Application No.: A.20-04-
Exhibit No.:
Witness: Stefan Covic

PREPARED DIRECT TESTIMONY OF

STEFAN COVIC

ON BEHALF OF

SAN DIEGO GAS & ELECTRIC COMPANY

*****REDACTED, PUBLIC VERSION*****

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

A Sempra Energy utility

April 15, 2020

TABLE OF CONTENTS

PREPARED DIRECT TESTIMONY OF
STEFAN COVIC
ON BEHALF OF
SAN DIEGO GAS & ELECTRIC COMPANY

I. INTRODUCTION

My testimony describes the resources San Diego Gas & Electric Company ("SDG&E") expects to use in calendar year 2021 to provide electric commodity service to its bundled service customers; provides a forecast of the procurement costs that SDG&E expects to record in 2021 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 2021 forecast of SDG&E's San Onofre Generating Station ("SONGS") Unit 1 Offsite Spent Fuel Storage Costs; provides a forecast of 2021 total greenhouse gas ("GHG") costs; and provides a 2021 forecast of Tree Mortality Non-Bypassable Charge Balancing Account ("TMNBCBA") costs. SDG&E witness Ms. Ngo uses my forecast of ERRA, Competition Transition Charge ("CTC") and Local Generation ("LG") in developing 2021 revenue requirements for each element. In addition, my testimony provides information that supports SDG&E witness Ms. Fuhrer's development of the GHG allowance revenue return allocation and the volumetric revenue return for small business and residential customers, as well as rates for the Green Tariff Shared Renewables ("GTSR") program and the Power Charge Indifference Adjustment ("PCIA").

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 2021, as well as forecasts of the supply resources that SDG&E expects to utilize to meet that load in calendar year 2021. The supply resources for which I provide forecasts include (1) conventional generation resources that are under contract for 2021; (2) generation resources owned by SDG&E; (3) renewable generation resources that are under contract for 2021; (4) Qualifying Facilities ("QFs") under the Public Utility Regulatory Policies Act ("PURPA") that are under contract for 2021; and (5) generation obtained through market purchases.

In Section IV of my testimony, I quantify the costs associated with the resources described in Section III, 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 V of my testimony, I provide a forecast of the 2021 SONGS Unit 1 Offsite Spent Fuel Storage Costs associated with SDG&E's 20% minority ownership interest in SONGS.

In Section VI of my testimony, I provide a forecast of the 2021 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 VII of my testimony, I provide a forecast of the 2021 TMNBCBA costs.

In Section VIII, 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 IX, I provide a statement of qualifications.

Finally, my testimony refers to the following attachments:

<u>Attachment A</u>: SDG&E 2021 ERRA and LG Expenses (CONFIDENTIAL)

Attachment B: SDG&E 2021 Generation Portfolio Delivery Volumes (CONFIDENTIAL)

Attachment C: SDG&E 2021 Renewable Resource Detail

Attachment D: SDG&E 2021 CTC & QF Detail (CONFIDENTIAL)

Attachment E: SDG&E GHG Detail. (CONFIDENTIAL)

II. 2021 FORECAST OF ENERGY REQUIREMENTS AND SUPPLY RESOURCES

A. Energy Requirements Forecast

As a starting point for my analysis, I developed a forecast of SDG&E's 2021 hourly bundled load requirement, which is based on the California Energy Commission's ("CEC") 2019 California Energy Demand ("CED") forecast for SDG&E. This forecast includes the load departure of Community Choice Aggregators (CCA) Clean Energy Alliance (CEA) and San Diego Community Power (SDCP). CCA Solana Energy Alliance (SEA) is expected to join CEA in 2021.[1] Using this forecast and adjusting for direct access load, I project that the energy requirements for SDG&E's bundled load for 2021 will be [redacted] The 2021 forecast is [redacted] or [redacted] less than SDG&E's forecasted bundled energy for 2020 [redacted].

B. Supply Resource Forecast

After determining the amount of energy that SDG&E's bundled load customers will require in 2021, I then proceeded to develop a forecast of the supply resources that will be

[1] Because SDG&E's forecast reflects significant load departures as CCAs are expected to depart SDG&E's bundled service throughout the year, the inputs and assumptions used to develop the forecast could be impacted by issues such as the specific timing and magnitude of CCA load departures, the Commission's direction on portfolio optimization and resource allocation to departing load and other issues being addressed in the PCIA OIR (R. 17-06-026), as well as other uncertainties.

needed to meet that demand. To quantify the generation associated with the supply resources, I used the same production cost model SDG&E has used in past ERRA forecasts. Inputs to this model include the characteristics of the various generation resources, including heat rate, variable Operating and Maintenance ("O&M") costs, other factors that impact the plant's dispatch, and natural gas and electric market prices. The natural gas and electric market price forecasts were derived using a recent (March 1, 2020) assessment of 2021 market prices, based on the average of forward prices over the previous 20 market trading days. I then ran the model which simulates a least-cost dispatch of the portfolio of SDG&E's resources for every hour of 2021. The supply resources fall into the following five categories.

