Decision **PROPOSED DECISION OF ALJ COOKE** (Mailed 5/18/2017)

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

Application of San Diego Gas & Electric Company (U902E) for Authority to Update Marginal Costs, Cost Allocation and Electric Rate Design.	Application 15-04-012 (Filed April 13, 2015)

DECISION ADOPTING REVENUE ALLOCATION AND RATE DESIGN FOR SAN DIEGO GAS & ELECTRIC COMPANY

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DECISION ADOPTING REVENUE ALLOCATION AND RATE DESIGN FOR SAN DIEGO GAS & ELECTRIC COMPANY

Summary

This decision addresses the application of San Diego Gas & Electric Company (SDG&E) to establish marginal costs, allocate revenues, and design rates for service provided to its customers. The uncontested Revenue Allocation Settlement Agreement is approved; the contested Schools Settlement Agreement is not adopted. This decision establishes new time-of-use periods to reflect the changing energy market, including a later on-peak period and a spring super-off-peak period, while affirming the grandfathering provisions for eligible solar customers previously established by the California Public Utilities Commission and extending the Eligibility Grace Period for schools. The decision establishes cost recovery of distribution costs between coincident and noncoincident demand charges based on the original testimony position of the Solar Energy Industries Association and retains the current split for generation capacity costs between coincident demand and volumetric charges. The decision establishes a three-year temporary waiver of the small commercial rate load limit for current small commercial accounts where electric vehicle charging load makes up at least 50 percent of their electric load.

Unless otherwise provided in this decision, the revised rates will become effective no earlier than December 1, 2017 and will allow SDG&E to collect the revenue requirement determined in Phase 1 of its 2015 General Rate Case.

This proceeding is closed.

1. Procedural Background

On April 13, 2015, San Diego Gas & Electric Company (SDG&E) filed Application (A.) 15-04-012 to establish marginal costs, allocate revenues, and

design rates for service provided to its customers in connection with its revenue requirements for service for 2016 - 2018, but, for the reasons described below, the original application was amended and the final filed version of the application is the Second Amended Application which was filed on February 9, 2016. This cost allocation and rate design proceeding is commonly referred to as Phase 2 of a utility's General Rate Case (GRC).[1]

In May 2015, protests were filed by City of San Diego (City), the San Diego Public Schools (Schools),[2] Utility Consumers Action Network (UCAN), Office of Ratepayer Advocates (ORA), and California Farm Bureau Federation (Farm Bureau). A response was filed by San Diego Unified Port District (Port District). SDG&E filed its reply on June 1, 2015. The first prehearing conference (PHC) was held on June 12, 2015.

On August 28, 2015, SDG&E filed a motion for authority to withdraw and refile the Phase 2 application. There were two primary reasons for this request. First, SDG&E had an open rate design window (A.14-01-027) in which SDG&E had requested authority to change its time-of-use (TOU) periods. SDG&E argued that the existing TOU periods did not reflect the current peak and off-peak periods. In August 2015, the CPUC found that there was insufficient evidence of a change in time of usage and denied SDG&E's request to change TOU periods.[3] Second, in July 2015, the CPUC issued D.15-07-001 directing the three major investor-owned utilities to make changes to residential rate design,

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[1] SDG&E Phase 1 GRC application, primarily addressing revenue requirements, was resolved by Decision (D.) 16-06-054 in A.14-11-003.

[2] The protest was filed jointly by a number of public school districts.

[3] D.15-08-040.

including a shift toward TOU default rates. By refiling its application, SDG&E would have an opportunity to respond to both of these changes. SDG&E's motion to refile the application was granted, and the amended application was filed on December 4, 2015.

On December 31, 2015 Alliance for Retail Energy Markets/Direct Access Customer Coalition filed a response. On January 6, 2016, protests to the first amended application were filed by California Solar Energy Industries Association (CalSEIA), The Utility Reform Network (TURN), ORA, Schools, Solar Energy Industries Association (SEIA), City, UCAN, Farm Bureau and the California City-County Street Light Association (CALSLA). Also on January 6, 2016, a response was filed by the Port District. SDG&E filed a reply on January 19, 2016.

The second PHC was held on January 26, 2016. At the PHC, SDG&E explained that it needed to make several corrections to the application and related testimony. Also at the PHC, parties and Energy Division asked that certain additional matters be addressed in the application, including a new rate for food banks as required by recently enacted Pub. Util. Code § 739.3.[4] As a result, the assigned Administrative Law Judge (ALJ) ruled that SDG&E could file a Second Amended Application. A formal ruling confirming the PHC ruling was filed on February 2, 2016.

As instructed, SDG&E filed its Second Amended Application on February 9, 2016. SDG&E held a workshop to present an overview of the Second Amended Application on February 22, 2016.

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[4] All subsequent references are to the Public Utilities Code unless otherwise specified.

A third PHC was held on March 16, 2016 to discuss any issues in the Second Amended Application that had not previously been addressed in protests, responses or prior PHCs. At the third PHC, the parties also discussed the procedural schedule proposed by SDG&E.

The Assigned Commissioner and Administrative Law Judge's Scoping Memo and Ruling (Scoping Memo) was issued on April 19, 2016. The Scoping Memo confirmed the categorization of the proceeding and need for evidentiary hearings, defined the issues, established a schedule, and included time for parties to attempt to settle disputed issues. A Public Participation Hearing was held in San Diego on September 14, 2016. The CPUC's Public Advisor has received a number of letters and electronic mail messages conveying the views of SDG&E's ratepayers on SDG&E's application. These messages are part of the proceeding record, and have been reviewed and considered by the assigned ALJ and members of the CPUC.

Pursuant to the schedule set forth in the Scoping Memo, ORA served its direct testimony on June 3, 2016. Intervenors submitted their direct testimony regarding some or all of the topics of marginal cost, revenue allocation and rate design on July 5, 2016. UCAN served supplemental testimony on demand distribution allocation factors on July 29, 2016.[5] SDG&E submitted its rebuttal testimony on August 30, 2016,[6] and pursuant to ALJ McKinney's

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[5] ALJ McKinney issued a ruling on July 21, 2016 that granted permission for UCAN to late-file opening testimony related to demand distribution allocation factors no later than August 2, 2016.

[6] ALJ McKinney extended SDG&E's time to submit rebuttal to August 30, 2016 in an August 24, 2016 e-mail ruling.

September 19, 2016 ruling, ORA and intervenors were provided with an opportunity to submit rebuttal on October 14, 2016.

In addition, as directed in the Scoping Memo, the CPUC hosted a pre-evidentiary hearing public workshop on October 10, 2016 to allow the parties to discuss issues in this case. At the workshop, the CPUC's Energy Division provided an overview of commercial demand charges that included definitions, history, and a summary of some of the issues that arise when considering how to split cost recovery between types of demand charges.[7]

On October 12, 2016, pursuant to CPUC Rule 12.1(b), SDG&E served a notice of a settlement conference related to revenue allocation and other issues. As set forth in the notice, an initial settlement conference was held on October 20, 2016. Continuing discussions related to the potential settlement of issues in this proceeding occurred among the interested parties after the settlement conference until the following six separate agreements and supporting motions were filed with the CPUC:

1. Revenue Allocation Settlement Agreement, filed November 4, 2016 by SDG&E, ORA, UCAN, Farm Bureau, Federal Executive Agencies (FEA), City, and CALSLA.
2. Joint Supplemental Testimony Secondary Substation and Primary Substation Service Rates, served November 14, 2016 by SDG&E and FEA.

[7] Although not testimony, the Energy Division presentation is part of the record because City incorporated it as an element of its rebuttal as Exhibit CSD-2: WAM-1 and no party objected to its receipt into evidence. Any conclusions drawn in the presentation reflect Energy Division's analysis based on the record developed as of that point in time. Those conclusions are not presented for the truth of the matter. Similar to argument in a brief, they are the conclusions that Energy Division reached after reviewing the record. Because we are relying on the same record, augmented by additional testimony and cross examination, our own analysis may reach the same, similar, or different conclusions.

3. Joint Supplemental Testimony on Agricultural Rates, served November 14, 2016 by SDG&E and Farm Bureau.
4. Joint Supplemental Testimony on Medium and Large Commercial Demand Charges, served November 14, 2016 by SDG&E, SEIA, FEA, and City.
5. Joint Supplemental Testimony on Residential and Small Commercial Customer Issues, served November 16, 2016 by SDG&E, ORA, City, and CALSLA.
6. Settlement Agreement Between SDG&E and San Diego Public Schools, filed November 18, 2016 by SDG&E and Schools.[8]

The settlement agreements listed above may be accessed at the Docket Card for this proceeding on the CPUC's website, www.cpuc.ca.gov. Joint Supplemental Testimony may be accessed at http://docs.cpuc.ca.gov/EFileSearchForm.aspx by selecting Supporting Documents and A1504012.

Evidentiary hearings were held on November 14, 15, and 29, 2016 to review the reasonableness of the various settlements and agreements, as well as to allow for cross examination of witnesses on unresolved issues. Opening Briefs were filed by SDG&E, ORA, UCAN, City, Schools, Farm Bureau, San Diego County Water Agencies (Water Agencies), FEA, CALSLA, City of Mission Viejo (Mission Viejo), San Diego Airport Parking Company (SD Airport Parking), CalSEIA, and SEIA on January 27, 2017.[9] Reply Briefs were filed by SDG&E, UCAN, City, Schools, Farm Bureau, FEA, CALSLA, SD Airport Parking, CalSEIA, SEIA, and Center for Accessible Technology on February 17, 2017. The proceeding was submitted for decision on February 17, 2017.

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[8] This proposed settlement will be referred to as the Schools Settlement for simplicity.

[9] CalSEIA neglected to file its Opening Brief, although it was timely served. Following a motion to late-file its brief, its brief was filed as of February 13, 2017.

2. Revenue Allocation and Rate Design Overview

The CPUC adopts most non-energy-related revenue requirements for each regulated energy utility in GRCs. Certain generation and purchased power expenses are authorized for rate recovery in Energy Resource Recovery Account proceedings. The process of assigning these, and other, revenue requirements to various customer classes for recovery is called revenue allocation and is typically performed in the GRC Phase 2 proceeding.[10] Marginal cost studies are an underlying element of the revenue allocation process. Rate design is the process of setting specific rates to recover the allocated revenue from that customer class.

In general, revenue is recovered through rates made up of three types of charges: fixed fees, demand based charges, or volumetric rates. Fixed fees, often called Monthly Service Fees, are ideally designed to recover the non-demand-related distribution system costs associated with serving a customer. Demand based charges are typically designed to recover distribution system capacity costs and generation capacity costs that are needed to meet customer demand based on system planning. These costs are generally recovered by two different types of charges, coincident (peak) and noncoincident demand charges, which are set on $/kilowatt (kW) basis and reflect the distribution and generation related capacity costs to serve a customer's highest load both during the TOU defined peak period (coincident) and load occurring at any time (noncoincident). Noncoincident demand charges are not time-dependent; they can only be avoided by flattening the load in all 15-minute

[10] Transmission rates, which are Federal Energy Regulatory Commission (FERC)-jurisdictional, are determined outside this process and are simply passed through to customers in final rates, which include generation, transmission, distribution, and a number of smaller rate components.

intervals. Coincident demand charges (similar to TOU rates) provide a time-varying marginal cost-based price signal for the customer to shift load and use energy efficiently. Volumetric charges generally recover more variable costs, particularly energy-related costs.[11] TOU rates are volumetric charges that vary by TOU period, and can substitute as a collection mechanism for costs typically collected by other means (for example, peak-related demand charges).

3. Standard of Review for Settlements

Because two settlements were filed, we summarize our standard of review for settlements. The CPUC has long favored the settlement of disputes. However, pursuant to Rule 12.1(d) of the CPUC's Rules of Practice and Procedure, the CPUC will not approve a settlement, whether contested or uncontested, unless it is found to be reasonable in light of the whole record, consistent with law, and in the public interest. Further, where a settlement agreement is contested, it will be subject to more scrutiny than an all-party settlement agreement. In this proceeding, the Revenue Allocation Settlement Agreement is uncontested; however, the Schools Settlement was contested.

Second, the settlements themselves are the subject of Article 12 of the CPUC's Rules of Practice and Procedure (Settlements). Uncontested settlements that address disputes over highly technical matters such as marginal costs, cost allocation and electric rate design can create some tension between the CPUC's policy of encouraging such settlements and the concomitant requirement that the CPUC affirmatively find that such settlements are, in fact, "reasonable, consistent

[11] However, residential rates typically do not include demand charges, nor (as of now) fixed charges, and some rate options substitute TOU volumetric charges for some demand-related revenue elements, *see* for example, SDG&E's Schedule DG-R.

with law, and in the public interest." Indeed, pursuant to Rule 12.6 of the CPUC's Rules of Practice and Procedure, which addresses confidentiality of settlements, "no discussion, admission, concession or offer to settle, whether oral or written, made during any negotiation on a settlement shall be subject to discovery, or admissible in any evidentiary hearing" if a participant in that settlement objects to its admission. Nevertheless, hearings were conducted in this proceeding to allow the parties and assigned ALJs to ask clarifying questions of the parties that entered into the settlements, and the settling parties worked collaboratively to testify on witness panels that enabled development of a detailed record on the settlements. This record provided additional information that supports our decisionmaking today, without causing settling parties to violate the spirit of Rule 12.6.

4. Issues to be Decided

As is typical for GRC Phase 2 applications, the three general subjects of SDG&E's application are marginal costs, revenue allocation, and rate design. The Scoping Memo further described the issues as:

1. Should SDG&E's sales forecast and marginal cost proposals be adopted?
2. Should SDG&E's proposed changes in allocation of distribution customer costs, distribution demand charges, and peak generation capacity costs be adopted? Specifically, SDG&E's proposals for certain non-residential customers include the following:
    - Monthly Service Fee: Shift business customers' monthly service fee towards full recovery of distribution customer costs.
    - Distribution Demand Charges: Shift recovery of distribution demand-related costs towards 100 percent noncoincident demand charges for customers with distribution demand charges.

- Peak Demand Charge: Shift recovery of generation capacity costs towards 90 percent recovery through a peak demand charge for customers with a commodity on-peak demand charge.

3. Should SDG&E's proposal to move recovery of California Solar Initiative and Self-Generation Incentive Program costs from distribution rates to Public Purpose Program rates be adopted?
4. Should SDG&E's proposed updates and changes to TOU periods and TOU rates be adopted?
5. Should SDG&E's proposed new rate option for dimmable lights be adopted?
6. Should SDG&E's other electric revenue allocation and rate design proposals, including new rates and phasing out of other rates, be adopted?
7. Should SDG&E's proposal to eliminate under/over collection requirements associated with dynamic pricing rate incentives be adopted?

This decision will cover each scoped issue within four broad topic areas: Sales Forecasts; Revenue Allocation; Time-of-Use Periods; and Rate Design Issues.

5. Sales Forecasts

SDG&E requests approval of the three-year sales forecast covering the years 2016-2018 presented in its rebuttal testimony, Exhibit SDG&E-14, which is based on California Energy Commission data in the 2015 Integrated Energy Policy Report (February 2016).[12] SDG&E proposes an annual compliance advice letter to present the rate impacts associated with implementation of the next test-

[12] The Revenue Allocation Settlement Agreement is based on this same sales forecast.

year sales forecast as part of SDG&E's annual Electric Consolidated advice letter for January 1 effective rates.

Only SDG&E, ORA, and Farm Bureau addressed the sales forecast in testimony, and only SDG&E and Farm Bureau addressed it on brief. Both ORA and Farm Bureau expressed concerns that SDG&E intended to perform more frequent sales forecast updates through the advice letter process. SDG&E's Opening Brief clarifies that it is not proposing to update the post-test-year sales forecasts outside of this proceeding but simply to reflect the next year's sales forecast in rates.

Given the lack of controversy over the proposed sales forecasts, the parties' reliance on them for the Revenue Allocation Settlement Agreement, and SDG&E's clarification of the purpose of the compliance advice letters, we approve the 2016, 2017 and 2018 sales forecast presented in Exhibit SDG&E-14 and direct SDG&E to file annual compliance advice letters, as part of SDG&E's annual Electric Consolidated advice letter for January 1 effective rates, to present the rate impacts of the post test-year sales forecasts approved in this proceeding.

6. Revenue Allocation

The Revenue Allocation Settlement Agreement reflects agreement on how to allocate authorized revenue requirements for distribution, commodity, California Solar Initiative, Self-Generation Incentive Program, Public Purpose Program, Competition Transition Charge, and Local Generation Charge among customer classes. The Revenue Allocation Settlement Agreement is designed to resolve the issues raised in prepared testimony regarding the allocation to SDG&E's customer classes of these revenue requirements. Additionally, parties addressed whether the CPUC should cap or limit the amount of SDG&E's revenue requirement that is allocated to any customer class, and if so, the level of

the cap. The November 4, 2016 Motion to Adopt the Revenue Allocation Settlement includes Tables 1-7 and a comparison table showing how the Revenue Allocation Settlement Agreement would modify allocations as compared to current and SDG&E proposed rates. In addition, following questioning by the ALJ at the evidentiary hearing, SDG&E served an additional illustrative rate exhibit, which was identified as Exhibit SDG&E-22.

