Application of SAN DIEGO GAS & ELECTRIC COMPANY (U902-E) for Approval of SB 350 Transportation Electrification Proposals	Application No. _______________ (Filed January 20, 2017)

PREPARED DIRECT TESTIMONY OF

CYNTHIA FANG

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY

CHAPTER 5

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

January 20, 2017

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CHAPTER 5

I. INTRODUCTION

My direct testimony presents San Diego Gas & Electric Company's ("SDG&E") proposed rate design and rate recovery for the transportation electrification ("TE") proposals that are the subject of this Application, submitted in compliance with Senate Bill ("SB") 350 and the Assigned Commissioner Ruling of Commissioner Peterman issued on September 14, 2016 in R.13-11-007[1] ("ACR").

SDG&E proposes the introduction of three new rates to support its TE proposals by introducing rate structures that reflect cost-causation principles and support the deployment of electric vehicles ("EVs") in such a manner that "should assist in grid management, integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions."[2] These three new proposals are:

- **Commercial Grid Integration Rate ("GIR")**: applicable to participants on SDG&E's proposed Fleet Delivery Services project;
- **Residential GIR**: applicable to participants on SDG&E's proposed Residential Charging Program; and
- **Public Charging GIR**: applicable to participants on SDG&E's proposed Electrify Local Highways and Green Taxi/Shuttle/Rideshare projects.

[1] *Assigned Commissioner's Ruling Regarding the Filing of the Transportation Electrification Applications Pursuant to Senate Bill 350* (September 14, 2016).
[2] Public Utilities Code ("P.U. Code") §740.12(a)(1)(G).

Regarding the Medium-Duty / Heavy-Duty and Forklift Port Electrification project and the Airport Ground Support Equipment project, they will not be separately metered.[3] Accordingly, these projects will receive service on whatever existing rate schedule the customer receives for electric service; there is no specific rate design proposal applicable to these projects. The Dealership Incentives project provides direct incentives to dealerships,[4] and therefore does not have any rate design proposals associated with the project.

A rate design based on cost-causation principles is critical to ensure that charging occurs in a manner consistent with electric grid conditions and provides customers with price signals to incent behavior which minimizes incremental system and local capacity needs. This is critical given the potential load that EV charging can impose on both system and local capacity needs. In any given month, SDG&E's average residential customer has a demand of approximately 4 kW.[5] Residential incremental load associated with EV charging can vary depending on the charging capacity of the electric vehicle and the level of Electric Vehicle Supply Equipment ("EVSE") (Level 1 or 2). For example, a Level 1 EVSE's incremental demand will be about 1.4 kW[6], while with a Level 2 EVSE the range can be between 3.3 to 6.6 kW[7]. Some EVs have the capability to generate an incremental demand of over 10 kW.[8] The addition of an EV can then result in a demand many times greater than a typical residential household load. SDG&E's small

[3] *See* the direct testimony of Randy Schimka (Chapter 3) for further details on projects and metering.
[4] *See* the direct testimony of Randy Schimka (Chapter 3) for further details on Dealership Incentives project.
[5] LOAD RESEARCH REPORT COMPLIANCE FILING OF SOUTHERN CALIFORNIA EDISON COMPANY (U 338-E), ON BEHALF OF ITSELF, PACIFIC GAS AND ELECTRIC COMPANY (U 39E), AND SAN DIEGO GAS & ELECTRIC COMPANY (U 902-M), PURSUANT TO ORDERING PARAGRAPH 2 OF D.16-06-011 (Joint IOU Electric Vehicle Load Research Report 5th Report), filed on December 20, 2016, pp. 90, Table 9. Demands based in 15-minute interval data.
[6] Electric Vehicle Charging Station Guidebook, 2014, http://www.ccrpcvt.org/wp-content/uploads/2016/01/20140626-EV-Charging-Station-Installation-Guide.pdf, at 9.
[7] *Id.* at 10.
[8] *Id.* Table 4.2, at 27.

commercial customers generally have a demand of 20 kW or less and the addition of commercial EV charging can result in an incremental demand of 15 to 75 kW depending on the type and quantity of EVSE. A single DC Fast Charger ("DCFC") has a peak demand of about 50 kW.[9] Commercial EV adoption by a small commercial customer would result in the customer to no longer be classified as a small commercial customer. In the case of commercial EV fleets, the incremental demand per commercial EV would then be multiplied by the number of vehicles in the fleet.

SDG&E's rate design proposals in this proceeding are intended to address the challenge of integrating TE in a manner consistent with California rate policy. Specifically, the focus of SDG&E's rate design proposals in this proceeding is: (1) to encourage economically efficient decision-making; (2) to encourage reduction of both coincident and non-coincident peak demand; (3) to provide a rate design that encourages cost-effective grid integrated charging solutions for EV customers; (4) to avoid cross-subsidies; (5) to base rates on cost causation; and (6) to examine alternative rate design.

In Rulemaking ("R.") 12-06-013, *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations* ("RROIR"), the Commission adopted ten Rate Design Principles ("RDPs") for rate design.[10] While the RROIR was limited to residential rate design, SDG&E believes that these Commission-adopted principles should guide the rate design for all customers. Table 5-1

[9] *Id.* at 27.
[10] Decision ("D.") 15-07-001 at 28.

below presents the RDPs in the four categories consistent with decision D.15-07-001[11]: cost of service, affordable electricity, conservation, and customer acceptance.

Table 5-1: Rate Design Principles

Cost of Service RDP	Affordable Electricity RDP	Conservation	Customer Acceptance
(2) Rates should be based on marginal cost; (3) Rates should be based on cost-causation principles; (7) Rates should generally avoid cross-subsidies, unless the cross-subsidies appropriately support explicit state policy goals; (8) Incentives should be explicit and transparent; (9) Rates should encourage economically efficient decision-making;	(1) Low-income and medical baseline customers should have access to enough electricity to ensure basic needs (such as health and comfort) are met at an affordable cost;	(4) Rates should encourage conservation and energy efficiency; (5) Rates should encourage reduction of both coincident and non-coincident peak demand;	(6) Rates should be stable and understandable and provide customer choice; (10) Transitions to new rate structures should emphasize customer education and outreach that enhances customer understanding and acceptance of new rates, and minimizes and appropriately considers the bill impacts associated with such transitions.

Only with accurate price signals that reflect the cost of service partnered with any incentives or subsidies deemed necessary to further public policy objectives that are separately and transparently identified, can the Cost of Service RDPs (RDPs 2, 3, 7, 8, 9), Conservation RDPs (RDPs 4 and 5), and Affordable Electricity RDP (RDP 1) be satisfied simultaneously. Only through rates that are based on marginal costs and cost-causation principles can we encourage reductions in both coincident and non-coincident peak demand (RDP 5) in a grid integrated manner (RDP 9), rather than through shifting costs to other customers.

