for support during the August 2020 heat storm to be particularly illuminating as megawatts customers were able to deliver were a significant portion of what was brought to bear on preventing further crisis during that time and was done ad hoc. I am confident that if the ECST was in place during the heat storm, the ISO would have seen far more

[22] Preliminary Root Cause Analysis at pg. 52-54 (noting maximum performance of approximately 80% of 1,632 MW total Resource Adequacy credits for CPUC-jurisdictional entities). Available at: http://www.caiso.com/Documents/Preliminary-Root-Cause-Analysis-Rotating-Outages-August-2020.pdf

[23] Final Root Cause Analysis at pg. 108. Available at: http://www.caiso.com/Documents/Final-Root-Cause-Analysis-Mid-August-2020-Extreme-Heat-Wave.pdf.

[24] See, e.g., Penn, "Its Electric Grid Under Strain, California Turns to Batteries" (N.Y. Times, Sept. 30, 2020)(Penn/NY Times), *available at* https://www.nytimes.com/2020/09/03/business/energy-environment/california-electricity-blackout-battery.html

[25] Id.

support than it actually received. In this regard, the views of CalSSA and Stem are insightful in showing that a doubling of actual response could have been possible.

**Q: Do you have any additional thoughts concerning the ECST and the situation confronting the state?**

A: Yes, I do. I encourage the Commission to be bold during this time of crisis. Harness markets and customer capital to solve this problem. Do not just rely on administrative action or mandates. The evidence of August 2020 is clear: Customers can respond and do respond to grid needs – particularly when incentivized to do so. [26]The Commission can harness the innovation of the DER industry and the actions of customers with the Emergency Capacity Services Tariff to address the capacity shortfall in a cost-effective and expedient manner.

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

A: Yes, it does.

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[26] Id.

