Application of SAN DIEGO GAS & ELECTRIC COMPANY (U 902 E) For Authority To Update Marginal Costs, Cost Allocation, And Electric Rate Design.

Application: 15-04-012
Exhibit No.: SDG&E-01

PREPARED DIRECT TESTIMONY OF

CYNTHIA FANG

ON BEHALF OF SAN DIEGO GAS & ELECTRIC COMPANY IN SUPPORT OF

SECOND AMENDED APPLICATION

CHAPTER 1

BEFORE THE PUBLIC UTILITIES COMMISSION

OF THE STATE OF CALIFORNIA

February 9, 2016

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CHAPTER 1

I. INTRODUCTION

This testimony provides the policy support for the electric revenue allocation and rate design proposals associated with the implementation of San Diego Gas & Electric Company's ("SDG&E") test year ("TY") 2016 General Rate Case ("GRC") Phase 1 electric revenue requirement,[1] and introduces the witnesses supporting the proposals. With the proposals in this proceeding, SDG&E continues to promote the movement towards accurate price signals and transparent incentives in the development and design of retail rates for its customers. SDG&E firmly believes that only with a rate design that consists of accurate price signals and transparent incentives can a sustainable path be created for the achievement of the State's energy policy goals, that is growth in renewables and distributed energy resources ("DER") in a manner that minimizes cost shift to non-participating customers as well as providing more equitable treatment for all customers and all technologies. Provision of accurate price signals and transparent incentives is the best way to reconcile the many policy principals and objectives set forth by the California Public Utilities Commission ("Commission"), including the Rate Design

[1] Application ("A.") 14-11-003.

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Principles set forth in Rulemaking ("R.") 12-06-013 Residential Rate Reform OIR ("RROIR").[2] Recognizing the importance of customer understanding and acceptance, SDG&E has taken a balanced approach in this proceeding by proposing a three-year transition path for the implementation of its various proposals.

II. POLICY OBJECTIVES

California continues to be a leader in shaping national energy policy, in particular with its adoption of a set of comprehensive policies and initiatives aimed at significantly reducing Greenhouse Gases ("GHG"). The achievement of these goals has not been blind to the potential rate and cost shift implications that these programs would have for electric utility customers. For instance, Renewables Portfolio Standards ("RPS") goals of 33% by 2020 include a cost limitation provision "…set at a level that prevents disproportionate rate impacts."[3] Assembly Bill ("AB") 327 requires that Net Energy Metering ("NEM") moves forward in a manner that (i)

[2] Attachment A to November 26, 2012 Scoping Memo and Ruling in 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")*:

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;
2. Rates should be based on marginal cost;
3. Rates should be based on cost-causation principles;
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 stability, simplicity and customer choice;
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; and
10. Transitions to the 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.

[3] California Public Utilities Code Section 399.15 (d).

is “based on the costs and benefits of the renewable electrical generation facility;”[4] (ii) ensures “total benefits of the standard contract or tariff to all customers and the electrical system are approximately equal to total costs;”[5] and (iii) ensures “sustainable growth.”[6]

Achieving these goals in a sustainable manner will require rates that reflect accurate prices and transparent incentives. A recent Rocky Mountain Institute (“RMI”) report, *Net Energy Metering, Zero Net Energy and the Distributed Energy Resource Future* (“Report”), observes that “California’s electricity system stands at the forefront of changes that are transforming the electricity industry globally. These changes include integration of increasing amounts of renewable electricity supplies, creation and execution of programs to improve customers’ energy efficiency, and implementation of new smart grid technologies for better coordination, control, and communication in managing the electricity grid.”[7] Indeed, there is consensus that the utility power grid “is evolving from a one-way centralized power delivery system to a more open, flexible, multipoint digitized network (or platform) with a collection of technologies and assets, some controlled by the utility and some not.”[8] This concept of the grid as a “plug-and-play platform” for integration of new services and technologies is relatively recent, but it is undeniably the shape of things to come. The Report points out that the transformed role of the consumer – from passive recipient of service to an active participant in an interconnected grid – brings a new dimension to the electric utility business environment. It notes that “the electricity system of the future is likely to encompass an increasingly diverse and

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[4] Public Utilities Code§ 2827.1(b)(3).
[5] Public Utilities Code § 2827.1(b)(4).
[6] Public Utilities Code § 2827.1(b)(1).
[7] Rocky Mountain Institute (“RMI”), Net Energy Metering, Net Zero Energy and the Distributed Energy Resource Future, p. 2. Available at: http://www.rmi.org/rmi_pge_adapting_utility_business_models.
[8] The Edison Foundation Institute for Electric Innovation, Innovations Across the Grid, Vol.2, December, 2014, p. 3. Available at: http://www.edisonfoundation.net/iei/Documents/IEI_InnovationsGrid_volII_final_LowRes.pdf

interconnected set of actors, with widely varying assets, behaviors, and motivations."[9] The Report observes further that "the effectiveness of a utility's role in conducting the orchestra of distributed energy resources that interact with its system will be a critical factor in achieving favorable outcomes for all stakeholders. *And the long-term health and stability of the electricity grid will be essential to making such a system work*. (emphasis added)"[10] In other words, significant investment in upgrading the grid will be necessary in order to successfully manage the evolution of the electric grid to a "grid of things" that seamlessly integrates new energy resources and technologies.

A. SDG&E's Rate Design Policy Objectives

SDG&E has set forth its rate design principles in various proceedings. In RROIR, the Commission adopted the following ten Rate Design Principles ("RDP") for rate design. While the RROIR was limited to residential rate design, SDG&E believes these principles should guide the rate design for all customers. Table 1 below presents the RDPs in the four categories consistent with D.15-07-001: cost of service, affordable electricity, conservation and customer acceptance.

Table 1: Rate Design Principles

Cost Of Service RDP	Affordable Electricity RDP	Conservation RDP	Customer Acceptance RDP
(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	(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

[9] RMI Report, supra, note 27, p. 2.
[10] Id.

explicit and transparent; (9) Rates should encourage economically efficient decision-making.			appropriately considers the bill impacts associated with such transitions.

