Proceeding: R.20-11-003 (Phase 2)

Exhibit No.: SDGE-7

Witnesses: Jeff DeTuri
Habibou Maiga

PREPARED PHASE 2 DIRECT TESTIMONY OF
SAN DIEGO GAS & ELECTRIC COMPANY
REGARDING SUPPLY-SIDE PROPOSAL FOR
INCREASING PEAK AND NET PEAK SUPPLY
RESOURCES IN 2022 AND 2023 AND COMMENTS ON
ENERGY DIVISON STAFF CONCEPT PAPER

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

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I. INTRODUCTION

The purpose of this testimony is to discuss supply-side issues identified in the *Assigned Commissioner's Amended Scoping Memo and Ruling for Phase 2* issued in the above-referenced proceeding by the California Public Utilities Commission (Commission) on August 10, 2021 (Amended Scoping Memo) and to provide comments regarding the "Utility-Scale Storage, Imports, and Generation" topic presented in the *Energy Division Staff Concept Paper* dated August 16, 2021 (Staff Paper).[1]

II. TO SUPPORT THE GOAL OF EXPEDITED PROCUREMENT, THE COMMISSION SHOULD PROVIDE GUIDANCE REGARDING COST RECOVERY FOR RESOURCES THAT ARE CAPABLE OF PROVIDING ADDITONAL CAPACITY (Witness: Jeff DeTuri)

The Amended Scoping Memo notes the direction set forth in the Emergency Proclamation signed by Governor Newsom on July 30, 2021 (Emergency Proclamation) that the Commission "work with the State's load-serving entities on accelerating plans for the construction, procurement, and rapid deployment of new clean energy and storage projects to mitigate the risk of capacity shortages and increase the availability of carbon-free energy at all times of day."[2] As a practical matter, it will be a challenge to secure additional resources given that the timeframe is short and that supply chains are constrained; achieving this objective will require flexibility and creative thinking. This mindset of openness is reflected in the Staff Paper

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1 Staff Paper, pp. 21-25.

2 Amended Scoping Memo, p. 2.

and will be essential to secure the additional capacity required to maintain reliability for the immediate future.

To this end, the Commission should consider enabling cost recovery for additional means of buttressing system reliability in the investor-owned utilities' (IOUs') distribution service territories beyond those eligible for cost recovery today. This could allow the State to capture 'low-hanging fruit' opportunities to improve reliability that might be missed if cost recovery is in question. For example, solutions could include but would not be limited to:

- Addition of energy storage to existing resources, which may not increase resource capacity but could help units run longer and provide more market products such as ancillary services;
- Addition of chillers to a combined cycle plant that would reduce the ambient temperature derate during summer months;
- Addition of resources that are not eligible for resource adequacy (RA) program credit but are capable of providing reliability benefits.

Thus, in accordance with the direction set forth in the Governor's Executive Order to increase the availability of supply resources, and given the need to establish cost recovery certainty as soon as possible to allow procurement activity to commence as soon as possible, SDG&E proposes that the Commission issue an immediate decision – **in advance of the decision anticipated in November, 2021** – establishing a clear means of cost recovery to enable procurement of additional capacity for the benefit of all customers in an IOU's distribution service territory. Specifically, the Commission should (i) clarify that the Cost Allocation Mechanism ("CAM") established under Public Utilities Code Section 365.1 allows recovery of costs for resources procured in response to direction provided in this proceeding that provide additional capacity but are not RA-eligible; and (ii) establish a new non-bypassable charge ("NBC") to recover the costs of solutions ordered in this proceeding that are not deemed to be CAM-eligible.