1. SDG&E-Contracted Conventional Generation

- SDG&E has multiple conventional generation resources under contract in its 2021 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; and the Morgan Stanley PPA, which provides firm energy deliveries at the Nevada Oregon Border ("NOB"). The OMEC facility was part of SDG&E's resource portfolio up until October of 2019 when the facility transitioned to an RA only contract. The forecasted generation for these contracts is detailed in Attachment B and is summarized in Table 1 below:

Table 1: Generation (GWh)			
	2021	2020	Difference
Carlsbad Energy Center	[redacted]		
Pio Pico Energy Center			
Orange Grove			
El Cajon Energy Center			
Escondido Energy Center			
Morgan Stanley NOB			
Total			

SDG&E also enters contracts each year to meet its California Public Utilities Commission ("CPUC") Resource Adequacy (RA) requirements.[2] Under its RA contracts, 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 2021, SDG&E has entered

[2] 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.

into contracts for up to a maximum of [redacted] of RA capacity. 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. Now that CCA load departure is imminent in 2021, SDG&E forecasts pro-rata sales of 645 MW of local and 137 MW of system RA to maintain an equivalent RA compliance position considering CCA load departure in 2021.

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 575 MW[3] combined cycle power plant;
- the Desert Star Energy Center ("Desert Star"), a 495 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, and Miramar at 30 MW; and
- the Cuyamaca Peak Energy Plant, consisting of a 45 MW simple cycle combustion turbine.

---

[3] SDG&E expects to perform an upgrade in 2020 that will increase the plant's capacity by approximately 20 MW (actual increase to be determined based on performance testing after the upgrade is complete).

These units are dispatched by the CAISO for generation and ancillary services ("A/S") awards based on economic merit.[4] The forecasted generation for these plants is detailed in Attachment B and is summarized in Table 2 below:

	Table 2: Generation (GWh)		
	2021	2020	Difference
Palomar	[redacted]		
Desert Star			
Miramar			
Battery Storage			
Cuyamaca			
Total			

3. Renewable Energy Contracts

The 2021 forecast of renewable energy supply from CPUC-approved contracts is 6,605 GWh, which includes 1,236 GWh of Renewable Energy Credit ("REC") quantities[5] that are delivered to SDG&E in conjunction with existing non-renewable imports. This forecast represents a decrease of 12 GWh from the 2020 forecast (6,617 GWh) and represents [redacted] of forecasted bundled sales. The forecasted generation associated with SDG&E's monthly renewable contracts is set forth in Attachment C.

For 2021, SDG&E forecasts it will receive 4,484 GWh of bundled renewable energy under 41 contracts with facilities that generate electricity using wind, solar, biogas, and non-

---

4 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.

5 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.

pumped hydro technologies. This number considers forecasted RPS sales for 2021 in the amount of 2,121 GWh. Forecasted sales represent a pro-rata reduction of renewable energy credits to maintain an equivalent RPS compliance position considering CCA load departure in 2021. The forecasted generation for projects that are currently on-line and operating is derived from generation profiles based on historical data. The forecasted generation for those projects that have recently come online and that are expected to continue operations in 2021[6] is based on historical data of resources that utilize similar renewable technologies.

In addition, SDG&E expects to receive 1,236 GWh of firmed-and-shaped power from three out-of-state wind projects, Rim Rock and Naturener Glacier 1 and 2 (Montana).[7] The RECs are delivered to California independently of the physical delivery of generation by the source wind projects. This is done by tagging equivalent quantities of the physical deliveries of other energy imports that SDG&E has already accounted for in its 2021 forecast. The forecasted energy mix from these renewable resources is shown in Table 3 below:

	Table 3: Generation (GWh)		
	2021	2020	Difference
Solar	[redacted]		
Wind			
Wind RECs			
Biogas			
Other			
RPS Sales			
Total			

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 firmed-and-shaped wind power from these contracts is delivered to California through the Morgan Stanley power contract described above.

4. Qualifying Facilities Contracts

In 2021, SDG&E will have approximately 110 MW of capacity under contract with three QFs.[8] The two largest QF contracts account for 106.5 MW or 98% of total QF capacity. All these QFs are in SDG&E's service area except for the Yuma Cogeneration Associates ("YCA") plant, a 56.5 MW natural gas-fired plant located in Arizona, the output of which is imported into CAISO.

SDG&E's QF 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 QF energy supply in 2021 is [redacted]. The forecasted generation for these plants is detailed in Attachment D.

5. Market Purchases and Surplus Sales

Under the Market Redesign and Technology Upgrade ("MRTU"),[9] there is no requirement that SDG&E balance its bundled load and its controlled generation quantities that clear the market. If, in any hour, the quantity of SDG&E's bundled load requirements purchased

---

[8] 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.

[9] In 2009, the CAISO implemented the Market Redesign and Technology Upgrade which primarily transformed the CAISO market from a zonal to a nodal priced market.

from the CAISO is greater than SDG&E-controlled generation dispatched by the CAISO, the difference may be viewed as equivalent to a market purchase.[10] Similarly, if more SDG&E generation is dispatched than SDG&E load requirements it is assumed to offset market purchases in other time periods. SDG&E forecasts that the quantity of equivalent market purchases will be [redacted] in 2021, an increase of [redacted] from the 2020 forecas [redacted].

III. 2021 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 $967 million of ERRA costs in 2021,[11] as reflected in Attachment A. This forecast is $183 million less than the $1.15 billion forecasted for 2020.