While there may appear to be tension between the individual RDP when examined individually, as stated in the RROIR, SDG&E believes that all of the ten RDP can be met with a rate design that meets the following guidance:

- Utilities charge for the services they provide;
- Rates are designed to recover costs on the same basis as they are incurred; and,
- Incentives or subsidies that have been deemed necessary to further public policy objectives are separately and transparently identified.[11]

Only when rate design is such that (1) utilities charge for the services they provide; (2) rates are designed to recover costs on the same basis as they are incurred; and (3) incentives or subsidies that have been deemed necessary to further public policy objectives are separately and transparently identified will the Cost of Service Rate Design Principles (RDP 2, 3, 7, 8, 9) be satisfied. Only through explicit and transparent incentives can we simultaneously encourage conservation and energy efficiency (RDP 4), encourage reductions in both coincident and non-coincident peak demand (RDP 5), and maintain affordability (RDP 1) for all customers. When all customers see the correct price signals to ensure economically-efficient decision making by all (RDP 9), then customers receive bill benefits for behavior that lowers the cost of service for all customers rather than for behavior that increases cost shifts to other customers. As SDG&E put forth in its vision statement for residential rates as part of the RROIR:

[11] R.12-06-013, Rebuttal Testimony of Caroline A. Winn (Chapter 1), p. CAW-3.

SGD&E will offer simple and fair rate options that empower customers to make efficient energy choices.[12]

This desired result can only occur by partnering outreach and education to ensure that the Customer Acceptance RDPs are satisfied.

SDG&E further explained its guiding principles in the NEM 2.0 Successor Tariff proceeding (R.14-07-002):

1. Fairness: Cost-based/transparent/reduce cross-subsidies.
2. Grid Enhancing: Rate Structure optimizes grid benefits.
3. Choice: Provides customers options.
4. Policy Goals: Aligns with State's goals and supports continued growth of DER adoption.[13]

While RROIR focused on the rate design for residential customers, in NEM 2.0, the emphasis included considerations for sustainable DER growth. However, the rate design needed to meet those objectives follows the same guidance as is needed to meet the policy objectives in RROIR – both require a rate design that reflects accurate prices and, where incentives are needed, they are direct and transparent. Only with a rate design that reflects accurate prices and direct, transparent incentives can there be a path for sustainable growth for all DER technologies in a manner that minimizes cost shifts to non-participating customers. A rate design that reflects accurate prices and transparent incentives is necessary to provide a platform for utility customers to make economically efficient decisions in their investments in energy resources; that is, choices

[12] *Id.* at CAW-4.

[13] SDG&E's NEM Successor Tariff Proposal, p. 12

for investments in energy efficiency ("EE"), demand response ("DR"), and DER, are done so with proper information. (i.e., based on accurate price signals).

SDG&E's rate design proposals in this Application, as described in the testimony of SDG&E witness Christopher Swartz (Chapter 2) and others, promote the following policy goals:

1. **Accurate price signals**: Providing customers with accurate price signals means that utilities charge for the services they provide and rates are designed to cover costs on the same basis as they are incurred. By sending customers clear price signals regarding the cost of electricity and the cost of using the electric grid for the services they receive, SDG&E aims to give customers the best possible opportunity to make wise decisions about their energy use and to mitigate cost shifts between customers. Cost-shifting is exacerbated with incentives that are buried in rates and not transparently identified.

2. **Transparent incentives**: Incentives or subsidies that have been deemed necessary to further public policy objectives are separately and transparently identified. 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 or from the customer.

3. **Customer options**: SDG&E believes that a critical aspect of SDG&E's policy framework is to balance the needs of customers while still providing a cost-based rate structure. SDG&E recognizes the importance of continuing to offer customers new cost-based rate options that best meet their needs.

4. **Transition paths to minimize impacts and inform customers**: SDG&E is committed to proactively providing customers with clear and timely information

to help customers prepare for any rate change including those presented in this Application. SDG&E believes that implementing rate design changes in transitional phases: (i) helps to minimize customer impacts and (ii) provides the best opportunity for customers to progressively become more engaged and informed about the choices that are available to them.

SDG&E's four policy objectives are summarized in the diagram below.

Diagram 1: SDG&E Rate Design Policy Objectives

B. Laying the Foundation for a Rate Design for the Future

Given the future challenges and opportunities faced by California investor-owned-utilities ("IOUs"), some of which are described herein, the importance of establishing the "right" rate design now cannot be overstated.

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There will likely be more change within the electric industry in the next ten years than in the past 100 – California must anticipate this change and implement a well-conceived rate design that furthers rather than impedes advancement. It is critical that as the State moves forward into the next decade, its rate design policies be carefully crafted to maintain the current momentum toward realization of a sustainable energy future that incorporates increasing amounts of DER through reliance on an advanced electric grid, while minimizing cost impacts on utility customers.

SDG&E has fully embraced the State's vision of increased DER integration. For example, as of the end of 2015, SDG&E had approximately 500 MW of customer sited solar and wind generation from nearly 75,000 customers. SDG&E currently has 19,000 electric vehicles within its service territory, and has recently received a final decision in its Vehicle Grid Integration ("VGI") Pilot application, where the role rate design plays in promoting grid integration was recognized.[14] In addition, the procurement plan set forth in D.13-10-040 in Rulemaking 10-12-007 *Order Instituting Rulemaking Pursuant to Assembly Bill 2514 to Consider the Adoption of Procurement Targets for Viable and Cost-Effective Energy Storage Systems* contemplates that SDG&E will have 165MW of energy storage by 2020. Given this rapid progress toward significant increases in DER now and continuing into the future, SDG&E submits that movement toward a more forward-thinking rate design, with more cost-based rates that provide customers with accurate price signals, is critical.

As we evolve from a world where all customers received "full service" from the utility, to one in which there is an abundance of choices available to customers for the various elements of

[14] D.16-01-045, issued January 28, 2016 (Application 14-04-014).

service previously solely provided by the utility (i.e., rooftop solar for a portion of their energy needs, batteries for "banking"), the need for accurate price signals that truly reflect the cost of the variety of services provided is critical. Achieving the State's energy policy goals in a sustainable manner requires growth not be dependent upon flawed rate design which creates cost shifts and results in indirect and at times unintended subsidies.

RMI's report, *Net Energy Metering, Net Zero Energy and the Distributed Energy Resource Future*, identifies the critical role that unbundling of rate design will play in achieving a 21st century utility business model.[15] A rate structure that ensures that the prices customers see accurately reflect the cost of services provided, will "unleash new investments and innovations in DERs," and will help to ensure that deployment of DER resources occurs in a manner that benefits the system as a whole.[16/] Current rate design is only part of the way there. Significant progress has been made in the rate structure for commodity services to better reflect the cost of services provided to customers:

- SDG&E's medium/large commercial and industrial ("M/L C&I") customers are now required to be on a mandatory time-of-use ("TOU") commodity rate with default dynamic pricing;[17]

[15] RMI: Net Energy Metering, Net Zero Energy and the Distributed Energy Resource Future, p. 2. Available at: http://www.rmi.org/rmi_pge_adapting_utility_business_models.