A. Recovery of Costs Through the Section 365.1 CAM

Decision ("D.") 21-02-028 provides that the cost of resources meeting certain eligibility criteria are recoverable through the CAM mechanism.[3] In particular, D.21-02-028 provides that resource that are, among other things, "deliverable during both the peak and net peak demand periods" are CAM eligible.[4] D.21-03-056 suggests that cost recovery under the CAM mechanism is not dependent on eligibility of the resource to provide RA credit:

> The net costs associated with this procurement shall be passed through to all benefiting customers consistent with the existing cost allocation mechanism. ***We clarify that because this procurement is additional to [load-serving entities' ("LSEs'")] RA requirements, there will not be RA capacity benefits to allocate to all LSEs, as is usually the case with resources procured through the cost allocation mechanism.*** In this instance, the benefits provided to all LSEs is increased electric reliability without requiring all LSEs to procure their share of these incremental resources under this expedited timeframe or be subject to RA program penalties for not doing so.[5]

The statutory provision establishing the CAM mechanism, Section 365.1(c)(2), contemplates a circumstance in which "the commission authorizes, in the situation of a contract with a third party, or orders, in the situation of utility-owned generation, an electrical corporation to obtain generation resources that the commission determines are needed to meet system or local area reliability needs for the benefit of all customers in the electrical corporation's distribution service territory," and provides that "the net capacity costs of those generation

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[3] D. 21-02-028, pp. 10-12.

[4] *Id*. at p. 11.

[5] D.21-03-056, p. 44 (emphasis added).

resources are allocated on a fully non-bypassable basis consistent with departing load provisions as determined by the commission . . ."[6] While the provision addresses allocation of the RA benefits of such resources, the statute does not appear on its face to *require* RA eligibility as a prerequisite to cost recovery through the CAM.[7]

This fact, along with the above-referenced discussion in D.21-03-056, suggests that a resource offering capacity that can help to provide system reliability but is not eligible for RA compliance is nonetheless eligible for CAM treatment. However, the ambiguity that exists on this point and the resulting lack of certainty regarding cost recovery for such resources is an impediment to procurement of these resources by the IOUs in their established role as 'reliability steward' for their distribution service territory[8] and as directed in D.21-03-056. Accordingly, the Commission should make clear in a decision issued as soon as possible – in advance of the decision expected to be adopted in November, 2021 – that the cost of resources that provide system capacity, whether or not they are able to satisfy RA obligations, are eligible for CAM treatment (provided that they meet other applicable Commission requirements).

B. Recovery of Costs Through a New Non-Bypassable Charge

The Staff Paper includes a recommendation for "a new non-bypassable charge (NBC) for cost recovery of costs associated with emergency procurement that adds additional reserve margin and does not already fit into an existing cost recovery mechanism."[9] SDG&E agrees that creation of a new NBC that provides certainty regarding recovery of costs that are not otherwise

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6 Public Utilities Code Section 365.1(c)(2)(A). All statutory references herein are to the Public Utilities Code unless otherwise noted.

7 *See* Section 365.1(c)(2)(C).

8 *See* D.07-11-051, p. 12, note 12.

9 Staff Paper, p. 22.

recoverable through the CAM would incentivize solutions that could help to provide reliability for Summer of 2022 (and 2023). Thus, establishing a new NBC for this purpose is aligned with the need to "take immediate action to reduce the strain on the energy infrastructure, increase energy capacity, and make energy supply more resilient this year to protect the health and safety of Californians," as well as the Governor's express direction to the Commission to "exercise its powers to expedite Commission actions, to the maximum extent necessary to meet the purposes and directives of this proclamation . . . to ensure that California has a safe and reliable electricity supply through October 31, 2021, to reduce strain on the energy infrastructure, and to ensure increased clean energy capacity by October 31, 2022."[10]

Accordingly, the Commission should establish a Reliability Enhancement Cost Allocation Mechanism ("RECAM") for recovery of costs that are not otherwise recoverable through the CAM. To recover costs through the proposed RECAM, the IOU should be required to demonstrate in an advice letter requesting Commission approval (Tier 1 or Tier 2, as appropriate) that the cost at issue is for a resource or solution that provides additional system reliability that benefits all customers in the IOU's distribution service territory and is not eligible for recovery under an existing cost recovery mechanism such as the CAM. The RECAM should be included in the distribution rate component and collected from all benefitting customers in a manner similar to the CAM charge.