Parties raised a number of issues regarding the calculation and methodologies used to derive marginal customer costs, marginal generation capacity costs, marginal energy costs, and marginal distribution demand costs. The Settling Parties[13] were able to reach agreement on the allocation of SDG&E's total revenue requirement among the rate classes, thereby making moot the need to litigate and resolve the differences regarding proposed marginal cost methodologies and forecasts. Thus, the Revenue Allocation Settlement Agreement does not reflect the approval of, or acceptance of, any of the Settling Parties' marginal cost proposals.

The Settling Parties intend that SDG&E should be authorized to implement the rates resulting from the Revenue Allocation Settlement Agreement as soon as practicable following the issuance of a final CPUC decision approving the Revenue Allocation Settlement Agreement. The Settling Parties agree that the allocation factors that were developed based on the caps to illustrative average utility distribution rates and the caps to illustrative average total rates shall apply to the CPUC-jurisdictional revenue requirements in place when the CPUC adopts a final decision in this proceeding. The Settling Parties

[13] The Settling Parties are SDG&E, ORA, UCAN, Farm Bureau, FEA, City, and CALSLA.

agree that the allocation factors, which were guided by the rate caps, will continue to apply to any future changes in SDG&E's rates until Phase 2 of SDG&E's next GRC proceeding is implemented.

The record supports a finding that the Revenue Allocation Settlement Agreement is reasonable, consistent with law, and in the public interest. Parties representing all customer groups presented testimony on revenue allocation issues. The record shows that the Revenue Allocation Settlement Agreement was reached with participation and consideration of various allocation options by representatives of a broad range of customer groups on SDG&E's system after significant give-and-take between the parties, which occurred over the course of ten settlement conference calls during two months. The result is a balanced settlement for all ratepayers. The allocations to individual rate elements were also assessed based on their impacts on total and utility distribution company class average rates and caps on the impacts were established to ensure that no particular customer class is disproportionately affected. Together, the process employed to reach agreement, the balancing of interests, the protection of all customer classes from disproportionate impact, and the conservation of resources that resulted from the settlement support our adoption of the Revenue Allocation Settlement Agreement.

We adopt the allocation factors set forth in Tables 1-7 of the Revenue Allocation Settlement Agreement and direct SDG&E to implement the resulting rates as soon as practicable following the issuance of a final CPUC decision approving the Revenue Allocation Settlement Agreement. These allocation factors will apply to any future changes in SDG&E's rates until the SDG&E's next Phase 2 GRC proceeding is implemented.

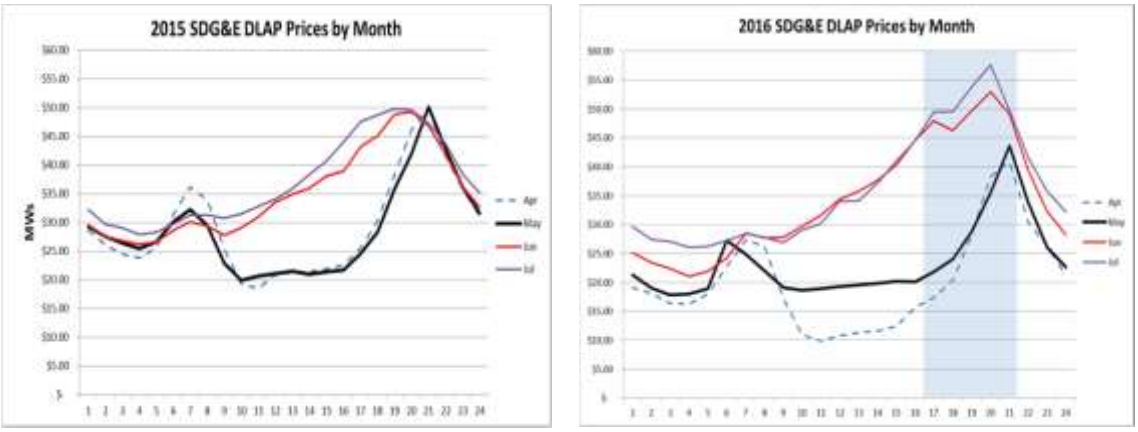
7. Time-of-Use Periods and Dynamic Pricing Periods

As followers of the CPUC's regulatory agenda are aware, updating time-of-use periods to reflect the current electric system features is high on the CPUC priority list. D.17-01-006 describes the principles we should adhere to when considering whether to change the current TOU periods and provides a good summary of the purpose of TOU periods and rates. While the principles adopted in D.17-01-006 are not binding on this rate design application, we will assess how proposed changes fit with the guidance set forth in that decision.

7.1. Seasonal Definition

SDG&E currently has a six-month summer (May-October) season and six-month winter (November-April) season and did not propose to change the seasonal definition. ORA recommended that SDG&E revise its summer season to cover only four months (July-October). In rebuttal testimony, SDG&E supported the movement of May to the winter season based on 2015 and 2016 Default Load Aggregation Point (DLAP) wholesale prices[14] and load data, and Exhibits JT-2 and JT-4 (discussed in Section 8. Rate Design, below) utilize the five-month summer season in their joint testimony.

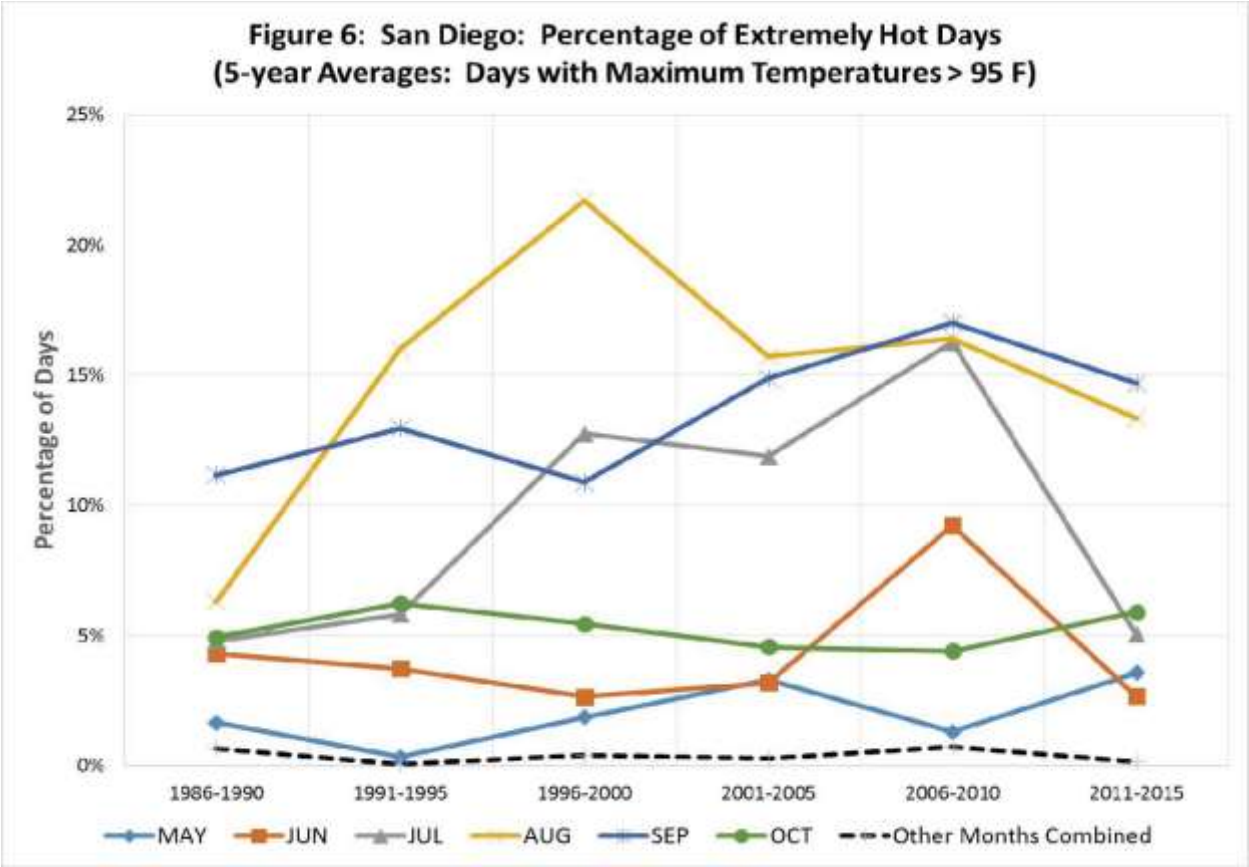
[14] DLAP is an hourly energy price determined according to CAISO tariff 27.2.2.1. The price is reflective of transmission congestion but does not reflect capacity costs.



(Chart 4 from Exhibit SDG&E-11 at 27)

SEIA opposes the switch from a six-month summer to a four-month summer as proposed by ORA. "SEIA reviewed 30 years (1985 - 2015) of data on daily high temperatures for 26 weather stations in the San Diego area, determining the percentage of daily high measurements that fell into the Extremely Hot (greater than or equal to 95 F) category."[15]

[15] SEIA Opening Brief at 12. Extremely Hot was defined using Southern California Edison Company's "extremely hot" category in its TOU-8-RTP schedule, which offers real-time pricing rates based on expected local temperatures.



(Exhibit SEIA-01 at 22.)

Taken together, the SDG&E DLAP prices for 2015 and 2016 and the SEIA figure shows that historically May is much like non-summer months in terms of the frequency of very hot days, a typical driver of peak electric demands. While we agree that SEIA made a strong case that the trend for May is increasing frequency of very hot days, we agree with SDG&E and ORA that based on current load data, May more closely aligns to April, not June or July. For that reason, we adopt a five-month summer (June-October) and seven-month winter (November-May) season and direct SDG&E to implement this revised seasonal definition as soon as practicable following the issuance of a final CPUC decision.

7.2. Base Time-of-Use Periods

"Historically, TOU rate intervals were designed to reflect time variations in the cost to serve loads, with higher-priced periods during summer week-day afternoons when the loads were the highest. Setting higher TOU rates during peak periods signals that electricity is more valuable at certain times of day and provides customers an incentive to reduce energy use or to generate on-site energy using renewable or other technologies at those times." (D.17-01-006 at 4.)

SDG&E's current standard TOU period includes a summer on-peak period of 11 a.m. to 6 p.m. on non-holiday weekdays and has been in effect since the 1980s. However, "deployment of grid-connected and behind-the-meter solar has increased the availability of energy during the afternoon and decreased the load on the grid. As a result, the peak periods, in terms of grid needs and cost, have shifted to later in the day. In addition, on spring days with low demand and high solar generation, there is a risk that there will be an excess of generation available, leading to curtailment of renewables and other resources." (D.17-01-006 at 5.) "The California Independent System Operator (CAISO)… has been particularly concerned with times when the available renewable generation is high but load is low. This situation has forced CAISO to curtail a small percentage of renewable generation. CAISO argues that in addition to peak periods, matinee rates (aka reverse demand response) with super-off peak periods during spring days may be necessary." (D.17-01-006 at 5-6, citations omitted.) "[A]nalyses show three phenomena affecting the setting of TOU periods: peak shift, spring over generation, and steep ramp." (D.17-01-006 at 14.)

SDG&E proposes to shift its on-peak period to 4 p.m. to 9 p.m. each day in light of the changed load and cost patterns, which are detailed in Exhibit SDG&E-3. SDG&E's proposed super-off-peak period would run from

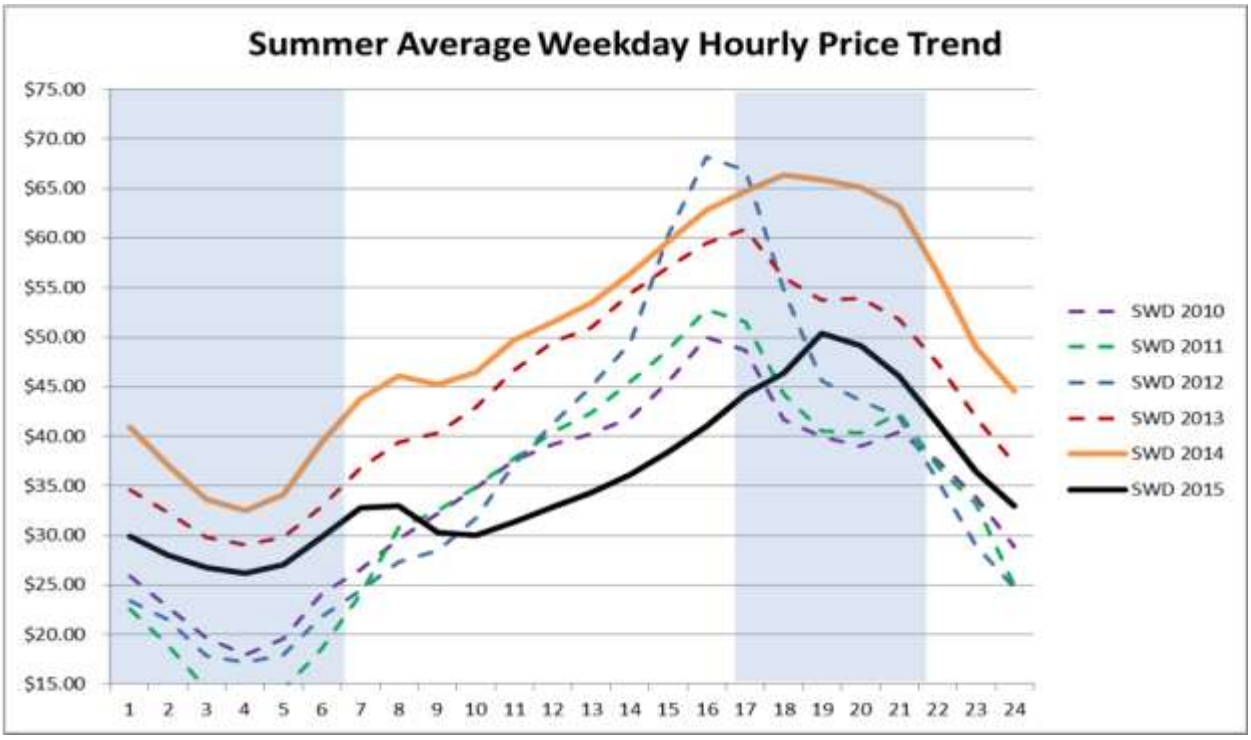
midnight to 6 a.m. weekdays and extend to 2 p.m. on weekends, with the off-peak period being all other hours.[16] SEIA is the primary opponent of SDG&E's time period proposals, recommending an on-peak period of 2 p.m. to 7 p.m. each day for the summer season, super-off-peak from 10 p.m. to 6 a.m., and all other hours off-peak. For the winter season, SEIA recommends an on-peak period of 4 p.m. to 8 p.m.

> SEIA's recommended summer on-peak TOU period is two hours earlier than the period proposed by SDG&E and the Office of Ratepayer Advocates (4 p.m. to 9 p.m.). This earlier on-peak period is justified by three considerations: first, the loads at the system and substation levels that drive marginal transmission and distribution (T&D) costs reach their peaks earlier in the day than the net loads that are the key determinant of the profile of marginal generation costs. Second, the on-peak period should focus not on the evening peak in net loads, but on the earlier hours of the steepest net load up-ramps that present the biggest challenge for system operators. Finally, a more moderate shift in TOU periods will mitigate the bill impacts on existing TOU customers who have made investments in preferred resources in reliance on SDG&E's current TOU periods. (SEIA-01 at i.)

Our review of the record shows that the current and forecast SDG&E area net loads and recent generation and commodity pricing patterns fully support the SDG&E base on-peak, off-peak, and super-off-peak period proposals when only marginal generation and energy costs are assessed. However, if weight is placed on the marginal transmission and distribution system drivers SEIA's earlier on-peak period start is also supportable. Chart RBA-5 of Exhibit SDG&E-

[16] ORA and Farm Bureau generally support SDG&E's proposed on-peak period but have entered into joint testimony with SDG&E about whether a two-period or three-period default TOU rate is preferred. The joint testimony is discussed in the Rate Design section below.

3, Figure 5 of Exhibit SEIA-01, and Chart RBA-Rebuttal-1 of Exhibit SDG&E-13 are instructive in our review.



