Application No.: A.22-05-XXX
Exhibit No.:
Witness: Matthew O'Connell

# PREPARED DIRECT TESTIMONY OF

# MATTHEW O'CONNELL

# ON BEHALF OF

# SAN DIEGO GAS & ELECTRIC COMPANY

*****REDACTED – PUBLIC VERSION*****

**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

**May 31, 2022**

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# I. INTRODUCTION

My testimony describes the resources San Diego Gas & Electric Company ("SDG&E") expects to use in calendar year 2023 to provide electric commodity service to its bundled service customers; provides a forecast of the procurement costs that SDG&E expects to record in 2023 to the Energy Resources Recovery Account ("ERRA"), Transition Cost Balancing Account ("TCBA"), Portfolio Allocation Balancing Account ("PABA"), and Local Generation Balancing Account ("LGBA"); provides a 2023 forecast of SDG&E's San Onofre Generating Station ("SONGS") Unit 1 Offsite Spent Fuel Storage Costs; provides a forecast of 2023 total greenhouse gas ("GHG") costs; and provides a 2023 forecast of Tree Mortality Non-Bypassable Charge ("TMNBC") costs. SDG&E witness Ms. Ghianni uses my forecast of ERRA, Competition Transition Charge ("CTC") and Local Generation ("LG") in developing 2023 revenue requirements for each element. In addition, my testimony provides information that supports SDG&E witness Ms. Morien's development of the GHG allowance revenue return allocation and the volumetric revenue return for non-residential and residential customers, as well as rates for the Green Tariff Shared Renewables ("GTSR") program and the Power Charge Indifference Adjustment ("PCIA"). SDG&E witness Ms. Miller uses the forecasted costs and volumes provided in my testimony to calculate PCIA costs, in order to discuss PCIA treatment and related issues.

## A. Summary of Testimony

In Section II of my testimony, I provide a forecast of the energy requirements that will be required to serve SDG&E's bundled customer load for 2023, as well as forecasts of the supply resources that SDG&E expects to utilize to meet that load in calendar year 2023. The supply resources for which I provide forecasts include (1) conventional generation resources that are under contract for 2023; (2) generation resources owned by SDG&E; (3) renewable generation resources that are under contract for 2023; and (4) Qualifying Facilities ("QFs") under the Public Utility Regulatory Policies Act ("PURPA") that are under contract for 2023.

In Section III of my testimony, I quantify the costs associated with the resources described in Section II, along with other electric procurement costs that are recorded in ERRA, such as market purchases, California Independent System Operator ("CAISO") charges and portfolio hedging costs. These costs are summarized in Attachment A.

In Section IV of my testimony, I provide a forecast of the 2023 SONGS Unit 1 Offsite Spent Fuel Storage Costs associated with SDG&E's 20% minority ownership interest in SONGS.

In Section V of my testimony, I provide a forecast of the 2023 GHG emissions and associated costs, both direct and indirect, incurred in connection with SDG&E's compliance with California's cap-and-trade program. I also provide a forecast of GHG allowance auction revenues.

In Section VI of my testimony, I provide a forecast of the 2023 TMNBC costs.

In Section VII, I provide a summary of SDG&E's meet-and-confer activities and information exchange with Community Choice Aggregators in SDG&E's service territory.

Lastly in Section VIII, I provide a statement of qualifications.

Finally, my testimony refers to the following attachments:

Attachment A: SDG&E 2023 ERRA and LG Expenses (CONFIDENTIAL)

Attachment B: SDG&E 2023 Generation Portfolio Delivery Volumes (CONFIDENTIAL)

Attachment C: SDG&E 2023 Renewable Resource Detail

Attachment D: SDG&E 2023 CTC & QF Detail (CONFIDENTIAL)

Attachment E: SDG&E GHG Detail (CONFIDENTIAL)

## II. 2023 FORECAST OF ENERGY REQUIREMENTS AND SUPPLY RESOURCES

### A. Energy Requirements Forecast

The sales forecast utilized in this filing was developed internally by SDG&E. This forecast includes the load departure of Community Choice Aggregators ("CCA") Clean Energy Alliance ("CEA") and San Diego Community Power ("SDCP"). Using this forecast and adjusting for direct access load, I project that the energy requirements for SDG&E's bundled load (ASR) for 2023 will be [redacted] The 2023 forecast is [redacted] or [redacted] less than SDG&E's forecasted bundled energy (ASR) for 2022 ([redacted]).

### B. Supply Resource Forecast

After determining the amount of energy that SDG&E's bundled load customers will require in 2023, I then develop a forecast of the supply that will meet that demand. To quantify the generation associated with the supply resources, I used the PLEXOS production cost modeling software. Inputs to this model include the characteristics of the various generation resources, including capacity, heat rate, operating constraints, both fixed and variable Operating and Maintenance ("O&M") costs, and other factors that impact each plant's dispatch and generation costs. The natural gas and electric market price forecasts were derived using a recent (March 23, 2022) assessment of 2023 market prices. The model simulates a least-cost dispatch of SDG&E's resource portfolio for every hour of 2023 to serve load. The supply resources fall into the following four categories.

#### 1. SDG&E-Contracted Conventional Generation

- SDG&E has multiple conventional generation resources under contract in its 2023 resource portfolio. These resources are available under a variety of contractual arrangements, including tolling contracts, fixed energy contracts, and contracts for Resource Adequacy only. The largest of the tolling and fixed energy contracts are: the Carlsbad Energy Center Power Purchase Agreement ("PPA") for the output of a 528 MW simple cycle combustion turbine unit;

- the Pio Pico Energy Center PPA for the output of a 336 MW simple cycle combustion turbine unit;
- the Orange Grove PPA for the output of two 48 MW simple cycle combustion turbine units;
- the El Cajon Energy Center PPA for the output of a 48 MW simple cycle combustion turbine unit;
- the Escondido Energy Center PPA for the output of a 48 MW simple cycle combustion turbine unit; The forecasted generation for these contracts is detailed in Attachment B and is summarized in Table 1 below:

| | Table 1: Generation (GWh) | | |
|---|---|---|---|
| | 2023 | 2022 | Difference |
| El Cajon Energy Center | [redacted] | | |
| Orange Grove | | | |
| Escondido Energy Center | | | |
| Pio Pico | | | |
| Carlsbad Energy Center | | | |
| Total | | | |

SDG&E also enters contracts each year to meet its California Public Utilities Commission ("CPUC") Resource Adequacy (RA) requirements.[1] Under its RA contracts,

[1] California Public Utilities Code Section 380 established the Resource Adequacy program to provide enough resources to the CAISO to ensure the safe and reliable operation of the grid in real time and to provide appropriate incentives for the siting and construction of new resources needed for reliability in the future.

SDG&E is entitled to show this capacity as meeting its RA obligation, but SDG&E does not have rights to the energy or ancillary services from these units. For 2023, SDG&E has been granted approval for contracts providing [redacted] of RA capacity and sales of [redacted] of RA capacity. R.20-05-003 is scheduled to resolve and establish the cost recovery mechanism for the resources in compliance with D.19-11-016, while D.21-03-056 establishes the cost recovery mechanism for resources as a result of procurement in R.20-11-003. Some of these contracts were executed prior to the official announcement of CCA load departure and were procured to meet load levels assuming no CCA load departure. The proposed decision issued on March 20, 2022 in R.20-05-003 is set to resolve the cost recovery mechanisms.

**2. SDG&E-Owned Dispatchable Generation**

SDG&E owns several generation facilities, which it uses to meet its bundled customer load, including the following:

- the Palomar Energy Center ("Palomar"), a 588 MW combined cycle power plant;
- the Desert Star Energy Center ("Desert Star"), a 485 MW combined cycle power plant;
- the Miramar Energy Facility ("Miramar I and II"), consisting of two 48 MW simple cycle combustion turbine units;
- the Battery Storage facilities, consisting of Escondido at 30 MW, El Cajon at 7.5 MW, Top Gun at 30 MW, Fallbrook at 40 MW, Kearny at 20 MW, Melrose at 20 MW, Pala-Gomez at 10 MW, and Westside Canal at 131 MW;
- the Cuyamaca Peak Energy Plant, consisting of a 45 MW simple cycle combustion turbine.

These units are dispatched by the CAISO for generation and ancillary services ("A/S") awards based on economic merit.[2] The forecasted generation for these plants is detailed in Attachment B and is summarized in Table 2 below:

| | Table 2: Generation (GWh) | | |
|---|---|---|---|
| | 2023 | 2022 | Difference |
| Palomar | [redacted] | | |
| Desert Star | | | |
| Miramar | | | |
| Battery Storage | | | |
| Cuyamaca | | | |
| Total | | | |

### 3. Renewable Energy Contracts

The 2023 forecast of renewable energy supply from CPUC-approved contracts is 5,718 GWh, which includes 1,236 GWh of Renewable Energy Credit ("REC") quantities[4] that are delivered to SDG&E in conjunction with existing non-renewable imports. This forecast represents a decrease of 12 GWh from the 2022 forecast (5,730 GWh). The forecasted generation associated with SDG&E's monthly renewable contracts is set forth in Attachment C.

For 2023, SDG&E forecasts it will receive 2,728 GWh of bundled renewable energy under 40 contracts with facilities that generate electricity using wind, solar, biogas, and non-pumped hydro technologies. This number considers forecasted RPS sales for 2023 in the amount of 2,990 GWh. Forecasted sales represent a reduction of renewable energy credits to maintain an

[2] SDG&E's dispatch model considered only generation dispatched for energy and not for A/S because the CAISO co-optimizes market awards between energy and A/S based on the opportunity cost of capacity. Thus, the economic benefit (and ERRA contribution) of using energy for generation is equivalent to using capacity for A/S.