Any request to recover costs through the RECAM should be voluntary and made at the sole discretion of the IOU. Since the Commission does not examine or approve the procurement costs of non-IOU LSEs and does not subject such costs to ongoing oversight, non-IOU LSEs

[10] Executive Department State of California, *Proclamation of a State of Emergency*, dated July 30, 2021.

should not be permitted to request recovery of costs through the RECAM. At this time, the RECAM should be limited to costs related to procurement undertaken in connection with the instant proceeding within the 2022-2023 timeframe. If the NBC proves to be a useful tool, its use could be expanded or extended in the future in this or another proceeding.

III. THE COMMISSION SHOULD NOT IMPOSE PENALTIES FOR DELAYS TO D.19-11-016 PROCUREMENT (Witness: Jeff DeTuri)

The Staff Paper points out that there are currently no penalties imposed on LSEs when resources procured to meet D.19-11-016 procurement obligations fail to meet their expected commercial operation date ("COD"), although D.20-12-044 raises the possibility of ordering backstop procurement in such situations and allocating the cost of that backstop procurement to one or more LSEs.[11] The Staff Paper suggests that the Commission could apply penalties to "any LSE that fails to achieve commercial online dates consistent with the order."[12] This approach is ill-advised for several reasons.

First, as a practical matter LSEs have no direct control over project development. It makes little sense and is poor public policy to impose penalties on an entity that cannot take reasonable action to avoid being penalized. LSEs already typically include performance requirements in their contracts with project developers and remain engaged in the project development process to urge adherence to project schedules; it is not clear what more LSEs can do to incent timely completion of projects. Put simply, project delays are not the result of a failure on the part of LSEs to press project developers to complete projects on time. Rather, delays are typically the result of supply chain issues, permitting delays, etc. Imposing penalties

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11 Staff Paper, p. 21.

12 *Id*.

on LSEs will do nothing to address those problems since there is nothing that LSEs can do beyond what they are *already* doing to encourage project developers to achieve COD. In other words, imposing penalties would serve no purpose.

Second, it is likely that penalties imposed on an LSE for project delay would be passed through to the project developer. California already presents many challenges to siting and development of new resources; the threat of additional penalties for delays that may be unavoidable (and/or the burden associated with defending against such penalties) would be an additional deterrent that could chill further project development within the state. This outcome is the exact opposite of the goal of expanding resource supply outlined in the Emergency Proclamation. The Emergency Proclamation seeks to ease existing restrictions in order to enhance system reliability; creating new restrictions that make development of resources *more* difficult and expensive is clearly at odds with this approach.

Third, it is not clear how the potential penalty framework would apply to contracts that have already been approved by the Commission. After-the-fact application of penalties to approved projects would change the risk profile of such projects and would interfere with regulatory certainty. Moreover, imposition of penalties could make project developers less likely to increase the amount of capacity available if doing so creates greater exposure to potential penalties. If it is not possible to pass through penalties to the developer of projects that have already been approved by the Commission, the LSE's customers could ultimately be forced to pay the cost of penalties resulting from project delays – it is hard to see how this serves the public interest.

Accordingly, the Commission should maintain the current approach of not imposing penalties on LSEs for project delays that are outside of their control and instead focus its attention on areas where Commission action can produce a positive result.

IV. GREATER TRANSPARENCY IS REQUIRED TO DETERMINE THE ACCURACY OF THE NEED ANALYSIS (Witness: Jeff DeTuri)

In its August 12, 2021 Administrative Law Judge Ruling (ALJ Ruling), the Commission notified parties to the instant proceeding of publication by the California Energy Commission (CEC) of its *Draft Preliminary 2022 Summer Supply Stack Analysis* (Draft Stack Analysis). The ALJ Ruling further directs that parties consider the Draft Stack Analysis in witness testimony submitted in the instant proceeding.