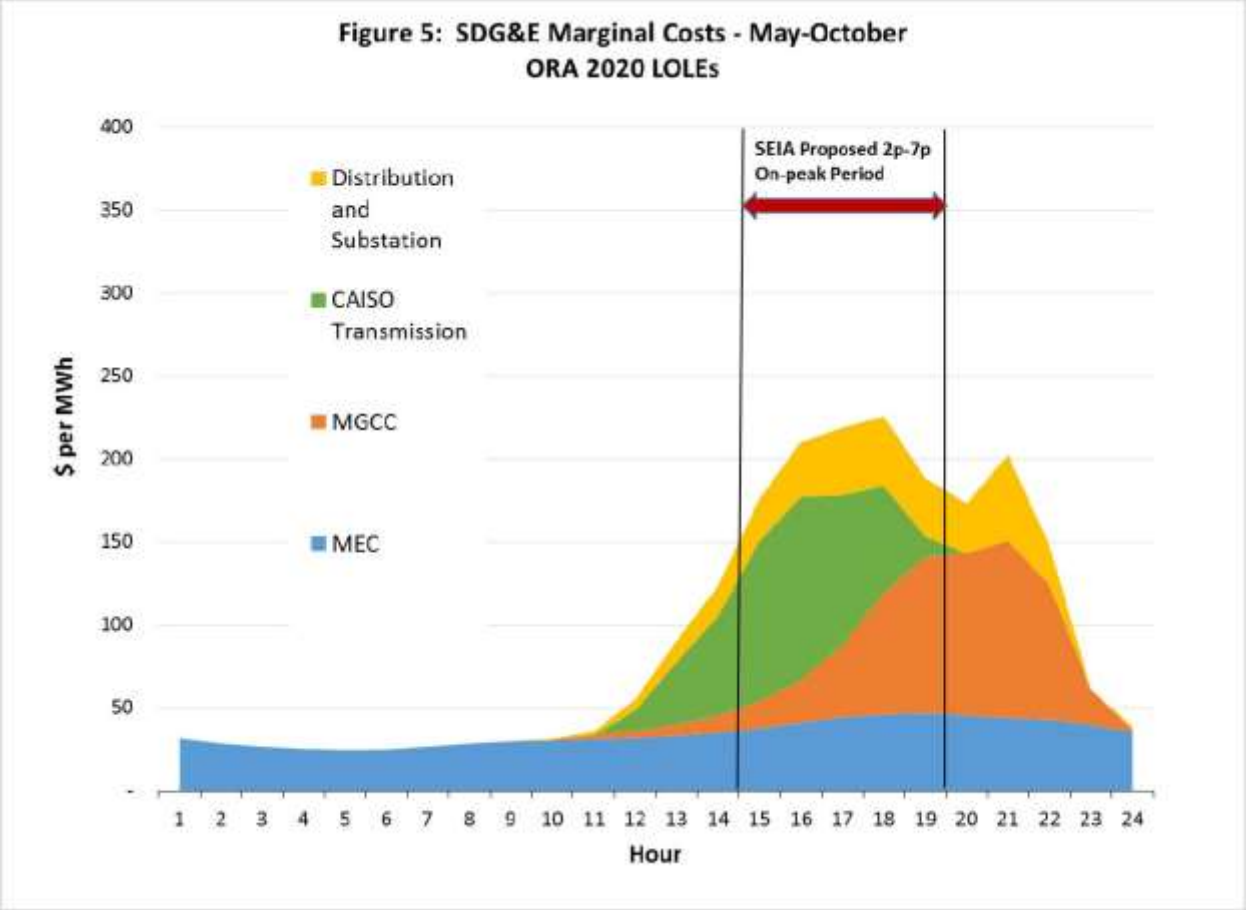
(Chart RBA-5 from Exhibit SDG&E-3 at RBA-10.)

This chart demonstrates the shift in hourly price trends since 2010 and convincingly shows that the highest SDG&E average DLAP prices are shifting later in the day.[17] However, when marginal transmission and distribution costs are overlaid, a different picture emerges.

Unlike the SDG&E charts, which show actual DLAP prices, the SEIA figure below shows a 2020 forecast of marginal costs of four different cost elements: marginal energy cost (MEC in the figure), marginal generation capacity cost

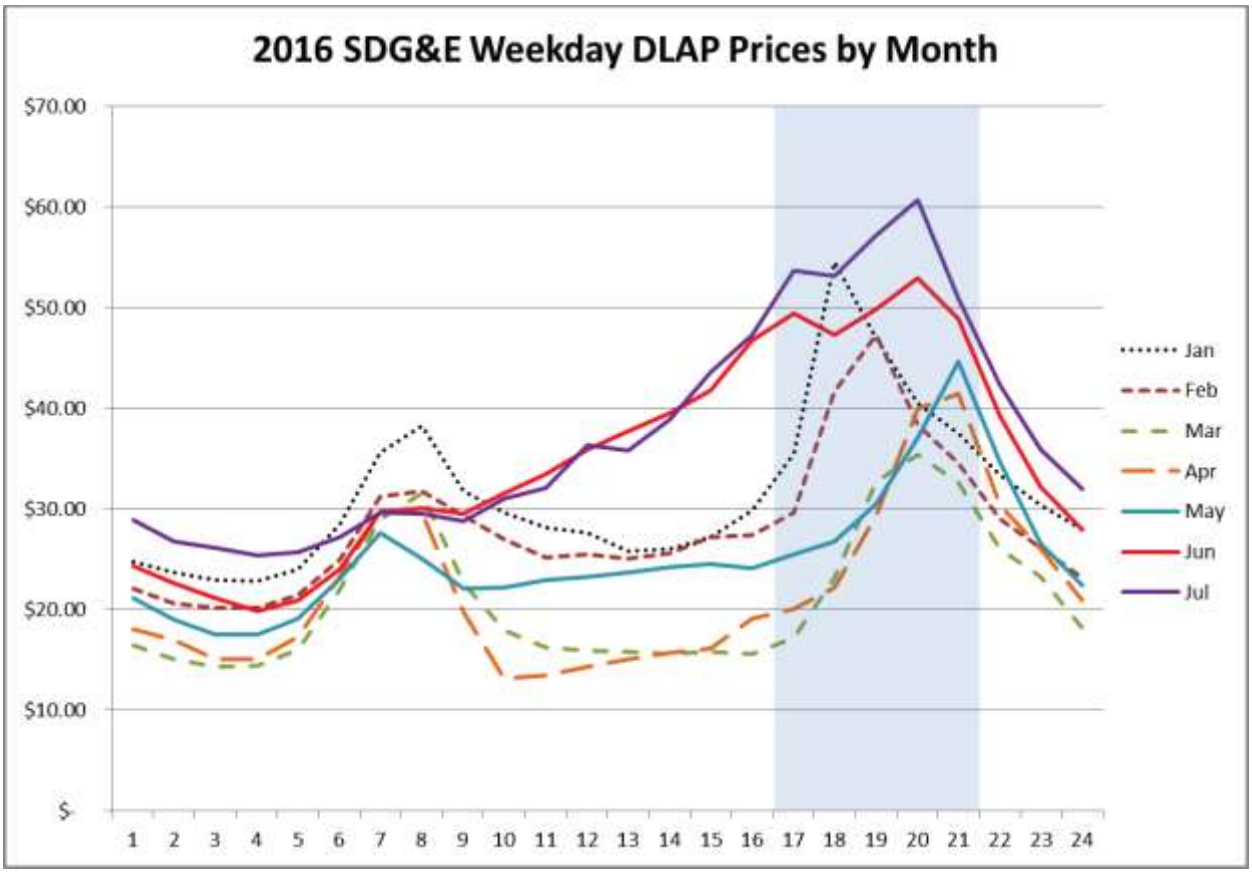
[17] The blue area between midnight and 6 a.m. is SDG&E's proposed weekday super-off-peak period and the blue area between 4 p.m. and 9 p.m. is SDG&E's proposed on-peak period. The remaining hours would be off-peak.

(MGCC in the figure), CAISO transmission cost, and distribution and substation cost. No party contested the methodology that SEIA utilized to arrive at this forecast of marginal distribution and transmission costs.



(From Exhibit SEIA-01 at 17.)

In rebuttal testimony, SDG&E updated its DLAP pricing information based on data from the first half of 2016. This data is instructive about recent price trends, particularly over the course of the spring months, which are important to our discussion of the proper super-off-peak period.



(Chart RBA-Rebuttal-1 from Exhibit SDG&E-13 at RBA-9.)

D.17-01-006, while not binding on this proceeding, provides guidance as we consider the correct TOU periods, indicating that "[m]arginal generation costs, consisting of marginal energy costs and marginal generation capacity costs, constitute the primary basis for setting TOU periods, but the time sensitivity of all utility marginal cost elements, based on hourly patterns, is relevant in assessing TOU periods." (D.17-01-006, Finding of Fact 15.) Considering the 2020 forecast transmission and distribution marginal costs would indicate a slightly earlier TOU period start for SDG&E, somewhere in the 3 p.m. time frame. However, the forecast data continues to support SDG&E's proposed 9 p.m. ending time for the on-peak period as it appears that the 2020 forecast shows distribution costs peaking between 8 p.m. and 9 p.m. The evidence also

supports adopting an on-peak period on weekends. For these reasons, we adopt an on-peak period of 3 p.m. to 9 p.m. daily.

For its super-off-peak period, SDG&E proposes midnight to 6 a.m. weekdays, extending to 2 p.m. on weekends. In its opening testimony, Farm Bureau proposes midnight to 2 p.m. weekdays, extending to 4 p.m. on weekends, and SEIA proposes 10 p.m. to 6 a.m. all days. SEIA would start the super-off-peak period at 10 p.m. instead of midnight to encourage load shifting to the late evening hours. "SEIA proposes to start the super-off-peak period at 10 p.m. in order to make it more convenient for customers to initiate night-time use of electricity. For example, for residential customers, this could be appliance use or vehicle charging. By 10 p.m. net loads, marginal costs, and energy prices are dropping rapidly." (Exhibit SEIA-01 at 18.)

Charts in Exhibits SDG&E-3 and SDG&E-13 show that there is a run-up of energy prices in the 7 a.m. to 9 a.m. period during weekdays of both winter and summer seasons, suggesting that these hours should not be included in the super-off-peak period. On the other hand, Exhibit SDG&E-13 (Chart RBA-Rebuttal-1) shows extremely low DLAP prices in March and April during the hours of 10 a.m. to 2 p.m., lending support to including mid-day hours in certain months in the super-off-peak period.

D.17-01-006 found "[t]he CAISO analysis shows a potential for curtailment of grid-connected solar generation during minimum net load events primarily in the early spring." (Finding of Fact 12.) "Where a utility utilizes two seasons for differentiating TOU rate time periods, it is reasonable to consider proposals to create an overlay of an elective or optional third season for super-off-peak usage." (Finding of Fact 22.) The evidentiary record in this proceeding supports that in March and April from 10 a.m. to 2 p.m. weekday and weekend prices

reflect similar or lower prices than the proposed midnight to 6 a.m. super-off-peak period and therefore should be incorporated into the super-off-peak period. Based on this evidence, we adopt SDG&E's super-off-peak period, further modified to add 10 a.m. to 2 p.m. weekdays in March and April. All hours not defined as on-peak or super-off-peak are considered off-peak.

TABLE 1: Adopted TOU Periods (Weekdays)

TOU Period	Summer	Winter
On-peak	3:00 p.m.-9:00 p.m.	3:00 p.m.-9:00 p.m.
Off-peak	6:00 a.m.-3:00 p.m.; 9:00 p.m.-midnight	6:00 a.m.-3:00 p.m. excluding 10:00 a.m.-2:00 p.m. in March and April; 9:00 p.m.-midnight
Super-off-peak	Midnight- 6:00 a.m.	Midnight- 6:00 a.m.; 10:00 a.m.-2:00 p.m. in March and April

TABLE 2: Adopted TOU Periods (Weekends and Holidays)

TOU Period	Summer	Winter
On-peak	3:00 p.m.-9:00 p.m.	3:00 p.m.-9:00 p.m.
Off-peak	2:00 p.m.-3:00 p.m.; 9:00 p.m.-midnight	2:00 p.m.-3:00 p.m.; 9:00 p.m.-midnight
Super-off-peak	Midnight- 2:00 p.m.	Midnight- 2:00 p.m.

SDG&E must establish its default TOU rates for all customer classes utilizing these foundational on-peak, off-peak, and super-off-peak TOU periods as soon as practicable following the issuance of a final CPUC decision.

7.3. Grandfathering Provisions for TOU Periods

D.17-01-006 established the qualifying attributes of customers who are entitled to remain on existing TOU periods during a five or ten-year transition depending on the customer type. As described in Ordering Paragraph 5 of D.17-01-006, for non-residential systems, this transition continues for ten years after issuance of a permission to operate, but in no event shall the duration continue beyond December 31, 2027 (for schools) or July 31, 2027 (for all other non-residential). For residential systems, this transition continues for five years after issuance of a permission to operate, but in no event shall the duration continue beyond July 31, 2022. Because this proceeding was moving forward concurrently with Rulemaking (R.) 15-12-012, there is substantial testimony regarding the issue of grandfathering, and some parties included additional recommendations to extend the TOU grandfathering provision to a broader set of eligible customers than established in D.17-01-006. Ordering Paragraph 5 of D.17-01-006 is binding on this proceeding and we do not revisit the TOU grandfathering duration adopted therein.

However, Schools have made a compelling argument that in light of their limited construction time frame, work must generally be performed in summer months, and therefore, that the Eligibility Grace Period end date adopted in D.17-01-006 should be extended to August 31, 2018 to ensure schools have two summer construction cycles to complete their projects. As described by Schools witness Duzyk, Assistant Superintendent of Business Services for the San Diego County Office of Education, "[t]his grace period is necessary given the long timelines for school customers to conduct a feasibility study and design, procure, construct and interconnect a distributed generation system. In my experience, projects can take up to three years from feasibility study to interconnection. This

assumes no significant procurement problems or related delays." (Exhibit SDPS-3 at 2.)

Schools also recommend that the interconnection project on file date should be extended to March 31, 2017. Schools submits that "[t]his extension would not increase the number of eligible projects but simply ensures that projects currently in the pipeline receive grandfathering." (Schools Reply Brief at 12.)

D.17-01-006 already identified a separate treatment for schools for the Eligibility Grace Period from other customers. The evidence proffered by witness Duzyk, an experienced school administrator working on school investments and sustainability initiatives, supports extending the schools Eligibility Grace Period by eight months, to August 31, 2018, and the interconnection on file date to March 31, 2017, to support in-progress project completion. Therefore, we direct SDG&E to file a Tier 2 Advice Letter within 30 days of the effective date of this decision to implement the revised Eligibility Grace Period and interconnection on file date.

7.4. Dynamic Pricing Period and Trigger

SDG&E offers a number of rates and tariffs that allow a critical event to be called which triggers dynamic pricing during the event period.[18] As described in D.12-04-045 at 133, "Dynamic Pricing programs provide electric rates that reflect wholesale market conditions." SDG&E's Dynamic Pricing programs include Critical Peak Pricing, Smart Pricing Program, and Peak-Time Rebate Program. These programs and rates impose a short-term rate increase on customers during

[18] Normally the event period is contained in, but may be shorter than, the on-peak TOU period. This is the case for SDG&E's current rates.

critical conditions and is intended to encourage customers to reduce demand on the top nine to 18 days of the year when capacity is needed. SDG&E considers whether to call dynamic pricing events based on conditions in both the San Diego Greater Reliability area and the San Diego sub-area.

SDG&E proposes to disconnect the dynamic pricing period from the adopted TOU on-peak period by setting a shorter four-hour dynamic pricing period (from 2 p.m. to 6 p.m.) on high-demand days; this event period does not coincide with SDG&E's proposed 4 p.m. to 9 p.m. on-peak period. SDG&E reviewed the historic occurrence of peak hours during dynamic pricing event days since 2010 and found the peak has occurred between 2 p.m. and 6 p.m., although this time frame appears to be shifting over time as additional solar energy is added to California's resource mix. (SDG&E Opening Brief at 29.) SDG&E argues that 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." (Exhibit SDG&E-1 at CF-23.) SDG&E also requests the ability to modify the dynamic pricing period more frequently than every five years, the effective period for TOU rates as described in Assembly Bill 327, as it updates its loss of load analysis over time.

Although SEIA argues that SDG&E's identification of a potential for a critical event to occur beginning at 2 p.m. is reason to include 2 p.m. in the base TOU period, no party has contested SDG&E's proposal to shorten the dynamic pricing event period or its request to be able to update the dynamic pricing event period in less than five years. We find merit in SDG&E's proposal to treat the dynamic pricing event period as independent from the base TOU period and to update it based on the changing loss of load analysis of today's market. Calling a

critical event provides flexibility to the utility to respond to exceptional loads, weather, or operating conditions when the base TOU pricing signals have failed to reduce load sufficiently to respond to immediate conditions. Therefore, we adopt a dynamic pricing event period of 2 p.m. to 6 p.m. for SDG&E's dynamic pricing programs and tariffs. SDG&E must implement this new dynamic pricing period as soon as practicable following the issuance of a final CPUC decision. SDG&E must update the critical event period annually by filing a Tier 2 Advice Letter based on a loss of load analysis of the San Diego Greater Reliability area and the San Diego sub-area similar to the one performed in support of Chart RBA-11 in Exhibit SDG&E-3 that demonstrates a substantial change in the Relative Loss of Load Expectation for SDG&E's local capacity areas. The Advice Letter should be served on the service lists of this proceeding and A.17-01-012 et al.