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 2021 PABA cost

---

[10] In some hours the quantity of SDG&E's bundled load requirements purchased from the CAISO is less than SDG&E-controlled generation sold to the CAISO. The difference may be viewed as equivalent to a market sale and the costs and revenues for such transactions are accounted for in the forecast by the total fuel expenses and total ISO Supply revenues.

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

forecast is $369.4 million.[12] This compares with a forecast of $359.1 million for 2020 filed in the 2020 ERRA forecast proceeding.

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 2021. 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 forecasted prices for energy, SDG&E's production cost model forecasts revenues totaling [redacted] for generation sold in 2021.

C. Contracted Energy Purchases

1. Purchased Power Contracts

SDG&E's forecast of total costs for conventional power purchase contracts in 2021 is [redacted]. These costs cover capacity payments and variable generation costs for Orange Grove, Wellhead, El Cajon and other facilities with which SDG&E has smaller contracts. The

12 In D.07-01-025, the Commission adopted the PCIA methodology for CCA customers. AL 3318-E, effective January1, 2019, established the PABA to record the "above-market" costs and revenues associated with all PCIA eligible resources by vintage subaccounts.

largest components in this category are Resource Adequacy capacity costs, expected to cost [redacted], and the Morgan Stanley contract, expected to cost [redacted]. This category also includes $22 million of pro-rata RA sales to maintain an equivalent RA compliance position considering CCA load departure in 2021. The assumed RA sales price is the Brown Market Price Benchmark provided by the Energy Division to calculate above market costs for PCIA.

2. Renewable Energy Contracts

SDG&E's renewable energy contracts usually contain only an energy payment and no capacity payment. In 2021, 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 $652 million for 2021 and are booked to ERRA with above market costs booked to PABA. This includes $22 million of REC sales to maintain an equivalent RPS compliance position considering CCA load departure in 2021. Attachment C details the renewable projects by fuel 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.[13] The estimated GT customer usage in

[13] 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.

2021 is 103.8 GWh.[14] The estimated GT charges include the cost of local solar[15] of [redacted]/megawatt hour ("MWh"), Grid Management Charges ("GMC") of $0.00072/kWh and Western Renewable Energy Generation Information System ("WREGIS") costs of $0.00001/kWh. The estimated total cost of GT in 2021 is $6.35 million. The estimated ECR customer usage in 2021 is 3.47 GWh. The estimated total cost of ECR in 2021 is $167,978. Additionally, the solar value adjustment was calculated as [redacted]/kWh.

3. Qualifying Facilities Contracts

SDG&E's QF 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.[16] For the dispatchable contracts, SDG&E pays fuel, variable O&M and capacity payments. Most of these contracts, whether PURPA or dispatchable, are considered CTC QF contracts,[17] and the ERRA expenses are based on delivered energy multiplied by the market price benchmark ("MPB"). Any costs, including

---

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

15 To meet immediate GT customer demand, SDG&E will draw on existing Renewables Portfolio Standard ("RPS") resources that are eligible to serve the GT component of the GTSR Program. The Interim GT Pool is a short-term approach and cost is based on the weighted average cost of contracts for included resources. Simultaneously, SDG&E will engage in procurement for projects built specifically to serve the GT component (GT Dedicated Procurement Projects). When GT Dedicated Procurement Projects are brought online, the Interim GT Pool will be phased out as allowed by program participation.

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

17 The CP Kelco contract, however, is not considered a CTC contract. Thus, unlike other QF contracts, 100% of CP Kelco contract costs are included in ERRA.

capacity payments, greater than the market price benchmark are booked to the TCBA. For the purposes of ERRA accounting, ERRA expenses for CTC QF contracts are recorded on Line 5 of Attachment A, "Contract Costs (CTC up to market)," and are forecasted to be [redacted] in 2021. 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.

D. Generation Fuel

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

In 2021, the ERRA expense for generation fuel purchased by SDG&E for Palomar, Miramar I & II, Desert Star and Cuyamaca is forecasted to be [redacted].[18] 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[19] and Schedule EG.[20]

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

---

[18] 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.

[19] Customer-procured Gas Franchise Fee Surcharge.

[20] Natural Gas Intrastate Transportation Service for Electric Generation Customers.

separate Local Generating Balancing Account. The Escondido Energy Center, Kelco, Grossmont, Pio Pico, Carlsbad Energy Center, El Cajon Energy Storage, Fallbrook Energy Storage, Powin Energy Storage, Miramar Energy Storage and Escondido Energy Storage contracts are included in this balancing account and are expected to cost [redacted], net of supply ISO revenue. Attachment A, attached hereto, details the breakdown of local generation expenses.

F. Integrated Resource Planning Procurement Track

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 Commission determined, for the 2017-2018 IRP cycle, that SDG&E is responsible for 242.9 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. The Commission ordered cost recovery for this procurement through a CAM-like mechanism, the details of which as of this filing are still unresolved. SDG&E expects the costs to flow through LGBA. CCAs and ESPs in SDG&E's service territory are responsible for around 50 MW of incremental procurement. 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.

G. CAISO Related Costs

SDG&E forecasts the miscellaneous CAISO costs to be [redacted] in 2021. 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 2021.

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,[21] 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 revenues for 2021 is [redacted], calculated as the marked-to-market profit/loss of hedges already in place, plus expected broker fees. 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 hedge transactions.