[16/] *See* 2014 RMI study, *Rate Design for the Distribution Edge: Electricity Pricing for a Distributed Resource Future*, p. 10.

[17] D.08-02-034 adopted default dynamic pricing for SDG&E's M/L C&I customers. D.15-08-040 adopted mandatory TOU rates for all M/L C&I, including Schedule AD customers which are the only M/L C&I customers currently not on a TOU rate. Schedule AD customers are scheduled to move to TOU rates by April 2016.

- SDG&E's small commercial customers are now required to be on a mandatory TOU commodity rate with default dynamic pricing;[18]
- SDG&E's agricultural customers are now required to be on a mandatory TOU commodity rate with large customers having dynamic pricing as their default rate and small/medium customers having dynamic pricing as an option;[19]
- SDG&E's residential class is now anticipated to default to a TOU commodity rate in 2019.[20] Currently, SDG&E's residential customers have TOU and dynamic pricing rate options.[21]

Much more remains to be done, however, to ensure accurate, cost-based rates. Included in this proceeding is a proposal to realign TOU periods to ensure that time differentiated price signals are occurring at the right times and sending customers the right "grid aligned" price signals.[22] As discussed below and in the testimony of SDG&E witness Robert Anderson, for example, SDG&E's current TOU periods fail to reflect developments over the past few years – in particular, an SDG&E commodity portfolio that includes substantial solar generation in the local reliability area – as well direction in AB 327 to establish TOU periods that are appropriate

[18] D.12-12-004 adopted mandatory TOU and default dynamic pricing rates for small commercial customers. Small commercial customers are schedules to be transitioned to mandatory TOU and default dynamic rates over the period November 2015 through April 2016.
[19] D.08-02-034 adopted default dynamic pricing for SDG&E's large agricultural customers. D.12-12-004 adopted mandatory TOU for all agricultural customers and optional dynamic pricing rates for small/medium agricultural customers. Agricultural customers are schedules to be transitioned to mandatory TOU rates over the period November 2015 through April 2016.
[20] D.15-07-001 at p. 5 and Ordering Paragraph ("OP") 10.
[21] D.12-12-004 adopted a new TOU rate and optional dynamic pricing rate for residential customers. These rates were implemented on February 1, 2015.
[22] See, CAISO Time of Use Analysis, January 22, 2016 Executive Summary signals.https://www.caiso.com/Documents/Jan22_2016ExplanationofDataAssumptionsandAnalyticalMethods-R1512012.pdf, at p. 3: "…it is prudent to evaluate current TOU rate periods to ensure time differentiated price signals are occurring at the right times and sending consumers the right 'grid aligned."

for at least five years,[23] which means that TOU periods must also reflect future needs. Ensuring correct TOU period definitions will continue to support an evolving electric system and a low GHG energy supply consistent with State goals. Accurately defined TOU periods will provide the right incentives to all customers and technology investments, whether it be investments in EE, DR, DER, or what direction to point their solar panels.

In addition, price signals for distribution services continue to be highly distorted – pricing for distribution services bears little relationship to the costs of the distribution infrastructure or the manner in which those costs are incurred. While distribution costs do not vary due to energy usage (*i.e.*, they are fixed, non-volumetric costs), most customers pay distribution costs on a volumetric basis. Only SDG&E's M/L C&I customers have a rate structure that recovers full distribution costs[24] through a monthly service fee ($/month) and demand charge. Small commercial customers currently only recover a small portion of distribution costs through a monthly service fee. Residential customers continue to have a rate structure that recovers *all* distribution costs through energy charges.

SDG&E has fully deployed Smart Meters and therefore, the technological constraints for cost-based rates no longer exist. Prior to Smart Meter deployment, 15-minute granular energy usage data (interval data) was primarily available to just those customers who exceeded 200kW in demand per month. With Smart Meters, all customers can now easily view their energy usage on-line at a granular level (hourly for residential and 15-minute for small commercial, M/L C&I and agricultural customers). This provides the ability for customers to make informed decisions

[23] AB 372 Sec. 7.745 (c)(3).
[24] With the exception of California Solar Initiative ("CSI"), Self Generation Incentive Program ("SCIP"), and Demand Response ("DR ") program costs, which are included in the distribution rate, but are not incurred on the basis of providing distribution services.

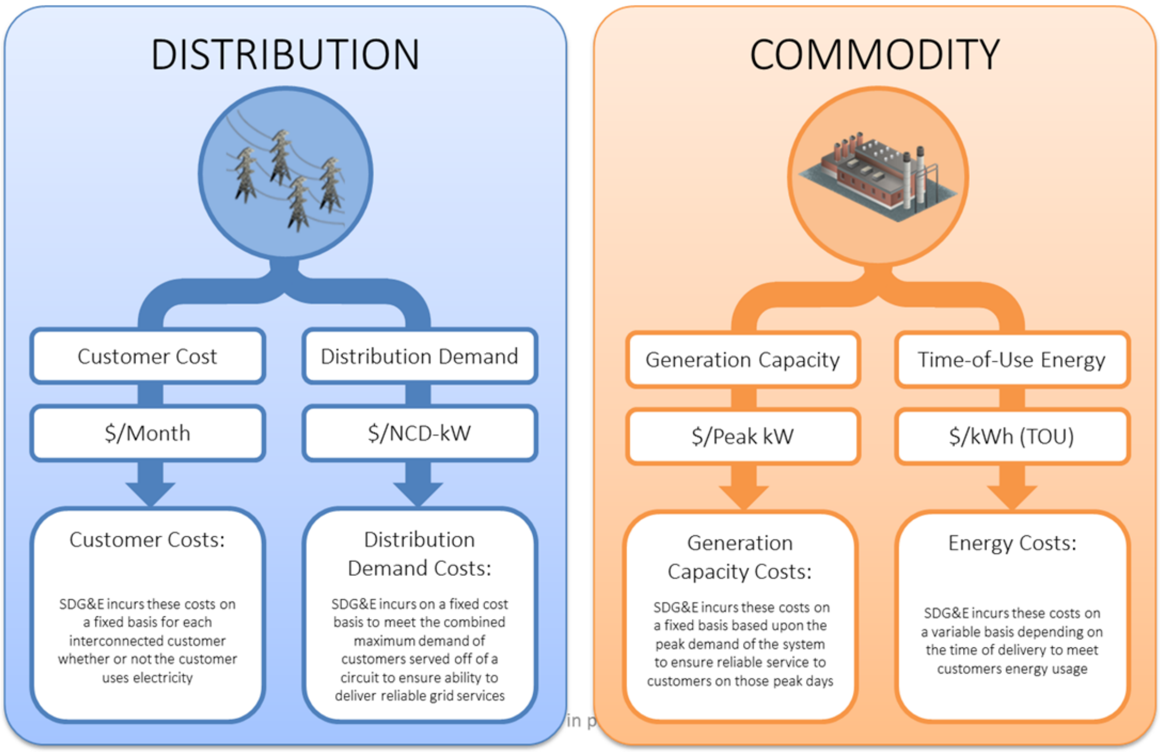
by providing highly detailed information about electricity usage and costs and as such creates the ability to provide customers with more accurate price signals. It is important for the utility to provide accurate price signals to customers with the availability of this usage data to provide customers with the ability to balance their energy usage with the cost of energy services as well as ensure that these infrastructure investments are fully utilized. With a better understanding of energy use and by providing accurate price signals customers can make informed decisions on how to optimize their electricity consumption and demand, and ultimately, reduce their bills.