The Draft Stack Analysis projects that an additional 600 MW to 5,200 MW of resources may be required to ensure electric system reliability for peak and net peak hours during summer 2022 without the use of contingency resources.[13] However, the analytical basis for this conclusion lacks transparency. For example, the Draft Stack analysis indicates that it relies on the demand forecast included in the Integrated Energy Policy Report (IEPR) 2020 Update, but it is not clear *which* demand profile is used and there are several different options to choose from. The 2020 IEPR Update has multiple versions of demand that use either a baseline or managed demand, and then sub-cases beneath each of those include low, mid, and high demand cases.[14] While the analysis states that the mid-demand case is used, it is unclear whether it is the managed or baseline mid-demand case. The recent proposed Preferred System Plan (PSP) in the Commission's Integrated Resource Plan (IRP) proceeding uses the managed mid-demand case.

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[13] Draft Stack Analysis, pp. 2-3.

[14] 2020 IEPR Update Report. Available at: https://efiling.energy.ca.gov/getdocument.aspx?tn=237269

Accordingly, to ensure consistency, SDG&E proposes to use this case for purposes of the need analysis for the demand case.

The baseline resource list is constructed using the California Independent System Operator (CAISO) 2021 Net Qualifying Capacity (NQC) list of resources with a hydro derate of 1,500 MW, and other specific imports, retirements, and procurement assumptions. Import assumptions are stated as the average of 2015-2020 CAISO RA showings. However, it is unclear if these import assumptions are the average hourly value that is set as a static amount, or if the average hourly values from 2015-2020 are used for each respective hour. It would be useful to compare the import assumption value to the CAISO maximum import capability (MIP) to determine how much additional import capacity, if any, is available.

In terms of additional procurement assumptions, SDG&E is unable to determine what recent Commission procurement orders are represented by the 840 MW of capacity assumed in August 2022 and the additional 556 MW carried over from 2021. The first IRP reliability procurement decision, D.19-11-016, ordered 3,300 MW of procurement from 2021 through 2023 with 1,650 MW online by August of 2021; 2,475 MW online by August of 2022; and the remainder by August 2023. In D.21-03-056, the Commission ordered the IOUs to conduct incremental emergency procurement totaling 1,000-1,500 MW, while the Amended Scoping Memo issued in the instant proceeding proposes that the IOUs expedite this procurement and extends the emergency procurement date to 2023.[15,16] It is not clear to SDG&E what amount of the stated Commission procurement in the Draft Stack Analysis is derived from each of these decisions or rulings, or indeed if the Draft Stack Analysis is missing this planned procurement.

[15] D.21-03-056.

[16] Amended Scoping Memo, p. 4.

The IRP PSP encompasses all new resources under development within the state and determines what additional procurement is necessary to ensure reliability in 2022 and beyond. The electric reliability determination of need should use this same need determination analysis to assess procurement needs or capacity shortfalls instead of seeking to recreate it (particularly within the short timeframe available).

V. THE COMMISSION SHOULD SUPPORT STREAMLINING OF THE INTERCONNECTION PROCESS TO ENABLE MORE RESOURCES TO COME ONLINE IN 2022 AND 2023 (Witness: Habibou Maiga)

SDG&E agrees with the suggestion offered by Pacific Gas and Electric Company ("PG&E") that "load serving entities ('LSEs') be informed by CAISO, based on any forthcoming procurement order, what amount of generation in the CAISO interconnection queue can come online within the stated compliance period."[17] This information will support contracting with resources that have the potential to be online by the summers of 2022 and 2023. In addition, SDG&E concurs with PG&E that "there may be opportunities for some resources to come online as Energy-Only or potentially fully-deliverable by the summer of 2023."[18] To the extent the inability to obtain Full Capacity Deliverability Status (FCDS) is delaying projects' online dates, switching to Energy-Only, or seeking Interim Deliverability Status, may allow an earlier In-Service Date. Depending on the locations of the resource, and prior studies performed by the CAISO, the CAISO should implement a screening process to determine which of the expedited Energy-Only resources could likely become FCDS without major upgrades. The results of the screening process would give the CAISO grid operators confidence that Energy Only resources

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[17] *Comments of Pacific Gas & Electric Company on Administrative Law Judge Ruling to Notice a Pending Amended Scoping Ruling*, filed August 6, 2021 (PG&E Comments on ALJ Ruling), p. 5.

[18] *Id*. at p. 7.

located in areas where transmission is unlikely to be limiting during hours of greatest system need, will contribute to supply reliability.