SDG&E also proposes to align the trigger for each of its dynamic pricing programs and tariffs to establish the same trigger for calling a critical event based on load forecasts and to reconcile other minor differences between the tariffs and programs that allow for dynamic pricing events to be called. No party opposed SDG&E's proposals with respect to the revised triggers, and they represent logical changes to simplify administration of these dynamic pricing programs. We direct SDG&E to implement the proposed changes to the dynamic pricing event triggers set forth in Exhibit SDG&E-9 as soon as practicable following the issuance of a final CPUC decision.

8. Rate Design Issues

Once revenue requirements are allocated to customer classes and time of use and seasonal definitions are adopted, we must design rates to collect the allocated revenues. Each of SDG&E's five customer classes (Residential, Small

Commercial, Medium/Large Commercial and Industrial (C&I), Agricultural, Streetlighting) has unique issues that we grapple with below. Our goal in adopting particular rate designs is to ensure that the adopted rates result in revenue collection equal to the costs allocated to that class while simultaneously meeting our other rate design objectives. Over the years, the CPUC has articulated its rate design principles as follows:[19]

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 noncoincident 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.

[19] These principles were described in both D.15-07-001 at 28 and D.17-01-006 at 37.

As we review the numerous rate design issues and proposals in this proceeding, we will consistently return to these guiding principles to assist in our evaluation.

8.1. Residential and Small Commercial Customer Rate Design

Initially, SDG&E proposed no changes to residential rate design other than the addition of an optional electric vehicle rate. No party opposed the optional electric vehicle rate.

For small commercial customers,[20] SDG&E initially proposed to double the monthly service fee over three years, increase the summer on-peak/summer super off-peak differentials to a ratio of 3.88 compared to the current 1.81, maintain the current Smart Peak Pricing program adder at the current level when a critical peak event is called, and establish optional rates (two-period TOU, greater fixed charge option, and reopen Schedule A-TOU). ORA, City, and CALSLA took issue with various aspects of the SDG&E small commercial customer proposals, recommending that the monthly service fee retain the current fixed charge level, Schedule A-TC[21] be moved to a new customer class, and the TOU differentials and Smart Pricing Program adder be reduced.

After testimony was served, these parties continued to discuss their differences as they relate to residential and small commercial customers and reached a joint proposal that was presented as joint testimony (Exhibit JT-4).

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[20] Small commercial customers are generally served on SDG&E schedule TOU-A. This Schedule is the Utility's standard tariff for commercial customers with a demand less than 20 kW. This Schedule is not applicable to any customer whose Maximum Monthly Demand equals, exceeds, or is expected to equal or exceed 20 kW for 12 consecutive months.

[21] This schedule serves Traffic Control customers.

Exhibit JT-4 recommends that the CPUC make no changes to residential tiered rate design as a result of this proceeding, with the exception of changes to the TOU seasonal definition, in which the summer period will begin in June instead of May and run through October, resulting in a winter period from November through May. In addition, the parties recommend we adopt SDG&E's proposal for the introduction of an optional Electric Vehicle rate with a $16 monthly service fee.

The parties propose the same seasonal definitions be applied to small commercial customers and residential customers. Exhibit JT-4 proposes that Schedule TOU-A for small commercial customers reflect a smaller increase to the monthly service fee than SDG&E had proposed as specified at 4 of Exhibit JT-4.[22] Under Exhibit JT-4, the Smart Peak Pricing Adder[23] would remain at the current level of $1.17/kWh for the term of this GRC Phase 2 and SDG&E would revise and reopen Schedule A-TOU for customer up to 40 kW in load, as proposed in SDG&E's testimony. Exhibit JT-4 proposes that for small commercial customers the default rate be a two-period TOU rate with a TOU commodity rate differential of 1.81 consistent with the current TOU-A ratio of summer on-peak to summer super off-peak for the two-period default, with an optional three-period TOU with a TOU commodity rate differential of 3.88 of summer on-peak to summer super off-peak. Rather than including 100 percent of the total

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[22] The agreed upon monthly service fees are:

- 0-5 kW: 2017 - $8/month, 2018 - $9/month, 2019 - $10/month
- 5-20 kW: $16/month
- 20-50 kW: $30/month
- >50 kW: $75/month

[23] SDG&E appears to use the term SPP and CPP interchangeably in the joint testimony and brief. For consistency, we use Smart Peak Pricing when discussing this Adder.

distribution costs in the Greater Fixed Charge Optional Rate as SDG&E originally proposed, Exhibit JT-4 proposes to allow SDG&E to implement a modified Greater Fixed Charge Optional Rate that includes only 50 percent of total distribution costs, including customer costs and distribution demand, through the demand differentiated customer charge with the remaining distribution costs recovered through distribution energy rates.

For Schedule A-TC, Exhibit JT-4 adopts the increase to the monthly service fee consistent with the levels for other small commercial tariffs.[24] Under the joint testimony, Schedule A-TC would continue as part of the small commercial class and maintain the existing SDG&E A-TC rate design adopted in SDG&E's 2012 GRC Phase 2 decision (D.14-01-002), which includes reduced distribution energy rates that reflect recovery of only marginal distribution demand costs.

For small commercial customers, the joint testimony represents a compromise of positions regarding monthly service fees, adoption of a two-period TOU default rate, the Greater Fixed Charge Optional Rate, and Schedule A-TC. Adoption of a two-period default TOU rate and the gradually increasing monthly service fee eases the transition for small commercial customers to default TOU while adoption of an optional three-period TOU and Greater Fixed Charge Optional Rate provides small commercial customers with the opportunity to experiment with different rates that fit best with their load profile.

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[24] The agreed upon monthly service fees are:

- 0-5 kW: 2017 - $8/month, 2018 - $9/month, 2019 - $10/month
- >5 kW: $16/month

For residential customers, we established rate design guidance in D.15-07-001 in R.12-06-013 which includes a transition for residential customers to adjust to default TOU schedules. Therefore, SDG&E's proposal to not make additional changes to rate design for residential customers beyond adding an optional Electric Vehicle rate is appropriate and consistent with the principle that 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.

The residential and small commercial rate design proposals set forth in Exhibit JT-4 represent a reasonable approach to move us closer to adopting rates based on cost causation, while providing stability, simplicity, and customer choice. The residential and small commercial rate design proposals set forth in Exhibit JT-4 are reasonable and should be adopted. We direct SDG&E to implement the residential and small commercial rate design proposals set forth in Exhibit JT-4 as soon as practicable following the issuance of a final CPUC decision.

8.1.1. Applicability Requirements for Small Commercial Tariffs

SDG&E proposes to redefine the applicability of its small commercial tariff Schedules A, TOU-A, and EECC-TOU-A-P to ensure that they truly reflect small commercial customers. The change is designed to ensure that customers whose Maximum Monthly Demand equals, exceeds, or is expected to equal or exceed 20 kW for 12 consecutive months and or exceeds 200 kW in two out of 12 consecutive months are placed on medium/large commercial rates, even if the commercial customer's demand drops below 20 kW for one month out of the

past 12 months. (SDG&E Opening Brief at 67.) SDG&E believes this change is consistent with a commitment made by parties to a settlement agreement adopted in D.14-01-002 and no party has opposed this proposal. The proposed applicability change better reflects the expectation that a small commercial customer's load will generally hover near the 20 kW level that establishes its eligibility for small commercial Schedules A, TOU-A, and EECC-TOU-A-P. The applicability change for small commercial Schedules A, TOU-A, and EECC-TOU-A-P is reasonable and should be adopted. We direct SDG&E to modify the applicability for small commercial rate Schedules A, TOU-A, and EECC-TOU-A-P as set forth in Exhibit SDG&E-8 as soon as practicable following the issuance of a final CPUC decision.

8.1.2. Reduction in Peak-Time Rebate Incentives

SDG&E introduced a Peak-Time Rebate incentive to residential customers in 2012 which provides incentives to customers for load reduction during critical peak hours. This program, approved in D.09-03-026, was established as a transitional option as the CPUC moved towards default TOU for residential customers, with an optional critical peak pricing rate. SDG&E now offers an optional critical peak pricing rate, referred to as its Smart Pricing Program, for residential customers that provides both incentives for load reduction and penalties for continued consumption during the critical peak period. In this application, SDG&E proposes to reduce over two years, and eliminate in the third year, the Peak-Time Rebate incentives since the Smart Pricing Program is operational in order to transition customers from "the less efficient [Peak-Time Rebate] PTR program to the more accurate and efficient dynamic pricing [Smart Pricing Program] SPP rate." (SDG&E Opening Brief at 65.) SDG&E believes its Smart Pricing Program rates are more efficient pricing signals because customers

are rewarded for load reductions during these hours and penalized for load consumption during the same hours, providing stronger motivation to provide demand response during these critical hours.

No party opposed SDG&E's proposal, it is consistent with our transitional objectives described in D.09-03-026, and it furthers our rate design principles to encourage conservation and economically efficient decision-making. SDG&E's proposal to reduce and eliminate its Peak-Time Rebate incentives is reasonable and should be adopted. We direct SDG&E modify the Peak-Time Rebate incentive as set forth in Exhibit SDG&E-1 and SDG&E-2 as soon as practicable following the issuance of a final CPUC decision.

8.2. Food Bank Rate per Assembly Bill 2218

SDG&E proposes to implement its program for eligible food banks pursuant to §739.3 by providing a 20 percent line item discount for the eligible food bank customers in its service territory. SDG&E proposes a self-certification process for the 22 customers it has identified as food banks, where the customer completes an eligibility affidavit. Once returned to SDG&E, the customer will receive a 20 percent line-item discount on their next monthly bill. The proposed discount would be recovered through Public Purpose Program (PPP) rates and from all non-California Alternate Rates for Energy (CARE) customers, with recovery of the discounts in rates addressed through annual PPP advice letters and future budgets 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.

No party addressed SDG&E's food bank proposal in testimony or briefs. In Exhibit SDG&E-25, SDG&E estimated that the annual revenue shortfall associated with the proposed 20 percent discount is $73,495. Currently, there are

a number of programs that provide rate assistance to residential customers, such as CARE, Family Electric Rate Assistance (FERA) and medical baseline, which recognize the need to ensure that all customers have access to energy services to meet their energy needs. In addition, the Expanded CARE program for non-residential customers provides equivalent benefits for non-profit group living facilities. Assembly Bill 327 established that the effective discount for residential as well as non-residential CARE-eligible customers should be between 30 and 35 percent. SDG&E recommends that eligible food banks receive a 20 percent discount because the focus of Assembly Bill 2218 is "to maintain their refrigeration units to house perishables such as fruits, vegetables, and dairy products" whereas the CARE program is intended to ensure access for residential customers to all energy service needs, which support refrigeration and other food related services, as well as lighting, heating, and cooling, etc.

Given that Assembly Bill 2218 addresses a more limited range of support for underserved and economically challenged families than CARE, and recognizing the cost of additional subsidies to other customers, we agree that the proposed 20 percent line item discount for eligible food bank customers is reasonable and adopt SDG&E's proposed food bank rate. We direct SDG&E to establish the food bank line item discount as soon as practicable following the issuance of a final CPUC decision.

8.3. Medium/Large Commercial and Industrial Rate Design

SDG&E's proposals for medium and large non-residential customers include:

- Shifting business customers' monthly service fees towards full recovery of distribution customer costs.[25]
- Shifting recovery of distribution demand-related costs towards 100 percent noncoincident demand charges for customers with distribution demand charges.
- Shifting recovery of generation capacity costs towards 90 percent recovery through a peak demand charge for customers with a commodity on-peak demand charge.

Each of these issues is addressed below.

8.3.1. Monthly Service Fee

SDG&E proposes changes to the recovery of distribution customer costs to move towards a more cost-based monthly service fee for Medium/Large C&I customers by increasing the monthly service fee for Medium/Large C&I customers by 20 percent per year during the GRC Phase 2 period. This change results in offsetting decreases to the distribution noncoincident demand charges for these customers. This proposal is uncontested and is consistent with our desire for rates to be established based on cost causation. The costs recovered through the monthly service fee are generally associated with serving individual customers and are not avoidable, in either the short or long run, based on changes in customer demand and therefore are appropriately recovered through a monthly service fee.[26] The Medium/Large C&I monthly service fee proposal

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[25] Distribution customer costs are also referred to as customer-related distribution costs. *See* Exhibit SDG&E-2, Table CS-16, at CS-22. The number shown in the column labelled "Cost-based monthly service fee" consists of SDG&E's proposed marginal customer access costs, multiplied by SDG&E's proposed distribution equal percent of marginal cost scaling factor.

[26] This should not be taken to imply that these customer-related distribution costs are the same for smaller and larger customers within a given customer class. Therefore in some instances a

Footnote continued on next page

set forth in Exhibit SDG&E-2 is reasonable and should be adopted. We direct SDG&E to implement the Medium/Large C&I monthly service fee rate design proposal set forth in Exhibit SDG&E-2 as soon as practicable following the issuance of a final CPUC decision.

8.3.2. Noncoincident and Coincident Peak Demand Charges

SDG&E's various Medium/Large C&I rate schedules currently rely on demand charges to recover distribution costs not recovered through a monthly service fee. Distribution-related costs that are not recovered through a monthly service fee are currently recovered approximately 65 percent through a noncoincident demand charge and 35 percent through on-peak (or coincident) demand charges.

SDG&E proposes to recover more demand-related distribution costs through noncoincident demand charges to reflect what it characterizes as the "more localized nature of these resources and better reflect how costs are incurred." (SDG&E Opening Brief at 45.) SDG&E describes how it designs its distribution system as follows:

> SDG&E designs its distribution facilities to meet the peak demand for that portion of the distribution system which serves customers located in the specific area. This means that a substation transformer, distribution transformer, or circuit is designed to meet the peak demand at its specific location. This method of design is the standard distribution planning process, not only at SDG&E but also throughout the utility industry. This method of design takes into account the

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demand-differentiated monthly service fee (as we have adopted for small commercial) may be more appropriate than a "one-size-fits-all" monthly service fee.

> individual customer loads on each circuit and substation bank. (SDG&E-5 at JB-2 to JB-3.)

In light of how it designs its distribution system, SDG&E's opening testimony proposed to increase the recovery of distribution costs through noncoincident demand charges from the current 65%/35% noncoincident demand/peak split and reduce the recovery through on-peak demand charges. The resulting noncoincident demand/peak split would be 75%/25% in Year 2 and 85%/15% in Year 3. FEA generally supported SDG&E's proposal but did not provide independent analysis for how it reached this conclusion.

In contrast, SEIA proposed reducing the recovery of distribution costs through noncoincident demand charges to a 39%/61% noncoincident demand/peak split. SEIA describes its recommendation as follows:

> SDG&E should recognize that a significant portion of the costs of SDG&E's distribution system are driven by diversified demands that generally are coincident with system peak demands. The costs of SDG&E's substations and the upstream portion of SDG&E's distribution system are not driven by the maximum loads of individual customers whenever those loads occur. As a result, SEIA strongly opposes SDG&E's proposal to allocate 100% of distribution costs through non-coincident demand charges in the rates of SDG&E's medium and large commercial customers. Instead, SEIA supports the allocation of 100% of SDG&E's substation costs and 50% of its feeder and local distribution costs, or 61% of total marginal distribution costs, on a time-dependent basis through on-peak rates. (Exhibit SEIA-01 at ii.)

SEIA argues that the above cited SDG&E testimony means that:

> SDG&E does not design its distribution system to meet the sum of the individual maximum demands of all customers on a circuit regardless of when those peaks occur, but instead to meet the aggregate, diversified peak demand of these

> customers… Thus, the aggregate, diversified peak demand on the circuit will be far less than [the sum of the individual maximum demands of all customers on a circuit] and, as [SDG&E witness] Baranowski conceded, SDG&E only designs its distribution system to meet this diversified demand on each system element. In sum, SDG&E designs its distribution system to meet the peak demand of each system element, not the sum of the peak demands of all individual customers. (Exhibit SEIA-01 at 25-26.)

SEIA agrees that some portion of distribution costs should be collected through noncoincident demand charges:

> On the portion of the distribution system closest to the customer, there is less diversity of load, and individual customers' maximum demand is a factor in system design. This is particularly true on circuits that serve a small number of large C&I customers. Thus, there is a rationale for using [noncoincident demand charges] to recover a portion of distribution system costs, but not 100%, because there is significantly greater diversity as one moves further up the distribution system, away from individual customers and toward higher-voltage distribution circuit, substation, and transmission facilities. (Exhibit SEIA-01 at 26.)

SEIA also points out that SDG&E's "marginal cost calculations assume that the annual peak demand on the distribution system is the key driver of distribution costs. It would be fundamentally inconsistent for the utility to calculate its distribution marginal costs on the basis of the annual peak demand on the distribution system, yet to charge customers for those costs based 100 percent on individual customer's non-coincident demands." (Exhibit SEIA-01 at 29.)