A fundamental premise of SDG&E's rate design proposals is that rates should be designed to recover costs in the same manner as they are incurred. This objective is fully aligned with the RDPs articulated in R.12-06-013; it is also enabled by technological developments related to deployment of Smart Meters, which eliminate technological constraints for cost-based rates.

Given the level of detail now available through Smart Meters, it is important for the utility to provide accurate price signals to customers to enable them to balance their energy usage with the related costs. With a better understanding of energy use, and with accurate price signals, customers can make informed decisions on how to optimize their electricity consumption and demand, and ultimately, reduce their bills. To that end, SDG&E proposes a rate design for the recovery of distribution and commodity resources.[25] A summary of the optimal cost-based rate design structure being addressed in this proceeding is provided in the diagram below.

[25] SDG&E's services provided to customers consist of distribution, transmission, and commodity resources. SDG&E does not address the rate structure for transmission resources herein because those assets are under the jurisdiction of the Federal Energy Regulatory Commission ("FERC").

Diagram 2



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

1) *Residential*: receive service under a fully bundled energy rate for the recovery of all rate components. The rate structure is tiered (currently 3-tiers) and differs by season.

2) *Small Commercial*: receive service under a partially unbundled rate structure that has a reduced monthly service fee ($/month) for partial recovery of customer-related distribution costs that varies by demand, while all remaining costs are recovered through energy rates with commodity rates that differ by season and time-of-use ("TOU") period.

3) *Medium and Large Commercial and Industrial* ("M/L C&I"): receive service under an unbundled rate structure that has: (1) distribution costs recovered through a monthly

service fee and demand charges, excluding program costs; (2) transmission costs recovered through demand charges including RS;[4] (3) commodity costs recovered through a peak demand charge and TOU energy rates; and (4) all other costs recovered through energy rates.

4) *Agricultural*: receive service under a partially unbundled rate structure that has a reduced monthly service fee ($/month) for partial recovery of customer-related distribution costs that varies by demand, with all remaining costs recovered through energy rates and commodity rates that differ by season and TOU period. Includes optional rate that has an unbundled rate structure much like M/L C&I.

5) *Streetlighting*: billed on a monthly per lamp basis.

Thus, there is little consistency in how costs are recovered from each customer class, notwithstanding the fact that they are incurred in the same manner by each customer class. In addition, costs may not be recovered in a way that reflects the manner in which they were incurred (this is particularly true with residential rates). In order to be truly cost-based, a typical electric rate would have to reflect the following structure:

- Customer Costs – SDG&E incurs these costs on a fixed basis for each interconnected customer whether or not the customer uses electricity; therefore, customer costs should be recovered in a fixed or monthly charge ($/month).
- Distribution Demand Costs – SDG&E incurs these costs independent of energy usage. These costs are incurred on the basis of local capacity needs to meet the combined maximum demand of customers served off of a given circuit. These costs are best

recovered on non-coincident demand ("NCD"), distribution demand costs should be recovered in a NCD charge ($/NCD – kW).

- Generation Capacity Costs – SDG&E does not incur these costs 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 SDG&E may require additional capacity ($/peak-kW).
- Commodity Energy Costs – SDG&E incurs these on a variable basis (based on energy usage) and the cost depends on the time of delivery. Therefore, these costs should be recovered in an energy charge ($/kWh) that varies by time period.

The necessary changes to SDG&E's current TOU proposal, as well as SDG&E's rate design proposals are discussed in further detail below.

1. TOU Period Definition

SDG&E's current standard TOU periods are presented in Table 1 below and include a summer on-peak period of 11am to 6pm on non-holiday weekdays. These TOU periods have been in effect since the early 1980s.[26] As is discussed in the testimony of Mr. Anderson (Chapter 3), changes in SDG&E's portfolio have resulted in a change in what drives the need for generation resources. That need is based no longer solely on loads, but on "net load," loads less solar and wind resources in the local reliability area that have become a growing part of SDG&E's portfolio of resources. This change has moved the timing of SDG&E's need for

[26] D.83-12-065, p. 164-167.

generation resources to later in the day during the summer, and has created a need for "flexible capacity" to accommodate "ramping needs," the changes fossil generation to meet net load that occur throughout the year as solar resources decline as the sun sets.

On January 31, 2014, SDG&E filed in its 2015 Rate Design Window ("RDW"), A. 14-01-027, where it proposed to shift its TOU periods to later in the day, from a summer on-peak period of 11am – 6pm to a summer on-peak period of 2-9 pm, in order to reflect the changing needs for generation resources. In addition, SDG&E proposed consistent TOU periods for all customer classes and included changing its off-peak to super-off peak for all classes. D.15-08-040, adopting SDG&E's 2015 RDW, denied without prejudice SDG&E's proposal to shift its TOU periods and SDG&E was permitted to introduce such a proposal in its currently open GRC Phase 2 proceeding, with the following additional requirements:

- Provide evidence to demonstrate the extent to which the need for local capacity will shift to later in the day, and that electric prices have already shifted ;[27]
- Provide more data and analysis supporting a change in TOU periods;[28]
- Provide a more credible forecast of load and prices, and[29]
- Demonstrate the need for change to customers and intervenors through dialogue.[30]

As presented in the testimony of Mr. Anderson, SDG&E continues to see the need for generation resources from 2-9 pm.