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.

---

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

I. Convergence Bids

SDG&E uses convergence bids[22] 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[23] 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 2021 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

---

[22] 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.

[23] 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.

offsetting market-congestion prices at various P-nodes over the 2021 period. Since there are no 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[24] 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.

---

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

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 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. 2021 Forecast

SDG&E estimates its 2021 SONGS Unit 1 offsite spent fuel storage expense to be $1.060 million, including adjustments for escalation, in accordance with the GE-Hitachi spent fuel storage contract.[25] 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. 2021 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 provides that compliance obligations in the electricity sector are applicable to "first deliverers of electricity."[26] Generally, first deliverers of electricity in 2021 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

---

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

[26] 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.

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 2021 GHG costs. Finally, in Section V.D, I discuss the 2021 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 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.[27] The forecast of GHG emissions from SDG&E facilities in 2021 is included in Table 4 below.

[27] 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.

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 2021.

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.[28] 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 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[29] to estimate the MWh related to unspecified electricity imports. The quantity is multiplied by the ARB default emission rate, which is 0.428 metric tons of CO_2e per MWh.

[28] 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.

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

Third, electricity from out-of-state renewable resources that are not imported can be used to offset the emissions of imports under the ARB Renewable Portfolio Standard ("RPS") adjustment. Specifically, the RPS adjustment is equal to the default emission rate multiplied by the MWh from the eligible renewable resources, as measured at the point of generation.[30] Of the total generation potentially eligible for RPS Adjustment, approximately 50% has been imported into California. As such, SDG&E is only able to utilize the remaining non-imported generation to calculate its RPS Adjustment. Both the emissions of imported power and the offsetting RPS adjustment 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

[30] ARB, Article 5: California Cap on Greenhouse Gas Emissions and Market-based Compliance Mechanisms, at 103, Section 95852(b)(4)(C), *available* at https://www.arb.ca.gov/cc/capandtrade/c-t-reg-reader-2013.pdf.

of the forecasted SDG&E load.[31] 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.

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

[31] 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.

power from CHP facilities. The GHG emissions from indirect sources are summarized on an annual basis in Table 4 below and monthly in Attachment E.

Table 4: 2021 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)	
Imports	[redacted]	[redacted]
RPS Adjustment	[redacted]	[redacted]
Total Direct Emissions		[redacted]

Resource	**Generation (GWh)**	
Net Market Purchases	[redacted]	[redacted]
CHP	[redacted]	[redacted]
Total Indirect Emissions		[redacted]
Total Forecasted Emissions		[redacted]

Conversions		
Natural Gas	0.05307	MTons/MMBtu
Market Purchases	0.428	MTons/MWh
Imports	0.428	MTons/MWh

C. 2021 GHG Costs

I calculated a proxy for the 2021 GHG emissions price as $17.90/MT. This figure was derived using a recent (March 1, 2020) assessment of 2021 GHG market prices based on the average of forward prices on the Intercontinental Exchange ("ICE") over the previous 20 trading day period, consistent with the period used for forecasting 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 2021 of $37.7 million for ERRA.

D. 2021 Allowance Auction Revenues

The ARB allocates cap-and-trade allowances to SDG&E for 2021. SDG&E is required to place all these allowances for sale in ARB's 2021 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.[32]

The total allowances that will be allocated to SDG&E for 2021 is expected to be 6,766,147 MT. The allowance price is the same proxy price as used in the calculation of GHG costs, which is $17.90/MT. The allowance auction revenue forecast is the allowances allocated times the allowance price [redacted].

The available funds for the clean energy and energy efficiency programs are equal to 15 percent of the forecasted 2021 allowance auction revenue amount or $18.2 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[33]. This program provides financial incentives for installation of solar energy systems

---

[32] 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.

[33] 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. The required funding set aside for the SOMAH Program has ended as of June 30, 2020.[34]

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").[35] 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 program ("PPP") funds. The DAC-SASH program funding is estimated to be $1.03 million. The previously requested and available funding for DAC-GT and CSGT is expected to cover all 2021 program related expenses. Therefore, SDG&E is not requesting any additional funding at this time.[36]

---

[34] SB 92, subset (8), and the 2020 ERRA Decision (D.20-01-005) at page 28 state that SOMAH's funding has concluded as of June 30, 2020. The Commission's Proposed Decision ("PD") for Rulemaking 14-07-002 and Application 16-07-015, issued on March 13, 2020, extends the SOMAH funding through June 30, 2026. This PD will be voted on no sooner than April 16, 2020. As such, SDG&E will include the SOMAH funding in its November 2021 ERRA Forecast Update.

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

[36] On August 2, 2019, SDG&E filed AL 3412-E and separately on January 31, 2020 SDG&E filed AL 3501-E. SDG&E is waiting for approval of AL 3412-E, currently suspended by the Commission, and AL 3501-E is contingent on the approval of 3412-E.

VI. 2021 FORECAST OF TMNBCBA COSTS

In this section, I describe the cost forecast for tree mortality related procurement costs.[37] The TMNBCBA costs will be recovered through the PPP charge. The 2021 forecasted costs are $[redacted] million.