City supported SEIA's proposal that the noncoincident demand/peak split for distribution cost recovery be 39%/61%. City believes that "rates based on non-coincident demands undercut the State's efforts to encourage energy

efficiency and renewable resources, both of which are explicitly encouraged through the State's Loading Order." (Exhibit CSD-1 at 33.) City also noted that SDG&E itself had signaled its intent to move away from noncoincident demand charges for transmission rates in draft testimony that it did not ultimately submit to the Federal Energy Regulatory Commission (FERC). City believes that since "SDG&E's loading of its distribution substations and its feeders are fairly coincident with summer peak demands on SDG&E's system, then the loading of distribution substations and feeders is therefore consistent with the loading of SDG&E's transmission system. As a result, SDG&E's recovery of its distribution substation and feeders should be based not on 100 percent non-coincident peak as proposed by SDG&E but instead on seasonal peak demands." (Exhibit CSD-1 at 33.) CalSEIA opposed SDG&E's proposed move to recover more distribution costs through noncoincident demand charges and presented an analysis of how the combined changes to TOU period and the noncoincident demand/peak split would impact customers with solar installations. (*See* generally, Exhibit CalSEIA-1 at 6-8.)

After opening testimony was served, parties continued discussions surrounding this issue. Ultimately SDG&E, SEIA, City, and FEA presented joint supplemental testimony, identified as Exhibit JT-3, which presented a new recommendation regarding recovery of distribution costs through noncoincident and peak charges. As described in Exhibit JT-3, SDG&E, SEIA, City, and FEA now propose:

- A change from the current noncoincident demand/peak split (65%/35%) for distribution cost recovery to 70%/30% for the term of this GRC Phase 2.
- SDG&E will conduct a study to examine the appropriate allocation of distribution costs between noncoincident

demand charges and system peak demand charges to be included in SDG&E's next GRC Phase 2 proceeding.

- SDG&E will conduct a study to examine the appropriate allocation of transmission costs between noncoincident demand charges and system peak demand charges to be filed at FERC prior to SDG&E's next GRC Phase 2. This FERC filing is expected to be made in late 2017/early 2018. SDG&E will provide parties to A.15-04-012 with an advance copy of this study six week before SDG&E's FERC filing.

Exhibit JT-3 does not provide additional justification for adoption of the proposal, indicating that the CPUC should consider it a non-precedential resolution of disputed issues.[27]

In its brief, CalSEIA opposes the 70%/30% noncoincident demand/peak split set forth in the joint testimony. CalSEIA encourages the CPUC to "reject any movement in the direction of shifting cost recovery from coincident demand charges to non-coincident demand charges. The [CPUC] should require SDG&E to do the two studies it recommends doing in the joint testimony. There is no need to "throw them a bone" in exchange for doing studies the utility should be doing anyway." (CalSEIA Opening Brief at 11-12.) In support of its position, CalSEIA points out that the CPUC has previously found that the "need for additional generation, transmission, and primary distribution capacity are driven by customers' coincident peak demand." (D.14-12-080, Finding of Fact 8.)

CalSEIA argues that "with the passage of SB 350 in 2015, which increased the Renewables Portfolio Standard to 50 percent, mid-day over-generation will

[27] Exhibit JT-3 mistakenly characterizes SEIA's original testimony as supporting a reduction of noncoincident demand recovery to 61 percent. (Exhibit JT-3 at 2.) Rather, SEIA's position was that noncoincident demand recovery should be reduced to 39%. (Exhibit SEIA-01 at 33.)

become a significant issue to address in the coming years." (CalSEIA Opening Brief at 12.) CalSEIA notes that the Energy Division's October 10, 2016 workshop presentation concluded that noncoincident charges can discourage mid-day energy use that benefits the grid by absorbing increasing mid-day generation due to solar production. CalSEIA also points out that recovering more distribution costs in peak demand charges will result in energy storage systems being operated to maximize grid benefits.

> The most common use case of energy storage systems currently is the reduction of demand charges for commercial customers. Storage systems react to increases in the host customer's load and shave off short-term peaks. However, if the price signals those customers are responding to are outside of peak periods, customers are using the limited discharge capacity of their storage systems at non-optimal times. If the demand charges that storage customers are responding to line up with peak system needs, the storage devices are used both for reducing sharp peaks in consumption and reducing consumption during peak load periods.
>
> The Energy Division presentation also correctly states that energy storage systems have a more difficult time responding to non-coincident demand charges than coincident demand charges. If a storage system has to be able to respond to increased customer demand at any time of the month, it must remain ready to perform this service at all times and may not be as effective at predicting and responding to customer behavior. If it only must respond to increased usage during peak periods, it will be more effective at performing that service and will be available to perform other services at other times of the month. (CalSEIA Opening Brief at 12-13.)

CalSEIA argues there is "a clear [CPUC] interest in moving toward increased time dependence in rates, and SDG&E's proposal to shift cost recovery toward non-coincident demand charges pushes against this tide." (CalSEIA

Opening Brief at 12.) SDG&E argues that the proposal to recover distribution costs via a 70%/30% noncoincident demand/peak split is a modest increase in the noncoincident demand charge and should be adopted until the proposed studies are completed.

The full record developed on the options for how to split the cost recovery of distribution costs between noncoincident demand and peak demand charges, as well as our recent decisions, state policy, and our rate design principles lead us to conclude that the proposal recommended by SEIA in Exhibit SEIA-01 to shift the noncoincident demand/peak split to 39%/61% should be adopted pending completion of the two studies proposed in Exhibit JT-3. As evidenced by a review of recent CPUC decisions, the CPUC is moving to greater use of TOU and other time-varying rates. TOU is now mandatory for all C&I customers, we have established a transition plan for residential customers to move to default TOU rates, and TOU rates are now mandatory for NEM 2.0 customers. This trend of increasing CPUC reliance on time dependent rates is important because it would be inconsistent to simultaneously increase our use of noncoincident demand charges which are non-time dependent.

Noncoincident demand charges incentivize customers to flatten their load, but given high penetration of solar resources, solar-following loads are becoming more desirable to avoid curtailing renewable resources and may be less costly to serve than customers with flat loads.[28] Noncoincident demand charges can

[28] *See* generally, Exhibit SDG&E-3 at RBA-9: 5-8 and the charts on RBA-10 and the following pages, and Exhibit SDG&E-13 at RBA-9, Charts RBA-Rebuttal-1 & RBA-Rebuttal 2. These charts show generally lower-than-average DLAP energy prices during peak solar hours (10 a.m. – 3 p.m.), for most months. SDPS-5 at 4, Figure 1 shows the solar production curve and load for a typical San Diego school.

discourage beneficial energy use, such as electric vehicle fleet charging (overnight or during hours with high solar generation), or Reverse Demand Response to encourage customers to use renewable energy that might otherwise be curtailed due to over-generation conditions. A customer (such as a school) with its highest load mid-day would have a higher noncoincident demand but lower coincident peak demand. However because cost causation for generation and transmission capacity is driven by coincident peak demands (now after 3 p.m.), schools and other daytime-load customers may be being overcharged relative to their role in cost causation.

We have previously found that noncoincident demand charges do not reflect cost causation for primary distribution, transmission, nor generation capacity costs (D.14-12-080, Finding of Fact 8) and therefore adopting the SEIA proposal that 100 percent of SDG&E's upstream substation costs and 50 percent of its feeder and distribution circuit costs should be recovered in time-dependent, peak demand charges is a logical next step to move rate design towards alignment with cost causation.[29] Adopting this proposal is also consistent with our rate design principles that rates should be based on marginal cost, encourage conservation and energy efficiency as well as reduction in both peak and noncoincident demand, avoid cross subsidies and support state policy goals, and encourage economically efficient decisionmaking.

As proposed in Exhibit SEIA-01 at 33, based on SDG&E's filed marginal costs for substations ($22 per kW-year) and feeder and distribution circuits ($78 per kW-year), this means that 61 percent of SDG&E's distribution costs

[29] Substations and a majority of distribution circuits are classified as primary distribution as that term was used in D.14-12-080.

should be recovered from time-dependent on-peak charges, with 39 percent allocated to noncoincident demand charges. We direct SDG&E to implement this outcome by allocating time-related distribution costs to peak-related demand charges for Schedules AL-TOU and A6-TOU, and to on-peak energy charges for Schedule DG-R as soon as practicable following the issuance of a final CPUC decision.

Although we do not adopt the ratemaking proposal in Exhibit JT-3, we find merit in the recommendation that SDG&E should perform additional studies on the appropriate allocation between noncoincident and peak charges for recovery of distribution (and transmission) costs to provide additional analysis on this issue. Therefore, SDG&E is directed to conduct a study to examine the appropriate allocation of distribution costs between noncoincident demand charges and system peak demand charges to be included in SDG&E's next GRC Phase 2 proceeding and conduct a study to examine the appropriate allocation of transmission costs between noncoincident demand charges and system peak demand charges to be filed at the FERC prior to SDG&E's next GRC Phase 2. SDG&E must consult with parties to this proceeding in preparing its research plan for the studies, and file the research plan as a Tier 2 Advice Letter within 120 days of the effective date of this decision.

In addition, we direct SDG&E to include at least one rate option available to each non-residential rate class (except streetlighting) that exempts usage during the adopted March and April super-off-peak daytime hours (both weekday and weekend) from distribution demand charges as soon as practicable following the issuance of a final CPUC decision. Our inclusion of March and April mid-day hours in the adopted super-off-peak period is designed to stimulate load shifting and alleviate renewable curtailments during periods of

abundant low cost energy generation, particularly during the spring mid-day hours, which has been termed the matinee period. "If demand charges also apply during these matinee periods, then the customer's increase in energy use during matinee periods could result in a higher demand charge. In other words, the volumetric rate would encourage increased use at the same time that the demand charge signals customers not to use a large amount of energy." (D.16-11-021 at 22.)[30]

8.3.3. Recovery of Generation Capacity Costs in Peak Demand Charges

50 percent of on-peak generation capacity costs are currently recovered through on-peak demand charges for Medium/Large C&I customers and Agricultural customers on Schedule PA-T-1. 20 percent of on-peak generation capacity costs are currently recovered through on-peak demand charges for Medium/Large Agricultural customers on Schedule TOU-PA. The remainder of the on-peak generation capacity costs are recovered through volumetric time-of-use energy rates. SDG&E proposes to increase the amount of recovery of on-peak generation capacity costs via the on peak (coincident) demand charge by increasing the percentage of recovery through on-peak demand charges by ten percent a year beginning in Year 2 until 90 percent is reached. Increasing the share of generation capacity costs recovered via peak demand charges will result in a compensating decrease in volumetric energy rates due to the reduction in

[30] We note that Southern California Edison Company has filed a Petition for Modification of D.16-11-021, arguing that from a timing perspective, it should be relieved of its obligation to implement the approved Matinee Pricing Pilot adopted in that decision. Whether the pilots adopted in D.16-11-021 go forward or not, the description of the conflicting incentives that low volumetric rates that result in demand charges would cause remains valid.

generation capacity costs recovered in energy rates. This proposal is uncontested.

In D.14-12-080, the CPUC adopted an Option R rate for Pacific Gas and Electric Company (PG&E) which shifted revenue collection for 100 percent of generation capacity costs away from demand charges and into volumetric energy charges in a manner that was determined to be revenue neutral within PG&E's E-19 and E-20 customer classes, and therefore had no cap on participation by eligible customers. Option R also shifted 75 percent of the distribution capacity costs out of the peak demand charges and into peak energy charges. In D.14-12-080, the CPUC found that the "need for additional generation, transmission, and primary distribution capacity are driven by customers' coincident peak demands." (D.14-12-080, Finding of Fact 8.) In addition, that decision found that "[d]ue to the benefits of load diversity, the capacity needed to reliably serve customers at the higher levels of the electric grid is determined by the average demands of individual customers during coincident peaks rather than each customer's single highest interval of demand during peak time of use billing hours." (D.14-12-080, Finding of Fact 9.) D.14-12-080 also found significant problems with PG&E's methodology for assessing peak demand charges (*see* Findings of Fact 11, 12, 18, and 19). Since SDG&E uses a similar methodology, basing such charges on a customer's highest 15-minute interval during the peak TOU period, we find it likely (as with PG&E) that the customer's maximum 15-minute interval demand could occur on a different day than the system maximum demand, which could result in a solar customer being under-credited for the capacity provided by the customer's rooftop solar system (Finding of Fact 12).

Although SDG&E's proposal to shift more of the recovery of on-peak generation capacity costs into peak demand charges is uncontested, we decline to adopt it as it is contrary to our findings in D.14-12-080, our rate design principles that support rates based on cost-causation principles, and encouraging the reduction of both coincident and noncoincident peak demand. Instead, SDG&E should retain the current ratio of cost recovery for generation capacity costs between the peak demand charge and volumetric energy costs for Medium/Large C&I and Agricultural customers.

In order to establish a better record on the appropriate allocation for the next rate design application, SDG&E must conduct a study to examine the appropriate allocation of generation capacity costs between volumetric and peak demand charges to be included in SDG&E's next GRC Phase 2 proceeding. We encourage SDG&E to seek input on study methodology from parties. SDG&E must include the study results in its 2019 Phase 2 GRC application, expected in December 2018. In this study, SDG&E should also consider whether a shorter duration peak demand period for assessing coincident peak-related demand charges should be established, relative to the adopted TOU peak period, as a means to partially alleviate some of the problems with coincident demand charges identified in D.14-12-080.[31]

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[31] For example, if the adopted peak period is 3 p.m. to 9 p.m. but the system peak hour typically occurs between 4 p.m. and 6 p.m., should the customer's coincident demand charge be based on the customer's maximum 15-minute demand occurring between 4 p.m. and 6 p.m.? This refinement could improve the accuracy of the coincident demand charge in reflecting the capacity actually utilized by the customer at the time of coincident peak, as well as the contribution (if any) of a customer's rooftop solar installation.

8.3.4. Substation Service Rate

Customers receiving service on secondary substation and primary substation rates do not pay distribution demand charges; instead the costs associated with substation service are reflected in their monthly service fee. Consistent with its proposal for other medium and large commercial and industrial customers, SDG&E proposed to increase the monthly service fee for customers receiving service on secondary substation and primary substation rates by 20 percent per year to reflect that substation customers continue to fully utilize distribution demand services.

In response, FEA proposed to set the monthly service fee for substation customers equal to the monthly service fee applicable to regular primary and secondary customers. FEA also proposed a noncoincident demand charge of $3/kW equal to the rounded Equal Percentage of Marginal Cost value of substation demand costs. SDG&E and FEA were the only parties who addressed the issue of the monthly service fees associated with substation rates.

SDG&E and FEA continued discussing their proposals and memorialized a joint proposal in Exhibit JT-1. Exhibit JT-1 would increase the monthly service fee for secondary substation and primary substation customers by three percent per year over the term of this GRC Phase 2, such that over a three-year period, there would be a total increase to the monthly service fee of 9 percent.

The substation rate design proposal set forth in Exhibit JT-1 represents a reasonable approach to move us closer to adopting rates based on cost causation, while providing stability and simplicity. The substation rate design proposal set forth in Exhibit JT-1 is reasonable and should be adopted. We direct SDG&E to implement the substation rate design proposal set forth in Exhibit JT-1 as soon as practicable following the issuance of a final CPUC decision.

8.3.5. M&L C&I "Cost-Based" Rate Option

SDG&E proposed an alternative "cost-based" rate option for Medium/Large customers that reflects "a cost-based [monthly service fee], distribution demand costs recovered through a [noncoincident] demand charge, with an exemption for demand in the super off-peak period, and an on-peak demand charge that reflects 90% of generation capacity…" (SDG&E Opening Brief at 49.) While we do not concur with SDG&E's representation of this rate as cost-based because the demand charge features of this rate run counter to the conclusions reached elsewhere in this decision, no party opposed SDG&E's proposal to offer Medium/Large customers this rate option, it is consistent with our interest in providing customer choice, and therefore, should be adopted. We direct SDG&E to establish the alternative medium and large commercial and industrial rate option described in Exhibit SDG&E-2 (at CS-49 and 50) as soon as practicable following the issuance of a final CPUC decision.

8.3.6. Schedule DG-R and OL-TOU

Schedule DG-R was approved by the CPUC in D.08-02-034 as part of a settlement agreement. Service under Schedule DG-R is available on a voluntary basis for all metered non-residential customers whose peak annual load is equal to or less than 2 MW, and who have operational, distributed generation, and the capacity of that operational distributed generation is equal to or greater than ten percent of their peak annual load. Schedule DG-R rates are based on the standard Medium/Large C&I Schedule AL-TOU with the noncoincident demand charge for transmission and distribution costs set at 50 percent of the equivalent noncoincident demand for other commercial schedules, and the residual distribution costs for Schedule DG-R recovered through a flat (non-time-varying) energy charge. SDG&E has not proposed to change the

structure of Schedule DG-R, but changes to the default TOU schedule (AL-TOU) for the monthly service fee and demand charges and TOU periods would impact Schedule DG-R because of its linkage to Schedule AL-TOU.