[3] The difference between the generation at Cuyamaca is shown as zero due to rounding.

[4] Renewable Energy Credits represent the green attribute of renewable generation and, while they can be purchased independent of physical delivery of generation from the source, they must accompany a delivery of "tagged" physical power to be imported into California.

equivalent RPS compliance position considering CCA load departure and voluntary allocations of RPS resources as designated in R.18-07-003.[5] These sales volumes are estimates only and do not represent specific current or future agreements with counterparties. Any sales agreements subsequently entered into by SDG&E will be included in the November Update filing. The forecasted generation for projects that are currently on-line and operating, and for those projects that have recently come online and are expected to continue operations in 2023 are derived from generation profiles based on historical data for similar technologies[6]. The forecasted energy mix from these renewable resources is shown in Table 3 below:

| | Table 3: Generation (GWh) | | |
|---|---|---|---|
| | 2023 | 2022 | Difference |
| Solar | 2,323 | 2,310 | 13 |
| Wind | 1,966 | 1,955 | 11 |
| Wind RECs | 1,236 | 1,236 | 0 |
| Biogas | 165 | 221 | (57) |
| Other | 28 | 7 | 20 |
| RPS Sales | (2,990) | (1,830) | (1,160) |
| Total | 2,728 | 3,900 | (1,173) |

### 4. Competitive Transition Charge (CTC) Contracts

In 2023, SDG&E will have approximately 106.5 MW of capacity under contract with three QFs.[7] All these CTC contracts are in SDG&E's service area except for the Yuma Cogeneration Associates ("YCA") plant, a 55 MW natural gas-fired plant located in Arizona, the output of which is imported into CAISO.

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5 Based on R.17-06-026 the amount of RPS sales is subject to change.

6 SDG&E did not include renewable energy quantities or costs associated with the Sustainable Communities Photovoltaic program because costs for this program are not charged to ERRA.

7 The actual number of active QF contracts is over 50, but many of these QF resources only serve on-site load and do not deliver net energy to SDG&E. As a result, these are not included in the production cost model analysis. The three QFs referenced above deliver net energy to SDG&E and are thus included in SDG&E's model.

SDG&E's CTC contracts include a combination of must-take and dispatchable resources. For must-take resources, SDG&E is obligated to pay the contract price for all delivered QF generation and schedule it into the CAISO market; SDG&E has no such obligation with dispatchable resources. SDG&E has amendments with Goal Line and YCA, which provide SDG&E with more economic dispatch rights. SDG&E forecasted the plants' dispatch in accordance with these terms. The forecast of CTC energy supply in 2023 is [redacted]. The forecasted generation for these plants is detailed in Attachment D.

## III. 2023 FORECAST OF ERRA EXPENSES

To quantify the costs associated with the supply resources described in Section II, the production cost model also tracks the costs of the economic dispatch. Electric procurement expenses incurred by SDG&E to serve its bundled load are also recorded to the ERRA. These expenses include, among other items, costs and revenues for energy and capacity cleared through the CAISO market, power purchase contract costs, generation fuel costs, market energy purchase costs, CAISO charges, brokerage fees, and hedging costs.

I expect that SDG&E will incur $444 million of ERRA costs in 2023,[8] as reflected in Attachment A. This forecast is $513 million less than the $957 million forecasted for 2022.

The above-market costs of all generation resources that are eligible for cost recovery through PCIA rates will be recorded in PABA going forward. SDG&E's 2023 PABA cost forecast is $15 million.[9] This compares with a forecast of $180 million for 2022 filed in the 2022 ERRA forecast proceeding.

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8 This amount does not include Franchise Fees and Uncollectible ("FF&U"), nor do any of the other figures in my testimony.

9 In D.07-01-025, the Commission adopted the PCIA methodology for CCA customers. AL 3318-E, effective January 1, 2019, established the PABA to record the "above-market" costs and revenues associated with all PCIA eligible resources by vintage subaccounts.

In the remainder of this Section, I will discuss in greater detail the cost forecasts for specific ERRA items.

### A. ISO Load Charges

The CAISO supplies and sells to SDG&E the energy and A/S necessary to meet SDG&E's bundled load requirement. Based on forecasted prices for energy and A/S, SDG&E's production cost model forecasts [redacted] of ISO load charges for 2023. This cost includes the indirect GHG costs embedded in the market price of energy. I present GHG quantities and costs in Section V.

### B. ISO Supply Revenues

In the CAISO market, all generation from SDG&E's resource portfolio is sold to the CAISO. Based on the market price benchmark for energy, SDG&E forecasts revenues totaling [redacted] for generation sold in 2023.

### C. Contracted Energy Purchases

#### 1. Purchased Power Contracts

SDG&E's forecast of total costs for conventional power purchase contracts in 2023 is [redacted]. These costs cover capacity payments and variable generation costs for facilities with which SDG&E has contracts. The largest components in this category are Resource Adequacy capacity costs, expected to cost [redacted]. This category also includes [redacted] of RA sale transactions to maintain SDG&E's RA compliance position considering CCA load departure in 2023.

#### 2. Renewable Energy Contracts

SDG&E's renewable energy contracts usually contain only an energy payment and no capacity payment. In 2023, SDG&E's renewable energy portfolio will include a cost for all the renewable power delivered based on contract prices and the renewable energy credits (RECs) described in Section II under "Renewable Energy Contracts." All costs associated with these contracts are forecasted to be $442.8 million for 2023 and are booked to ERRA with above market costs booked to PABA. This includes $41 million of REC sales to maintain an equivalent RPS compliance position considering CCA load departure and expected allocations according to the VAMO process outlined in R.18-07-003. Attachment C details the renewable projects by technology type, their costs, and forecasted energy deliveries.

Customers who opt into the Green Tariff Shared Renewables ("GTSR") program, which consists of both a Green Tariff ("GT") component and an Enhanced Community Renewables ("ECR") component, pay a subset of the renewable costs.[10] The estimated GT customer usage in 2023 is 1.3 GWh[11]. The Interim Pool Sales for 2023 are forecast to be zero because forecasted customer usage is lower than the forecasted generation from Midway and Wister solar projects. The estimated GT charges include the cost of local solar[12] of [redacted], Grid Management Charges ("GMC") of $0.3488/MWh and Western Renewable Energy Generation Information System ("WREGIS") costs of $0.004/MWh. The estimated total energy procurement cost of GT in 2023 is $67,388. The estimated ECR customer usage in 2023 is 0.00 GWh. The estimated total cost of ECR in 2023 is $0. Additionally, the solar value adjustment was calculated as

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[10] Decision 15-01-051 authorizing the GTSR program was approved on January 29, 2015. The GT and ECR components are two separate rate offerings under the GTSR Program accessing different pools of solar resources and with different terms.

[11] GT and ECR usage forecasts were developed using average consumption estimates for each customer class in conjunction with program enrollment targets.

[12] Cost of local solar is an average price of projects built specifically to serve the GT component (GT Dedicated Procurement Projects).

[redacted].[13] These GTSR rates are illustrative and full details of SDG&E's GTSR proposal are discussed in the testimony of SDG&E witness Gwendolyn Morien.

### 3. Competitive Transition Charge (CTC) Contracts

SDG&E's CTC contracts consist of dispatchable capacity or firm capacity PURPA contracts. These contracts include provisions for both energy and capacity payments. The energy payments for QFs that are under firm capacity PURPA contracts are forecasted using SDG&E's Short-Run Avoided Cost ("SRAC") formula.[14] For the dispatchable contracts, SDG&E pays fuel, variable O&M and capacity payments. These contracts, whether PURPA or dispatchable, are considered CTC contracts,[15] and the ERRA expenses are based on delivered energy multiplied by the market price benchmark ("MPB"). Any costs, including capacity payments, greater than the market price benchmark are booked to the TCBA. For the purposes of ERRA accounting, ERRA expenses for CTC contracts are recorded on Line 5 of Attachment A, "Contract Costs (CTC up to market)," and are forecasted to be [redacted] in 2023. Attachment D details the breakdown of all the units discussed in this section and shows the associated costs, both ERRA and TCBA, and the forecasted energy deliveries. These costs include the indirect GHG cost embedded in the market price that flows through the SDG&E SRAC formula. I present GHG quantities and costs in Section IV of my testimony.

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13 Due to minimal participation forecasted for 2023 in the GTSR program, the NQC of the resources that are used to serve these customers is assumed to be zero.

14 The derivation of the SRAC price for QF contracts is posted monthly on an SDG&E website: http://www2.sdge.com/SRAC/.

15 The CP Kelco contract is not considered a CTC contract for cost allocation purposes.

### D. Generation Fuel

#### 1. Palomar, Desert Star, Miramar and Cuyamaca (Fuel Expenses that are Recovered through ERRA)

In 2022, the ERRA expense for generation fuel purchased by SDG&E for Palomar, Miramar I & II, Desert Star and Cuyamaca is forecasted to be [redacted].[16] These forecasted expenses include in lieu of gas fees for Palomar, which are also recovered in ERRA. These costs are calculated based on SDG&E's forecasted fuel usage for this plant and the applicable tariffs, Schedule GP-SUR[17] and Schedule EG.[18]

### E. Local Generation

As previously noted, SDG&E has entered into contracts for generation resources which specifically provide local Resource Adequacy for the SDG&E system. Because these contract costs are allocated to both bundled and unbundled customers, the costs are accounted for in a separate Local Generating Balancing Account. The Carlsbad Energy Center, El Cajon Energy Storage, Top Gun Energy Storage, Fallbrook Energy Storage, Escondido Energy Center, Escondido Energy Storage, Pio Pico, Kelco, Grossmont, a portion of Sentinel Energy Center, Melrose Energy Storage, Pala-Gomez Creek Energy Storage, Westside Canal Energy Storage, and Sagebrush Energy Storage contracts are included in this balancing account and are expected to cost [redacted], net of supply ISO revenue. Attachment A details the breakdown of local generation expenses.