While SDG&E provides these rate proposals as part this TE Application, SDG&E proposes not to limit the applicability of the proposed GIR to participants of SDG&E's TE proposals, and instead proposes that they be made available to all customers. This will ensure that these rates "comport with the definition of TE to allow all types of electric 'vehicles, vessels,

[11] *Id.* at 264.

trains, boats, or other equipment' (e.g. aircraft) that are mobile sources of air pollution and GHG [Greenhouse Gas] emissions"[12] and "facilitate the use of complementary technologies that assist customers in their efficient integration of vehicles with the grid."[13]

The ACR notes that "simply shifting costs to other ratepayer classes does not comport with cost causation rate design principles and may not be a viable solution."[14] SDG&E agrees that simply shifting costs to other non-participating customers does not provide a sustainable solution. Given the importance of a cost-based rate structure to provide the price signals to encourage charging to occur in a manner that is consistent with grid conditions, SDG&E believes that proposing a transitional incentive in the near term is appropriate in order to support the State's TE goals as well as encourage the election of the GIR rates more broadly.

My testimony is organized as follows:

- **Section II – SB 350 Rate Design Proposals:** describes the details of SDG&E's rate design proposals to support the goals of TE projects.
- **Section III – Cost Recovery:** describes the methodology for recovering the costs associated with SDG&E's TE proposals; and
- **Section IV – Summary and Conclusion:** provides a summary of the rate design proposals.

II. SB 350 RATE DESIGN PROPOSALS

SDG&E proposes three rates to support SDG&E's proposed TE projects: (1) a commercial hourly dynamic rate (Commercial GIR) with a monthly Grid Integration Charge ("GIC") that varies based on customer size or demand, which recovers distribution costs for commercial customers with EV fleet/commercial vehicle charging; (2) a residential hourly

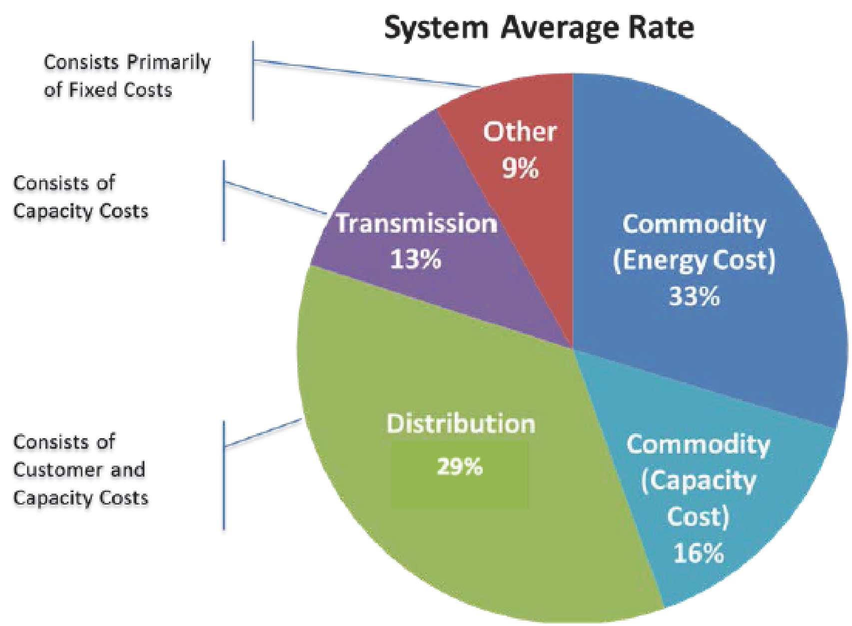
[12] *Id*. at 21.
[13] *Id.*
[14] ACR at 20.

dynamic rate (Residential GIR) with a monthly GIC that varies based on customer size or demand, which recovers distribution costs for residential homes with EV charging, and (3) a public charging hourly dynamic rate (Public Charging GIR). All three proposed rates also include system and circuit dynamic adders consistent with SDG&E's Power Your Drive pilot rate approved pursuant to D.16-01-045 in SDG&E's Application ("A.") 14-04-014 for Approval of its Electric Vehicle-Grid Integration ("VGI") Pilot Program. In addition, SDG&E proposes to include a monthly incentive to support the State's TE goals as well as encourage the election of the GIR rates more broadly.

A. Cost-Based Rate Design

Utility rates recover the costs of services related to commodity resources, distribution resources, transmission resources, and the costs of public policy programs. Under SDG&E's current effective rates, commodity services represent 49% of total costs recovered, distribution represents 29%, transmission covers 13% and the remaining 9% represents the costs of State and Commission mandated programs.

Chart 5-1: Breakout of System Average Rate



When reviewing the breakdown of the cost of utility services, only a fraction (one-third) of the services recovered in electric utility rates are driven by the kilowatt-hour (kWh) energy usage of customers. The majority of the costs to serve customers are fixed. These costs are incurred independent of customer usage (kWh) and are driven either by (1) the number of customers or (2) the capacity needs of customers, on both the system and individual circuits, which result from their maximum load or demand of the customers.

Under SDG&E's current rate design, the standard rate structure differs according to customer class.

1) **Residential Customers:** under the standard rate schedule, residential customers receive service under a fully bundled energy rate for the recovery of all rate components. The rate structure is tiered (currently 2 tiers) and differs by season.

2) **Small Commercial Customers:** (i.e., commercial customers with a demand less than 20 kW) under the standard rate schedule, small commercial customers

receive service under a partially unbundled rate structure that has a below-cost monthly service fee ($/month) which varies by the customer's demand for partial recovery of customer-related distribution costs, while all remaining costs are recovered through energy rates which include commodity rates that differ by season and time-of-use ("TOU") period.

3) **Medium/Large Commercial &Industrial ("M/L C&I") Customers:** under the standard rate schedule, M/L C&I customers receive service under an unbundled rate structure that has: (1) distribution costs recovered through a monthly service fee and demand charges; (2) transmission costs recovered through demand charges; (3) commodity costs recovered through a peak demand charge and TOU energy rates; and (4) all other costs, such as public purpose program costs, recovered through energy rates.

4) **Agricultural Customers**: under their standard rate schedule receive service on a rate that varies depending on size, with small agricultural customers seeing a rate structure similar to SDG&E's Small Commercial customers and medium and large agricultural customers seeing a rate structure that includes demand charges as well as an optional rate that has an unbundled rate structure much like M/L C&I customers.