[27] D.15-08-040, Findings of Fact ("FOF") 6 and 8, and Conclusions of Law ("COL") 3.
[28] *Id*., FOF 10 and COL 4.
[29] *Id.*, FOF 9.
[30] *Id*., at p. 26.

In SDG&E's 2015 RDW proceeding, A. 14-01-027, most intervening parties expressed concerns about the proposed TOU period changes. SDG&E's TOU proposal presented in this proceeding better aligns TOU periods with current system needs, while also addressing the following intervenors' concerns:

- **Office of Ratepayer Advocates ("ORA") –** In its testimony provided in SDG&E's 2015 RDW proceeding, ORA expressed its concern that there is not enough clear evidence pointing to the need for a seven hour on-peak period.[31] ORA proposed an alternative to SDG&E's proposal, an optional TOU rate with a shorter on-peak period, which would allow for a stronger price signal, and potentially a greater response from customers.[32] SDG&E's TOU period proposal in this proceeding does include a shorter on-peak period; however, as the standard rate for all customers rather than limited to an option. The basis for this is to provide all customers the same price signal to use electricity when supply is high (i.e. during the day when solar is generating) but demand is low.
- **California Farm Bureau Federation ("Farm Bureau") and Water Districts –** Both the Farm Bureau and the Water Districts opposed SDG&E's TOU proposal in its 2015 RDW due, in part, to the reduction in off-peak hours on weekends. Their concern stemmed from the fact that weekends and holidays currently offer the only off-peak daylight hours, and that reduced off-peak hours would necessitate increased water rates to offset costs.[33,34] The proposed TOU changes in this proceeding

[31] ORA RDW Direct Testimony Set 1 – pp. 2, lines 3-5.
[32] ORA RDW Direct Testimony Set 1 – pp. 3, lines 4-7.
[33] California Farm Bureau Federation ("CFBF") 2015 RDW Direct Testimony – pp. 27, lines 12-18.
[34] 2015 RDW Testimony of Gary Arant – pp. 2.

extended the weekend off-peak hours and would maintain 12:00 am to 2:00 pm as super off-peak hours in both Summer and Winter on weekends and holidays.

SDG&E submits a similar proposal to change TOU periods in this proceeding. However, while SDG&E's proposed on-peak TOU period in this proceeding differs from that of RDW, SDG&E continues to a see need for generation resources during the 2 pm to 9 pm on-peak timeframe, presented in the testimony of Mr. Anderson. But, in re-examining potential ways to meet that need and incorporating feedback from intervening parties in the 2015 RDW proceeding, SDG&E makes the following modifications to the 2015 RDW TOU period proposal:

- **On-peak Period Shortened to Five Hours**: While SDG&E continues to see the need during 2 pm to 9 pm, SDG&E proposes to meet that need through a combination of (1) a shorter 4 pm to 9 pm summer on-peak period now applied every day including weekends and holidays to meet ramping needs that occur every day and (2) a shorter event period for dynamic pricing rates of 2 pm to 6 pm for those 0-9 event days of the year where local reliability may be threatened.
- **Expanded Weekend Super Off-peak Hours**: Previously SDG&E proposed a 12 midnight to 6am super off-peak period. SDG&E's proposal is for a super off-peak period applicable to all rate schedules to be all midnight to 6 am weekdays and with extended hours on weekend and holidays of midnight to 2 pm.
- **Simplified TOU Periods**: SDG&E continues to propose the same TOU periods for all customers and all rate schedules and now proposes the same TOU periods for summer and winter, though with different rates for summer and winter. While the analysis presented in the testimony of Mr. Anderson supports a winter on-peak period of 5 pm to 9 pm, SDG&E is proposing to make the winter on-peak period match the summer period

by also adding the 4 pm – 5 pm hour to the on-peak period to simplify the TOU periods to be identical for summer and winter.

- Off-peak represents all others hours.
- **Critical Peak Pricing ("CPP") Period Shortened to Four Hours:** SDG&E's CPP period proposal is the same as was presented in its RDW. However, in this Application (with the proposed shorter on-peak hours) SDG&E proposes to address need identified during the 2-9 pm period through a combination of a shorter five-hour on-peak TOU period from 4-9 pm and a shorter four-hour CPP period from 2-6 pm on high demand days.

SDG&E's proposed TOU periods are presented the Table 2 below, which includes a comparison with current and 2015 RDW proposed TOU periods.

Table 2: Comparison of Current and Proposed TOU Periods

	TOU Period	Current Standard TOU	2015 RDW Proposal	2016 GRC P2 Proposal
Summer	On-Peak	11 a.m.-6 p.m. weekdays	2-9 p.m. weekdays	**Shorten to 5 hours** (4-9 p.m. daily)
	Semi-Peak	6-11 a.m. and 6-10 p.m. weekdays	All other hours	-
	Off-Peak	All other hours, weekends/holidays	-	All other hours
	Super Off-Peak	-	12-6 a.m. daily	**Expanded Weekend Hours** (12 a.m.-2 p.m. weekends/holidays, 12-6 a.m. weekdays)

Winter	On-Peak	5-8 p.m. weekdays	5-9 p.m. weekdays	**Simplified same as summer**
	Semi-Peak	6 a.m.-5 p.m. and 8-10 p.m. weekdays	All other hours	
	Off-Peak	All other hours, weekends/holidays	-	
	Super Off-Peak	-	12-6 a.m. daily	
	CPP Period	11 a.m.-6 p.m. year round	2-6 p.m. year round	**Shorten CPP Period to 4 hours** (2-6 p.m. year round)

Regardless of the TOU period definition, the high cost hours will continue to be the high cost hours. For TOU periods to be effective in aligning costs, TOU period definitions should provide a group of high cost hours in the on-peak period, low cost hours in the super-off peak, with mid-cost hours in the "mid-peak" period. TOU period definitions that follow that guidance will create price signals that provide customers information about the high cost periods and the low cost periods and thereby incent economically efficient behavior that reduce system costs when customers reduce their bills by shifting energy usage to low cost time periods and avoiding usage during high cost time periods. Under a TOU energy-only rate, a cost-based TOU differential results from the average price for marginal energy in the period and the occurrence of generation capacity need in the period.