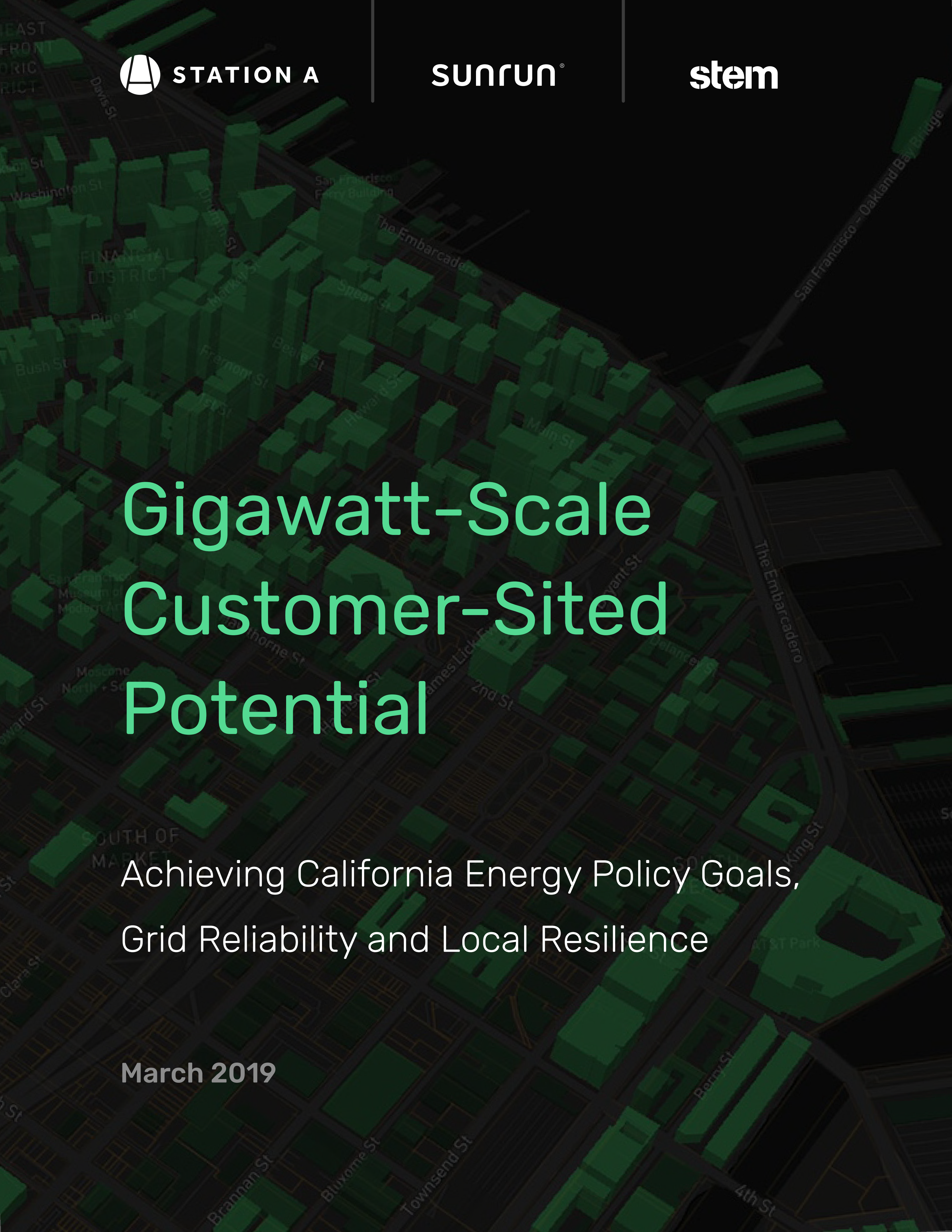
Attachment A

Summary of ECST

- Eligibility
  - Any customer, or aggregation of customers, willing to commit at least 200 kW
  - Must provide capacity during net peak hours or emergency events
  - ECST open so long as there is a capacity shortfall or reevaluated by December 31, 2023
  - Customers able to remain on ECST for 25 years
- Compensation
  - Retail generation credit during normal conditions
  - Customers must be on TOU rate
  - Departing Load and Standby Charges are not assessed under ECST
  - During emergency capacity events within parameters to be determined, $2.00/kWh compensation will be paid for either exported energy or demand reduction
    - Commission could institute Top 200 hours as eligible for this compensation to put bounds on this
- Performance Requirements
  - DERs must be CARB-certified resources
  - DERs must have verified capacity to deliver firm emergency service and have an availability factor greater than 95%
  - DERs must commit at least 200 kW of as-available capacity
  - As-available capacity must be designated in interconnection agreement under contractual obligation
  - Maintenance must be performed outside of April-October months
- Interconnection
  - Rule 21 export tariff framework
  - Expedited timeline of 6-9 months
  - NO invocation of Rule 2 for special facilities
  - Utility distribution network upgrades eligible for full cost recovery
  - Utilities authorized to dramatically expand/invest in interconnection resources necessary to accomplish <9-month interconnection timeline of DERs
- Program costs
  - No customer marketing budget necessary beyond costs for utility website update
  - Customer interconnection costs (unknown)
  - Distribution network upgrade costs (unknown)
  - $2M per 1,000 MW committed capacity at $2.00/kWh payments
  - Rates would otherwise be cost-based

Attachment B

STATION A | sunrun | stem



# Gigawatt-Scale Customer-Sited Potential

## Achieving California Energy Policy Goals, Grid Reliability and Local Resilience

**March 2019**

# Gigawatt-Scale Customer-Sited Potential

## Achieving California Energy Policy Goals, Grid Reliability and Local Resilience

California has chosen the groundbreaking path of achieving 100% clean energy by 2045,[1] driving transformation in how the grid will be powered and managed. Simultaneously, California must tackle the challenge of adapting the grid for a changing climate, fire risk and increasing need for resilience. Even as a transformation unfolds, the grid must remain stable and reliable. To achieve this will require innovation that draws on all of the solutions that the state can bring to bear.

**Station A**, a software company whose platform allows users to explore the feasibility of customer-sited clean energy on a building-by-building basis,[2] has worked with **Sunrun** and **Stem**, as market leaders in the deployment of distributed energy resources in California, to quantify the potential for customer-sited solar and battery storage to provide grid reliability capacity in key geographies across the state. This includes areas where local grid reliability has been or may become a concern in relation to the retirement of existing generation resources. By quantifying the aggregate potential, our goal is to bring focus to the enormous resource that California has across cities, suburbs and even rural areas to bolster grid reliability while driving clean energy uptake and increasing grid resilience.