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16 Capital and non-fuel operating costs for these plants are recovered in the Non-Fuel Generation Balancing Account ("NGBA") as required by D.05-08-005, Resolution E-3896 and D.07-11-046.

17 Customer-procured Gas Franchise Fee Surcharge.

18 Natural Gas Intrastate Transportation Service for Electric Generation Customers.

**F. Integrated Resource Planning and Electric Reliability Procurement Tracks**

The Integrated Resource Plan (IRP) proceeding, R.16-02-007, issued Decision (D.)19-11-016, requiring 3,300 MW of procurement by all LSEs within the CAISO for purposes of long-term statewide planning. The decision requires at least 50% of the resources to come online by August 1, 2021, 75% by August 1, 2022, and 100% by August 1, 2023. The Commission determined that SDG&E is responsible for 292.9 MW of incremental procurement beyond the State's existing portfolio of resources. SDG&E may also be responsible for incremental procurement of LSEs in its service territory that fail to procure, whether by choice or by consequence, their allocation of the total procurement need identified. This "on-behalf-of" procurement is additive to the IOU procurement for its own share of the identified need. In D.19-11-016, the Commission ordered cost recovery for this "backstop" procurement through a modified Cost Allocation Mechanism ("CAM") mechanism. A proposed decision addressing the Modified Cost Allocation Mechanism ("MCAM") for compliance with D.19-11-016 was issued in the Spring of 2022, with the final decision D.22-05-015 issued in late May. Until the Commission adopted the cost recovery for procurement undertaken as a result of the Decision, SDG&E requested the Commission in its Tier Advice Letter AL 3707-E to authorize SDG&E to establish a new memorandum account, the Resource Adequacy Procurement Memorandum Account ("RAPMA"), to track and record costs related to the procurement of incremental RA capacity required by D.19-11-016 and related administrative costs. These applicable contract expenses are included in the Modified CAM – RAPMA memorandum account in this ERRA forecast and will be incorporated into SDG&E's ERRA October Update according to D.22-05-015.

The Integrated Resource Plan (R.20-05-003) issued Decision D.21-05-035 requiring all LSEs in CAISO to procure a total of at least 11,500 megawatts (MW) of net qualifying capacity

(NQC). The decision requires 2,000 MW by 2023, an additional 6,000 MW by 2024, an additional 1,500 MW by 2025, and an additional 2,000 MW by 2026. The Commission determined that SDG&E is responsible for 361 MW of incremental procurement beyond the State's existing portfolio of resources. Due to updated load departure forecasts since the decision, SDG&E and San Diego Community Power (SDCP) filed advice letter 3967-E requesting to adjust the capacity requirements to ensure both parties' respective obligations more accurately account for load migration expected to occur during 2022 and 2023. SDG&E and SDCP mutually agreed and requested Commission approval to increase SDG&E's total procurement obligation by 114.3 MW and correspondingly decrease SDCP's obligation by the same amount. SDG&E's new procurement requirement would be 475.3 MW. Any procurement resulting from this order must be requested via advice letter outlining details of the resource and cost recovery methods. SDG&E has not yet requested approval for any resources resulting from this decision. LSEs were not given the opportunity to opt out of this procurement, and any procurement costs as a result of this decision will be allocated to bundled customers through PCIA. However, the IOUs are designated as backstop procurers in the event an LSE fails to reach their targets, and any backstop procurement costs SDG&E incurs is authorized to be recovered through the CAM cost recovery mechanism.

In the Electric Reliability proceeding (R.20-11-003), D.21-03-056 directed the IOUs within CAISO to procure additional resource capacity for the summers of 2021 and 2022. In a subsequent decision (D.21-12-015), the IOUs were directed to procure additional resource capacity for the summers of 2022 and 2023. Both decisions authorize the IOUs to seek CAM cost recovery for any resulting procurement. Any new resources procured or contracts entered into by SDG&E as a result have their costs included accordingly.

### G. CAISO Related Costs

SDG&E forecasts the miscellaneous CAISO costs to be [redacted] in 2023. SDG&E also forecasts the cost of the Federal Energy Regulatory Commission ("FERC") Fees and Western Renewable Energy Generation Information System to be [redacted] in 2023.

### H. Hedging Costs & Financial Transactions

SDG&E's resource portfolio has substantial exposure to gas price volatility because of fuel requirements for its gas-fired resources, as well as the gas price-based pricing formula for its QF contracts. To manage this exposure, SDG&E engages in hedging activity, consistent with its CPUC-approved procurement plan,[19] and it will book the resulting hedging costs and any realized gains and losses from hedge transactions to ERRA consistent with its CPUC-approved hedge plan. The estimate of hedging costs for 2023 is [redacted], calculated as the marked-to-market profit/loss of hedges already in place. The profit/loss of these and future hedges placed will rise and fall with market prices. Therefore, the final cost or savings will not be known until the settlement process has been completed for the hedging transactions. SDG&E has only hedged costs for January through March of 2023.

SDG&E may also trade short-term financial power products to hedge its long or short position against potentially volatile CAISO market clearing prices. SDG&E does not include a forecast of net cost or benefit from these power hedges due to the unpredictability of market prices relative to the price of the hedges.

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[19] SDG&E's 2014 Long-Term Procurement Plan, Appendix B: Electric and Gas Hedging Strategy.

**I. Convergence Bids**

SDG&E uses convergence bids[20] to hedge certain operational risks in the day-to-day management of its portfolio. It is not possible to forecast the gains or losses associated with potential convergence bidding activity because of the unpredictable relationship between day-ahead and real-time prices. Therefore, SDG&E did not forecast an ERRA revenue/charge for convergence bids.

**J. Congestion Revenue Rights (CRRs)**

Market participants, including SDG&E, were allocated CRRs by the CAISO for which they can nominate source and sink P-nodes[21] to match those in their portfolio. If congestion arises between the source and sink P-nodes, the CAISO will pay the market participant holding the CRR the congestion charges to offset the congestion costs incurred. SDG&E expects its CRRs to generate revenues from the CAISO to offset congestion costs incurred within its portfolio. However, expected revenues were not forecast for the 2023 ERRA forecast because SDG&E assumed congestion-free clearing prices to develop forecasts for load requirement costs and generation revenues. A forecast of CRR revenues would have required SDG&E to forecast offsetting market-congestion prices at various P-nodes over the 2023 period. Since there are no

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[20] A convergence bid (also known as a virtual bid) is not backed by any physical generation or load and is thus completely financial. Convergence bidding allows market participants to arbitrage expected price differences between the Day-Ahead and Real-Time markets. Using convergence bids, market participants can sell (buy) energy in the Day-Ahead market, with the explicit requirement to buy (sell) that energy back in the Real-Time market, without intending to physically consume or produce energy in Real-Time. Convergence bids that clear the Day-Ahead market will either earn (or lose) the difference between the Day-Ahead and Real-Time market prices at a specified node multiplied by the megawatt volume of their bids.

[21] The source and the sink are the two ends of a path for which congestion may occur. The CRR represents the difference in the Marginal Cost of Congestion component of the Locational Marginal Prices for the Nodal Prices of the source and sink.

forward market prices for congestion, we do not have a strong basis to perform this forecast without introducing complexity and additional uncertainty into the forecast.

Market participants, including SDG&E, are offered the ability to purchase CRRs through an auction process. SDG&E may elect to participate in the annual and monthly auction processes to procure the incremental CRRs. Since the incremental CRRs volumes cannot be forecasted, the incremental CRR costs and revenues also cannot be forecasted.

### K. Inter-Scheduling Coordinator Trades (IST)

In the CAISO market, SDG&E may transact ISTs[22] bilaterally with counterparties to hedge long or short positions. Under an IST purchase, SDG&E pays the counterparty the contracted energy price and in return receives payment from the CAISO based on the market clearing price. Under an IST sale, SDG&E receives payment from the counterparty based on the contracted energy price and in return pays the market clearing price to the CAISO. For IST purchases and sales, the payment to, or revenue from, the counterparty is largely offset by the respective credit from, or payment to, the CAISO. Because ISTs are used as a hedge against unknown market prices, SDG&E does not include a forecast of the net cost or benefit from these transactions.

## IV. SONGS UNIT 1 OFFSITE SPENT FUEL STORAGE COSTS

### A. Background

SONGS Unit 1 ceased operation on November 30, 1992. Defueling was completed on March 6, 1993. On July 18, 2005, SDG&E submitted AL 1709-E, which removed SONGS Unit 1 shutdown O&M expense from the revenue requirement pursuant to D.04-07-022. Southern

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[22] ISTs are financial bilateral transactions which allow SDG&E to hedge long or short price positions in the market.

California Edison Company ("SCE"), the majority owner of SONGS, has decommissioned the Unit 1 facility, and as of 2010, most of the Unit 1 structures and equipment have been removed and disposed of, except for areas shared by Units 2 and 3 for which physical decommissioning and dismantlement has only recently begun.

Spent fuel assemblies from SONGS Unit 1 have been stored since 1972 at the General Electric-Hitachi spent fuel storage facility located in Morris, Illinois. There are 270 spent fuel assemblies from SONGS Unit 1 currently in storage at that facility. Because there are no other facilities currently available in the U.S. for the commercial storage of spent nuclear fuel, those 270 assemblies are expected to remain at the Morris facility until they are accepted for ultimate disposal by the U.S. Department of Energy. Pursuant to the terms of the storage contract with General Electric-Hitachi, payments are made monthly by SCE, which in turn bills SDG&E for its 20% ownership share.