SDG&E also agrees with PG&E that it is "critical for the Commission, CEC, and CAISO to coordinate efforts to streamline the process for bringing new resources online."[19] There may be opportunities for the Commission to approve Purchase Power Agreements (PPAs) in parallel or to have some degree of overlap with the CEC's generation permitting responsibilities. PG&E's suggestion that LSEs be informed by the CAISO as to likely online dates for generators in the CAISO queue[20] makes sense and would add an additional layer of helpful coordination.

There may also be an opportunity for the CAISO to temporarily shorten its two-year long interconnection process. This could be accomplished by allowing generators in Cluster 13 and Cluster 14 to sign Generator Interconnection Agreements (GIAs) and go to construction after the first interconnection study phase. The Transmission Planning Process (TPP) could then be used to identify and address any reliability issues that would otherwise be considered in the second interconnection study phase.

The California Energy Storage Alliance (CESA) suggests that the Commission "take all actions available, including waivers to its existing tariff processes, to expedite the interconnection process for . . . in-front-of-the-meter ('IFOM') and behind-the-meter ('BTM') energy storage as part of this proceeding." Specifically, CESA states that "the Commission should consider various fast-track or streamlined interconnections strategies in this proceeding, including provisional export permits for non-exporting energy storage or vehicle-to-x ('V2X') resources in the ELRP, increased staffing to support interconnection studies, potential strategies

[19] *Id*. at p. 8.

[20] PG&E Comments on ALJ Ruling, p. 5.

to overcome delayed utility construction of upgrades, and expansion of the Rule 21 notification-only pilot for small non-exporting storage systems, as adopted in D.21-06-002."[21]

SDG&E agrees that expediting the interconnection process is key to bringing new resources online in timely fashion. Indeed, SDG&E continuously seeks opportunities to refine and streamline the Rule 21 interconnection process. The primary function of Rule 21 is to ensure safe and reliable operation of IFOM and BTM generating facilities interconnecting to SDG&E's distribution system over which the Commission has jurisdiction. SDG&E supports and continuously seeks opportunities to cost-effectively refine and streamline the interconnection process to bring resources on-line for all applicants as quickly as possible. For example, in February of 2013, SDG&E launched its Distribution Interconnection Information System (DIIS) which offers a web-based interconnection application and project tracking portal for customers.

Since the launch of DIIS SDG&E has approved over 200,000 interconnection requests and has made a variety of significant system upgrades. The average application approval time for the 200,000 requests, after SDG&E's receipt of a completed application and an electrical release from the local authority having jurisdiction, is less than five calendar days. Moreover, during 2019, SDG&E provided permission to operate to its small[22] Net Energy Metering (NEM) customers, on average, within three calendar days. The average approval time for non-NEM projects during 2019 was less than four business days and the average approval time for large NEM[23] projects was 2.1 calendar days. These key performance metrics clearly demonstrate

21 *Comments of the California Energy Storage Alliance on E-mail Ruling Seeking Responses Regarding a Proposed Amended Scope and Schedule to Address Reliability Issues in 2022 and 2023*, filed August 6, 2021, p. 3.

22 Systems with a capacity $\leq$ 30 kilowatts.

23 Systems with a capacity > 30 kilowatts.

SDG&E's consistent readiness to meet the needs and timing requirements of its customers. However, as important as it is to expedite the interconnection process, further streamlining efforts must not compromise electric system reliability or the safety of the public and SDG&E personnel.

American Clean Power – California (ACP-CA) offers that "by ensuring that this cycle of the IRP includes the most recent transmission planning and reliability studies prepared in the 2021-22 TPP cycle, the CPUC will better enable near-term transmission solutions that may provide additional deliverability on the system."[24] ACP-CA does not specify what information in these studies could be used in the current IRP cycle to provide "additional deliverability," or at what stage in the current IRP cycle the information would be incorporated. However, if the CAISO studies do indicate that there is more near-term deliverability on the system than is assumed in the current IRP process, SDG&E supports highlighting this information and considering its implications for procurement decisions that could bring additional resources online by the summers of 2022 and 2023.