This analysis identifies techno-economic potential for 48 gigawatts of rooftop solar and 42 gigawatt-hours of battery storage which together would provide approximately **9 gigawatts** of Resource Adequacy (RA) across the Investor-Owned Utility (IOU) service territories. Key geographies have Local RA potential of hundreds to thousands of megawatts. This potential was evaluated without grid reliability revenue; the addition of this revenue could increase scale potential even further.

1. California State Legislature. *"SB100 California Renewables Portfolio Standard Program: Emissions of Greenhouse Gases". https://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201720180SB100.* September 2018
2. The Station A platform is accessible at *https://app.stationa.com*

As the CPUC, CAISO, and utilities identify approaches to maintain reliability while increasing resilience and clean energy, and the CEC identifies paths to achieve California's energy policy goals, customer-sited solar and battery storage resource potential can be a key pillar and should be at the forefront for consideration. The results of our analysis show that the scale of customer-sited potential is far greater, relative to the scale of local reliability needs, than has been observed in recent relevant procurements. The scale of resource potential should inform existing and future procurement and sourcing approaches from IOUs and CCAs that will more successfully drive the maximum deployment of customer-sited solar and battery storage to be cost-effectively drawn on for local and flexible capacity needs.

Specifically, current RA frameworks undervalue the capability of behind the meter resources to deliver cost-effective capacity, especially at the local level. Our analysis illustrates that fully 2.5 GW of aggregate RA potential would be "stranded," even after being developed, based on current rules limiting batteries participating as Proxy Demand Resources (PDR).

## **Customer-Sited Resources are Inherently Well-Suited** for Local Reliability and Resilience

Enabling a transition to a cleaner energy mix includes ensuring reliability in local and sub-local areas, meaning clean resources must be found in every local area or there is a risk that reliability-based revenue streams will run counter to California policy goals, if they have the effect of delaying the retirement of thermal generation. Load is driven by businesses and homes, which are also the sites for customer-sited solutions. This means that, as our analysis shows, there is substantial potential for customer-sited solutions in every local area that makes major demands on the grid.

Importantly, customer-sited solar and battery storage not only supports local reliability, it is inherently aligned with increasing resilience. The more resources that exist within communities on a customer-sited basis - *especially solar-paired storage resources that can operate indefinitely regardless of grid availability* - the lower the impact or risk posed by de-energization, transmission contingencies, or other disruptions to the grid. Finally, resources that are sited on the distribution grid are inherently situated to provide distribution deferral value related to reliability.

## Nature and Purpose of this Analysis

To inform the processes driving California's approach to reliability, resilience and clean energy, Station A, Sunrun and Stem have sought to highlight on a broad basis the clean energy grid reliability potential that exists in California's single-family home, and Commercial & Industrial (C&I) segments specifically. As leading developers of such resources, Sunrun and Stem operate competitively but see on a daily basis potential that may be opaque to observers outside of industry. Working with the aid of Station A's independent analysis, we have sought to illuminate this potential in a format that can inform all interested parties.

Our estimates for customer-sited solar and battery storage potential in local areas should be considered **techno-economic potential**, relating to the expected viability of solar and battery storage to create positive economics for customers based on factors such as building stock, energy usage expectations, and current costs for solar, storage and retail electricity in today's underlying tariff environment.

The potential for RA value from these resources is estimated based on the expected usage of this storage to deliver RA via PDR in CAISO, as described below, and takes into account seasonal variation due to variation in solar production. Estimates reflect the annual average of RA capacity across the year, with potential for higher values in summer when California's peak demand and thus maximum need for RA actually occurs.

It should be noted that this techno-economic potential does not factor in capacity revenue of any kind. This underscores two facts: first, that customer-sited resources will emerge independently of capacity revenue and second, that the cost to utilize these assets for grid reliability can be cost effective because customer value covers a portion of the cost of deployment. By adding potential revenue from services that enhance grid reliability, deployment can be accelerated, the overall market opportunity expanded, and these resources will be fully utilized for reliability value above and beyond their use for customer value.