### B. 2023 Forecast

SDG&E estimates its 2023 SONGS Unit 1 offsite spent fuel storage expense to be $1.17 million, including adjustments for escalation, in accordance with the GE-Hitachi spent fuel storage contract.[23] The storage contract utilizes the Bureau of Labor Standards' labor non-financial corporations and industrial commodities indices to forecast escalation rates, which are included in SCE's billing statement to SDG&E. This estimate is based on a spent fuel storage cost forecast prepared by SCE's Nuclear Fuel Manager utilizing the contract escalation terms.

## V. 2023 FORECAST OF GHG COSTS

In this section, I describe the cost forecast for GHG compliance obligations under the California Air Resources Board ("ARB") cap-and-trade program. The cap-and-trade program

[23] SDG&E may recover these costs through ERRA per D.15-12-032.

provides that compliance obligations in the electricity sector are applicable to "first deliverers of electricity."[24] Generally, first deliverers of electricity in 2023 are electricity generators inside California that emit more than 25,000 metric tons ("MT") of GHG, and importers of electricity from outside of California. SDG&E is the first deliverer for its utility-owned generation, for generation it purchases under third-party tolling agreements in California, and for its imports of electricity into California. The cost of allowances and offsets is a direct GHG cost. In Section V.A below, I address direct GHG compliance costs associated with SDG&E utility-owned generation plants, procurement of electricity from third parties under tolling agreements, and electricity imports attributed to SDG&E.

SDG&E customers also face a second type of GHG compliance cost – indirect costs. Indirect costs are costs embedded in market electricity prices, or costs that SDG&E incurs from third parties under contracts. The party selling the power is responsible for the GHG allowance acquisition, but it implicitly charges SDG&E for the cost of acquiring allowances. In Section V.B below, I address indirect GHG costs. In Section V.C, I describe the calculation of both direct and indirect 2023 GHG costs. Finally, in Section V.D, I discuss the 2023 allowance auction revenues and the allocations of those revenues.

### A. Direct GHG Emissions

Each first deliverer of electricity within California must surrender to ARB one allowance or offset for each MT of carbon dioxide emissions or its equivalent ($CO_2e$). Under ARB's first deliverer approach, SDG&E will have a direct compliance obligation for GHG emissions from burning natural gas at facilities in its portfolio, including carbon dioxide, methane, and nitrous

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[24] ARB, Article 5: California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms, at 60, Section 95811(b), *available* at https://www.arb.ca.gov/cc/capandtrade/c-t-reg-reader-2013.pdf.

oxide. I forecasted SDG&E's expected direct GHG compliance costs using the same production simulation model results that produced the ERRA expenses discussed above. The amount of fuel needed for each natural gas fired plant is provided as an output based on the expected operation of the plant, including fuel associated with starts. The fuel volume is then multiplied by an emissions factor of 0.05307 MT of $CO_2e$ per MMBtu to calculate direct emissions obligations for each plant.[25] The forecast of GHG emissions from SDG&E facilities in 2023 is included in Table 4 below.

Similarly, the estimated emissions for tolling agreements are estimated by multiplying the forecast of MMBtu of natural gas burned from the production simulation by the emission factor of 0.05307 MT of $CO_2e$ per MMBtu. Table 4 below provides the forecast of GHG emissions from generators that are under tolling agreements with SDG&E in 2023.

In addition, SDG&E imports out-of-state electricity to a delivery point inside California, and it is thus responsible for the GHG emissions attributed to generation of that electricity. There are three categories of GHG emissions associated with imports.

First, there are imports from "specified sources" (*i.e.*, imports where the source of the power is known), which consist of either a specific plant or an asset-controlling supplier.[26] Accordingly, power from SDG&E's Desert Star combined-cycle generation plant in Nevada, for example, is included on the same basis as SDG&E's other utility-owned facilities—multiplying

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[25] ARB's Mandatory Reporting Regulations requires use of emission factors from federal regulations - 40 Code of Federal Regulations ("C.F.R.") Section 98. For pipeline natural gas, there are three components – CO2, CH4, and NO2. Using Tables C-1 and C-2 from 40 C.F.R. Subpart C Section 98 we calculate an overall emissions rate of 0.05307 MT/MMBtu. SDG&E's portfolio of GHG emitting resources uses only natural gas, not other fuels.

[26] SDG&E currently does not have any contracts with asset-controlling suppliers such as the Bonneville Power Administration or Powerex. ARB assigns an emissions factor based on the entire portfolio for these suppliers.

the forecast of MMBtu of natural gas burned from the production simulation by the emission factor of 0.05307 MT of $CO_2e$ per MMBtu.

Second, imported power from "unspecified sources" is multiplied by an estimated transmission loss factor of 1.02[27] to estimate the MWh related to emitting generation from unspecified electricity imports. The quantity is multiplied by the ARB default emission rate, which is 0.428 metric tons of $CO_2e$ per MWh. For any market purchases of energy, 2.5% of the total purchased power is considered to be an unspecified power import with direct GHG emissions.

Third, electricity from out-of-state renewable resources that are not imported was used to offset the emissions of imports under the ARB Renewable Portfolio Standard ("RPS") adjustment in previous ERRA forecasts. In this forecast, SDG&E has been directed to exclude the RPS adjustment from the forecasted GHG emissions. The emissions of imported power are shown in Table 4 below. Monthly emissions for all categories are summarized in Attachment E.

**B. Indirect GHG Emissions**

In addition to the direct GHG costs described above, the cap-and-trade program results in GHG compliance costs being embedded in the market price of electricity procured in the wholesale market and from third parties. The cost to purchase electricity from the wholesale market, as well as from suppliers under contracts that include market-based prices, will have these embedded costs of compliance with the cap-and-trade program built into the electricity price. The compliance instrument will be procured by the first deliverer, rather than by SDG&E, as purchaser. SDG&E's expected indirect GHG compliance costs are based on an assumption that all power sold by SDG&E-controlled assets are used by SDG&E customers, up to the level

[27] Transmission losses on SDG&E's system are measured at approximately 2% of load requirement.

of the forecasted SDG&E load.[28] If the total CAISO market purchases exceed the MWh from SDG&E-controlled generation, then the assumption is that SDG&E entered into market purchases to cover this difference. To estimate the GHG emissions embedded in these net CAISO market purchases, SDG&E used the ARB's default emissions rate, which is 0.428 MT per MWh, and considers 97.5% of the total purchased energy to contain indirect GHG emissions. The rest is considered as imported power with direct GHG emissions as described earlier.

In addition to market purchases, contracts with some Combined Heat and Power ("CHP") facilities are included as indirect costs. Specific CHP contracts require payments based on a market electricity price (with embedded GHG costs), or a fixed heat rate with the GHG cost based on the contract heat rate; or in other cases, a reimbursement of GHG expenditures incurred by the CHP facility associated with sales to SDG&E. These contracts represent a second source of indirect GHG costs in that the CHP owner acquires GHG compliance instruments.

Contractual GHG costs do not provide a good estimate of actual GHG costs. Accordingly, determining actual GHG costs is difficult because it requires knowledge of confidential counterparty data and the choice of method used to split the GHG emissions between electricity production and useful thermal energy. For simplicity, SDG&E estimates GHG costs associated with CHP on the assumption that the CHP units, on average, are as efficient as unspecified power, assigning a 0.428 MT per MWh emissions rate to all purchases of power from CHP facilities.

[28] In fact, however, the generation is bid into the CAISO market and dispatched by CAISO to meet statewide needs. The simplifying assumption is used to calculate net CAISO market purchases – all CAISO purchases less all resources that are forecasted to successfully bid into the CAISO market by SDG&E, including imports. However, SDG&E does make an adjustment for expected sales of renewable energy beyond regulatory requirements.

Finally, SDG&E forecasts REC sales to maintain an equivalent RPS compliance position considering CCA load departure in 2023 and allocations according to R.18-07-003. REC sales remove the GHG-free attribute of the renewable resource generation. To estimate the GHG emissions of the unbundled renewable generation, SDG&E treats this the same as imported power from unspecified sources. The GHG emissions from indirect sources are summarized on an annual basis in Table 4 below and monthly in Attachment E.

| Table 4: 2023 GHG Total Emissions Forecast | | |
|---|---|---|
| **Resource** | **Fuel (000 MMBtu)** | **GHG (000 Metric Tons)** |
| Palomar - UOG | [redacted] | [redacted] |
| Desert Star - UOG - Out of State | [redacted] | [redacted] |
| Orange Grove - PPA | [redacted] | [redacted] |
| Escondido Energy Center - PPA | [redacted] | [redacted] |
| Pio Pico - PPA | [redacted] | [redacted] |
| Carlsbad Energy Center - PPA | [redacted] | [redacted] |
| Miramar - UOG | [redacted] | [redacted] |
| Yuma - PPA Out of State | [redacted] | [redacted] |
| **Fuel-Based** | [redacted] | [redacted] |
| | **Generation (GWh)** | **GHG (000 Metric Tons)** |
| Imports | [redacted] | [redacted] |
| **Total Direct Emissions** | | [redacted] |

| **Resource** | **Generation (GWh)** | **GHG (000 Metric Tons)** |
|---|---|---|
| Net Market Purchases | [redacted] | [redacted] |
| Unbundled RPS after REC Sales | [redacted] | [redacted] |
| CHP (CP Kelco) | [redacted] | [redacted] |
| **Total Indirect Emissions** | | [redacted] |
| **Total Forecasted Emissions** | | [redacted] |

### C. 2023 GHG Costs

I calculated a proxy for the 2023 GHG emissions price as $28.96/MT. This figure was derived using a recent (March 23, 2022) assessment of 2023 GHG market prices based on the forward prices on the Intercontinental Exchange ("ICE"), consistent with the forecasted natural gas and electricity prices associated with the forecast of emissions in Table 4 above. The GHG cost forecast multiplies the expected emissions, both direct and indirect, by the forecasted proxy GHG price resulting in forecasted GHG costs for 2023 of [redacted], with [redacted] of direct GHG costs in LGBA, [redacted] of direct GHG costs in ERRA, and [redacted] of indirect GHG costs.