City argues that any changes to Schedule DG-R "will harm existing solar customers who are on this schedule, and will also create a disincentive for new customers to adopt solar through this rate, as the economic benefit of adopting solar is reduced." (Exhibit CSD-1 at 20.) City recommends the CPUC (1) de-link Schedule DG-R from Schedule AL-TOU so the proposed changes in the monthly service fee and demand charges do not affect this schedule and (2) grandfather Schedule DG-R TOU time periods currently in effect for a minimum of 20 years from enrollment on the tariff.

The primary issues raised by City regarding Schedule DG-R are obviated by the fact that customers on Schedule DG-R will be grandfathered onto the existing TOU time periods to the extent they meet the eligibility requirements set forth in Ordering Paragraph 5 of D.17-01-006. Similar protections were granted to residential net energy metering successor tariff customers in D.16-01-044. The CPUC has made clear that grandfathering protection adopted for current solar customers "only applies to the TOU time periods; rates should still be adjusted to reflect changes in revenue requirement and cost allocation." (D.17-01-006 at 59.) In addition, this decision adopts the proposal set forth in SEIA's testimony regarding demand charges, which mitigates the negative impacts on this rate schedule that City describes. For these reasons, we retain the linkage of Schedule DG-R to Schedule AL-TOU and direct SDG&E to implement changes to Schedule DG-R as necessary based on changes to Schedule AL-TOU as soon as practicable following the issuance of a final CPUC decision.

Schedule OL-TOU is a rate that is applicable only to metered outdoor sports and recreation area lighting and safety and security lighting at these venues. SDG&E proposes to modify the commodity rate for this schedule to recover on-peak capacity costs in the on-peak energy rate, and the off-peak capacity costs in the off-peak energy rates. No party opposed this proposal and we direct SDG&E to implement its proposed changes to Schedule OL-TOU as soon as practicable following the issuance of a final CPUC decision.

8.4. Schools

Schools are typically served under multiple rate schedules with multiple meters and accounts per location. "Public schools in San Diego County have experienced energy cost increases of an average of over 40% since 2013, with some schools seeing over 70% increases in electricity bills." (SDPS-5 at 2.) "This increase translates into more than $37 million per year in increased utility costs for public schools. In addition, while schools have traditionally invested in solar and other renewable energy programs to reduce energy costs, these programs will become less economical in the future [because] the proposed time-of-use (TOU) shift will devalue solar systems in the future." (SDPS-2 at 3.) Despite "(1) unique project financing structures due to their ineligibility for the federal tax credit and (2) inability to raise revenue to offset price changes[, solar s]chools have been able to devote more resources to operations through capital savings from solar. Any reduction in these savings [resulting from the TOU period shift] will hurt schools and students." (SDPS-3 at 2.)

With this background in mind, along with prior CPUC guidance,[32] SDG&E and Schools engaged in an effort establish a rate design approach specific to schools that provides some relief to these critical public institutions. The key terms of the Schools Settlement are:

- All school accounts (both schools sites and administrative facilities for K-12 public school districts and the San Diego County Office of Education) receive a 12.5 percent line item discount to their monthly electric bills through December 31, 2019.[33]
- All school accounts will receive a bill comparison of their annual bills calculated on historic usage, using both current effective rates and rates adopted by the final decision in this proceeding. If an account is identified as negatively impacted by the bill impacts analysis, SDG&E will provide a separate line item fixed indifference payment depending on whether grandfathering provisions are adopted.
- In the event that a final decision in this proceeding includes provisions related to "grandfathering" outside of a TOU settlement, the fixed indifference payment will not be applicable to negatively impacted solar accounts, but would continue to be available to negatively impacted non-solar accounts. All public school accounts, including solar accounts, will continue to receive the 12.5 percent line item discount.

SDG&E and Schools argue that the Schools Settlement meets the CPUC's settlement standards discussed in Section 3 above. Their arguments focus on two elements, whether it is reasonable in light of the whole record and in the

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[32] D.15-08-040 at 26, fn. 49.

[33] On brief, Schools argue that the discount should cover the period May 1, 2017 through December 31, 2019 even if rates are not implemented until a later date. In its reply brief, SDG&E conceptually agrees with this recommendation with some clarification.

public interest. UCAN argues that because the Legislature declined to adopt a bill in support of an explicit discount for schools in Senate Bill 1041, while at the same time adopting an explicit discount for food banks in Assembly Bill 2218, adopting a discount for a subset of customers like schools is not consistent with law.

Under questioning by the ALJs, SDG&E clarified that the revenue shortfall resulting from this settlement is intended to be collected from all customer classes. (RT at 310.) Under cross-examination by Farm Bureau, SDG&E witness Fang confirmed that the annual revenue shortfall from the 12.5 percent discount would be about $10 million, and the annual revenue shortfall from the fixed indifference amount would be about $1.6 million. (RT at 282.) Under cross-examination by UCAN, SDG&E witness Fang confirmed that the Medium/Large C&I class as a whole (which includes 98 percent of billed usage for schools) will see a decrease of its share of allocated revenue of between 1.3 and 1.0 percent annually over three years as compared to the system average change, excluding the 12.5 percent line item discount. (RT at 299-300.)

TURN, UCAN and the Farm Bureau submitted joint comments opposing the Schools Settlement. Among other things, these parties argue that "absent a statute and legislative directive to do so, the CPUC should decline the opportunity to give one subset of customers in the C&I class discounted rates at the expense of all other ratepayers." In addition, they argue that "[i]f the Commission is going to provide rate relief for [the Schools] . . . then any lost revenues associated with this relief should be allocated entirely to the C&I class and should not burden any other customer class." (UCAN/TURN/Farm Bureau November 28, 2016 Joint Comments at 4 and 11.)

SDG&E and Schools filed a joint reply. FEA filed a reply, explaining "while FEA is not taking a position on the substance of the settlement between SDG&E and [Schools], FEA believes that fairness and consistency require that the burden of the settlement be spread broadly throughout all rate classes. Should the proposal be to confine the recovery of these discounts solely within the C&I customer classes, FEA would then be compelled to oppose the settlement in its entirety." (FEA December 6, 2016 Reply Comments at 3.) SDG&E counters TURN/UCAN/Farm Bureau, arguing "that the size of the proposed Schools' discount is well-calibrated when compared with existing legislatively-directed and non-legislatively-directed discounts. For example, legislatively directed CARE discounts range from 30% to 35% and SDG&E's proposed legislatively-directed food bank discount is 20%. In contrast, the proposed Schools' discount reasonably compares with the non-legislatively-directed, Commission-approved FERA discount of 12%." (SDG&E Opening Brief at 15, citations omitted.) SDG&E also points out that SDG&E is authorized to recover its FERA revenue from all of its non-CARE customers and this approach is consistent with the purpose of the discount and fixed indifference amount contained in the Schools Settlement: to support the Schools in providing a larger public benefit. For this reason, SDG&E argues any revenue shortfall is appropriately recovered from all non-CARE customers.

SDG&E and Schools focus on the fact that schools serve a public good and do not have the flexibility of other commercial customers to modify their business operations to respond to the changing energy market or to raise revenues in any substantial manner to address increased energy costs.

> SDG&E does believe that this discount would be appropriate for [recovery by] all customer classes given that the nature of the discounts, what we're looking to address, we do feel sort

> of fits the public goods type of categorization of what is currently considered for public purpose programs. So we do see this as sort of a broader public good and therefore do believe that [it is] appropriate to recover [the discount] from all ratepayers. (RT at 309.)

While the public interest argument has been compellingly presented, the annual cost of the discounts (approximately $11.6 million/year) will be borne by other customers who, while they may have more flexibility to pass costs on to others or shift their load to avoid increased energy costs, may also serve a public good. As UCAN points out, the City, "the U.S. Navy, nonprofits and charities are all similarly situated with the [Schools], with the exception that they are not going to receive a SDG&E rate discount and will now, if the settlement is approved, be paying for the [Schools] special rate discount of approximately $35 million of 3 years." (UCAN Reply Brief at 4.) "When other ratepayers are asked to support a substantial discount to a limited group of customers, the Commission must closely scrutinize all aspects of the matter to ensure all ratepayers are being treated fairly." (Farm Bureau at 13.) "Although schools, of course, are invaluable to communities and the State funding for them is appropriately through the general tax system, electric ratepayers are merely a subset of the general taxpaying public and should not be made to substitute as a source of revenue." (Farm Bureau Opening Brief at 12.)

Under examination by the ALJ, it became clear that many schools themselves may not receive information about their electric costs and thus have little incentive or information to effectively manage their energy usage because electric bills are received and paid in central business offices. (RT at 322-324.) In addition, the evidence shows that the "majority of the 40 individual school

districts analyzed [by SDG&E] showed annual bill benefits from SDG&E's TOU proposal." (Exhibit SDG&E-11 at CF-48.)

The school districts in the analysis performed by SDG&E that are negatively impacted by the changing TOU on-peak period are schools that installed solar, who will receive less revenue crediting for their solar generation as a result of the modified TOU period. The evidence in this proceeding, discussed extensively in Section 7.2, demonstrates that the market value of generation production during the mid-day hours when solar is producing has lower value than in the past because of its increasing abundance. In recognition that customers, including schools, have made investments in solar facilities in reliance on expected revenue streams based on today's TOU periods, we have adopted grandfathering provisions in D.17-01-006, and today's decision expands the grace period for in-progress solar installations in schools located in SDG&E's service territory to take advantage of that grandfathering provision.

The modifications adopted today to the SDG&E proposed on-peak TOU period, demand charges, generation demand cost recovery, and grandfathering for solar schools, all are expected to reduce the impacts of the changing time-of-use periods on affected solar school accounts. In light of these changes, we find that the additional line item and fixed indifference discounts proposed for schools place an inappropriate burden on other customers and therefore should not be adopted.

8.5. Electric Vehicle Fleets

SDG&E did not propose a rate unique to electric vehicle fleet operators. City recommends that a specific rate for commercial fleet electric vehicle owner be adopted because "it … wishes for purposes of its Climate Action Plan to encourage other businesses in the City with fleet vehicles to convert to electric

drive." (City Opening Brief at 25.) Fleet operators, like SD Airport Parking, who operate 24/7, and may not have the flexibility to shift all charging to super-off-peak hours, may find their new exposure to demand charges as a limiting factor to pursuing electrification.[34] SD Airport Parking proposes to increase the applicability of SDG&E's small commercial schedule (Schedule A-TOU) from 20 kW to 60 kW for commercial customers with EV fleet charging.

SDG&E does not support tripling the size of the rate schedule for small commercial customers, which generally is 20 kW or below. However, in the event the CPUC were to adopt SD Airport Parking's proposal, SDG&E recommends it only be approved on a limited basis for customers who would transition off of small commercial schedules (like Schedule TOU-A) due to electric vehicle fleet charging, and only apply if there is a time gap between when SDG&E updates small commercial eligibility requirements resulting from this decision (July 2018) and implementation of vehicle integration rates adopted in A.17-01-020.

Because the grid-integrated rate proposed in A.17-01-020 still includes a sizeable fixed charge applied directly to commercial customers' maximum annual demand, it is not clear that proposal would address SD Airport Parking's concerns, which stem from its business model which will require some level of charging during on- and off-peak hours. SD Airport Parking made a compelling

[34] Commercial customers such as SD Airport Parking with newly-electrified vehicle fleets may be moved from small commercial (under 20 kW) status to Medium/Large commercial rates due to the increase in demand resulting from vehicle charging. Such customers will be newly exposed to demand charges which are not present in small commercial rates.

case that without some relief from demand charges, it will be very challenging for fleet operators to make a business case for electrification.

SD Airport Parking has pointed out that both PG&E and Southern California Edison Company (SCE) implemented specialized rates to promote fleet electrification, but SDG&E has not. We have previously granted, in Resolution E-4628, the ability of PG&E transit operators to utilize PG&E's small service TOU energy rates (the equivalent of SDG&E's small commercial rates) for a period of three years if they applied by September 2016. Similarly, in Resolution E-4514, we expanded the eligibility of SCE's small general service tariff for a period of three years ending December 2015, to government agencies that purchased or obtained zero emissions electric buses.

Because transportation electrification is a critical aspect of meeting California's climate goals, we agree with SD Airport Parking that some sort of temporary relief from demand charges is needed. Therefore, we direct SDG&E to offer a three-year temporary exemption on the small commercial load limit to current small commercial (including government) accounts with EV fleet charging. Current small commercial customers with EV fleet charging that comprises at least 50 percent of the customer's maximum load should be offered the opportunity to switch to rates adopted in A.17-01-020, but may remain on the small commercial rate for up to three years, effective with the billing cycle one month after the effective date of this decision. We direct SDG&E to modify the eligibility language in its small commercial tariff consistent with this guidance as soon as practicable following the issuance of a final CPUC decision.

8.6. Agricultural Customer Rate Design

Farm Bureau summarized the evolution of positions on agricultural customer rate design in its Opening Brief:

> Rate design changes for schedule TOU-PA on which most agricultural customers take service, were addressed in a number of documents through the course of this proceeding. SDG&E presented its proposals in testimony supporting its Application; Farm Bureau analyzed the proposals and recommended revisions for SDG&E's treatment of those customers through its direct testimony. Thereafter, SDG&E addressed Farm Bureau's recommendations in its rebuttal testimony. As the matter of rate design for this group of customers continued to evolve, there were nevertheless clear differences among the parties about how the rates should be structured over the next few years, particularly with respect to how a transition to changing time-of-use periods would be administered. The testimony of these joint parties and the Comparison Exhibit indicates the contrasting positions of the two parties. (Farm Bureau Opening Brief at 2-3, footnotes omitted.)

SDG&E and Farm Bureau continued to discuss their differences and ultimately submitted joint testimony as Exhibit JT-2. Exhibit JT-2 recommends that the Basic Service Fee (the monthly service fee), excluding adders, increase by 20 percent on January 1, 2018. Exhibit JT-2 recommends that current TOU-PA customers retain their current schedule with current TOU periods through March 1, 2019 unless they enroll on optional schedules. Exhibit JT-2 clarifies that all customers on TOU-PA could be subject to new TOU periods in 2022, consistent with the expectation of review and updating of TOU periods in 2022 pursuant to Assembly Bill 327, regardless of when they move to the adopted TOU periods. At hearing, the parties also clarified that the TOU-PA on-peak demand charges would increase in Year 2 to recover 30 percent of the CPUC approved commodity capacity costs. (RT 404:26- 405:24.) Consistent with the approach used for small commercial customers, demand variant monthly

service fee adders will be applied in lieu of noncoincident demand charges[35] and the default TOU will be a two-period TOU rate[36] with an optional three-period TOU rate. Summer is defined as June through October, shortening the summer period by one month.

Exhibit JT-2 balances the opening positions of SDG&E and Farm Bureau, enables agricultural customers to adjust to changing electric rate structures, and is consistent with the joint testimony offered for residential and small commercial customers. The agricultural customer rate design proposals set forth in Exhibit JT-2 are reasonable and should be adopted. We direct SDG&E to implement the agricultural customer rate design proposals set forth in Exhibit JT-2 as soon as practicable following the issuance of a final CPUC decision.

SDG&E proposed a medium and large agricultural rate option that would reflect "a cost-based [monthly service fee], distribution demand costs recovered through a [noncoincident] demand charge, with an exemption for demand in the super off-peak period, and an on-peak demand charge that reflects 90% of generation capacity…" (SDG&E Opening Brief at 43.) While we do not concur

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[35] The agreed upon monthly service fee adders are:

- 20-75 kW: $10/month.
- 75-100 kW: $35/month
- 100-200 kW: $50/month
- >200 kW: $100/month

[36] JT-2 defines on-peak as 4 p.m. - 9 p.m. weekdays except holidays and retains rate differentials consistent with current TOU-PA on/off-peak differentials. We recognize that the 4 p.m. – 9 p.m. peak period proposed in JT-2 deviates from the base TOU periods we adopt elsewhere in this decision, however we are willing to consider deviations when circumstances warrant.

with SDG&E's representation of this rate as cost-based,[37] no party opposed this option, it is consistent with our interest in providing customer choice, and should be adopted. We direct SDG&E to establish the medium and large agricultural rate option described in Exhibit SDG&E-12 (at CS-41 and CS-42) as soon as practicable following the issuance of a final CPUC decision.

SDG&E also proposed to eliminate the four different on-peak TOU period options currently available under Schedule PA-T-1 to create a single on-peak TOU period consistent with SDG&E's TOU period proposal for all C&I customers. This recommendation was opposed by City who argued it could introduce financial and operational difficulties for customers taking service under Schedule PA-T-1. Consolidation of TOU periods for Schedule PA-T-1 to be consistent with the TOU periods proposed in JT-2 simplifies customer choices and conforms these options with accurate price signals and should be adopted.

8.7. Street Lighting Rate Design

Streetlights are generally billed based on a per-lamp rate that differs by technology, wattage, number of lamps, ballast, as well as a variety of services. With the exception of distribution costs, which are recovered on a kilowatt basis, the monthly per lamp rate for each rate component is based on a kilowatt-hour per lamp usage assuming dusk to dawn operational hours of 4,165 hours per year. (SDG&E Reply Brief at 37.)