Estimates represent the potential if all customers that are prime candidates for solar and battery storage today were to adopt this technology instantaneously. This analysis does not suggest the rate at which such adoption can be expected to occur. Rather, these numbers are intended to spur discussion of the approaches that will maximize the realization of this potential. Such approaches should include eliminating regulatory impediments to market potential that exist today and structuring procurement approaches to incorporate a resource type that is deployed in a modular form over years based on customer demand rather than in "lumpy" large-scale investments solely based on utility contracts.

If the potential exists and customer-sited resources have unique and inherent value towards multiple key policy goals while delivering grid reliability on a cost-effective basis, then approaches to local reliability should begin with this question. A criterion for procurement processes, as well as planning, tariffs and programmatic initiatives, should be their success against this potential. The objective should be speeding the achievement of California policy goals, including clean energy and resilience, in ways that bring the maximum benefits to all of California's citizens.

## **Representing Customer-Sited Resources** in Key Grid Modeling Efforts

Station A, Sunrun and Stem are forthright in acknowledging that this analysis is indicative as compared to the highly sophisticated models that inform California grid and resource planning. We challenge those determining the modeling approaches for such processes to improve on these numbers through approaches with greater economic sophistication that will yield greater detail, and then to consider how the load flexibility and reliability resources they create can interact with local reliability requirements in nuanced ways. Relevant processes include Integrated Resource Planning (IRP), the CAISO Transmission Planning Process (TPP), and potentially others including the Integrated Energy Policy Report (IEPR). The general methodologies we use can be translated to other datasets to enable such approaches.

It should be noted that this analysis reflects today's techno-economic viability. Given decreasing solar and battery storage costs, our estimates should be considered floors that will increase over time as more homes and businesses become prime candidates for adopting these technologies. This lends further importance to creating nuanced models that are integrated into California's planning processes and update over time to reflect increasing potential.

## Using Customer-Sited Solar and Battery Storage for Local Resource Adequacy and Flexible Resource Adequacy

Customer-sited solar and battery storage are able to deliver grid reliability via existing mechanisms in CAISO to provide RA alongside traditional resources. The primary mechanism for this is participation as a PDR. In the context of PDR, solar and battery storage are joined by other load flexibility technologies, the potential for which should not be minimized. However, solar and battery storage are well suited to provide long-duration capacity that has particular salience for Local RA requirements that may extend beyond the requirements of System RA. In addition, solar and battery storage can provide Flexible RA, a growing need as renewable energy penetration creates variability in supply and new ramping requirements.

To focus attention on the specific value of customer-sited solar and battery storage, we have expressed potential in megawatts of RA from solar and battery storage organized as PDR. While Local RA requirements will vary in terms of duration and timing, we have used System RA as a generic starting point and proxy. In general, the amount of Local RA available for a given need should relate to System RA potential according to the ratio of the duration of Local RA need to the 4-hour duration of System RA. This is to say, 150 MW of System RA potential at 4-hour duration could be expected to translate to roughly 100 MW of Local RA potential of 6-hour duration. This could vary based on the time of day of this need in relation to solar production.

## **Key Issues and Considerations for Local Resource Adequacy** from Customer-Sited Solar and Battery Storage

Significant barriers still exist to fully realizing the value of solar and battery storage as PDR. Specifically, the RA that customer-sited storage can provide is limited to the coincident load on the associated customer meter in a given hour. While a customer-sited energy storage system may have additional capacity available at times of system or local need above the load on a given customer's meter, any injections back onto the grid are valued at zero and therefore would not be provided. To highlight the impact that this has on aggregate potential, which is dramatic, we identify two different sets of RA potential: one under current RA accounting, and one that allows the system to benefit from batteries discharging fully during hours of need. If this issue is not addressed, no matter how much of the techno-economic potential is realized, a material portion of the RA potential from customer-sited solar and battery storage will be unutilized.

Second, we necessarily worked from today's identified Local Areas and Sub-Local Areas and the mapping resources available publicly for the selected areas. As grid conditions evolve, Local Area definitions will change. This underscores further the need for the sophisticated modeling efforts that drive grid and resource planning to incorporate customer-sited resource potential from the bottom up, so that for any given geographic boundary an updated view of potential can be identified and incorporated at the very front end of conceptualization of options for addressing local needs.