### D. 2023 Allowance Auction Revenues

The ARB allocates cap-and-trade allowances to SDG&E for 2023. SDG&E is required to place all these allowances for sale in ARB's 2023 quarterly auctions. I developed the forecast of allowance revenues by multiplying the total number of allowances allocated to SDG&E for consignment by a forecast price for the allowances.[29]

The total allowances that will be allocated to SDG&E for 2023 is expected to be 6,586,708 MT. SDG&E's Forecast 2023 Allocated Allowances (MT) represents the SDG&E allocation as established in Table 9-4 of the Cap-and-Trade regulation. This new quantity is reflected in the forecast column within Appendix G template D-1. The allowance price is the same proxy price as used in the calculation of GHG costs, which is $28.96/MT. The allowance auction revenue forecast is the allowances allocated times the allowance price, which totals $190.8 million.

A portion of the allowance auction revenue is reserved for clean energy and energy efficiency projects initiated by the Solar on Multifamily Affordable Housing ("SOMAH") Program.[30] This program provides financial incentives for installation of solar energy systems

[29] I assumed all allowances are sold in the auction process, which is consistent with the assumption that the market-clearing price is above the price floor.

[30] D.17-12-022 Ordering Paragraph ("OP") 4, at 69, states that the IOUs "each shall reserve 10% of the proceeds from the sale of greenhouse gas allowances defined in Public Utilities Code Section 748.5 through its annual Energy Resource Recover Account (ERRA) proceedings for use in the Solar on Multifamily Affordable Housing Program, starting with its ongoing 2018 ERRA forecast proceeding."

on multifamily affordable housing properties, as specified in the statute. For 2023, the funding amount is $19.1 million, which is 10% of SDG&E's total forecasted allowance revenue amount.[31] Any true-ups for allowance revenues set aside for clean energy and energy efficiency projects are addressed in the testimony of SDG&E witness Kristina Ghianni.

D.18-06-027 (issued on June 22, 2018), adopted three new programs to promote the installation of renewable generation among residential customers in disadvantaged communities ("DACs"): the DAC - Single-family Solar Homes ("DAC-SASH"), the DAC – Green Tariff ("DAC-GT") and the Community Solar Green Tariff ("CSGT").[32] SDG&E shall fund these programs first through available GHG allowance revenues proceeds and if such funds are exhausted, the programs will be funded through public purpose programs ("PPP") funds. The DAC-SASH program funding request is estimated to be $1.03 million. The previously requested and available funding for DAC-GT and CSGT is expected to cover all 2023 program related expenses. Therefore, SDG&E is not requesting any additional funding at this time.[33]

## VI. 2023 FORECAST OF TMNBC COSTS

In this section, I describe the cost forecast for tree mortality related procurement costs.[34] The TMNBC costs will be recovered through the PPP charge as addressed in the testimony of SDG&E witness Gwendolyn Morien. The 2023 forecasted costs are [redacted].

This concludes my prepared direct testimony.

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[31] D.20-04-012, issued on April 23, 2020, continues authorization of allocation of funds to the SOMAH program through June 30, 2026.

[32] D.18-06-027 at OPs 1, 11 and 12.

[33] On February 1, 2022, SDG&E filed AL 3944-E which requested no funding for 2023.

[34] Per D.18-12-003, SDG&E filed Advice Letter 3343-E18 requesting approval to establish TMNBCBA as directed by Resolution E-4770 and Resolution E-4805.

## VII. QUALIFICATIONS

My name is Matthew A. O'Connell. My business address is 8315 Century Park Court, San Diego, CA 92123. I am employed by SDG&E and my current title is Principal Resource Planner in the Electric & Fuel Procurement Department. My responsibilities include running computer models that forecast energy needs for both physical and financial operational needs.

I joined SDG&E in January, 2020. Prior to joining SDG&E, I worked as an electric grid modeler and data analyst at the National Renewable Energy Laboratory (NREL) in Golden, CO. I received a B.S. in Mechanical Engineering from Rowan University in Glassboro, NJ and a M.S. in Mechanical Engineering from Colorado State University in Fort Collins, CO.

I have previously testified before the California Public Utilities Commission.

# ATTACHMENT A

# (CONFIDENTIAL)

# SDG&E 2023 ERRA AND LG EXPENSES

# ATTACHMENT A

PRIVILEGED AND CONFIDENTIAL PURSUANT TO P.U.C. CODE 583, 454.5(g), GO 66-C and D.06-06-066 as needed

***ATTACHMENT A - SDG&E 2023 ERRA and LG EXPENSES***

| | | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| 1 | **EXPENSES ($)** | | | | | | | | | | | | | |
| 2 | ISO Load Charges (Energy & A/S Costs) | [redacted] | | | | | | | | | | | | |
| 3 | ISO Supply Revenues | [redacted] | | | | | | | | | | | | |
| 4 | Contract Costs (non-CTC) | [redacted] | | | | | | | | | | | | |
| 5 | Contract Costs (CTC up to market) | [redacted] | | | | | | | | | | | | |
| 6 | Generation Fuel | [redacted] | | | | | | | | | | | | |
| 7 | CAISO Misc Costs | [redacted] | | | | | | | | | | | | |
| 8 | Hedging Costs & Financial Transactions | [redacted] | | | | | | | | | | | | |
| 9 | Contract Costs - CHP Costs (AB1613) | [redacted] | | | | | | | | | | | | |
| 10 | Customer Incentives - SPP, DR,20/20 | [redacted] | | | | | | | | | | | | |
| 11 | Rewards/Penalties - Palomar Energy Ctr | [redacted] | | | | | | | | | | | | |
| 12 | WREGIS Costs | [redacted] | | | | | | | | | | | | |
| 13 | ISO CRRs Costs | [redacted] | | | | | | | | | | | | |
| 14 | ISO Convergence Bidding Costs | [redacted] | | | | | | | | | | | | |
| 16 | Purchased Tradable Renewable Energy Credits (TRECs | [redacted] | | | | | | | | | | | | |
| 17 | Sales Tradable Renewable Energy Credits (TRECs) | [redacted] | | | | | | | | | | | | |
| 18 | Net Surplus Compensation Costs (AB920) | [redacted] | | | | | | | | | | | | |
| 19 | Authorized Disallowances | [redacted] | | | | | | | | | | | | |
| 20 | Greenhouse Gas & Carrying Costs | [redacted] | | | | | | | | | | | | |
| 21 | **Total Balancing Account Expenses** | [redacted] | | | | | | | | | | | | **$ 443,962,159** |
| 22 | **PABA Portion of ERRA Expenses** | [redacted] | | | | | | | | | | | | **$ 15,355,050** |
| | **Line 4 Contract Costs (non-CTC)** | | | | | | | | | | | | | |
| | Lake Hodges | [redacted] | | | | | | | | | | | | |
| | El Cajon Energy Center Peaker Costs | [redacted] | | | | | | | | | | | | |
| | Orange Grove Peaker Costs | [redacted] | | | | | | | | | | | | |
| | Other RA Capacity Costs (RA RFO, DRAM) | [redacted] | | | | | | | | | | | | |
| | RA Sales | [redacted] | | | | | | | | | | | | |
| | REC Sales | [redacted] | | | | | | | | | | | | |
| | CFD Revenues | [redacted] | | | | | | | | | | | | |
| | Green Tariff Excess | [redacted] | | | | | | | | | | | | |
| | Renewable Energy | $ 39,835,992 | $ 38,554,421 | $ 43,250,750 | $ 47,832,620 | $ 41,597,587 | $ 43,354,449 | $ 39,887,242 | $ 37,288,891 | $ 36,751,443 | $ 41,375,898 | $ 36,903,938 | $ 36,689,147 | **$ 483,322,376** |
| | **Line 4 Total** | [redacted] | | | | | | | | | | | | |
| | **Line 6 Generation Fuel** | | | | | | | | | | | | | |
| | Palomar | [redacted] | | | | | | | | | | | | |
| | Desert Star | [redacted] | | | | | | | | | | | | |
| | Miramar | [redacted] | | | | | | | | | | | | |
| | Miramar 2 | [redacted] | | | | | | | | | | | | |
| | Cuyamaca | [redacted] | | | | | | | | | | | | |
| | **Line 6 Total** | [redacted] | | | | | | | | | | | | |
| | **In Lieu Gas Fees** | | | | | | | | | | | | | |
| | Palomar | [redacted] | | | | | | | | | | | | |
| | **Line 8 Hedging Costs & Financial Transactions** | | | | | | | | | | | | | |
| | Hedging Costs | [redacted] | | | | | | | | | | | | |
| | Broker Fees | [redacted] | | | | | | | | | | | | |
| | **Line 8 Total** | [redacted] | | | | | | | | | | | | |
| | **LG Expenses** | | | | | | | | | | | | | |
| | Carlsbad Energy Center | [redacted] | | | | | | | | | | | | |
| | El Cajon Energy Storage | [redacted] | | | | | | | | | | | | |
| | Top Gun Energy Storage | [redacted] | | | | | | | | | | | | |
| | Fallbrook Energy Storage | [redacted] | | | | | | | | | | | | |
| | Escondido Energy Center | [redacted] | | | | | | | | | | | | |
| | Escondido Energy Storage | [redacted] | | | | | | | | | | | | |
| | Melrose Energy Storage | [redacted] | | | | | | | | | | | | |
| | Pala-Gomez Creek Storage | [redacted] | | | | | | | | | | | | |
| | Westside Canal Storage | [redacted] | | | | | | | | | | | | |
| | Pio Pico | [redacted] | | | | | | | | | | | | |
| | Grossmont | [redacted] | | | | | | | | | | | | |
| | Kelco | [redacted] | | | | | | | | | | | | |
| | Sentinel Energy Center RA | [redacted] | | | | | | | | | | | | |
| | Sagebrush Storage | [redacted] | | | | | | | | | | | | |
| | LG Revenue | [redacted] | | | | | | | | | | | | |
| | Emissions | [redacted] | | | | | | | | | | | | |
| | **Total LG Expense** | [redacted] | | | | | | | | | | | | |