While the costs of utility services are incurred in the same manner for all customer classes, there is little consistency in how costs are recovered from each customer class, with the rate structure for some customer classes recovering costs in a manner that does not reflect cost-causation. This is particularly true with residential rates. In order to be truly cost-based, an electric rate would have to reflect the following structure:

- **Customer Costs**: These costs are independent of a customer's energy use and are required for each interconnected customer whether or not the customer uses electricity; therefore, customer costs should be recovered in a fixed or monthly charge ($/month).
- **Energy Costs**: These costs are incurred on a variable basis (based on energy usage) with costs dependent on the time of delivery and as such should be recovered in an energy rate ($/kWh) that is variable by time period.
- **Capacity-related Costs**: These costs include Generation Capacity costs, Distribution Demand costs and Transmission costs.
    - **Generation Capacity Costs** – These costs are not incurred on the basis of energy usage, but rather on the basis of meeting net peak capacity needs of the system; therefore, system capacity costs should be recovered in a demand charge consistent with the time period in which those costs occur, which is demand at the time of net system peak when additional capacity ($/peak-kW) may be required.
    - **Distribution Demand Costs** – These costs are incurred independent of a customer's energy usage to reliably meet the local capacity needs of the combined maximum demand of customers served off of a given circuit and as such are more appropriately recovered through a demand charge based on customer's maximum demand, such as a non-coincident demand charge ($/NCD-kW), rather than customer demand at time of system peak.
    - **Transmission Costs** – These capacity costs are incurred to meet reliability requirements, which also include (1) the need to address contingency

conditions (e.g., the forced outage of one or more transmission line that can occur at any time), (2) policy obligations (such as delivering and integrating renewable resources to meet Renewable Portfolio Standard ("RPS") requirements), (3) economics (where the economic benefits to consumers from reducing Local Capacity Requirements ("LCRs") or minimizing congestion-related costs offset the cost of the transmission upgrade) and (4) maintenance (such as aging infrastructure replacement and where new transmission is needed to allow other transmission facilities to be removed from service for maintenance without interruption of customer load).

B. Rate Design Proposals

SDG&E proposes the introduction of three new rates to support its TE projects:

- **Commercial GIR**: applicable to participants on SDG&E's proposed Fleet Delivery Services project;
- **Residential GIR**: applicable to participants on SDG&E's proposed Residential Charging Program; and
- **Public Charging GIR**: applicable to participants on SDG&E's proposed Electrify Local Highways and Green Taxi/Shuttle/Rideshare projects.

1. Cost Basis for Grid Integration Rate Structure

Rate design that provides accurate price signals is one in which costs are recovered from customers on the same basis on which they are incurred. As described above, a typical electric cost-based rate would have the following structure:

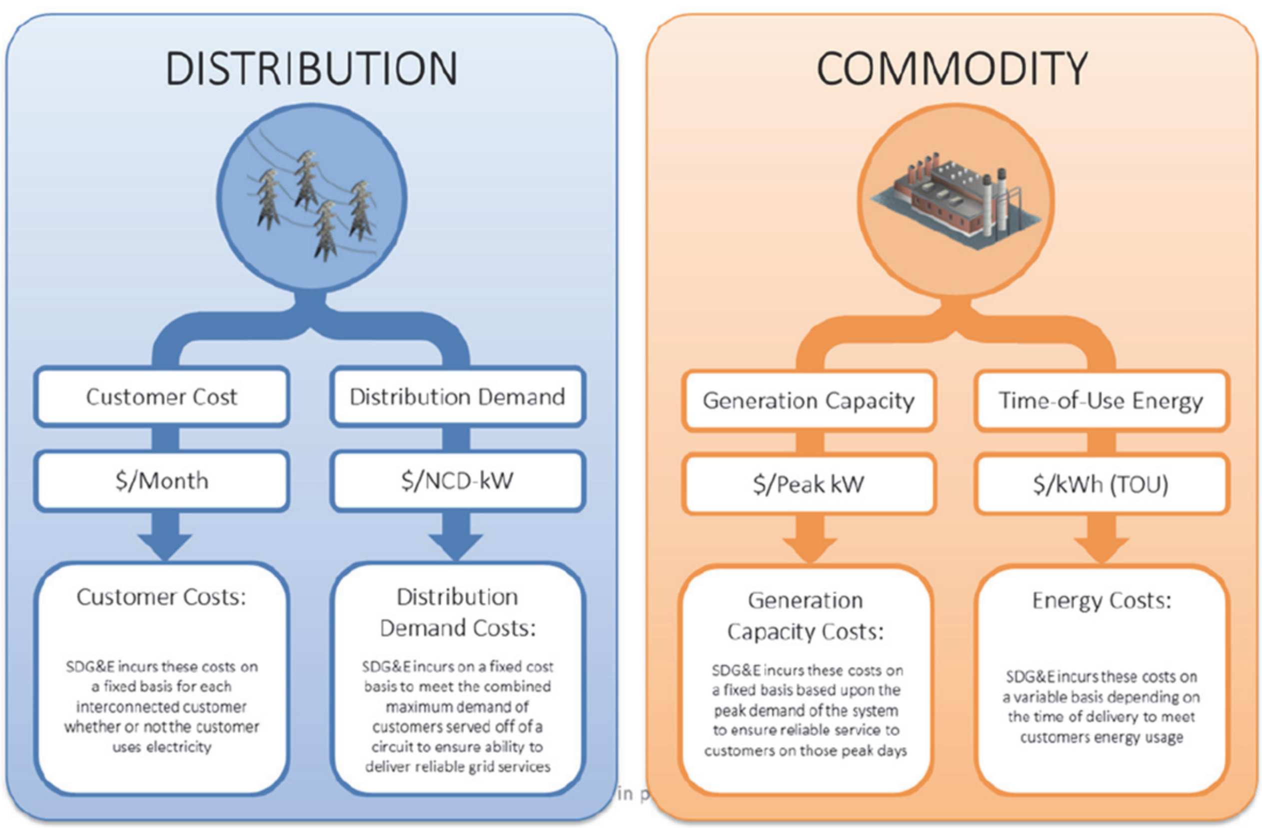
- **Fixed Charge** for the recovery of Customer Costs – SDG&E incurs these costs on a fixed basis for each interconnected customer whether or not the customer uses electricity and therefore should be recovered in a fixed or monthly charge ($/month).
- **Peak Demand Charge** for the recovery of System Capacity Costs – SDG&E incurs these costs independent of energy usage, and instead incurs them on the basis of meeting peak capacity needs of the system and therefore should be recovered in a peak demand charge, that is demand at time of system peak, ($/peak-kW).
- **Non-coincident Demand ("NCD") Charge** for the recovery of Local Capacity Costs – SDG&E incurs these costs independent of energy usage, and instead incurs them on the basis of local capacity needs to meet the combined maximum demand of customers served off of a circuit and therefore should be recovered in a NCD charge ($/NCD-kW).
- **Energy Charge** for the recovery of Energy Costs – SDG&E incurs these on a variable basis (based on energy usage) and the cost depends on the time of delivery. Therefore, these costs should be recovered in an energy charge ($/kWh) that varies by time period.