On brief, CALSLA disagrees with SDG&E's opening testimony where SDG&E had proposed to change the method to recover distribution customer costs from street light customers from a $/kW basis to a $/lamp basis. CALSLA

[37] The same reservations about SDG&E's proposed alternative Medium/Large C&I rate option expressed earlier in this decision apply here.

recommends that SDG&E to continue to recover these costs from street lighting customers on a $/kW basis to encourage energy conservation. As described in the procedural history section, SDG&E has modified its testimony a number of times over the course of this proceeding and its current testimony no longer proposes recovery of these distribution costs on a $/lamp basis, but rather it retains the current $/kWh basis.

We confirm that SDG&E should continue to recover customer access costs on a $/kW basis as set forth in Exhibit SDG&E-2.

8.7.1. Streetlighting Rate Models

One of SDG&E's requests in this proceeding is that we find its updated streetlighting cost studies to be reasonable. (Exhibit SDG&E-02.) SDG&E utilizes both a Consolidated Model (revenue allocation) and a Lighting Model (rate design). SDG&E describes its approach to developing streetlighting rates as follows:

> For the rate components, excluding distribution, the Consolidated Model develops the class average rates that are then used as an input to the Lighting Model, which then converts these rates into the many per lamp rates by multiplying the class average rate by the estimated energy use per lamp type included in the Lighting Model. For distribution rates, the Consolidated Model develops the authorized distribution revenue allocation as an input to the Lighting Model, which then develops the per lamp distribution rate based on the distribution lighting cost study and lamp count presented in the Lighting Model. (SDG&E Reply Brief at 37.)

CALSLA and City both take issue with SDG&E's models, with CALSLA questioning the total allocated revenue and electric sales used by SDG&E to calculate the proposed streetlight rates and arguing that the street light sales and revenue requirement are inconsistent between the revenue allocation and street

light rate design models. CALSLA requests the CPUC order SDG&E to submit a streetlight rate design model that is consistent with the proposed Revenue Allocation Settlement. SDG&E explains that the Consolidated Model first develops class-average rates based on revenues allocated to the class. These revenues come from the Revenue Allocation Settlement. The class-average rates then serve as inputs to the Lighting Model for the development of lamp-specific rates, which reflect a wide variety of different types of streetlights.

We find that SDG&E has adequately explained the interaction of the Revenue Allocation Settlement, the Consolidated Model, and the Lighting Model and that no discrepancy exists in the authorized revenues and rates. We find the updated streetlighting cost studies reasonable and adopt the proposed streetlighting rates set forth in Exhibit SDG&E-12 except as set forth below with respect to the dimmable streetlight and ancillary device rate options. We direct SDG&E to implement the streetlighting rates described in Exhibit SDG&E-12, modified as set forth below with respect to the dimmable streetlight and ancillary device rate options, as soon as practicable following the issuance of a final CPUC decision.

8.7.2. Dimmable Streetlight Rate Option

This proceeding is the first time a fully adaptive, dimmable streetlight rate schedule has been before the CPUC. CALSLA, City, and SDG&E all filed extensive testimony on dimmable streetlight rate issues. SDG&E recommends that the CPUC adopt (1) its $4.1 million estimate of start-up implementation costs for the new streetlighting rate options (which SDG&E proposes to recover via a one-time upfront fee of $8,000 per participating city and a monthly per meter start-up fee of $0.10 ($/meter-month)) and (2) its proposed rate structure to recover ongoing implementation and maintenance costs ($0.10 per meter for

start-up implementation costs and $0.45 per meter for ongoing maintenance costs) associated with the new streetlighting rate options. In addition, SDG&E recommends that the CPUC allow SDG&E to establish a memorandum account to track these costs and revenues of these new rate options for reexamination in a future rate proceeding.

CALSLA explains its belief that SDG&E's proposed software development costs are excessive and how software development can be streamlined to reduce cost. It suggests that $2.3 million is a more reasonable estimate for start-up implementation costs. (Exhibit CALSLA-1 at 26-30 and 36.) However, its focus, along with City, is that SDG&E's proposed dimmable rate design is economically infeasible for interested customers. In order to ensure success, CALSLA argues that energy savings captured through dimming should offset the administration and maintenance costs of the dimmable rate program. "CALSLA conducted an analysis of the most common dimmable lamps and their likely amount of dimming. The result of the analysis was unfavorable – high program costs would outweigh energy charge savings for a number of interested customers. Under SDG&E's proposal, customers would opt out and have no incentive to conserve energy through dimming." (CALSLA Reply Brief at 3, citation omitted.) CALSLA put forward an alternative monthly dimmable rate structure in which administration and maintenance costs are scaled to various lamps based on wattage. CALSLA argues its proposed rate structure is economically feasible for all interested customers and would encourage energy conservation. In its opening brief, City supports CALSLA's proposal.

SDG&E opposes CALSLA's proposal and argues that it costs the same to transmit data and cover administrative costs regardless of lamp size, and therefore the rate structure should apply the same rates for these costs,

regardless of lamp size, or the rate design will shift costs inappropriately, in conflict with our principle that rates should be consistent with cost causation.

Because dimmable streetlights support California energy policy, the CPUC should tailor the adopted dimmable streetlight rate design to maximize participation. Because the targeted customers for this dimmable option have indicated that SDG&E's proposed rate design will limit participation, we adopt monthly fees based on wattage as CALSLA proposes, not on a fixed charge per lamp as SDG&E proposes. A wattage-based rate will enable cities with lower-wattage lamps to participate and will provide customers with higher-wattage lamps motivation to implement conservation strategies for their streetlights. We do adopt the SDG&E proposed $8,000/city up-front participation payment, and find $2.3 million a reasonable estimate for start-up implementation costs. We direct SDG&E to implement the dimmable streetlight rate option, as modified above, as soon as practicable following the issuance of a final CPUC decision.

While it is unclear whether CALSLA's proposed wattage-based rates, in combination with the up-front per city payment, will adequately collect the revenue allocated to the streetlighting customer class, a key component of SDG&E's dimmable rate proposal is the inclusion of a memorandum account, which will record the implementation and ongoing maintenance costs of the rate program and revenue shortfall. The proposed memorandum account provides a financial safety valve and allows the true costs of the dimmable rate program to be monitored with the reasonableness of program costs in excess of $2.3 million and any revenue under or over-recovery from the new rate design addressed in future rate proceedings. Adopting a memorandum account ensures that the costs to implement the program that exceed the authorized start-up costs are

reviewed for reasonableness and there is no revenue under or over-collection as a result of adopting wattage-based rate design for dimmable streetlights.

8.7.3. Ancillary Device Rate Option

In order to effectively control dimmable streetlights, these installations are operated by control modules installed on streetlight poles that are capable of supplying power and metering services to other devices attached to street light poles. Service to ancillary devices is differentiated from general small commercial service or streetlighting service because the streetlight customer owns the meter, the ancillary device's point of connection to the grid is shared with streetlights, but the ancillary device may be owned by a third party and may be a non-streetlighting use. SDG&E and CALSLA disagree on the appropriate fee structure for ancillary device customer costs and ongoing maintenance charges.

> "SDG&E proposes a total monthly service fee of $10.77 per ancillary device…CALSLA's counterproposal is a monthly service fee of $3.18 based on the average of the [New Customer Only] NCO street light customer access cost and the Schedule UM monthly fee. In its opening brief, CSD supports CALSLA's ancillary device rate proposal." (CALSLA Reply Brief at 3-4, citations omitted.)

CALSLA argues that SDG&E's proposed monthly service fee inappropriately includes new transformer and service drops, when in fact the ancillary devices will use the existing streetlighting infrastructure for these purposes.

Like the dimmable streetlight rate option, it is unclear whether CALSLA's proposed ancillary services rate will collect the necessary revenue, however, a key component is the inclusion of a memorandum account, which will record the implementation and ongoing maintenance costs of the rate program and revenue shortfall. The proposed memorandum account allows the true costs of the

ancillary rate program to be monitored with the reasonableness of program costs addressed in future rate proceedings. Therefore, we adopt CALSLA's monthly service fee for ancillary devices of $3.18, plus monthly fees of $0.10 for implementation costs and $0.45 for ongoing maintenance. We direct SDG&E to implement the ancillary device rate option, as modified above, as soon as practicable following the issuance of a final CPUC decision.

8.7.4. Closing LS-1 Class C and Establishing Transfer Payment

SDG&E offers two options for streetlighting customers that request installation of non-standard equipment. These customers are served on the LS-1 tariff and can select Class B or Class C status. Class B customers pay lower ongoing rates in return for payment of more costs upfront. For Class C customers, the upfront costs are capped, costs above the cap are rolled into rates, resulting in higher ongoing rates than LS-1 Class B. Once a class is selected, the tariff does not allow movement between Class B and C. SDG&E proposes to close Class C to new customers, and allow existing Class C customers to transfer to Class B with payment of a transfer fee in order to avoid cost shifting to other streetlighting customers. On brief, SDG&E supports waiver of the transfer fee for customers who have been billed on Class C rates for more than fifteen years as recommended by CALSLA and the City of Mission Viejo in testimony.

In light of the uncontested nature of the current SDG&E proposal (to close Class C and allow transfer with payment of a transfer fee, with the transfer payment waived for customers that have been billed on Class C for more than 15 years), we adopt this treatment of Schedule LS-1 Class C. This treatment of Schedule LS-1 Class C supports our rate design principle favoring rates that are stable and simple, is reasonable, and should be adopted. We direct SDG&E to

modify Schedule LS-1 as described in Exhibit SDG&E-2, as modified in Mission Viejo's Opening Brief (at 2), as soon as practicable following the issuance of a final CPUC decision.

8.8. Other Rate Design Issues

8.8.1. Dynamic Pricing Incentive Under/Over Collection

In Exhibit SDG&E-2 and SDG&E-12, SDG&E proposed to eliminate the requirement to retain the revenue under/over collections associated with dynamic pricing rate incentives within the customer class eligible for the specific rate, as established in D.08-02-034 and D.12-12-004. In its Opening Brief, SDG&E withdrew its under/over collection proposal for the term of this GRC Phase 2, following opposition by ORA and Farm Bureau. (SDG&E Opening Brief at 61.) In light of SDG&E's change of position on brief, we do not approve the proposal to eliminate the current requirement to recover revenue under/over collections associated with dynamic pricing rate incentives within the customer class eligible for the specific rate.

8.8.2. Moving California Solar Initiative and Self-Generation Incentive Program to the Public Purpose Program Rate Component

Today, revenue to recover the costs of providing incentives under the California Solar Initiative and the Self-Generation Incentive Program is collected as part of the distribution rate component. SDG&E proposes to shift cost recovery of these programs to the PPP rate component. SDG&E argues that this shift will ensure that distribution rates will more accurately reflect distribution system costs and appropriately treat the cost recovery of these programs as a public policy objective. ORA described these incentive programs as providing

"broad environmental benefits for all California ratepayers."
(Exhibit ORA-1 at 6-9.)

No party opposed SDG&E's proposal to move the cost recovery of these programs to the PPP rate component. This shift supports our rate design principles favoring rates that are based on cost causation principles and making incentives explicit and transparent, is reasonable, and should be adopted. We direct SDG&E to modify cost recovery of California Solar Initiative and the Self-Generation Incentive Program costs as described in
Exhibit SDG&E-1 and SDG&E-11 as soon as practicable following the issuance of a final CPUC decision.

8.8.3. Elimination of Legacy Rate Schedules

A number of SDG&E's rate schedules have been closed to new customers for several years, and SDG&E proposes to eliminate several of these closed non-residential schedules in order simplify customer choices and reduce the administrative cost of operating its billing system. SDG&E would move customers to rate schedules that include time-of-use billing consistent with CPUC decisions over the last several years when the schedules are closed. No party opposes this proposal. Elimination of these tariffs supports our rate design principles of stability, simplicity, and customer choice, is reasonable, and should be adopted. We direct SDG&E to eliminate the legacy rate schedules as described in Exhibit SDG&E-2 as soon as practicable following the issuance of a final CPUC decision. In order to minimize administrative cost and simplify customer education efforts for these closed schedules, SDG&E need not update the TOU periods for these schedules as part of its implementation of new TOU periods. Consistent with our rate design principles, SDG&E should perform

appropriate education and outreach to the affected customers to promote customer understanding of their new rate schedules.

9. Implementation Timing

At the November 29, 2016 evidentiary hearing, SDG&E notified the parties of issues with its customer information platform used to manage functions such as billing and payment processing, credit, service orders and outages, customer information and other applications. The result is that implementation of the rates adopted herein is not feasible by the dates anticipated in a September 19, 2016 ALJ ruling.

Following discussion at the evidentiary hearing and further review of other implementation factors, SDG&E proposes a staged approach resulting in three "releases" to implement aspects of this decision. The releases were described in a December 21, 2016 Status Report, May 11, 2017 Update, and May 15, 2017 Amended Update. As proposed, Release 1 would occur December 1, 2017 to: implement the Revenue Allocation Settlement (Year 3), food bank line-item discount, Schools Settlement (includes line-item discount and fixed indifference payment), and TOU grandfathering consistent with D.17-01-006; update the sales forecast to the Year 3 sales forecast; and update TOU periods for standard/default rate schedules for:

- All existing TOU rate schedules for the Medium/Large C&I class;
- All existing rate schedules for the Residential class;
- New standard two-period TOU rate schedule for Small Commercial;
- Schedule PA-T-1;
- Event periods for all dynamic pricing rates (CPP, SPP, and PTR); and

- Updated seasonal definitions for all schedules.

In addition, Release 1 would implement rate design proposals as follows:

- Year 1 increase to monthly service fees for substation, small commercial, Medium/Large C&I customers;
- Increase monthly service fee for Schedule TOU-PA by 20 percent on January 1, 2018, excluding adders for customers with load ≥ 20 kW, and Year 2 Commodity Peak Demand Charge increase;
- Changes to noncoincident demand and peak demand charges; and
- Medium/Large C&I and Agricultural (PA-T-1) Year 2 Commodity Peak Demand Charge increase.

As proposed, Release 2 would occur July 1, 2018 to: implement remaining TOU periods updates (schedule TOU-PA two-period, TOU-PA three-period, three-period option for Small Commercial, cost-based options) and the transition path leading to the elimination of PTR; change applicability for Small Commercial; update A-TOU; eliminate legacy rate schedules (A, AY-TOU, AD, PA); move California Solar Initiative and Self-Generation Incentive Program recovery from distribution rates to PPP rates; implement streetlighting changes other than the Dimmable Streetlighting Rate Option and the Ancillary Device Rate Option; and Year 2 increase to monthly service fees for substation, small commercial, Medium/Large C&I customers.

As proposed, Release 3 would occur August 1, 2018 to implement the Dimmable Streetlighting Rate Option and the Ancillary Device Rate Option.

SDG&E also proposes to implement the Year 3 increases to Commodity Peak Demand Charges for Medium/Large C&I and Agricultural (PA-T-1) and Schedule TOU-PA customers, and Year 3 increases to monthly service fees for substation, small commercial, Medium/Large C&I customers on January 1, 2019.

Although we would prefer all of the decision to go into effect at once, practically we see no logical alternative to the phased release process SDG&E suggests. Therefore, we adopt SDG&E's proposed implementation approach except that SDG&E shall not implement the Schools Settlement or the proposed changes to Commodity Peak Demand Charges.

10. Outstanding Procedural Matters

The CPUC affirms all rulings made by the assigned Commissioner and assigned ALJ. All motions not previously ruled on are deemed denied.

In comments on the proposed decision, SDG&E requested an extension of time to file its 2019 GRC Phase 2 application, seeking a March 1, 2018 filing date to update 2019 sales forecasts, and a December 1, 2018 filing date for the remainder of its Phase 2 application. SDG&E proposes that the studies required by this decision be filed as part of the December 1, 2018 application. No party opposes these requests. In light of the timing of this decision and the resource constraints of the parties, the requested extensions are appropriate and should be approved.

11. Comments on Proposed Decision

The proposed decision of ALJ Cooke in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on June 26, 2017 by SDG&E, ORA, UCAN, FEA, Farm Bureau, Schools, Water Agencies, SEIA, CalSEIA, and SD Airport Parking. Reply comments were filed on July 3, 2017 by SDG&E, UCAN, FEA, Farm Bureau, Schools, and SEIA. Minor changes have been made throughout in response to comments.

12. Assignment of Proceeding

Michael Picker is the assigned Commissioner and Michelle Cooke is the assigned ALJ in this proceeding.

Findings of Fact

1. SDG&E's 2016-2018 sales forecast presented in Exhibit SDG&E-14 is uncontested and was relied on in the Revenue Allocation Settlement Agreement.

2. SDG&E plans to reflect the next year's sales forecast in rates as part of its Electric Consolidated advice letter.

3. The Revenue Allocation Settlement Agreement is an uncontested settlement entered into by parties representing all impacted customer groups after significant give and take between the parties.