# ATTACHMENT B

## (CONFIDENTIAL)

## SDG&E 2023 GENERATION PORTFOLIO DELIVERY VOLUMES

# Attachment B

PRIVILEGED AND CONFIDENTIAL PURSUANT TO P.U.C. CODE 583, 454.5(g), GO 66-C and D.06-06-066 as needed

***ATTACHMENT B - SDG&E 2023 GENERATION PORTFOLIO DELIVERY VOLUMES (GWh)***

| | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| CTC | [redacted] | | | | | | | | | | | | |
| Non-CTC QF | | | | | | | | | | | | | |
| **TOTAL** | | | | | | | | | | | | | |
| Renewable - Bio Gas | 16.1 | 14.5 | 16.1 | 15.5 | 14.6 | 12.3 | 12.9 | 12.8 | 12.3 | 12.7 | 12.3 | 12.7 | **164.6** |
| Renewable - Other | 0.1 | 0.1 | 0.2 | 0.2 | 0.2 | 3.2 | 3.4 | 3.5 | 3.0 | 3.1 | 2.6 | 2.5 | **22.1** |
| Renewable - Solar | 155.9 | 159.6 | 200.7 | 211.3 | 207.2 | 198.9 | 209.2 | 210.6 | 193.8 | 194.3 | 162.9 | 149.9 | **2,254.3** |
| Renewable - Wind | 191.6 | 159.7 | 167.7 | 220.3 | 161.6 | 187.1 | 150.5 | 124.0 | 125.2 | 176.7 | 147.0 | 154.9 | **1,966.4** |
| Renewable - Wind REC | 110.3 | 155.1 | 134.5 | 93.6 | 78.4 | 91.9 | 73.7 | 63.6 | 100.9 | 84.5 | 119.4 | 130.0 | **1,236.0** |
| Midway-Green Tariff-EcoChoice | 4.9 | 4.9 | 6.2 | 6.4 | 6.2 | 5.9 | 6.3 | 6.6 | 5.8 | 5.9 | 5.0 | 4.7 | **68.7** |
| Renewable - RPS Sales | (260.0) | (218.5) | (272.2) | (300.3) | (266.3) | (259.3) | (236.2) | (228.5) | (224.8) | (261.0) | (247.1) | (215.7) | **(2,989.9)** |
| **TOTAL NON-CTC RENEWABLE** | **218.9** | **275.4** | **253.1** | **247.0** | **201.9** | **239.9** | **219.8** | **192.6** | **216.2** | **216.1** | **202.1** | **239.0** | **2,722.2** |
| Miramar | [redacted] | | | | | | | | | | | | |
| Miramar 2 | | | | | | | | | | | | | |
| Cuyamaca | | | | | | | | | | | | | |
| Palomar | | | | | | | | | | | | | |
| Desert Star | | | | | | | | | | | | | |
| Grossmont | | | | | | | | | | | | | |
| Kelco | | | | | | | | | | | | | |
| Lake Hodges | | | | | | | | | | | | | |
| El Cajon Energy Center | | | | | | | | | | | | | |
| Orange Grove | | | | | | | | | | | | | |
| Escondido Energy Center | | | | | | | | | | | | | |
| Pio Pico | | | | | | | | | | | | | |
| Carlsbad Energy Center | | | | | | | | | | | | | |
| Johanna Energy Storage | | | | | | | | | | | | | |
| Kearny Energy Storage | | | | | | | | | | | | | |
| Valley Center Energy Storage | | | | | | | | | | | | | |
| El Cajon Energy Storage | | | | | | | | | | | | | |
| Top Gun Energy Storage | | | | | | | | | | | | | |
| Escondido Energy Storage | | | | | | | | | | | | | |
| Fallbrook Energy Storage | | | | | | | | | | | | | |
| Miguel Energy Storage | | | | | | | | | | | | | |
| Sagebrush Storage | | | | | | | | | | | | | |
| Melrose Storage | | | | | | | | | | | | | |
| Pala-Gomez Storage | | | | | | | | | | | | | |
| Westside Canal Storage | | | | | | | | | | | | | |
| **TOTAL GENERATION** | | | | | | | | | | | | | |

# ATTACHMENT C

# SDG&E 2023 RENEWABLE RESOURCE DETAIL

# Attachment C

PRIVILEGED AND CONFIDENTIAL PURSUANT TO P.U.C. CODE 583, 454.5(g), GO 66-C and D.06-06-066 as needed