TOU period definitions that fail to follow that guidance will result in high cost hours in multiple periods, which once averaged, will result in muted TOU differentials and thereby fail to provide customers meaningful signals regarding their actual cost of service and thereby providing customers with little opportunity to save on their bills with changes in energy consumption.

Since the definition of TOU periods are intended to provide customers with accurate information regarding the high cost periods for commodity services and the low cost periods for commodity services, TOU period definitions should be the same for all customers.

SDG&E proposes to address need identified during the 2-9 pm period through a combination of a shorter five-hour on-peak TOU period from 4-9 pm and a shorter four-hour CPP period from 2-6 pm on high demand days. Currently, SDG&E's CPP event period is 11am – 6 pm, consistent with the definition of the current summer on-peak period. SDG&E's proposal would result in a CPP event period that was defined differently than the on-peak period. When reviewing the historic occurrence of peak during CPP event days since 2010, the peak has occurred between 2-6 pm. While this is changing with the addition of significant solar energy, the 2016 loss of load analysis detailed in the testimony of Mr. Anderson still shows a significant probability of the need for capacity in the 2 pm – 6 pm period, in particular for the San Diego sub-area of the San Diego Greater Reliability area. CPP will address that need. Currently the availability of CPP-related options includes:

- CPP-D as the default commodity rate for M/L C&I customers since 2008,[35]
- TOU-A-P as the default commodity rate for small commercial customers beginning November 1, 2015.[36]
- TOU-PA-P as the optional commodity rate available for agricultural customers on May 1, 2014 and the default rate for large agricultural customers beginning November 1, 2015, and

[35] D.08-02-034.
[36] D.12-12-004.

- PTR optionally available for residential customers in 2012[37] and TOU-DR-P optionally available for residential customers on February 1, 2015.[38]

While AB 327 provides the guidance that TOU periods should be effective for a minimum of five years, SDG&E proposes the ability to change CPP event periods more frequently. As the need for capacity in the local sub-area changes with added rooftop solar after 2016, the CPP period can be adjusted to later in the day.

While TOU periods are intended to provide customers with that "every day" price signal for when costs of providing commodity services are high, CPP is intended to incent customers to respond on those top 9 days of the year of the need for capacity. [39] By shortening the time period to respond and retaining greater flexibility to change the period to meet potentially future changing needs, event-based rates can provide more demand response during the times of expected need for capacity.

2. Accurate Price Signals for Distribution

In his inaugural address earlier this year, Governor Brown described the key role to be played by the electric grid in enabling California to realize a clean energy future. Adoption of a rate design that ensures that all users of the electric grid are paying for the service they receive is essential to accomplishing Governor Brown's vision of a fully-integrated advanced electric grid. Governor Brown described the transformation of the electric grid into a platform capable of supporting "a wide range of initiatives: more distributed power, expanded rooftop solar, micro-grids, an energy imbalance market, battery storage, the full integration of information technology

[37] D.08-02-034.
[38] D.12-12-004.
[39] While 0-18 events are permitted in a calendar year, the design is based on an average of 9 days.

and electrical distribution and millions of electric and low-carbon vehicles."[40] Indeed, the electric grid is a critical enabler of the State's policy agenda. In addition to providing safe and reliable services, strategic investments in the grid will be critical for the on-going support of integration of increasing levels of renewable energy and DER, utilization of battery storage, clean transportation efforts, demand response programs and more.

As discussed above, achieving the State's ambitious goals for increased DER adoption through reliance on a technologically advanced electric grid requires a rate structure that ensures that the prices customers see accurately reflect the cost of the services provided. While some progress has been made toward this goal, further changes in the area of distribution rates is critical. The infrastructure costs within the distribution rate component include (i) customer-related costs; and (ii) distribution demand related costs.

(I) 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 meter" services. 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 & collections,

[40] Edmund G. Brown Jr., Inaugural Address Remarks as Prepared January 5, 2015. Available at: http://gov.ca.gov/news.php?id=18828.

branch office, customer contact center, residential customer services, commercial & industrial services, communications, and customer programs.

(ii) Distribution demand costs include the costs of the grid that is needed to deliver electric services to the customer. 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.; and
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.

Customer-related 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. Distribution demand 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 $/kW-non-coincident demand ("NCD") basis to reflect cost-causation.

As is discussed in SDG&E witness John Baranowski's testimony (Chapter 5), SDG&E's electric distribution system is designed to meet individual customer service requirements, not to meet system peak demand. Designing the system in this way is a utility industry standard method, and it increases the system's safety and reliability, and decreases the possibility of system failures. A system that is designed this way is best supported by the recovery of distribution related costs through a non-coincident demand charge, rather than a peak demand charge.

III. GRC PHASE 2 APPLICATION OVERVIEW

SDG&E's proposals in this Application include the traditional elements of GRC Phase 2 proceedings, such as marginal cost analysis, revenue allocation and rate design as well as proposals for new rate options. The Application is supported by the following testimony:

- **Chapter 2 (Christopher Swartz)**: Presents SDG&E's proposal to update rates to reflect updated sales forecast, time of use ("TOU") period definition, updated electric revenue allocation and rate design proposals, as well as various compliance requirements, with rate design proposals including:
    - Movement towards more cost-based rates which includes:
        - Moving the Monthly Service Fee ("MSF") for business customers towards more cost based recovery of customer costs;
        - Moving the recovery of distribution demand charges toward 100% non-coincident demand ("NCD") for medium/ large commercial and industrial ("M/L C&I") customers with distribution demand charges;
        - Moving the recovery of peak generation capacity costs toward more cost based recovery through a peak demand charge for customers using a commodity on-peak demand charge; and
        - Moving small commercial and agricultural customers toward more cost-based TOU rate differentials.
    - Providing additional options for customers to better manage their energy costs.
    - Updated streetlighting rates.
- **Chapter 3 (Robert B. Anderson):** Provides the evidentiary basis for SDG&E's proposal for updated TOU periods.