SDG&E's rates consist of the following components: (1) Transmission; (2) Distribution; (3) Public Purpose Program ("PPP"); (4) Nuclear Decommissioning ("ND"); (5) Competition Transition Charge ("CTC"); (6) Local Generation Charge ("LGC"); (7) Reliability Services ("RS"); (8) the Total Rate Adjustment Component ("TRAC"); (9) Department of Water

Resources Bond Charge ("DWR-BC"); and, (10) Commodity.[15] In addition, rates also include Greenhouse Gas costs as well as Greenhouse Gas allowance revenues. A more detailed discussion of the Distribution and Commodity components of SDG&E's proposed GIR rates are presented below. SDG&E's proposed GIR rates will recover all other components[16] in a manner consistent with the standard rate for the class, with the exception of TRAC for the Residential GIR and Federal Energy Regulatory Commission ("FERC")-jurisdictional Transmission and RS rates for Commercial and Public Charging GIR which are discussed in more detail below.

Diagram 5-1 summarizes the cost-based structure for Distribution and Commodity services.

Diagram 5-1 – Cost-Based Rate Design Structure



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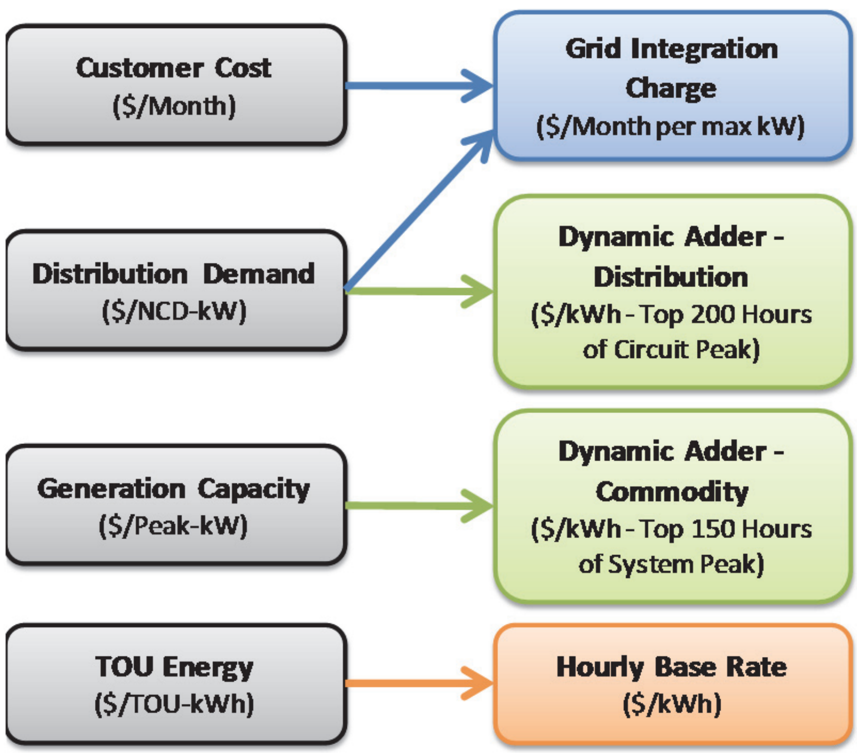
[15] Includes Department of Water Resources Credit.

[16] Transmission, PPP, ND, CTC, LGC, RS, TRAC, and DWR-BC.

A rate design that truly reflects cost-causation requires that all the above components are appropriately set to recover the correct costs. The elimination or reduction of one component (i.e., demand charge or fixed charge), results in another component (i.e., energy rates) being over-inflated and therefore no longer accurately reflecting the costs in the same manner in which they are incurred.

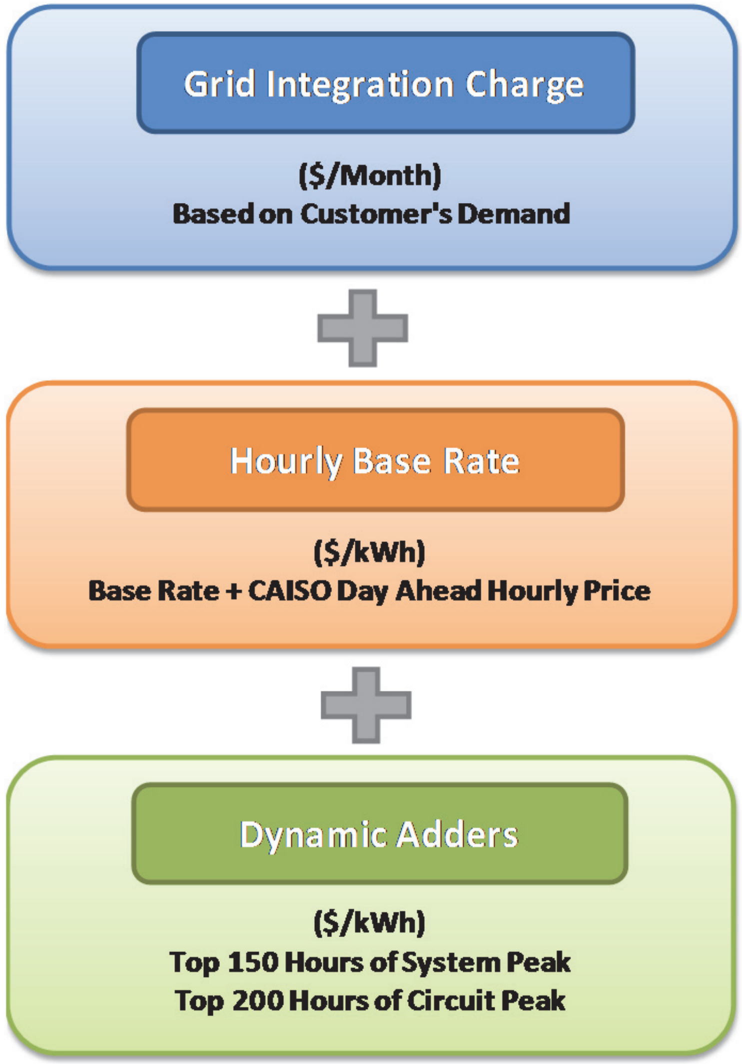
To ensure charging under SDG&E's TE proposals occurs in a grid integrated manner, SDG&E proposes that participants be required to take service on alternative rate structures based on cost-causation principles. The mapping of the components of a cost-based rate to the GIR components is presented below in Diagram 5-2 below.

Diagram 5-2: Cost Basis for Grid Integration Rate



SDG&E's proposed GIRs consist of three components: (1) Grid Integration Charge, (2) Hourly Base Rate, and (3) Dynamic Adders. These are presented in Diagram 5-3 and described in more detail below.