VII. MEET-AND-CONFER ACTIVITIES

D.19-06-026 adopted a meet-and-confer requirement whereby: (a) A meeting between load-serving LSEs that anticipate load migration shall occur reasonably in advance of the filing deadline for initial year ahead forecasts; and (b) In each LSE's initial year ahead forecast filing, each LSE shall describe the dates of meetings with other LSEs to discuss load migration, any agreements, and any continued areas of disagreement.[38]

Additionally, In OP 1 of its *Proposed Decision Considering Working Group Proposals on Departing Load Forecast and Presentation of Power Charge Indifference Adjustment Rate on Bills and Tariffs* (filed February 25, 2020), the Commission ordered SDG&E to report in each regulatory filing its meet-and-confer activities and information exchange with Community Choice Aggregators in SDG&E's service territory, if the regulatory filing involves a departing load forecast.[39]

---

[37] 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. At the time of this filing, SDG&E's Advice Letter has not been approved.

[38] *Decision Adopting Local Capacity Obligations for 2020-2022, Adopting Flexible Capacity Obligations for 2020, and Refining the Resource Adequacy Program at OP 14* (filed in Rulemaking (R.) 17-09-020).

[39] Filed in R.17-06-026.

SDG&E held a meet-and-confer meeting regarding load forecasting on March 23, 2020. SDG&E invited numerous entities to participate in the March 23rd meet-and-confer meeting.[40] Attendees to the meeting included representatives for Calpine, San Diego Community Power, and Clean Energy Alliance. The items addressed at the meet-and-confer meeting included: (1) an overview of SDG&E's load forecast process for departing load; (2) an overview of the meet-and-confer requirement; (3) an overview of regulatory proceedings and schedules; (4) an overview of load data to support regulatory filings; and (5) a discussion of future load forecast cycles. The parties continue to exchange information regarding load forecasting through a collaborative effort. The parties have reached agreement on the process by which the non-IOU LSEs are to provide forecast data to SDG&E as well as the templates to be used to submit their data. There have not been any specific areas of disagreement at this point. Information provided by the non-IOU LSEs to SDG&E include monthly energy sales, peak demand and customer forecast data.

This concludes my prepared direct testimony.

[40] SDG&E sent an invite to recipients on the R.17-09-020 and R.19-11-009 distribution lists.

VIII. QUALIFICATIONS

My name is Stefan Covic. My business address is 8315 Century Park Court, San Diego, CA 92123. I am employed by SDG&E and my current title is Senior 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 April 2019. Prior to joining SDG&E, I worked as an energy analyst at Bear Valley Electric Service, a small IOU in Big Bear Lake, CA. I received a Bachelor of Physics and a Master of Economics degrees from the University of California, Irvine.

I have previously testified before the California Public Utilities Commission

.

ATTACHMENT A

(CONFIDENTIAL)

SDG&E 2021 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 2020 ERRA and LG EXPENSES

		Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020
1	**EXPENSES ($)**													
2	ISO Load Charges (Energy & A/S Costs)	[redacted]												
3	ISO Supply Revenues	[redacted]												
4	Contract Costs (non-CTC)	[redacted]												
5	Contract Costs (CTC up to mkt)	[redacted]												
6	Generation Fuel	[redacted]												
7	CAISO Misc Costs	[redacted]												
8	Hedging Costs & Financial Transactions	[redacted]												
9	Contract Costs - CHP Costs (AB1613)	[redacted]												
10	Customer Incentives - SPP, DR,20/20	[redacted]												
11	Rewards/Penalties - Palomar Energy Ctr	[redacted]												
12	WREGIS Costs	[redacted]												
13	ISO CRRs Costs	[redacted]												
14	ISO Convergence Bidding Costs	[redacted]												
16	Purchased Tradable Renewable Energy Credits (TRECs)	[redacted]												
17	Sales Tradable Renewable Energy Credits (TRECs)	[redacted]												
18	Net Surplus Compensation Costs (AB920)	[redacted]												
19	Authorized Disallowances	[redacted]												
20	Greenhouse Gas & Carrying Costs	[redacted]												
21	**Total Balancing Account Expenses**	[redacted]												**$ 966,510,235**
22	**PABA Portion of ERRA Expenses**	[redacted]												**$ 369,346,677**
	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]												
	CFD Revenues	[redacted]												
	Morgan Stanley Index Costs	[redacted]												
	Renewable Energy	$ 36,289,682	$ 41,562,233	$ 49,165,689	$ 64,327,258	$ 67,614,804	$ 66,481,944	$ 63,959,318	$ 67,937,748	$ 58,302,299	$ 53,173,912	$ 45,051,607	$ 38,211,731	$ 652,078,228
	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]												
	Market Purchases and Sales													
	Total Market Costs	[redacted]												
	Total Sales Revenue	[redacted]												
	Net Costs (Revenues)	[redacted]												
	LG Expenses													
	Carlsbad Energy Center cost	[redacted]												
	El Cajon Energy Storage cost	[redacted]												
	EPC Energy Storage cost	[redacted]												
	Fallbrook Storage Cost	[redacted]												
	Powin Storage Cost	[redacted]												
	Escondido Energy Center Cost	[redacted]												
	Escondido Energy Storage Cost	[redacted]												
	Pio Pico cost	[redacted]												
	LG CHP cost	[redacted]												
	Local Generation Revenue	[redacted]												
	Total LG Expense	[redacted]												