## **Customer-Sited Solar and Battery Storage Capacity** in Select Local Areas and Sub-Local Areas

The results of Sunrun and Stem's analysis can be seen below, for a selection of Local and Sub-Local Areas. These have been chosen to represent a cross-section of geographies across California with widely varying building stock and climate characteristics, demonstrating that customer-sited solar and battery storage can serve as a key resource across the entirety of California's grid. For reference, we identify the aggregate solar techno-economic potential identified across the CA IOU's as being 47.8 GW.

Notably, researchers at NREL have estimated purely technical rooftop solar potential in California at 128.9 GW[3]. Against this total potential, the techno-economic potential for the residential and C&I segments in the IOU territories is broadly reasonable. Our approach for determining solar techno-economic viability and then building on this to identify storage sizing and RA potential is described in the Methodology section.

### Local Resource Adequacy Potential: Selected Local & Sub-Local Areas

| **Local Area** | **Solar Potential** MWdc | **Energy Storage Potential** MWh | **Resource Adequacy Potential** MW @ 4 hour duration, limited by load | **Resource Adequacy Potential** MW @ 4 hour duration, full ESS utilization |
|---|---:|---:|---:|---:|
| **LA Basin** | 14,391 | 12,886 | 2,149 | 2,723 |
| **San Diego** | 4,455 | 5,570 | 928 | 1,194 |
| **Greater Bay Area** | 10,476 | 8,169 | 1,294 | 1,855 |
| San Jose / Moss Landing Sub-Local Area | 3,607 | 2,176 | 338 | 498 |
| Pittsburg Sub-Local Area | 1,343 | 1,132 | 175 | 261 |
| Oakland Sub-Local Area | 348 | 336 | 56 | 67 |
| **Greater Fresno** | 1,687 | 1,384 | 241 | 333 |
| **Stockton** | 1,694 | 1,357 | 224 | 300 |
| **Kern** | 977 | 754 | 129 | 168 |

3. Pieter Gagnon, Robert Margolis, Jennifer Melius, Caleb Phillips, Ryan Elmore. *"Rooftop Solar Photovoltaic Technical Potential in the United States: A Detailed Assessment".* National Renewable Energy Laboratory. January 2016

Because the boundaries of local areas change over time, we include for reference the overall resource potential we find in each of the IOUs, indicating the full scale of additional potential that exists should new local reliability needs be identified.  A comprehensive modeling approach used for grid planning would incorporate underlying potential across all IOU territory to be used in analysis of evolving local reliability needs.

### Customer-Sited Potential by Utility Service Territory[4]

| **Utility Service Territory** | **Solar Potential** MWdc | **Energy Storage Potential** MWh | **Resource Adequacy Potential** MW @ 4 hour duration, limited by load | **Resource Adequacy Potential** MW @ 4 hour duration, full ESS utilization |
|---|---:|---:|---:|---:|
| **IOU Territories** | 47,781 | 42,392 | 6,730 | 9,245 |
| **PG&E** | 23,347 | 19,039 | 2,870 | 4,086 |
| **SDG&E** | 4,455 | 5,570 | 928 | 1,194 |
| **SCE** | 19,979 | 17,782 | 2,931 | 3,965 |

4. The San Diego Local Area coincides with SDG&E Service Territory and is reflected in both tables

# Conclusion

## Gigawatt Potential to Support Policy and Grid Planning Goals

Customer-sited solar and battery storage across residential and C&I segments can provide upwards of **9,200 MW** of RA across California, including **2,515 MW** that are enabled by improvements to the CAISO PDR structure to enable RA value for the full capacity of customer-sited batteries. This includes hundreds of megawatts in areas where recent procurements have or are expected to focus on front-of-meter solutions with more limited resilience and customer benefits and that do not necessarily increase the clean energy mix on California's grid.

The mix of resources that will provide reliability on California's grid is too important to ignore a key potential clean resource that can be found at scale in every part of the state. This is especially the case when the status quo trajectory suggests that, even as solar and battery storage deployments grow day-by-day through autonomous customer adoption, only a fraction of this potential will be utilized as local reliability through LSE procurement.