Diagram 5-3: Grid Integration Rate Structure



- **Grid Integration Charge** for the recovery of customer costs and the majority (80%) of distribution-demand costs. The GIC is a fixed monthly charge that is based on a customer's maximum annual demand. The GIC would include an exemption for demand that occurs during the super-off peak period.
- **Hourly Base Rate** for the recovery of all other utility costs
  - The "base" component for the recovery of all other rate components including FERC-jurisdictional rates which include Transmission and RS,

PPP, ND, CTC, LGC, DWR-BC, and remaining commodity costs not addressed below.[17] This hourly base component is based on the class average rates of each respective class of customer; and

    - The California Independent System Operator ("CAISO") day-ahead hourly price.[18]

- **Dynamic Adders** for the recovery of portion of generation and distribution capacity costs:
    - A critical peak pricing signal (Commodity Critical Peak Pricing Hourly Adder, or "C-CPP Hourly Adder"), applied to the top 150 system hours and provided to customers on a day-ahead basis for the recovery of 50% of generation capacity related costs; and
    - A circuit-level critical peak pricing signal (Distribution Critical Peak Pricing Hourly Adder, or "D-CPP Hourly Adder"), applied to the top 200 circuit hours and provided to customers on a day-ahead basis for the recovery of 20% of distribution demand-related costs.

The components of the GIR design proposal described above are modified to fit the specific context of each type of customer for the three GIR and are described in more detail below.

2. Commodity Grid Integration Rate Design

Commodity costs consist of the cost of providing energy services, including the cost of energy, capacity/resource adequacy, and regulatory compliance, and as such, a cost-based rate structure for the recovery of commodity costs would consist of: (1) **energy charges** ($/kWh)

[17] TRAC is applicable to residential customers and would be applicable to the Residential GIR and is discussed in more detail below.
[18] Based on SDG&E's Default Load Aggregation Point day-ahead price.

variable by TOU period and season for the recovery of commodity energy cost; and (2) **peak demand charges** ($/kW) or **Critical Peak Pricing (CPP) Adder** ($/kWh) for the recovery of generation capacity costs.

Under a TOU rate, cost-based TOU differentials result from the average price for marginal energy in the period and the occurrence of generation capacity need in the period with the on-peak period defining the high-cost hours for commodity services. Under SDG&E's current standard TOU structure, SDG&E's on-peak period is a 7-hour period during the summer that occurs 5 days a week for 6 months out of the year. During the winter, the on-peak period is currently a 3-hour period. This results in a total of approximately 1,300 high-cost hours out of 8,760 hours in a year, or approximately 15%.[19]

A CPP rate is a commodity rate structure that includes a higher energy price ($/kWh) applied to peak periods on critical system event days that are called on a day-ahead basis. The CPP rate is designed to recover the costs of system capacity during event days, up to 18 days per year with an assumed 9 days per year, called on a day-ahead basis rate rather than through a peak demand charge every month of the year in order to solicit demand response. Given that system capacity costs are driven by anticipated growth in system peak load, CPP rates are based on preset triggers to call events on a day-ahead basis that would apply a premium price (i.e., CPP Adder to the Otherwise Applicable Tariff ("OAT") energy price) during a pre-defined event period. On event days, the CPP Adder is applied to the pre-defined 7-hour event period of 11 a.m. to 6 p.m., resulting in total annual CPP hours of 0 to 126 hours with rate design based on an average of 63 hours.

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[19] 1,300 hours = 7 hours x 5 days/week x ½ (52 weeks) + 3 hours x 5 days/week x ½ (52 weeks). This estimate excludes holidays.

SDG&E's Commodity GIR will consist of the following:

- A **C-CPP Hourly Adder** applied to the top 150 system peak hours on a day-ahead basis for the recovery of 50% of generation capacity costs; and
- An **hourly commodity base rate**, which includes the CAISO day-ahead hourly price for the recovery of energy costs and remaining commodity costs through the base rate.

The Commodity CPP Adder provides an alternative to peak demand charges that still provide incentives for customers to avoid adding to system load which may delay the need for new capacity investments. Customers will be notified on a day-ahead basis when forecasted load exceeds an established threshold with the threshold calculated based on the top 150 system hours from the previous year, which represents approximately 1.71% of annual hours.[20] By moving from a TOU rate structure to an hourly dynamic rate structure, the proposed TE commodity rate allows SDG&E to focus on a small number of truly high cost hours, the 150 system peak hours, while still reflecting the cost basis of commodity services.

3. Distribution Grid Integration Rate Design

The cost-causation behind distribution costs differ from system and commodity costs in that the cost drivers focus more on localized demand drivers. This is because the distribution system is built to meet local, as opposed to system, demand. A cost-based rate structure for the recovery of distribution costs would include (i) a **Monthly Fixed Charge** for the recovery of customer-related costs; and (ii) a **NCD Charge** for the recovery of distribution demand related costs.

Customer-related costs include the costs of ensuring that customers are ready to receive services from the utility before they even begin to use electricity, also described as "curb to

[20] Top system hours (150) over hours in a year (8760) = 1.71% of annual hours.

meter" services. These costs are incurred independent of the amount of energy that a customer uses, and are incurred on a per customer basis, and therefore should be collected on a $/month basis to reflect cost-causation. These costs include:

1) The cost of the meter, which provides the ability to measure customer's energy and load;

2) The cost of the service lines, which connect individual customers to their service transformer;

3) The cost of the transformer, which step down voltage to levels that are usable and more safe; and

4) The cost of customer services, which represents costs for such activities as customer service field, advanced metering, billing, credit and collections, branch office, customer contact center, residential customer services, commercial and industrial services, communications, and customer programs.

Distribution demand costs consist of the costs of the grid that is needed to deliver electric services to the customer. These costs ensure ability to deliver energy services, and as such are impacted by customer load and customer generation and therefore, should be recovered on a $/NCD-kW basis to reflect cost-causation. Distribution demand costs include the following:

1) Feeders and Local Distribution: the costs associated with the primary distribution system and consist of switches, conductors, capacitors, line regulators, insulators, poles, vaults, conduit, fuses etc.

2) Substation: the costs associated with the point of conversion from transmission to distribution voltages occurs and consists of transformers, circuit breakers, switches, insulators, bus work, control houses, system protection etc.

SDG&E's Distribution GIR will consist of the following:

- A **GIC** monthly fixed charge for the recovery of customer costs and the majority (80%) of distribution demand costs that is based on customer's maximum annual demand.[21] The GIC would include an exemption for demand that occurs during the super-off peak.
- A **D-CPP Hourly Adder** applied to the top 200 circuit peak hours on a day-ahead basis for the recovery of 20% of distribution demand costs.

All customers require distribution resources in order to receive energy services. SDG&E's proposed distribution rate structure for its GIR is intended to ensure that participants on the GIR rates will continue to contribute towards their fair share of use of distribution resources, through the GIC, and receive a price signal to incentivize grid integrated behavior, through the D-CPP Adder.