- **Chapter 4 (Kenneth E. Schiermeyer)**: Provides support for SDG&E's proposal for updated 2016 test-year sales forecast and describes SDG&E's proposal to update test-year sales annually.
- **Chapter 5 (John Baranowski)**: Sets forth the basis for recovery of distribution demand costs through a non-coincident demand charge.
- **Chapter 6 (William G. Saxe)**: Supports SDG&E's proposed distribution marginal costs (both customer costs and demand costs) as well as the cost basis for distribution revenue allocation.
- **Chapter 7 (Jeffrey J. Shaughnessy)**: Sets forth the basis for SDG&E's commodity marginal cost showing (both energy costs and generation capacity costs) as well as the cost basis for commodity and Competition Transition Charge ("CTC") revenue allocation.
- **Chapter 8 (Jennifer Reynolds)**: Describes SDG&E's proposal for small commercial rate eligibility compliance requirements pursuant to D.14-01-002 adopting SDG&E 2012 GRC Phase 2 Application (A.11-10-002)[41] and describes SDG&E's stakeholder outreach efforts.
- **Chapter 9 (Leslie Willoughby)**: Describes the change in requirements to SDG&E's event day trigger threshold for its Critical Peak Pricing default ("CPP-D") rate, to align with the Smart Pricing Program ("SPP") and Peak-Time Rebate triggers, to ensure consistency across all of SDG&E's dynamic rate offerings .

[41] D.14-01-002, p. 16.

IV. SDG&E'S RATE DESIGN PROPOSALS ARE ALIGNED WITH THE COMMISSION'S RATE DESIGN POLICY OBJECTIVES

A. SDG&E's Proposals Provide a Gradual Transition Path to Accurate Price Signals and Promote Transparent Incentives.

SDG&E's Application includes rate design proposals to better reflect SDG&E's cost to serve customers, more specifically rates that better reflect marginal cost and cost-causation. As described in the testimony of SDG&E witness Swartz (Chapter 2), SDG&E proposes a gradual movement toward cost-based rates for all of its customers, which more accurately reflect how costs are incurred. SDG&E proposes to gradually transition the MSF for business customers towards a more cost-based fee.

SDG&E also proposes a gradual transition for customers with demand charges to charges that better reflect how costs are incurred, as presented by Mr. Swartz (Chapter 2). The costs recovered through demand charges are capacity costs that are independent of a customer's energy usage, but rather are dependent on a customer's energy profile. For customers with demand charges, SDG&E's proposal is a transition path for a more cost-based recovery of generation capacity through an on-peak commodity demand charge and more cost-based recovery of distribution capacity costs through a distribution non-coincident demand charge. Mr. Baranowski (Chapter 5) describes how customer-specific demand (i.e., non-coincident demand) drives the design of SDG&E's electric system and its resultant costs. By providing a price signal related to more localized resources (i.e., distribution) based on non-coincident demand, and by providing price signals for system-level resources (i.e., generation capacity) based on system pricing (i.e., system peak demand), SDG&E rates are better designed to recover costs on the basis they are incurred. SDG&E is also proposing a gradual transition path for implementing these proposals, to provide the best opportunity for customers to progressively become more engaged and informed about the choices that are available to them and to understand how the changes will impact them.

In addition, SDG&E proposes to move the collection of California Solar Initiative ("CSI") and Self-Generation Incentive Program ("SGIP") revenues from the distribution rate component to the Public Purpose Program ("PPP") rate component. This change supports SDG&E's policy objective of providing more accurate price signals by ensuring that incentives are explicit and transparent. Distribution costs are intended to accurately reflect the costs to provide distribution services. Currently, CSI and SGIP are collected through distribution rates, which obscure the cost of distribution services. CSI and SGIP are incentives intended to further California policy and as such these costs should not be included as part of SDG&E's overall distribution costs. Moving the collection of CSI and SGIP to PPP increases transparency in the cost of distribution services to customers.

In addition, SDG&E is proposing to gradually reduce and eliminate the Peak-Time Rebate ("PTR") credit adjustment, now that the SPP rate options are available for residential customers. This proposal is consistent with SDG&E's position in its dynamic pricing proceeding,[42] which described PTR as a "transitional mechanism" that would be available "until a dynamic pricing rate can be implemented for residential customers."[43] SDG&E proposes a multi-year transition plan to reduce and ultimately eliminate the PTR credit.

Finally, SDG&E proposes the implementation of an electric rate assistance program for eligible food banks pursuant to Public Utilities Code ("PU Code") Section 739.3, which was added by AB 2218. On September 26, 2014 Governor Brown signed into law AB 2218 requiring

[42] See, D.12-12-004.
[43] See, A.10-07-009, Prepared Direct Testimony of William G. Saxe (Chapter 3), pp. WGS-20 and WGS-21.

that "each electrical corporation and gas corporation subject to the direction and supervision by the commission, to develop and implement a program of rate assistance to eligible food banks, as defined, at a fixed percentage to be determined by the commission."[44] Currently, in addition to rate assistance programs for eligible residential customers, such as CARE, FERA and medical baseline, which recognize the need to ensure these customers have access to energy services to meet all of their energy needs, the Expanded CARE program for non-residential customers provides equivalent benefits (discount of 30-35%) for non-profit group living facilities. AB 327 provides that the effective discount for residential as well as non-residential CARE-eligible customers be between 30 to 35%.[45] AB 2218 recognizes the critical role that eligible food banks play to "stabilize our most underserved and economically challenged families from across the state."[46] One of the primary reasons identified justifying the need for this program which would increase subsidies paid for by all other customers is the electricity costs "to maintain their refrigeration units to house perishables such as fruits, vegetables, and dairy products."[47] The CARE program, which offers a 30-35% discount, is intended to ensure access for residential customers to all energy service needs for residential customers which support refrigeration and other food related services, as well as lighting, heating, and cooling, etc. Given that AB 2218 addresses a more limited range of support for underserved and economically challenged families and recognizing the cost of additional subsidies to other customers, SDG&E proposes a 20% line item discount for eligible food bank customers. SDG&E proposes that the recovery of this discount be consistent with the recovery of the CARE discount, that is, that the recovery be through PPP rates and be recovered from all non-CARE customers. In addition, recovery of the

[44] PUC Section 739.3(a).
[45] PUC Section 730.2(c)(1).
[46] April 21, 2014, hearing of the Assembly Committee on Utilities and Commerce, AB 2218 Bill Analysis, p. 1.
[47] Id.

discounts in rates would be addressed through annual PPP advice letters and going forward budgets would be addressed through SDG&E's Low Income proceedings. As is the case with the current CARE discount, SDG&E would record the cost of the discount and associated revenues in a balancing account. SDG&E witness Christopher Swartz (Chapter 2) speaks to the eligibility requirements for this program.