***ATTACHMENT C - SDG&E 2023 RENEWABLE RESOURCE DETAIL***

| Power Purchase Deliveries (GWh) | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **BIO GAS** | | | | | | | | | | | | | |
| MM San Diego LLC- Miramar Landfill | 3.4 | 3.1 | 3.4 | 3.3 | 2.0 | - | - | - | - | - | - | - | 15.1 |
| MM San Diego LLC - North City | 1.2 | 1.1 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 1.2 | 14.4 |
| Sycamore Energy | 2.5 | 2.3 | 2.5 | 2.4 | 2.5 | 2.4 | 2.5 | 2.5 | 2.4 | 2.5 | 2.4 | 2.5 | 29.6 |
| HL Power | 8.9 | 8.1 | 8.9 | 8.6 | 8.9 | 8.6 | 9.2 | 9.0 | 8.6 | 8.9 | 8.6 | 8.9 | 105.5 |
| **Subtotal** | **16.1** | **14.5** | **16.1** | **15.5** | **14.6** | **12.3** | **12.9** | **12.8** | **12.3** | **12.7** | **12.3** | **12.7** | **164.6** |
| **OTHER** | | | | | | | | | | | | | |
| Small Hydro | 0.5 | 0.4 | 0.7 | 0.7 | 0.8 | 0.8 | 0.8 | 0.7 | 0.6 | 0.5 | 0.4 | 0.5 | 7.5 |
| Bright Canyon Hybrid | - | - | - | - | - | 2.9 | 3.2 | 3.3 | 2.9 | 2.9 | 2.5 | 2.4 | 20.1 |
| **Subtotal** | **0.5** | **0.4** | **0.7** | **0.7** | **0.8** | **3.8** | **4.0** | **4.0** | **3.5** | **3.4** | **2.9** | **2.8** | **27.6** |
| **SOLAR** | | | | | | | | | | | | | |
| NRG Borrego Solar | 3.2 | 3.2 | 4.0 | 4.2 | 4.0 | 3.8 | 4.1 | 4.3 | 3.8 | 3.8 | 3.3 | 3.1 | 44.7 |
| Sol Orchard | 1.8 | 1.8 | 2.2 | 2.3 | 2.2 | 2.1 | 2.3 | 2.4 | 2.1 | 2.1 | 1.8 | 1.7 | 24.9 |
| Solar Energy Project | 0.5 | 0.5 | 0.7 | 0.7 | 0.7 | 0.6 | 0.7 | 0.7 | 0.6 | 0.6 | 0.5 | 0.5 | 7.4 |
| NLP Valley Center Solar | 0.3 | 0.3 | 0.4 | 0.4 | 0.4 | 0.3 | 0.4 | 0.4 | 0.3 | 0.3 | 0.3 | 0.3 | 4.0 |
| NLP Granger A82 | 0.4 | 0.4 | 0.5 | 0.5 | 0.5 | 0.4 | 0.5 | 0.5 | 0.4 | 0.4 | 0.4 | 0.4 | 5.2 |
| Arlington Valley Solar | 15.7 | 17.1 | 20.3 | 22.2 | 22.7 | 20.8 | 21.1 | 21.2 | 20.3 | 20.2 | 16.4 | 15.1 | 233.1 |
| Calipatria | 2.4 | 2.4 | 3.1 | 3.2 | 3.1 | 2.9 | 3.2 | 3.3 | 2.9 | 2.9 | 2.5 | 2.4 | 34.4 |
| Campo Verde | 17.0 | 17.0 | 21.4 | 22.3 | 21.5 | 20.5 | 21.9 | 22.9 | 20.1 | 20.4 | 17.4 | 16.4 | 238.8 |
| Catalina_Solar | 9.7 | 11.5 | 15.6 | 17.3 | 18.3 | 19.2 | 19.6 | 19.5 | 17.9 | 16.5 | 12.3 | 8.8 | 186.2 |
| Centinela Solar1 | 15.4 | 15.4 | 19.4 | 20.1 | 19.4 | 18.5 | 19.3 | 17.8 | 18.2 | 18.5 | 15.8 | 14.9 | 212.7 |
| Centinela Solar2 | 5.4 | 5.4 | 6.8 | 7.1 | 6.8 | 6.5 | 6.8 | 6.2 | 6.4 | 6.5 | 5.5 | 5.2 | 74.7 |
| Desert Green | 0.8 | 0.8 | 1.0 | 1.0 | 1.0 | 0.9 | 1.0 | 1.0 | 0.9 | 0.9 | 0.8 | 0.7 | 10.8 |
| Imperial Valley Solar I | 24.5 | 24.4 | 30.8 | 32.0 | 30.9 | 29.5 | 31.5 | 33.0 | 28.9 | 29.4 | 25.1 | 23.6 | 343.6 |
| Midway Solar | 2.4 | 2.4 | 3.1 | 3.2 | 3.1 | 2.9 | 3.2 | 3.3 | 2.9 | 2.9 | 2.5 | 2.4 | 34.4 |
| Maricopa West Solar | 1.8 | 2.1 | 2.8 | 3.1 | 3.3 | 3.5 | 3.6 | 3.5 | 3.3 | 3.0 | 2.2 | 1.6 | 33.9 |
| TallBear Seville | 2.4 | 2.4 | 3.1 | 3.2 | 3.1 | 2.9 | 3.2 | 3.3 | 2.9 | 2.9 | 2.5 | 2.4 | 34.4 |
| SolarGen 2 | 18.4 | 18.3 | 23.1 | 24.0 | 23.2 | 22.1 | 23.6 | 24.7 | 21.7 | 22.0 | 18.8 | 17.7 | 257.7 |
| Cascade SunEdison | 2.1 | 2.3 | 2.6 | 2.8 | 2.9 | 2.8 | 3.1 | 3.1 | 2.6 | 2.5 | 2.2 | 2.1 | 31.0 |
| Csolar IV South | 15.9 | 15.9 | 20.0 | 20.8 | 20.1 | 19.2 | 20.5 | 21.4 | 18.8 | 19.1 | 16.3 | 15.4 | 223.3 |
| Csolar IV West | 18.4 | 18.3 | 23.1 | 24.0 | 23.2 | 22.1 | 23.1 | 21.3 | 21.7 | 22.0 | 18.8 | 17.7 | 253.7 |
| Wister Solar Project | 2.4 | 2.4 | 3.1 | 3.2 | 3.1 | 2.9 | 3.2 | 3.3 | 2.9 | 2.9 | 2.5 | 2.4 | 34.4 |
| **Subtotal** | **160.8** | **164.5** | **206.8** | **217.7** | **213.4** | **204.8** | **215.5** | **217.2** | **199.6** | **200.2** | **167.9** | **154.6** | **2,323.0** |
| **WIND** | | | | | | | | | | | | | |
| Glacier Wind (TREC) | 49.4 | 80.9 | 63.3 | 43.0 | 37.5 | 44.7 | 36.2 | 31.0 | 48.3 | 35.4 | 48.1 | 61.2 | 578.8 |
| Rim Rock (TREC) | 60.8 | 74.2 | 71.3 | 50.6 | 40.9 | 47.2 | 37.5 | 32.6 | 52.6 | 49.1 | 71.4 | 68.8 | 657.2 |
| Kumeyaay | 14.3 | 14.1 | 13.4 | 16.1 | 12.0 | 13.2 | 12.1 | 9.7 | 10.0 | 13.9 | 11.9 | 12.6 | 153.3 |
| Coram Energy | 1.3 | 1.6 | 2.2 | 2.7 | 2.5 | 2.5 | 2.0 | 2.0 | 1.6 | 1.8 | 1.5 | 1.4 | 23.0 |
| Energia Sierra Juarez | 35.8 | 27.7 | 28.0 | 38.9 | 25.9 | 33.7 | 26.0 | 19.7 | 21.1 | 30.8 | 24.8 | 27.3 | 339.7 |
| Energia Sierra Juarez 2 | 24.3 | 18.7 | 19.0 | 26.3 | 17.5 | 22.8 | 17.6 | 13.4 | 14.3 | 20.9 | 16.8 | 18.5 | 229.9 |
| Manzana Wind | 16.8 | 21.3 | 29.1 | 34.9 | 32.4 | 32.1 | 26.6 | 26.4 | 21.0 | 23.6 | 19.3 | 17.9 | 301.3 |
| Oak Creek Wind Power | 0.9 | 0.7 | 0.6 | 0.8 | 0.6 | 0.6 | 0.5 | 0.4 | 0.5 | 0.8 | 0.7 | 0.7 | 7.7 |
| Ocotillo Express | 61.2 | 47.3 | 47.8 | 66.4 | 44.2 | 57.6 | 44.4 | 33.7 | 36.1 | 52.7 | 42.4 | 46.6 | 580.3 |
| Pacific Wind | 34.5 | 26.4 | 25.6 | 31.4 | 24.7 | 22.2 | 19.6 | 17.3 | 19.1 | 30.0 | 27.7 | 28.1 | 306.6 |
| San Gorgonio | 2.6 | 2.0 | 2.0 | 2.8 | 1.9 | 2.4 | 1.9 | 1.4 | 1.5 | 2.2 | 1.8 | 2.0 | 24.5 |
| **Subtotal** | **301.9** | **314.8** | **302.2** | **313.9** | **240.0** | **279.0** | **224.2** | **187.7** | **226.0** | **261.2** | **266.4** | **284.9** | **3,202.4** |
| **RPS SALES** | | | | | | | | | | | | | |
| **Subtotal** | **(260.0)** | **(218.5)** | **(272.2)** | **(300.3)** | **(266.3)** | **(259.3)** | **(236.2)** | **(228.5)** | **(224.8)** | **(261.0)** | **(247.1)** | **(215.7)** | **(2,989.9)** |
| **Total Power Purchase Costs ($000)** | | | | | | | | | | | | | |
| Biogas | $ 1,157 | $ 1,045 | $ 1,157 | $ 1,120 | $ 1,145 | $ 1,091 | $ 1,154 | $ 1,138 | $ 1,091 | $ 1,127 | $ 1,091 | $ 1,127 | $ 13,444 |
| Other | $ 4 | $ 4 | $ 4 | $ 4 | $ 5 | $ 5 | $ 5 | $ 4 | $ 4 | $ 4 | $ 4 | $ 4 | $ 51 |
| Solar | $ 15,577 | $ 15,658 | $ 19,383 | $ 20,205 | $ 19,938 | $ 19,161 | $ 20,115 | $ 20,214 | $ 18,746 | $ 18,857 | $ 16,102 | $ 15,059 | $ 219,014 |
| Wind | $ 18,880 | $ 15,750 | $ 16,655 | $ 21,359 | $ 16,171 | $ 18,259 | $ 15,007 | $ 12,689 | $ 12,741 | $ 17,508 | $ 14,812 | $ 15,538 | $ 195,369 |
| Wind (REC) | $ 3,944 | $ 5,333 | $ 4,754 | $ 3,318 | $ 2,756 | $ 3,235 | $ 2,578 | $ 2,225 | $ 3,546 | $ 3,061 | $ 4,371 | $ 4,586 | $ 43,707 |
| RPS Sales | $ (3,561) | $ (2,994) | $ (3,729) | $ (4,114) | $ (3,649) | $ (3,552) | $ (3,236) | $ (3,131) | $ (3,080) | $ (3,576) | $ (3,385) | $ (2,954) | $ (40,961) |
| GTSR Interim Pool Transfer | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - | $ - |
| **Subtotal** | **$ 36,001** | **$ 34,797** | **$ 38,224** | **$ 41,893** | **$ 36,364** | **$ 38,198** | **$ 35,621** | **$ 33,140** | **$ 33,049** | **$ 36,981** | **$ 32,995** | **$ 33,360** | **$ 430,623** |

# ATTACHMENT D

# (CONFIDENTIAL)

# SDG&E 2023 CTC QUALIFYING FACILITY DETAIL

# Attachment D

PRIVILEGED AND CONFIDENTIAL PURSUANT TO P.U.C. CODE 583, 454.5(g), GO 66-C and D.06-06-066 as needed

***ATTACHMENT D - SDG&E 2023 CTC DETAIL***

| CTC - Dispatchable (GWh) | Jan | Feb | Mar | Apr | May | Jun | Jul | Aug | Sep | Oct | Nov | Dec | 2023 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| Goal Line | [redacted] | | | | | | | | | | | | |
| Yuma Cogen Associates | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| **CTC QF - SRAC Priced (GWh)** | | | | | | | | | | | | | |
| Aggregation of Hydro Units (S01) | [redacted] | | | | | | | | | | | | |
| **Subtotal** | | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| **ERRA Expenses ($000)** | | | | | | | | | | | | | |
| CTC (up to market) | [redacted] | | | | | | | | | | | | |
| | | | | | | | | | | | | | |
| **TCBA Expenses ($000)** | | | | | | | | | | | | | |
| CTC (above market) | [redacted] | | | | | | | | | | | | $ 11,098 |

# ATTACHMENT E

# (CONFIDENTIAL)

# SDG&E GREENHOUSE GAS DETAIL

# Attachment E

PRIVILEGED AND CONFIDENTIAL PURSUANT TO P.U.C. CODE 583, 454.5(g), GO 66-C and D.06-06-066 as needed

***ATTACHMENT E - SDG&E GREENHOUSE GAS (GHG) DETAIL***

| **2022 Direct Emissions (MT)** | **JAN** | **FEB** | **MAR** | **APR** | **MAY** | **JUN** | **JUL** | **AUG** | **SEP** | **OCT** | **NOV** | **DEC** | **2023** |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| California UOG Plants | [redacted] | | | | | | | | | | | | |
| California Tolling Generators | | | | | | | | | | | | | |
| Specified Imports | | | | | | | | | | | | | |
| Unspecified Imports (Market Purchases) | | | | | | | | | | | | | |
| **Total Direct Emissions** | | | | | | | | | | | | | |
| **2022 Indirect Emissions (MT)** | | | | | | | | | | | | | |
| Unspecified Imports (Market Purchases) | [redacted] | | | | | | | | | | | | [redacted] |
| Unbundled RPS after REC Sales | | | | | | | | | | | | | |
| CHP | | | | | | | | | | | | | |
| **Total Indirect Emissions** | | | | | | | | | | | | | |
| **2022 Total Forecasted Emissions** | | | | | | | | | | | | | 3,274,032 |

# ATTACHMENT F

# DECLARATION OF MATTHEW O'CONNELL

**BEFORE THE PUBLIC UTILITIES COMMISSION**
**OF THE STATE OF CALIFORNIA**

**DECLARATION**
**OF MATTHEW O'CONNELL**

**A.22-05-**
**Application of San Diego Gas & Electric Company (U 902-E)**
**for Approval of Its 2023 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts**

I, Matthew O'Connell, declare as follows:

1. I am the Principal Resource Planner for San Diego Gas & Electric Company ("SDG&E"). I sponsored my Prepared Direct Testimony ("Testimony") in support of SDG&E's Application for Approval of its 2023 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts ("Application"). Additionally, as the Principal Resource Planner, I am thoroughly familiar with the facts and representations in this declaration, and if called upon to testify I could and would testify to the following based upon personal knowledge.