To ensure GIR customers pay for their fair share of the distribution system, SDG&E proposes a GIC for the recovery of all customer-related distribution costs and 80% of distribution demand-related costs. Rather than a monthly fixed charge and a NCD for the recovery of distribution costs which consist of customer costs and distribution demand-related costs, SDG&E proposes a single monthly service fee that varies depending on customer size (maximum annual demand) for the recovery of customer costs and the majority of distribution demand costs. While such a charge does not fully reflect the costs associated with all of a customer's non-coincident demand, it does provide some reflection of the difference in Distribution Demand costs resulting from differences in customer size while providing for greater bill stability as customers, especially residential customers, become accustomed to the concept of demand. To further

[21] The Maximum Annual Demand shall be the highest Maximum Monthly Demand for the current and prior eleven months.

facilitate grid integrated EV charging, SDG&E proposes a super off-peak exemption for the GIC. This exemption would result in demand that occurs during the super off-peak period[22] from being excluded from the determination of maximum demand for the application of the GIC.

In addition, SDG&E proposes a transitional direct and transparent incentive in the near term is appropriate in order to support the State's TE goals as well as encourage the election of the GIR rates more broadly ensure. The direct and transparent incentive in the form of a monthly payment ($/month) reduces the GIC for a period of 5 years while it transitions to cost-based levels. When incentives or subsidies have been deemed necessary to further public policy objectives, it is only when they are applied separately (i.e., outside of rate design) and can be transparently identified, that cost-causation principles can still be maintained.

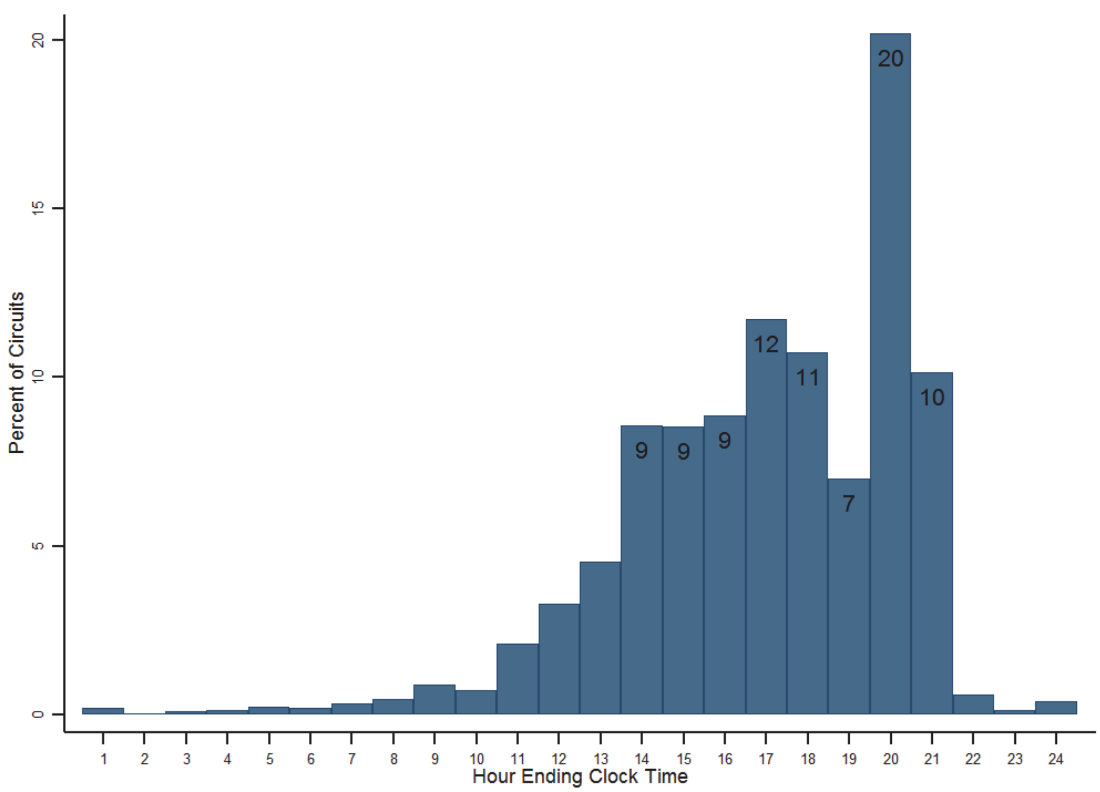
Building upon the foundation of accurate price signals, subsidies that advance state policy goals should be transparently identified in utility bills, separate from the charges for services provided to the customer. Given that these incentives are intended to facilitate TE consistent with the direction provided in SB 350,[23] SDG&E proposes that the costs of these incentives be recovered from all customers.

As noted above, the distribution system is built to meet local, as opposed to system, demand. In order to provide reliable service to a range of distribution circuits, each of which has different levels of peak demand, the distribution system is designed to have adequate capacity to serve the combined peak demand of all customers served off of a distribution circuit, without regard to when that demand occurs (non-coincident peak). The distribution costs utilities incur to provide service to customers is therefore best measured on the basis of a customer's individual maximum demand, distinct from demand at time of peak system capacity need. As seen in Chart

[22] Defined as midnight to 6 a.m. on weekdays and midnight to 2 p.m. on weekends and holidays.
[23] ACR at 4-6.

5-2, distribution circuits peak over a wide range of times that do not necessarily coincide with times of system peak capacity need. This has traditionally translated into a NCD charge based on a customer's maximum demand at any time, as contrasted with a peak demand charge that measures a customer's demand during the system peak capacity need period.

Chart 5-2: Distribution of 2014-2016 SDG&E Circuit Peaks by Hour Ending



The concept of peak load driving incremental costs is true whether that load is system load or local distribution load with the difference being the question of system or circuit peak. The ability to forecast load at the circuit level allows for the ability to break from traditional rate design tools for addressing concerns regarding local capacity at the circuit level given the diversity of circuits that make up the distribution system and to explore alternative rate design approaches to address the same issues.

In addition to the GIC to ensure that all customers pay for their fair share of the use of distribution grid service, SDG&E proposes that a portion of distribution demand costs (20%) be recovered through a CPP Adder applied to the top 200 hours of circuit peak to encourage grid integrated behavior. This adder would be the same value for all circuits but applied to different hours based on the top 200 hours for the specific circuit.

Similar to the C-CPP Hourly Adder applied to the top 150 system peak hours, the D-CPP Hourly Adder will be added to the top 200 hours on a day-ahead basis when the forecasted load exceeds a threshold level based on historic load. The forecast model is based upon historical hourly load at the circuit level with explanatory variables based on the local weather, and calendar-based variables (weekends, holidays, day of week, month, etc.). Historic circuit load will be used to determine the threshold amount for forecasting the top 200 circuit peak hours. When the forecast identifies an hour exceeding the prior year's top 200-hour threshold, a D-CPP Hourly Adder will be applied and presented to the customer on a day-ahead basis. Year-to-year differences in load can result in actual circuit peak hours that differ from the forecasted top 200 hours.