Customer-sited resource potential should be evaluated on its ability to serve **identified grid needs** and should not be discounted in the ability to fully serve local reliability because these resources take a different form than traditional resources.

Customer-sited resources and resulting load flexibility must be fully reflected in grid reliability modeling in order to accurately identify the best path towards a clean, reliable grid for California. Equally importantly, procurement approaches must continually be evaluated on their success in sourcing from the broadest pool of resources to deliver grid reliability in a manner that most cost-effectively supports California's broader policy goals.

If these steps are taken, the continued growth of customer-sited resources will be properly valued and prioritized, and the role that they can play to support an energy transformation will be more fully realized.

# Methodology

To identify techno-economic potential for customer-sited solar and storage, we sought to identify from building stock databases the sites likely to have energy usage and related characteristics enabling customers to realize savings on their energy costs relative to retail electricity rates given current tariffs and current solar and storage costs.

The potential for C&I solar and storage was based on a bottom-up analysis of individual buildings in the Station A platform, and the potential for residential solar and storage was evaluated based on a methodology informed by Station A and applied to a residential building stock and demographic datasets provided by Sunrun.

Given trends towards lower solar and storage costs, it can be assumed that techno-economic potential will increase. In the future, a greater number of the sites that can physically accommodate solar and storage will also see an economic benefit from adopting them.

## Identifying the Building Stock

We started by identifying building stock with the physical characteristics to support solar and storage.

For the C&I segment, we built our analysis on Station A's geospatial dataset, which includes all buildings with a footprint over 10,000 $ft^2$ in California, as well as all land parcels in the state.

For the residential segment, we identified building stock potential based on home size by square footage, which was used to estimate energy usage. A minimum square footage threshold was used as a cutoff, below which it was estimated that attractive year one savings from solar and/or solar paired with storage could not generally be achieved. This is based on comparing the levelized cost of solar and storage to the utility retail rates, accounting for minimum bill charges.

## Computing Solar Potential per Building

Based on the selected building stock, we applied further restrictions based on the amount of solar that could be installed as well as the potential that physical characteristics would prevent successful solar installation.

At each C&I site, we estimated the maximum technical potential for rooftop solar using industry-standard metrics for perimeter setbacks, roof coverage, and PV energy density. We disallowed solar on sites over 6 stories. We applied a limit to the solar potential based on net energy metering rules, disallowing system sizes that would generate more than 100% of the building's estimated energy usage in a typical year.

We then applied an economic filter. First, we estimated a Power Purchase Agreement (PPA) price for the system based on its estimated cost to build, accounting for policy incentives including the Investment Tax Credit (ITC), its expected annual production, and a rate of return required by the project developer. We then used the building's likely tariff and estimated energy usage to calculate the avoided cost of energy for the building. We only included sites at which the avoided cost of energy was greater than the estimated PPA price for the solar array.

For the residential segment, economic viability of roofs for solar depends on factors such as:
**a.** angling of roof planes for sufficient insolation, primarily based on azimuth
**b.** roof materials and quality
**c.** shading from trees or other structures

Estimates for the percentage of homes of sufficient square footage that meet these criteria of roof suitability were derived for each local area from data in Sunrun's prior evaluation of tens of thousands of homes across California for solar. Sizing for solar was based on observed average solar installations in California of approximately 6.5 kW per home.

## Computing Energy Storage Potential per Building

We evaluated energy storage based on the expected electricity bill savings it could provide to customers. This ignores the resilience value of energy storage, which may lead customers to adopt energy storage even when it is not economically optimal or to adopt larger energy storage systems than are justified on a pure cost basis. Our energy storage sizing is therefore conservative, especially in the residential segment. Differences in sizing between residential and C&I segments results from the differing tariff structures (Time of Use versus Demand Charges) under which each segment generally receives electricity service.

To calculate energy storage potential in the C&I segment, we assumed that Energy Storage Systems (ESS) could be installed indoors or outdoors. We calculated the technical potential for energy storage indoors and outdoors using industry-standard metrics for ESS energy density, minimum and maximum size limitations, and property line and building setbacks. At each site, we chose either indoor or outdoor installation for energy storage based on potential system size and cost to build.