2. I am providing this Declaration to demonstrate that the confidential information ("Protected Information") in support of the referenced Application falls within the scope of data provided confidential treatment in the IOU Matrix ("Matrix") attached to the Commission's Decision ("D.") 06-06-066 (the Phase I Confidentiality decision). Pursuant to the procedure adopted in D.08-04-023, I am addressing each of the following five features of Ordering Paragraph 2 of D.06-06-066:

- that the material constitutes a particular type of data listed in the Matrix;
- the category or categories in the Matrix the data correspond to;
- that SDG&E is complying with the limitations on confidentiality specified in the Matrix for that type of data;
- that the information is not already public; and
- that the data cannot be aggregated, redacted, summarized, masked, or otherwise protected in a way that allows partial disclosure.

3. The Protected Information contained in my Testimony constitutes material, market sensitive, electric procurement-related information that is within the scope of Section 454.5(g) of the Public Utilities Code.[1] As such, the Protected Information is allowed confidential treatment in accordance with the Matrix, as follows:

| **Location of Protected Information** | **Matrix Reference** | **Reason for Confidentiality and Timing** |
|---|---|---|
| MO-3 | V.C | LSE Total Energy Forecast – Bundled Customer; confidential for the front three years |
| MO-4 Table 1 | IV.F | Forecast of Post-1/1/2003 Bilateral Contracts; confidential for three years |
| MO-5 | VI.A<br><br><br>VII.B | Utility Bundled Net Open Position for Capacity; confidential for the front three years<br>Contracts and power purchase agreements between utilities and non-affiliated third parties |
| MO-6 Table 2 | IV.A | Forecast of IOU Generation Resources; confidential for three years |
| MO-8 | IV.B | Forecast of Qualifying Facility Generation; confidential for three years |
| MO-9, MO-10 | II.A.2<br><br>II.B.1<br><br><br>II.B.3<br><br>II.B.4<br><br><br>IV.J | Utility Electric Price Forecasts; confidential for three years,<br>Generation Cost Forecasts of Utility Retained Generation, confidential for three years,<br>Generation Cost Forecasts of QF Contracts, confidential for three years,<br>Generation Cost Forecasts of Non-QF Bilateral Contracts, confidential for three years,<br>Forecast of Wholesale Market Purchases; confidential for the front three years |
| MO-11 | II.A.2 | Utility Electric Price Forecasts; confidential for three years, |
| MO-12 | II.B.3 | Generation Cost Forecast of QF Contracts; confidential for three years |

[1] In addition to the details addressed herein, SDG&E believes that the information being furnished in my Testimony is governed by Public Utilities Code Section 583 and General Order 66-D. Accordingly, SDG&E seeks confidential treatment of this data under those provisions, as applicable.

| Location of Protected Information | Matrix Reference | Reason for Confidentiality and Timing |
|---|---|---|
| MO-12, MO-13 | II.B.1<br><br>II.B.4 | Generation Cost Forecasts of Utility Retained Generation, confidential for three years,<br>Generation Cost Forecasts of Non-QF Bilateral Contracts, confidential for three years, |
| MO-15 | I.A.4 | Long-term Fuel (gas) Buying and Hedging; confidential for three years |
| MO-23 Table 4,<br>MO-24 | Justification for confidentiality provided in Declaration of Praem Kodiath | GHG emissions forecast: Providing these forecasts to market participants would allow them to know SDG&E's GHG forecasted GHG obligation, thereby compromising SDG&E's contractual bargaining power such that customer costs are likely to rise. Thus, the release of this non-public confidential information will unjustifiably allow market participants to use this information to the disadvantage of SDG&E's customers. |
| MO-26 | II.B.4 | Generation Cost Forecasts of Non-QF Bilateral Contracts, confidential for three years |
| Attachment A - SDG&E 2023 ERRA and LG Expenses | XI | Monthly Procurement Costs; confidential for three years |
| Attachment B - SDG&E 2023 Generation Portfolio Delivery Volumes<br><br>• CTC and non-CTC QF generation data<br><br>• UOG and non-UOG gas, pumped hydro storage, and battery storage generation data | IV.A<br><br>IV.E<br><br>IV.B<br><br>IV.F | Forecast of IOU Generation Resources; confidential for three years<br>Forecast of Pre-1/1/2003 Bilateral Contracts; confidential for three years<br>Forecast of Qualifying Facility Generation; confidential for three years<br>Forecast of Post-1/1/2003 Bilateral Contracts; confidential for three years |

| Location of Protected Information | Matrix Reference | Reason for Confidentiality and Timing |
|---|---|---|
| Attachment D - SDG&E 2022 CTC Qualifying Facility (QF) Detail<br>• CTC QF dispatchable and non-dispatchable data<br>• Long-Term Power Purchase CTC data<br>• TCBA Expenses data | IV.E<br><br>IV.B<br><br>II.B.4<br><br>II.B.3 | Forecast of Pre-1/1/2003 Bilateral Contracts; confidential for three years<br>Forecast of Qualifying Facility Generation; confidential for three years<br>Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years<br>Generation Cost Forecast of QF Contracts; confidential for three years |
| Attachment E - SDG&E Greenhouse Gas (GHG) Detail | Justification for confidentiality provided in Declaration of Praem Kodiath | GHG emissions forecasts: Providing these forecasts to market participants would allow them to know SDG&E's GHG forecasted GHG obligation, thereby compromising SDG&E's contractual bargaining power such that customer costs are likely to rise. Thus, the release of this non-public confidential information will unjustifiably allow market participants to use this information to the disadvantage of SDG&E's customers. |

4. I am not aware of any instances where the Protected Information has been disclosed to the public. To my knowledge, no party, including SDG&E, has publicly revealed any of the Protected Information.

5. SDG&E will comply with the limitations on confidentiality specified in the Matrix for the Protected Information.

6. The Protected Information cannot be provided in a form that is aggregated, partially redacted, or summarized, masked, or otherwise protected in a manner that would allow further disclosure of the data while still protecting confidential information.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct.

Executed this 16th day of May, 2022, at San Diego, California.

*/s/ Matthew O'Connell*____________
Matthew O'Connell
Principal Resource Planner
San Diego Gas & Electric Company

# ATTACHMENT G

# DECLARATION OF PRAEM KODIATH REGARDING CONFIDENTIALITY OF CERTAIN DATA/DOCUMENTS PURSUANT TO D.16-08-024, *et al.*

**BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA**

**DECLARATION OF PRAEM KODIATH REGARDING CONFIDENTIALITY OF CERTAIN DATA/DOCUMENTS PURSUANT TO D.16-08-024, *et al.***

I, Praem Kodiath, do declare as follows:

1. I am the Resource Planning Manager in the Energy Supply Department for San Diego Gas & Electric Company ("SDG&E"). I have been delegated authority to sign this declaration by Estela de Llanos, Vice President of Energy Supply. I have reviewed Matthew O'Connell's Prepared Direct Testimony ("Testimony") in support of SDG&E's Application for Approval of its 2023 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts ("Application"). I am personally familiar with the facts and representations in this Declaration and, if called upon to testify, I could and would testify to the following based upon my personal knowledge and/or information and belief.

2. I hereby provide this Declaration in accordance with Decisions ("D.") 16-08-024, D.17-05-035, and D.17-09-023 to demonstrate that the confidential information ("Protected Information") provided in the Testimony is within the scope of data protected as confidential under applicable law.

3. In accordance with the legal authority described herein, the Protected Information should be protected from public disclosure.

I declare under penalty of perjury under the laws of the State of California that the foregoing is true and correct to the best of my knowledge.

Executed this 16th day of May, 2022, in San Diego.

*/s/ Praem Kodiath*
Praem Kodiath
Resource Planning Manager – Energy Supply

# ATTACHMENT A

## SDG&E Request for Confidentiality on the following information in its Application for Approval of Its 2023 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts

| **Location of Protected Information** | **Legal Authority** | **Narrative Justification** |
|---|---|---|
| MO-23 Table 4,<br>MO-24, and<br>Attachment E - SDG&E Greenhouse Gas (GHG) Detail<br><br>Application Attachment G, Template D-2: Forecasted Emissions and Costs | D.14-10-033;<br>D.16-08-024;<br>D.17-05-035;<br>D.17-09-023;<br>Public Utilities Code Section 454.5(g). | The information does not expressly fall within any category of the IOU Matrix applicable to electric procurement information, but is market-sensitive information in that providing these GHG emissions forecasts to market participants would allow them to know SDG&E's forecasted GHG obligation, thereby compromising SDG&E's contractual bargaining power such that customer costs are likely to rise. Thus, the release of this non-public confidential information will unjustifiably allow market participants to use this information to the disadvantage of SDG&E's customers. |