ATTACHMENT B

(CONFIDENTIAL)

SDG&E 2021 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 2020 GENERATION PORTFOLIO DELIVERY VOLUMES (GWh)

	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020
CTC QF	[redacted]												
Non-CTC QF													
TOTAL QF													
Renewable - Bio Gas	20.8	18.8	20.8	20.2	20.8	20.2	20.8	20.8	20.2	20.8	20.2	20.8	**245.3**
Renewable - Other	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	**3.9**
Renewable - Solar	212.1	221.2	249.1	299.7	330.7	362.4	349.0	338.3	297.2	262.9	231.5	195.0	**3,349.2**
Renewable - Wind	111.3	133.8	185.3	294.8	310.3	252.8	128.1	182.8	145.2	147.2	167.6	132.3	**2,191.5**
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**
Renewable - RPS Sales	(176.8)	(176.8)	(176.8)	(176.8)	(176.8)	(176.8)	(176.8)	(176.8)	(176.8)	(176.8)	(176.8)	(176.8)	**(2,121.1)**
TOTAL NON-QF RENEWABLE	**278.0**	**352.4**	**413.3**	**531.9**	**563.7**	**550.9**	**395.3**	**429.2**	**387.0**	**339.1**	**362.3**	**301.7**	**4,904.7**
Miramar	[redacted]												
Miramar 2													
Cuyamaca													
Palomar													
Desert Star													
Kelco													
Lake Hodges													
Morgan Stanley													
El Cajon Energy Center													
Orange Grove													
Escondido Energy Center													
Pio Pico													
Carlsbad Energy Center													
El Cajon Energy Storage													
EPC Energy Storage													
Escondido Energy Storage													
Fallbrook Energy Storage													
Powin Energy Storage													
TOTAL GENERATION													
Market Purchases													
TOTAL PORTFOLIO DELIVERIES													
Surplus Energy Sold													
Energy Storage Charging Load													
Non-ERRA Resource Generation													
LOAD REQUIREMENT (GWh)													