From the maximum technical potential, we limited the ESS power capacity to 100% of the customer's peak load when paired with solar, and 50% of the customer's peak load when not paired with solar. We assumed all ESS to have a 2:1 ratio of MWh to MW.

We filtered potential ESS sites based on economic criteria. We determined the likely tariff at each building and used it to estimate the electricity bill savings provided by an ESS, modeling savings due to reduced demand charges and due to "energy arbitrage," the process of shifting energy consumption from more expensive time of use periods to cheaper ones. We calculated system cost to build based on system size and whether it was located indoors or outdoors, accounting for policy incentives including the Self-Generation Incentive Program (SGIP). We filtered out systems that didn't provided sufficient bill savings to meet an ESS developer's required internal rate of return.

Every C&I property was modeled with stand-alone solar, stand-alone storage, and solar paired with storage, and we selected the product combination with the highest savings for the customer. Where solar and storage were sited together, we modeled cost savings from both the ITC and SGIP.

For the residential segment, storage capacity was modeled based on an assumed single ESS size for each home set at 8.8 kWh usable ESS capacity, in line with existing product availability for the residential market. The added levelized cost of an ESS was incorporated into estimates of customer savings, which is diminished in certain cases and leads to storage attachment of less than 100%.

The vast majority of solar systems sized to annual energy usage in California, averaging approximately 6.5 kW, can utilize an ESS of larger size and can be expected to do so in the future. Customers adopting batteries for resilience value might also choose to adopt large batteries. This would have the effect of increasing the RA potential, potentially dramatically so under rules enabling the full capacity of the battery to provide RA value.

## Computing Resource Adequacy Potential

RA potential was estimated by modeling a 4-hour discharge of the ESS during CAISO's current Must Offer Obligation period. Local RA will vary, but this measure is used as a starting point.

For the C&I segment, RA capacity was de-rated relative to a 4-hour discharge from installed ESS capacity to account for the expected state-of-charge of the ESS given multiple operating parameters, including demand charge mitigation, energy arbitrage, and solar charging constraints.

For the residential segment, RA potential was estimated by modeling daily discharging of the ESS for 4 hour duration during CAISO's current Must Offer Obligation period, and subsequent recharging of the ESS on the subsequent day via solar. 100% of ESS charging is assumed to come from the paired solar system. Solar insolation was modeled for each hour of the year based on TMY3 data, varying by region of California. The result is a seasonal variation in RA per unit per month that is lowest in winter and highest in summer. The estimate shared reflects the average of all months of the year, underestimating the RA available during California's annual peak in summer. For estimates of RA based on current PDR rules that limit utilization of storage for RA purposes to coincident hourly load, household load was estimated based on climate zone and the approximate portion of a given Local Area or Sub-Local Area falling into each climate zone.

# About the Authors

## Station A

Station A is a software company offering a platform that provides the insights needed to take any building to zero carbon emissions. The platform connects clean energy developers with building owners and enables them to plan and execute projects. Station A's mission is to enable a carbon-neutral future by scaling and automating the clean energy development process. Station A's customers include the country's leading clean energy developers and technology providers. Join the Station A platform today at ***www.stationa.com***.

## Sunrun

Sunrun is the nation's largest residential solar, battery storage and energy services company. With a mission to create a planet run by the sun, Sunrun has led the industry since 2007 with its solar-as-a-service model, which provides clean energy to households with little to no upfront cost and at a saving compared to traditional electricity. Sunrun offers a home solar battery service, Sunrun Brightbox, that manages household solar energy, storage and utility power with smart inverter technology. For more information, please visit ***www.sunrun.com***.

## Stem

Stem creates innovative technology services that transform the way energy is distributed and consumed. Athena™ by Stem is the first AI for energy storage and virtual power plants. It optimizes the timing of energy use and facilitates consumers' participation in energy markets, yielding economic and societal benefits while decarbonizing the grid. The company's mission is to build and operate the smartest and largest digitally-connected energy storage network for our customers. For more information, please visit ***www.stem.com***.