SDG&E proposes to collect 20% of the distribution demand costs through the D-CPP Hourly Adder and the remainder through the GIC. The D-CPP Adder component of the GIR is designed to provide an incentive for grid integrated behavior, with the majority of distribution costs recovered through the GIC in order to ensure that TE participants continue to pay for their fair share of costs for the use of the distribution system. At this time SDG&E includes 20% of the distribution demand cost for recovery in the D-CPP with the remainder of distribution demand costs to be recovered through the GIC.

4. Grid Integration Rates

SDG&E proposes the introduction of three new rates to support its TE proposals: (1) Commercial GIR, (2) Residential GIR, and (3) Public Charging GIR. The components of the GIR design proposal described above are modified to fit the specific context of each type of customer under the three GIR described in more detail below.

a. Commercial GIR

To support SDG&E's proposed Fleet Delivery Services Project, SDG&E proposes a Commercial GIR based on the M/L C&I class rates. As noted above, the recovery of all rate components with the exception of Distribution, Commodity and FERC-jurisdictional rates (Transmission and RS) will be consistent with SDG&E's standard M/L C&I rate schedule, Schedule AL-TOU. As noted above, cost-based recovery of Transmission costs would be recovered through demand charges. Currently for SDG&E's M/L C&I customers, FERC-jurisdictional rates for Transmission and RS are currently recovered through demand changes. However, to support the transition of TE participants to GIR, at this time SDG&E proposes to apply the FERC VGI pilot rates to the Commercial GIR for the recovery of Transmission and RS costs. SDG&E will revisit this issue in the future. Diagram 5-4 below provides the proposed illustrative Commercial GIR.

Diagram 5-4: Commercial GIR[24]

Grid Integration Charge	
(kW)	**($/Mo.)**
0-20	522.37
20-50	882.55
50-100	1,458.85
100-200	2,539.41
200-300	3,980.15
300-400	5,420.90
400-500	6,861.64
500+	up to 160K

+

Hourly Base Rate	
	(¢/kWh)
Base Rate	9.690
+	
CAISO Day Ahead Hourly Price	

+

Dynamic Adders	
	(¢/kWh)
System Top 150 Hours	50.535
Circuit Top 200 Hours	18.656

The GIC for the Commercial GIR will be applied to a customer's maximum annual demand[25] with an exemption for demand that occurs during the super-off peak period.

In addition, SDG&E proposes to include a fixed monthly incentive which in Year 1 provides a 25% reduction in the GIC and will be phased out by Year 5, at which time the GIC

[24] Rates presented are based on secondary service.
[25] This is defined in SDG&E's Electric Rule 1, Sheet 6, as:

> The Maximum Annual Demand shall be the highest Maximum Monthly Demand for the current and prior eleven months. If during the prior eleven months there is a month(s) when there was not a demand registering device in place then no Maximum Demand shall be assumed. http://regarchive.sdge.com/tm2/pdf/ELEC_ELEC-RULES_ERULE1.pdf.

will have reached cost-based levels. SDG&E's proposed incentive for the Commercial GIR is presented in Table 5-2 below.

Table 5-2: Commercial Grid Integration Charge

Commercial Grid Integration Charge						
		Year 1	Year 2	Year 3	Year 4	Year 5
Demand	w/o Incentive	w/ Incentive	w/ Incentive	w/ Incentive	w/ Incentive	w/ Incentive
(kW)	($/Mo.)	($/Mo.)	($/Mo.)	($/Mo.)	($/Mo.)	($/Mo.)
0-20	522.37	391.78	424.42	457.07	489.72	522.37
20-50	882.55	661.92	717.08	772.23	827.39	882.55
50-100	1,458.85	1,094.14	1,185.32	1,276.50	1,367.67	1,458.85
100-200	2,539.41	1,904.56	2,063.27	2,221.98	2,380.70	2,539.41
200-300	3,980.15	2,985.12	3,233.88	3,482.64	3,731.39	3,980.15
300-400	5,420.90	4,065.67	4,404.48	4,743.29	5,082.09	5,420.90
400-500	6,861.64	5,146.23	5,575.09	6,003.94	6,432.79	6,861.64
500+	up to 160K					up to 160K

b. Residential GIR

To support SDG&E's proposed Residential Charging Program, SDG&E proposes a Residential GIR based on the residential class rates. As noted above, the recovery of all rate components with the exception of Distribution, Commodity and TRAC will be consistent with SDG&E's standard Residential rate schedule, Schedule DR. Schedule DR is a tiered rate schedule in which TRAC subsidies and charges are designed to maintain total Residential rates consistent with D.15-07-001. The Residential GIR is an untiered rate and as such the TRAC rate component will be based on the class average TRAC rate. Diagram 5-5 below provides the proposed illustrative Residential GIR.

Diagram 5-5: Residential GIR

Grid Integration Charge	
(kW)	**($/Mo.)**
0-3	29.49
3-6	48.05
6-9	66.61
9+	94.45

+

Hourly Base Rate	
	(¢/kWh)
Super Off Peak	7.013
Other Times	13.543
+	
CAISO Day Ahead Hourly Price	

+

Dynamic Adders	
	(¢/kWh)
System Top 150 Hours	69.348
Circuit Top 200 Hours	18.780

For the Residential GIR, the GIC will be applied to maximum annual demand, but based on average hourly demand rather than demand based on 15-minute interval data. This will include an exemption for demand that occurs during the super-off peak period.

In addition, SDG&E proposes to include a fixed monthly incentive which in Year 1 provides a reduction in the GIC such that TE participants with demand 0 to 3 kW receive a GIC of $10 in Year 1 and will be phased out by Year 5, at which time the GIC will have reached cost-based levels. SDG&E's proposed incentive for the Residential GIR is presented in Table 5-3 below.

Table 5-3: Residential Grid Integration Charge

Residential Grid Integration Charge						
Demand	w/o Incentive	Year 1 w/ Incentive	Year 2 w/ Incentive	Year 3 w/ Incentive	Year 4 w/ Incentive	Year 5 w/ Incentive
(kW)	($/Mo.)	($/Mo.)	($/Mo.)	($/Mo.)	($/Mo.)	($/Mo.)
0-3	29.49	10.00	14.87	19.74	24.62	29.49
3-6	48.05	16.29	24.23	32.17	40.11	48.05
6-9	66.61	22.59	33.59	44.60	55.60	66.61
9+	94.45	32.03	47.63	63.24	78.84	94.45