Note 1: Total Portfo io Deliveries do not include Wind REC

Note 2: Load Requirement is SDG&E bundled load including transmission losses

ATTACHMENT C

SDG&E 2021 RENEWABLE RESOURCE DETAIL

Attachment C

ATTACHMENT C - SDG&E 2020 RENEWABLE RESOURCE DETAIL													
Power Purchase Deliveries (GWh)	**Jan**	**Feb**	**Mar**	**Apr**	**May**	**Jun**	**Jul**	**Aug**	**Sep**	**Oct**	**Nov**	**Dec**	**2020**
BIO GAS													
Lakeside BioGas LLC	2.2	2.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	26.3
MM Prima Deshecha Energy LLC	9.1	8.2	9.1	8.8	9.1	8.8	9.1	9.1	8.8	9.1	8.8	9.1	107.3
MM San Diego LLC- Miramar Landfill	2.2	2.0	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	2.2	26.3
BIOGAS_FIT	7.3	6.6	7.3	7.0	7.3	7.0	7.3	7.3	7.0	7.3	7.0	7.3	85.4
Subtotal	**20.8**	**18.8**	**20.8**	**20.2**	**20.8**	**20.2**	**20.8**	**20.8**	**20.2**	**20.8**	**20.2**	**20.8**	**245.3**
OTHER													
SMALL_HYDRO_RAM	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	0.3	3.9
Subtotal	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**0.3**	**3.9**
SOLAR													
NRG Borrego Solar	3.8	4.4	5.6	7.2	8.2	8.0	6.9	6.2	6.3	4.2	4.1	3.3	68.3
Sol Orchard	1.9	2.2	2.8	3.5	3.4	4.0	3.5	2.3	2.8	2.5	1.9	1.7	32.6
Solar Energy Project	1.0	1.3	1.8	2.0	1.8	2.2	2.3	2.1	1.7	1.5	1.2	1.1	19.9
SOLAR_PV_FIT	0.9	0.9	0.9	1.0	1.1	1.2	1.2	1.2	1.1	1.1	1.0	0.9	12.5
Arlington Va ley Solar	21.1	19.4	21.2	29.4	36.2	39.3	37.0	36.8	32.2	23.1	21.4	18.0	335.0
Calipatria	2.5	2.7	2.7	3.9	4.6	5.1	4.9	4.4	3.6	2.9	2.3	2.3	41.9
Campo Verde	24.3	23.1	24.1	27.3	28.9	30.6	31.6	31.2	28.1	28.7	26.2	22.4	326.4
Catalina_Solar	16.8	20.1	21.0	25.4	26.8	26.6	24.9	25.3	23.8	21.2	17.2	15.9	264.8
Centinela Solar1	20.3	21.4	25.2	29.9	33.0	38.5	37.0	35.1	29.5	26.0	23.1	18.5	337.3
Centinela Solar2	7.3	7.7	9.1	10.8	11.9	13.9	13.3	12.6	10.6	9.4	8.3	6.6	121.4
Desert Green	1.0	0.9	0.9	1.2	1.5	1.6	1.1	1.2	1.1	1.1	1.0	0.9	13.5
Imperial Valley Solar I	26.9	30.4	37.4	45.6	50.5	56.9	53.8	52.1	43.4	37.5	31.1	25.5	491.0
Maricopa West Solar	2.2	3.6	3.9	4.4	5.9	4.7	5.9	5.8	5.0	3.9	2.3	1.9	49.4
TallBear Seville	3.2	3.4	4.0	4.8	5.3	6.2	5.9	5.6	4.7	4.2	3.7	3.0	54.0
SolarGen 2	24.3	25.6	30.3	35.9	39.6	46.2	44.4	42.2	35.4	31.2	27.7	22.2	404.8
Cascade SunEdison	3.2	3.8	4.8	5.6	6.2	6.4	5.2	5.4	5.0	4.1	3.2	2.5	55.4
Csolar IV South	18.8	18.9	21.8	24.0	24.6	26.6	26.7	25.6	23.5	22.4	21.6	18.4	273.0
Csolar IV West	26.2	24.9	26.0	29.5	31.2	33.0	34.1	33.6	30.4	31.0	28.3	24.2	352.3
Subtotal	**205.6**	**214.7**	**243.4**	**291.3**	**320.5**	**350.9**	**339.7**	**328.8**	**288.1**	**255.9**	**225.5**	**189.1**	**3,253.7**
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	15.9	14.7	17.3	18.0	16.6	13.2	5.4	7.5	8.3	11.2	15.6	11.8	155.6
Coram Energy	1.4	1.5	1.3	2.5	3.3	3.4	3.0	3.6	2.1	1.3	1.5	1.5	26.5
Energia Sierra Juarez	31.0	34.1	51.8	57.1	53.6	46.5	17.5	27.9	28.6	28.7	36.7	28.9	442.4
Manzana Wind	31.9	29.3	34.7	36.1	33.2	26.5	10.9	14.9	16.5	22.4	31.2	23.7	311.2
Oak Creek Wind Power	0.3	0.3	0.4	0.8	0.8	0.7	0.6	0.7	0.4	0.3	0.3	0.4	5.9
Ocotillo Express	16.2	31.6	51.9	81.0	102.8	74.0	42.4	62.8	39.9	34.2	22.5	17.1	576.5
Pac fic Wind	13.9	20.9	24.2	37.8	40.9	37.4	27.6	33.1	17.7	18.3	21.9	19.2	312.9
San Gorgonio	0.7	1.4	3.5	4.4	5.6	4.4	3.2	4.5	3.3	2.0	1.1	0.9	35.1
ESJ 2	-	-	-	57.1	53.6	46.5	17.5	27.9	28.6	28.7	36.7	28.9	325.4
Subtotal	**221.5**	**288.9**	**319.8**	**388.4**	**388.7**	**344.7**	**201.8**	**246.4**	**246.1**	**231.7**	**287.0**	**262.3**	**3,427.5**
RPS SALES													
Subtotal	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(176.8)**	**(2,121.1)**
Total Power Purchase Costs ($000)													
BIO GAS	$ 1 757	$ 1 587	$ 1 757	$ 1 700	$ 1 757	$ 1 700	$ 1 786	$ 1 786	$ 1 729	$ 1 786	$ 1 700	$ 1 756	$ 20 804
OTHER	$ 27	$ 24	$ 27	$ 26	$ 27	$ 26	$ 27	$ 27	$ 26	$ 27	$ 26	$ 27	$ 317
SOLAR	$ 22,075	$ 23,604	$ 26,396	$ 31,561	$ 33,925	$ 38,029	$ 48,113	$ 46,570	$ 39,959	$ 35,324	$ 24,369	$ 20,750	$ 390,674
WIND	$ 10 506	$ 13 030	$ 18 236	$ 29 779	$ 31 259	$ 25 617	$ 13 508	$ 19 395	$ 15 106	$ 15 034	$ 16 612	$ 13 102	$ 221 184
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	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (1,837)	$ (22,047)
Subtotal	**$ 36,473**	**$ 41,741**	**$ 49,333**	**$ 64,548**	**$ 67,887**	**$ 66,770**	**$ 64,175**	**$ 68,166**	**$ 58,529**	**$ 53,395**	**$ 45,240**	**$ 38,384**	**$ 654,640**

ATTACHMENT D

(CONFIDENTIAL)

SDG&E 2021 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 2020 CTC QUALIFYING FACILITY (QF) DETAIL

CTC QF - Dispatchable (GWh)	Jan	Feb	Mar	Apr	May	Jun	Jul	Aug	Sep	Oct	Nov	Dec	2020
Goal Line QF	[redacted]												
Yuma Cogen Associates QF													
CTC QF - SRAC Priced (GWh)													
Aggregation of Hydro Units (SO1)	[redacted]												
Subtotal													
ERRA Expenses ($000)													
CTC QF	[redacted]												
(to Line 5 of Attachment A)													
TCBA Expenses ($000)													
CTC QF	[redacted]												$ 16,473

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

2020 Direct Emissions (MT)	JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC	2020
California UOG Plants	[redacted]												
California Tolling Generators													
Specified Imports													
Unspecified Imports													
RPS Adjustment													
Total Direct Emissions													
2020 Indirect Emissions (MT)													
Market Purchases	[redacted]												
CHP													
Total Indirect Emissions													
2020 Total Forecasted Emissions	[redacted]												3,275,239