Finally, the Independent Energy Producers Association (IEP) notes that "one possible source of new supply that could come online quickly is the installation of reciprocating engines or microturbines at existing generation facilities that have available additional interconnection capacity."[25] SDG&E agrees that if unused interconnection capacity exists, it does provide an opportunity for bringing new resources online more quickly than would otherwise be the case. To the extent the data are not confidential, SDG&E recommends that the CAISO provide a

[24] *American Clean Power – California Response to E-mail Ruling Seeking Responses Regarding a Proposed Amended Scope and Schedule to Address Reliability Issues in 2022 and 2023*, filed August 6, 2021, pp. 2-3.

[25] *Comments of the Independent Energy Producers Association on the Email Ruling Regarding a Proposed Amended Scope and Schedule*, filed August 6, 2021, p. 2.

listing of the locations where unused interconnection capability is available. SDG&E notes that the addition of new resources at these locations does not need to be limited to the reciprocating engines or microturbines mentioned by IEP; other types of resource additions can also be considered.

VI. CONCLUSION

This concludes SDG&E's prepared Phase 2 direct testimony.

STATEMENT OF QUALIFICATIONS

My name is Jeff DeTuri. My business address is 8315 Century Park Court, San Diego, CA 92123. I am employed by SDG&E and my current title is Policy and Strategy Manager in the Electric & Fuel Procurement Department. My responsibilities include leading a team that develops energy procurement strategy and serves as a key liaison to regulatory agencies and legislators to solve procurement-related issues and design and implement procurement-related strategies involving the purchase or sale of commodities.

I joined SDG&E in August 2003 and have held various positions with increasing levels of responsibility within San Diego Gas & Electric. Prior to joining SDG&E, I worked as an accounting professional for various companies throughout San Diego County. I received a Bachelor of Accountancy degree and a Master of Business Administration from the University of San Diego.

I have previously testified before the California Public Utilities Commission.

STATEMENT OF QUALIFICATIONS

My name is Habibou Maiga. My business address is 8315 Century Park Court, San Diego, CA 92123. My current title is Grid Planning and Optimization Manager in the Electric System Planning Department of San Diego Gas & Electric Company (SDG&E). My responsibilities include planning SDG&E's transmission system to meet future regional reliability needs, policy objectives, and compliance obligations. This is achieved through simulations of the transmission grid and engineering optimal expansion plans.

I have a bachelor's degree in electrical engineering from the University of Texas at Arlington and a master's degree in electrical engineering from Arizona State University. I am a registered Professional Electrical Engineer with approximately 13 years of experience in the electric power industry. My work experience includes electric transmission planning, protection engineering, and operations. I’ve worked for SDG&E for approximately 8 years.

I have not previously testified before the California Public Utilities Commission.

VERIFICATION

In accordance with Rules 1.11 and 13.7 of the Rules of Practice and Procedure of the California Public Utilities Commission, I hereby declare under penalty of perjury that factual statements in my testimony are true and correct of my own knowledge, except as to matters that are stated on information or belief, and as to those matters I believe them to be true. Insofar as statements in my testimony are in the nature of opinion or judgment, such statements represent my best professional judgment. I adopt this testimony as my sworn testimony in this proceeding.

Executed this 1st day of September, 2021, at San Diego, California

/s/ Jeff DeTuri
Jeff DeTuri
SDG&E Electric & Fuel Procurement Department
Policy and Strategy Manager

VERIFICATION

In accordance with Rules 1.11 and 13.7 of the Rules of Practice and Procedure of the California Public Utilities Commission, I hereby declare under penalty of perjury that factual statements in my testimony are true and correct of my own knowledge, except as to matters that are stated on information or belief, and as to those matters I believe them to be true. Insofar as statements in my testimony are in the nature of opinion or judgment, such statements represent my best professional judgment. I adopt this testimony as my sworn testimony in this proceeding.

Executed this 1st day of September, 2021, at San Diego, California

/s/ Habibou Maiga
Habibou Maiga
SDG&E Electric System Planning Department
Grid Planning and Optimization Manager