B. SDG&E Proposes Rate Options that Allow Customer Choice.

In addition to its proposal for a transition path to move existing rate schedules towards a more cost-based rate structure, SDG&E also proposes to introduce more fully cost-based options to be available for customers that vary by customer class. These cost-based options vary by customer class due to the differences between existing rates available in each class. SDG&E recognizes the need for a transition path to move existing rate schedules towards a more cost-based rate structure for existing rate schedules in order to (1) mitigate customer bill impacts and (2) allow for continued customer education and outreach, SDG&E also believes it is important to provide more cost-based options for customers which will provide customers with price signals that reflect their cost of service. Doing so will provide customers with accurate price signals that incent economically efficient behavior that in turn would help to reduce system costs while enabling customers to also reduce their energy bills.

SDG&E witness Swartz (Chapter 2) describes SDG&E's proposals to introduce the following new rate options for customers:

1. Residential EV: more cost-based option for residential EV customers that includes a monthly service fee and a rate design to further incent charging in the super off-peak period.

2. Small Commercial: (i) A new option that provides bill stability for small business customers that have less flexibility to change their energy use and (ii) another option that introduces small commercial customers to demand charges and provides for another way to save energy by managing their demand.

3. M/ C&I: A new option for M/L C&I customers that have flexibility to shift energy use to SDG&E's Super Off-Peak period.

4. Street lighting: a new dimmable option available to street lighting customers.

C. SDG&E Proposes a Gradual Implementation Path for Rate Design Changes, to Minimize Impacts and Enhance Customer Transition.

In this Application, SDG&E is attempting to create greater transparency for its customers and the Commission as to the intent and direction of its vision for electric rate design. In the quest for accurate prices and transparent incentives to provide the necessary foundation for the State's vision for a low carbon future to be achieved in a sustainable manner, these changes must be done with consideration of customer bill impacts along the way. For this reason, SDG&E has proposed a multi-year transition path for proposals to continue movement toward cost-based rates (as identified in Section A above). In addition, as discussed in more detail in the testimony of Ms. Reynolds, SDG&E commits to educating and informing customers about rate design changes before they occur. Providing customers with information about upcoming rate design changes will give customers the opportunity to make more informed decisions about their energy use prior to change occurring.

D. SDG&E Proposes Annual Sales Updates for Greater Stability in Rates and Customer Bills.

Currently SDG&E utilizes the test-year sales adopted in its rate design proceedings (RDW or GRC Phase 2 proceedings) for the development of rates for the recovery of authorized revenue requirements. Once adopted, these test-year sales remain in effect until the next test-year sales with the implementation of the next approved rate design proceeding with no mechanism for additional adjustments in interim years. SDG&E's current effective rates are based on a 2015 test-year sales from its 2015 RDW proceeding (A.14-01-027) which was implemented November 1, 2015.[48] Prior to that, SDG&E's rates were based on a 2012 test-year sales from its 2012 GRC Phase 2 proceeding (A.11-10-002) which was implemented May 1, 2014.[49] Prior to the implementation of SDG&E's 2012 GRC Phase 2, SDG&E rates were based on 2009 test-year sales from its 2009 RDW proceeding (A.08-11-014) which was implemented on January 1, 2010.[50] Table 3 below presents SDG&E's actual system annual sales since 2010 and compares to the authorized sales at that time.

Table 3: Comparison of Historic Authorized and Actual Sales

Year	Authorized Sales (GWh)	Actual Sales (GWh)
2010	20,890	19,485
2011	20,890	19,515
2012	20,890	20,026
2013	20,890	19,757
2014	20,809	20,116

This variance between actual and authorized sales creates greater volatility to customer rates and bills due to the impact of balancing accounts intended to capture these differences. As discussed in more detail in the testimony of Mr. Schiermeyer, in addition to the approval of 2016 test-year sales, SDG&E requests approval of post-test year sales for the interim years until SDG&E's next rate design proceeding. A fully developed test-year forecast would continue to be requested through rate design proceedings. SDG&E proposes the ability to make these

[48] AL 2791-E, approved on October 29, 2015, for rates effective November 1, 2015.
[49] AL 2595-E and AL 2595-E-A, approved on July 22, 2014, for rates effective May 1, 2014.
[50] AL 2115-E, approved on December 15, 2009, for rates effective on January 1, 2010.

adjustments through a Tier 2 advice letter that would then be incorporated into SDG&E's annual Electric Consolidated advice letter for January 1 effective rates.

V. CONCLUSION AND SUMMARY

As California continues to look forward to a clean energy future, SDG&E plays a critical role in this pursuit. SDG&E's rate proposals would provide the necessary platform for utility customers to make economically efficient decisions in their investments in energy resources; that is, choices for investments in energy efficiency ("EE"), demand response ("DR"), and DER, are made with proper information based on accurate price signals (i.e. without cross subsidies). SDG&E's proposals continue to build a solid foundation for California's clean energy policies through accurate price signals and direct, transparent incentives. The proposals in this Application continue the path to further SDG&E's rate design vision as well as the Commission's rate design policy objectives by (i) continuing movement toward equitable pricing for all customers through accurate price signals; (ii) transparently identifying subsidies deemed necessary to further public policy; (iii) continuing to provide customers with options that best meet their needs; while (iv) providing a transition path that minimizes customer impacts.

This concludes my prepared direct testimony.

VI. WITNESS 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 San Diego Gas and Electric ("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, and preparation of various regulatory filings. 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 California Public Utilities 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 the electric and natural gas utilities.

APPENDIX – GLOSSARY OF ACRONYMS

AB	Assembly Bill
C&I	Commercial and Industrial
COS	Cost of Service
CPP-D	Critical Peak Pricing Default
CSI	California Solar Initiative
CTC	Competition Transition Charge
DER	Distributed Energy Resources
DR	Demand Response
EE	Energy Efficiency
ERRA	Energy Resource Recovery Account
GHG	Greenhouse Gas
GRC	General Rate Case
IOUs	Investor-Owned-Utilities
MSF	Monthly Service Fee
NCD	Non-Coincident Demand
NEM	Net Energy Metering
PG&E	Pacific Gas & Electric Company
PPP	Public Purpose Program
PTR	Peak-Time Rebate
RMI	Rocky Mountain Institute
RPS	Renewables Portfolio Standard
SB	Senate Bill
SCE	Southern California Edison Company
SDCAN	San Diego Consumer Action Network
SDG&E	San Diego Gas & Electric Company
SGIP	Self-Generation Incentive Program
SPP	Smart Pricing Program
TOU	Time of Use
TY	Test Year