ATTACHMENT F

DECLARATION OF STEFAN COVIC

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

DECLARATION
OF STEFAN COVIC

A.20-04-___
Application of San Diego Gas & Electric Company (U 902-E)
for Approval of Its 2021 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts

I, Stefan Covic, declare as follows:

1. I am the Senior Resource Planner for San Diego Gas & Electric Company ("SDG&E"). I included my Prepared Direct Testimony ("Testimony") in support of SDG&E's April 15, 2020 Application for Approval of its 2021 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts ("Application"). Additionally, as the Senior 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**
SC-3	V.C	LSE Total Energy Forecast – Bundled Customer; confidential for the front three years
SC-5 Table 1 and SC-6	IV.F	Forecast of Post-1/1/2003 Bilateral Contracts; confidential for three years
SC-5 and SC-6	VI.A	Utility Bundled Net Open Position for Capacity; confidential for the front three years
SC-7 Table 2	IV.A	Forecast of IOU Generation Resources; confidential for three years
SC-7 and SC-8 Table 3	V.H	Net capacity and energy forecasts by retail provider; confidential for the front three years
SC-9	IV.B	Forecast of Qualifying Facility Generation; confidential for three years
SC-10	IV.J	Forecast of Wholesale Market Purchases; confidential for the front three years
SC-11	II.A.2 V.C	Utility Electric Price Forecasts; confidential for three years, LSE Total Energy Forecast, confidential for the front three years
SC-11	II.A.2 II.B.1 II.B.3 II.B.4	Utility Electric Price Forecasts; confidential for three years, Generation Cost Forecasts of Utility Retained Generation, confidential for three years, Generation Cost Forecasts of QF Contracts, confidential for three years, Generation Cost Forecasts of Non-QF Bilateral 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
SC-11 SC-12 SC-13 SC-27	II.B.4	Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years
SC-14	II.B.3	Generation Cost Forecast of QF Contracts; confidential for three years
SC-14	II.B.1	Generation Cost Forecasts of Utility Retained Generation, confidential for three years
SC-11	II.A.2	Utility Electric Price Forecasts; confidential for three years
SC-16 SC-24 Table 4	I.A.4	Long-term Fuel (gas) Buying and Hedging; confidential for three years
SC-24 Table 4		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.
Attachment A - SDG&E 2021 ERRA and LG Expenses	XI	Monthly Procurement Costs; confidential for three years

Location of Protected Information	**Matrix Reference**	**Reason for Confidentiality and Timing**
Attachment B - SDG&E 2021 Generation Portfolio Delivery Volumes		
• Cuyamaca, Palomar, Desert Star, and Miramar data	IV.A IV.E	Forecast of IOU Generation Resources; confidential for three years Forecast of Pre-1/1/2003 Bilateral Contracts; confidential for three years
• QF data	IV.B	Forecast of Qualifying Facility Generation; confidential for three years
• Kelco, Lake Hodges, Wellhead, and Orange Grove data	IV.F	Forecast of Post-1/1/2003 Bilateral Contracts; confidential for three years
• Market Purchase data	IV.J	Forecast of Wholesale Market Purchases; confidential for the front three years
• Surplus Energy Sold data	IV.K	Forecast of Wholesale Market Sales; confidential for the front three years
Load Requirement data	V.C	LSE Total Energy Forecast – Bundled Customer; confidential for the front three years
Attachment D - SDG&E 2021 CTC Qualifying Facility (QF) Detail		
• QF data	IV.E	Forecast of Pre-1/1/2003 Bilateral Contracts; confidential for three years
• Long-Term Power Purchase CTC data	IV.B	Forecast of Qualifying Facility Generation; confidential for three years
• CTC QF & Non CTC QF data	II.B.4	Generation Cost Forecast of Non-QF Bilateral Contracts; confidential for three years
• TCBA Expenses data	II.B.3	Generation Cost Forecast of QF Contracts; confidential for three years

Location of Protected Information	Matrix Reference	Reason for Confidentiality and Timing
Attachment E - SDG&E Greenhouse Gas (GHG) Detail	Justification for confidentiality provided in Declaration of Hillary Hebert	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 15th day of April, 2020, at San Diego, California.

Stefan Covic

____

Stefan Covic
Senior Resource Planner
San Diego Gas & Electric Company

ATTACHMENT G

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

I, Hillary Hebert, do declare as follows:

1. I am a Resource Planning Manager in the Resource Planning department for San Diego Gas & Electric Company ("SDG&E"). I have been delegated authority to sign this declaration by Miguel Romero, Vice President of Energy Supply. I have reviewed Stefan Covic's Prepared Direct Testimony ("Testimony") in support of SDG&E's "Application for Approval of its 2021 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 15th day of April, 2020, in San Diego.

Hillary Hebert

ATTACHMENT A

SDG&E Request for Confidentiality
on the following information in its Application for Approval of Its 2021 Electric Procurement Revenue Requirement Forecasts and GHG-Related Forecasts

Location of Protected Information	Legal Authority	Narrative Justification
SC-25 Table 4, and Attachment E - SDG&E Greenhouse Gas (GHG) Detail Application Attachment G, Template D-2: Forecasted Emissions and Costs, and Template D-5: Forecasted Emissions Intensity	D.14-10-033; D.16-08-024; D.17-05-035; D.17-09-023; 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.