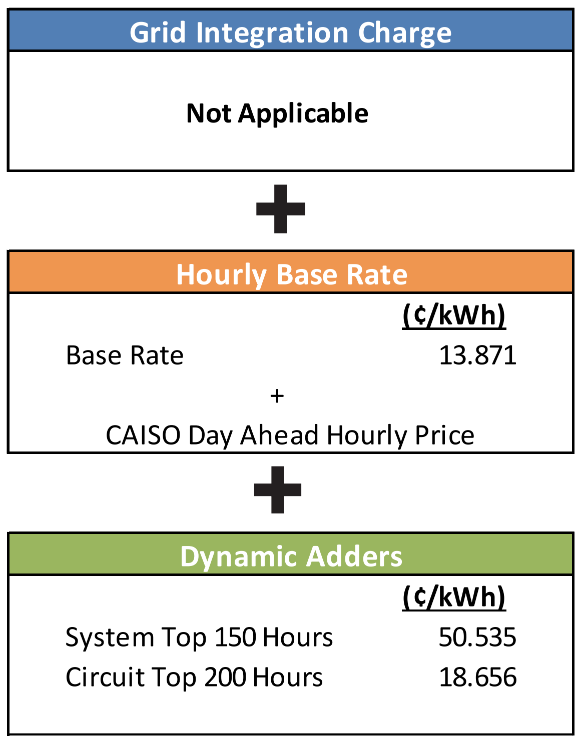
c. Public Charging GIR

To support SDG&E's proposed Electrify Local Highways and Green Taxi/Shuttle/Rideshare projects, SDG&E proposes a Public Charging GIR based on the M/L C&I class rates. Given that the load for these charging facilities associated with SDG&E's proposed Electrify Local Highways and Green Taxi/Shuttle/Rideshare projects is expected to exceed 20kW,[26] the Public Charging GIR to support these projects is based on SDG&E's M/L C&I class rates consistent with the definition of that class. As noted above, the recovery of all rate components with the exception of Distribution, Commodity and FERC-jurisdictional rates (Transmission and RS) will be consistent with SDG&E's standard M/L C&I rate schedule, Schedule AL-TOU. Consistent with proposed Commercial GIR, SDG&E proposes similar treatment for the recovery of FERC-jurisdictional rates for Transmission and RS costs. Specifically, SDG&E proposes at this time to apply the FERC VGI pilot rates to the Public Charging GIR for the recovery of Transmission and RS costs. SDG&E will revisit this issue in the future. SDG&E's proposed Electrify Local Highways and Green Taxi/Shuttle/Rideshare projects propose the addition of public charging infrastructure designed for use by multiple customers and Green Taxi/Shuttle/Rideshare drivers to charge their vehicles at these locations. Therefore, there is no single dedicated customer associated with these sites. As such, the Public

[26] *See* the direct testimony of Randy Schimka (Chapter 3) for further details.

Charging GIR will not include a GIC for the recovery of customer-related distribution costs and distribution demand-related costs. Instead, SDG&E proposes to recover distribution-related costs not recovered in the D-CPP adder through the base energy rates for the Public Charging GIR. Diagram 5-6 below provides the proposed illustrative Public Charging GIR.

Diagram 5-6: Public Charging GIR



III. COST RECOVERY

Table 5-4 below presents the illustrative class average electric rate impacts for 2018 through 2021 of the proposed revenue requirements presented in the testimony of SDG&E witness Michael A. Calabrese (Chapter 6). SDG&E proposes to recover ongoing costs associated with its six Priority Review Projects, and its Residential Charging Program proposals as part of its post-2019 General Rate Case ("GRC") Phase 1.

Table 5-4: Class Average Rates Impact

		2018		2019		2020		2021	
	Current 1/1/17	Proposed Rate	% Change from Current	Proposed Rate	% Change from Current	Proposed Rate	% Change from Current	Proposed Rate	% Change from Current
Residential	24.896	24.881	-0.06%	24.876	-0.08%	25.044	0.59%	25.079	0.74%
Small Comm.	23.399	23.384	-0.06%	23.380	-0.08%	23.542	0.61%	23.576	0.76%
Med & Lg C&I	19.374	19.366	-0.04%	19.364	-0.05%	19.457	0.43%	19.477	0.53%
Agriculture	17.389	17.380	-0.05%	17.377	-0.07%	17.482	0.53%	17.504	0.66%
Lighting	19.565	19.556	-0.05%	19.554	-0.06%	19.647	0.42%	19.667	0.52%
System Total	21.783	21.771	-0.06%	21.768	-0.07%	21.896	0.52%	21.923	0.64%

SDG&E proposes to recover the costs of implementing the TE proposals, which consists primarily of costs for such things as charger equipment, transformers, services and meters, as addressed in the testimony of Randy Schimka (Chapters 3 and 4), through distribution rates, consistent with the recovery of similar costs. The first year of proposed revenue requirement impacts are anticipated to have an annual bill impact of approximately -$0.21[27] in 2018 for a typical residential customer using 500 kWh per month in both the Inland and Coastal climate zones, as compared to current rates. On a percentage basis, this equates to an increase of 0.0% for a typical residential customer in both the Inland and Coastal climate zones. The year 2021 proposed revenue requirement impacts are anticipated to have an annual bill impact of approximately $11.25 for a typical residential customer using 500 kWh per month in both the Inland and Coastal climate zones, as compared to current rates. On a percentage basis, this equates to an increase of 0.7% for a typical residential customer in both the Inland and Coastal climate zones.

[27] *See* the direct testimony of Michael A. Calabrese (Chapter 6) for further details regarding the revenue requirements.

IV. SUMMARY AND CONCLUSION

SDG&E recommends that the Commission adopt the three new rate proposals:

1. **Commercial GIR**: applicable to participants on SDG&E's proposed Fleet Delivery Services project;
2. **Residential GIR**: applicable to participants on SDG&E's proposed Residential Charging Program; and
3. **Public Charging GIR**: applicable to participants on SDG&E's proposed Electrify Local Highways and Green Taxi/Shuttle/Rideshare projects.

In addition, SDG&E recommends that the GIR be made optionally available to all customers.

This concludes my prepared direct testimony.

V. STATEMENT OF QUALIFICATIONS

My name is Cynthia Fang and my business address is 8330 Century Park Court, San Diego, California 92123. I am the Rate Strategy and Analysis Manager in the Customer Pricing Department of SDG&E. My primary responsibilities include the development of cost-of-service studies, determination of revenue allocation and electric rate design methods, analysis of ratemaking theories, preparation of various regulatory filings, and overseeing the electric load analysis, electric demand forecasting and electric rate strategy for SDG&E. I began work at SDG&E in May 2006 as a Regulatory Economic Advisor and have held positions of increasing responsibility in the Electric Rate Design group. Prior to joining SDG&E, I was employed by the Minnesota Department of Commerce, Energy Division, as a Public Utilities Rates Analyst from 2003 through May 2006.

In 1993, I graduated from the University of California at Berkeley with a Bachelor of Science in Political Economics of Natural Resources. I also attended the University of Minnesota where I completed all coursework required for a Ph.D. in Applied Economics.

I have previously submitted testimony before the Commission and the FERC regarding SDG&E's electric rate design and other regulatory proceedings. In addition, I have previously submitted testimony and testified before the Minnesota Public Utilities Commission on numerous rate and policy issues applicable to electric and natural gas utilities.