4. The Revenue Allocation Settlement Agreement reflects agreement on how to allocate the authorized revenue requirements for distribution, commodity, California Solar Initiative, Self-Generation Incentive Program, PPP, Competition Transition Charge, and Local Generation Charge among customer classes.

5. The Revenue Allocation Settlement Agreement does not reflect the approval of, or acceptance of, any of the Settling Parties' marginal cost proposals.

6. Although not binding on this proceeding, D.17-01-006 describes the principles we should adhere to when considering whether to change the current TOU periods.

7. Based on current load data, May more closely aligns with April than June or July in terms of its load shape.

8. The current forecast for SDG&E area net loads and recent generation and commodity pricing patterns support the SDG&E base on-peak, off-peak, and super-off-peak period proposals when only marginal generation and energy costs are assessed.

9. Marginal generation costs, consisting of marginal energy costs and marginal generation capacity costs, constitute the primary basis for setting TOU periods, but the time sensitivity of all utility marginal cost elements, based on hourly patterns, is relevant in assessing TOU periods.

10. The 2020 forecast transmission and distribution marginal costs support starting SDG&E's on-peak TOU period at 3 p.m.

11. The 2020 forecast data supports SDG&E's proposed 9 p.m. ending time for the on-peak TOU period.

12. DLAP prices are extremely low in March and April during the hours of 10 a.m. and 2 p.m.

13. D.17-01-006 established the qualifying attributes of customers who are entitled to remain on existing TOU periods during a five or ten-year transition depending on the customer type.

14. D.17-01-006 identified separate treatment for schools for the Eligibility Grace Period.

15. The peak hours during dynamic pricing event days since 2010 have occurred between 2 p.m. and 6 p.m., although this time frame appears to be shifting over time as additional solar energy is added to California's resource mix.

16. We established rate design guidance in D.15-07-001 which includes a transition for residential customers to adjust to default TOU schedules.

17. For small commercial customers, the joint testimony in Exhibit JT-4 represents a compromise of positions regarding monthly service fees, adoption of a two-period TOU default rate, the Greater Fixed Charge Optional Rate, and Schedule A-TC.

18. The proposed applicability change for small commercial tariffs reflects the expectation that a small commercial customer's load will generally not exceed 20 kW.

19. Smart Pricing Program rates are more efficient pricing signals than Peak-Time Rebate incentives because customers are rewarded for load reductions during these hours and penalized for load consumption during the same hours, providing stronger motivation to provide demand response during these critical hours.

20. The annual revenue shortfall associated with the proposed 20 percent food bank discount is $73,495.

21. The costs recovered through the proposed Medium/Large C&I monthly service fee are generally associated with serving individual customers and are not avoidable, in either the short or long run, based on changes in customer demand and therefore are appropriately recovered through a monthly service fee.

22. Distribution-related costs that are not recovered through a monthly service fee are currently recovered approximately 65 percent through a noncoincident demand charge and 35 percent through on-peak demand charges.

23. A significant portion of the costs of SDG&E's distribution system are driven by diversified demands that generally are coincident with system peak demands.

24. SDG&E designs its distribution system to meet the peak demand of each system element, not the sum of the peak demands of all individual customers.

25. Noncoincident demand charges do not reflect cost causation for primary distribution, transmission, or generation capacity costs.

26. Allocation of 100 percent of SDG&E's substation costs and 50 percent of its feeder and local distribution costs to on-peak demand charges results in 61 percent of allocated distribution costs being recovered on a time-dependent basis through on-peak demand charge rates.

27. Inclusion of March and April mid-day hours in the adopted super-off-peak TOU period is designed to stimulate load shifting during periods of abundant low cost energy generation and alleviate renewable curtailments.

28. Due to the benefits of load diversity, the capacity needed to reliably serve customers at the higher levels of the electric grid is determined by the average demands of individual customers during coincident peaks, rather than each customer's single highest interval of demand during peak the TOU period.

29. SDG&E and FEA were the only parties who addressed the issue of the monthly service fees associated with substation rates.

30. No party opposed SDG&E's proposal to offer Medium/Large customers a "cost-based" rate option.

31. Customers on Schedule DG-R will be grandfathered onto the existing TOU time periods to the extent they meet the eligibility requirements set forth in Ordering Paragraph 5 of D.17-01-006.

32. No party opposed SDG&E's proposal to modify Schedule OL-TOU to recover capacity costs through the energy commodity rates.

33. The CPUC has made clear that the grandfathering protection adopted for current solar customers only applies to the TOU time periods and that rates should be adjusted to reflect changes in revenue requirement and cost allocation.

34. The annual revenue shortfall from the proposed 12.5 percent schools discount is $10 million, and the annual revenue shortfall from the fixed indifference amount is $1.6 million.

35. The Medium/Large C&I class includes 98 percent of billed usage for schools.

36. The Medium/Large C&I class as a whole will see a decrease of its share of allocated revenue of between 1.3 and 1.0 percent annually over three years, as compared to the system average change.

37. Many schools do not receive information about their electric costs and thus have little incentive or information to effectively manage their energy usage because electric bills are received and paid in central business offices.

38. The majority of the 40 individual school districts analyzed by SDG&E showed annual bill benefits from SDG&E's TOU proposal.

39. The school districts that are negatively impacted by the changing TOU on-peak period are schools that installed solar, who will receive less revenue crediting for their solar generation as a result of the modified TOU period.

40. In recognition that customers, including schools, have made investments in solar facilities in reliance on expected revenue streams based on today's TOU periods, we adopted grandfathering provisions in D.17-01-006.

41. Both PG&E and SCE implemented specialized rates to promote commercial fleet electrification, but SDG&E has not.

42. Exhibit JT-2 balances the opening positions of SDG&E and Farm Bureau, enables agricultural customers to adjust to changing electric rate structures, and is consistent with the joint testimony offered for residential and small commercial customers.

43. No party opposed the agricultural customer optional rate.

44. SDG&E utilitizes both a Consolidated Model (revenue allocation) and a Lighting Model (rate design) to develop streetlighting rates.

45. No discrepancy exists in the authorized revenues and rates between the Revenue Allocation Settlement, the Consolidated Model, and the Lighting Model.

46. It is unclear whether CALSLA's proposed wattage-based dimmable streetlight rates, in combination with the up-front per city payment will adequately collect the revenue allocated to the streetlighting customer class.

47. Service to ancillary devices is differentiated from general small commercial service or streetlighting service because the streetlight customer owns the meter, the ancillary device's point of connection to the grid is shared with streetlights, but the ancillary device may be owned by a third party and may be a non-streetlighting use.

48. No party opposed SDG&E's proposal to move the cost recovery of the California Solar Initiative and the Self-Generation Incentive Program to the PPP rate component.

49. A number of SDG&E's rate schedules have been closed to new customers for several years.

50. Problems with SDG&E's customer information platform used to manage functions such as billing and payment processing, credit, service orders and outages, customer information and other applications will not allow rates adopted in this decision to be implemented until December 1, 2017.

51. No party opposed SDG&E's proposal to extend the filing date of its 2019 GRC Phase 2 application.

Conclusions of Law

1. Given the lack of controversy over the proposed sales forecasts, the parties' reliance on them for the Revenue Allocation Settlement Agreement, and SDG&E's clarification of the purpose of the compliance advice letters, we should

approve the 2016, 2017 and 2018 sales forecast presented in Exhibit SDG&E-14 and direct SDG&E to file annual compliance advice letters, as part of SDG&E's annual Electric Consolidated advice letter for January 1 effective rates, to present the rate impacts of the post test-year sales forecasts approved in this proceeding.

2. The Revenue Allocation Settlement Agreement is reasonable, consistent with the law, and in the public interest because of the process employed to reach agreement, the balancing of interests, the protection of all customer classes from disproportionate impact, and the conservation of resources that resulted from the settlement.

3. We should adopt a five-month summer (June-October) and seven-month winter (November-May) season.

4. We should adopt an on-peak period of 3 p.m. to 9 p.m. daily.

5. We should adopt SDG&E's super-off-peak period, further modified to add 10 a.m. to 2 p.m. weekdays in March and April, as the super-off-peak period.

6. The evidence proffered by witness Duzyk, an experienced school administrator working on school investments and sustainability initiatives, supports extending the schools Eligibility Grace Period by eight months, to August 31, 2018, and the interconnection on file date to March 31, 2017, to support in-progress project completion.

7. We should adopt a dynamic pricing event period of 2 p.m. to 6 p.m. for SDG&E's dynamic pricing programs and tariffs.

8. The residential and small commercial rate design proposals set forth in Exhibit JT-4 represent a reasonable approach to move us closer to adopting rates based on cost causation, while providing stability, simplicity, and customer choice.

9. The applicability change for small commercial Schedules A, TOU-A, and EECC-TOU-A-P is reasonable.

10. SDG&E's proposal to reduce and eliminate its Peak-Time Rebate incentives is reasonable.

11. The proposed 20 percent line item discount for eligible food bank customers is reasonable.

12. The Medium/Large C&I monthly service fee proposal set forth in Exhibit SDG&E-2 is reasonable.

13. There is a rationale for using noncoincident demand charges to recover a portion of distribution system costs, but not 100 percent because there is significantly greater diversity as one moves further up the distribution system, away from individual customers and towards higher-voltage distribution circuit, substation, and transmission facilities.

14. It would be fundamentally inconsistent for the utility to calculate its distribution marginal costs on the basis of the annual peak demand on the distribution system, yet to charge customers for those costs based 100 percent on individual customers' noncoincident demands.

15. Based on SDG&E's filed marginal costs for substations ($22 per kW-year) and feeder and distribution circuits ($78 per kW-year), 61 percent of SDG&E's distribution costs should be recovered from time-dependent on-peak demand charges, with 39 percent allocated to noncoincident demand charges pending completion of the two studies proposed in Exhibit JT-3.

16. SDG&E's proposal to shift more of the recovery of on-peak generation capacity costs into peak demand charges is contrary to our findings in D.14-12-080, our rate design principles that support rates based on cost-causation

principles, and encouraging the reduction of both coincident and noncoincident peak demand.

17. SDG&E should retain the current ratio of cost recovery for generation capacity costs between the peak demand charge and volumetric energy costs for Medium/Large C&I and Agricultural customers.

18. The substation rate design proposal set forth in Exhibit JT-1 represents a reasonable approach to move us closer to adopting rates based on cost causation, while providing stability and simplicity.

19. We should retain the linkage of Schedule DG-R to Schedule AL-TOU.

20. SDG&E's Schedule OL-TOU proposal is reasonable.

21. The modifications adopted today to the SDG&E proposed on-peak TOU period, demand charges, generation demand cost recovery, and grandfathering for solar schools, all are expected to reduce the impacts of the changing time-of-use periods on affected solar school accounts.

22. The additional line item and fixed indifference discounts proposed for schools place an inappropriate burden on other customers and therefore should not be adopted.

23. Current small commercial customers with EV fleet charging that comprises at least 50 percent of the customer's maximum load should be offered the opportunity to switch to rates adopted in A.17-01-020, but may remain on the small commercial rate for up to three years, effective with the billing cycle one month after the effective date of this decision.

24. The agricultural customer rate design proposals set forth in Exhibit JT-2 are reasonable.

25. SDG&E should continue to recover customer access costs from streetlighting customers on a $/kWh basis as set forth in Exhibit SDG&E-2.

26. The streetlighting rates described in Exhibit SDG&E-12, modified with respect to the dimmable streetlight and ancillary device rate options are reasonable.

27. The CPUC should tailor the adopted dimmable streetlight rate design to maximize participation.

28. The SDG&E proposed $8,000/city up-front participation payment and $2.3 million start-up implementation costs are reasonable.

29. Adopting a memorandum account ensures that the costs to implement the dimmable streetlight program and ancillary device rate option that exceed the authorized start-up costs are reviewed for reasonableness and there will be no revenue under- or over-collection as a result of adopting wattage-based rate design for dimmable streetlights or CALSLA's recommended ancillary device rates.

30. We should adopt CALSLA's monthly service fee for ancillary devices of $3.18, plus monthly fees of $0.10 for implementation costs and $0.45 for ongoing maintenance.

31. Allowing SDG&E to close Schedule LS-1 Class C and allow transfer with payment of a transfer fee, with the transfer payment waived for customers that have been billed on Class C for more than 15 years, supports our rate design principle favoring rates that are stable and simple, and is reasonable.

32. Shifting the California Solar Initiative and the Self-Generation Incentive Program costs to the PPP rate supports our rate design principles favoring rates that are based on cost causation principles and making incentives explicit and transparent, is reasonable, and should be adopted.

33. Elimination of legacy tariffs supports our rate design principles of stability, simplicity, and customer choice, is reasonable, and should be adopted.

34. SDG&E's proposed phased rate implementation approach is reasonable in light of problems with its customer information platform.

35. SDG&E's proposed extension of filing dates for its 2019 GRC Phase 2 application is reasonable in light of the timing of this decision and the resource constraints of the parties.

O R D E R

IT IS ORDERED that:

1. San Diego Gas & Electric Company must implement the specific terms of this decision as one or more Tier 1 Advice Letters no later than 45 days prior to the December 1, 2017 effective date of rates (Release 1). Release 1 implements: the Revenue Allocation Settlement; food bank line-item discount; Time-of-Use grandfathering consistent with Decision (D.) 17-01-006; extended D.17-01-006 Eligibility Grace Period for schools; the sales forecast; event periods for all dynamic pricing rates; updated seasonal definitions for all schedules; and adopted Time-of-Use periods for standard/default rate schedules for:

- All existing Medium/Large Commercial and Industrial classes other than legacy rate schedules that will be eliminated in Release 2;
- All existing rate schedules for the Residential class;
- New standard two-period Time-of-Use rate schedule for Small Commercial;
- Schedule PA-T-1, including the elimination of PA-T-1 demand options;
- Year 1 increase to monthly service fees for substation, small commercial, Medium/Large C&I customers, and Schedule PA-T-1;

- Increase monthly service fee for Schedule TOU-PA by 20 percent on January 1, 2018, excluding adders for customers with load ≥ 20 kW;
- Changes to noncoincident demand and peak demand charges; and
- Changes to Schedule OL-TOU.

2. San Diego Gas & Electric Company must implement the specific terms of this decision as one or more Tier 1 Advice Letters no later than 45 days prior to the July 1, 2018 effective date of rates (Release 2). Release 2 implements: Schedule TOU-PA two-period rate option; TOU-PA three-period rate option; three-period rate option for Small Commercial; "cost-based" options; the transition path leading to the elimination of Peak-Time Rebate; applicability changes for Small Commercial; updated A-TOU; elimination of legacy rate schedules (A, AY-TOU, AD, PA); moving California Solar Initiative and Self-Generation Incentive Program recovery from distribution rates to Public Purpose Program rates; streetlighting changes other than the Dimmable Streetlighting Rate Option and the Ancillary Device Rate Option; and Year 2 increase to monthly service fees for substation, small commercial, Medium/Large Commercial and Industrial customers.

3. San Diego Gas & Electric Company must implement the specific terms of this decision as one or more Tier 1 Advice Letters no later than 45 days prior to the August 1, 2018 effective date of rates (Release 3). Release 3 addresses: Dimmable Streetlighting Rate Option and the Ancillary Device Rate Option.

4. San Diego Gas & Electric Company must implement the specific terms of this decision as one or more Tier 1 Advice Letters no later than 45 days prior to January 1, 2019. The January 1, 2019 rate changes reflect: Year 3 increases to

monthly service fees for substation, small commercial, Medium/Large Commercial and Industrial customers on January 1, 2019.

5. As part of its annual Electric Consolidated advice letter for January 1 effective rates, San Diego Gas & Electric Company must present the rate impacts of the post test-year sales forecasts approved in this proceeding.

6. The motion dated November 4, 2016 requesting adoption of the Revenue Allocation Settlement Agreement is granted, and the Year 3 allocation factors set forth in Tables 1-7 of the Revenue Allocation Settlement Agreement must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

7. The five-month summer (June-October) rate season and seven-month winter (November-May) rate season must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

8. The time-of-use periods defined in Table 1 and 2 herein must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

9. The dynamic pricing event triggers set forth in Exhibit SDG&E-9 must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

10. The residential and small commercial rate design proposals set forth in Exhibit JT-4 must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

11. The applicability changes for small commercial rate Schedules A, TOU-A, and EECC-TOU-A-P as set forth in Exhibit SDG&E-8 must be implemented by San Diego Gas & Electric Company in its Release 2 advice letter.

12. The modified Peak-Time Rebate incentives set forth in Exhibits SDG&E-1 and SDG&E-2 must be implemented by San Diego Gas & Electric Company in its Release 2 advice letter.

13. The 20 percent line item food bank discount must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

14. The Year 1 Medium/Large Commercial and Industrial and Schedule PA-T-1 monthly service fee rate design set forth in Exhibit SDG&E-2 must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

15. The Year 2 Medium/Large Commercial and Industrial and Schedule PA-T-1 monthly service fee rate design set forth in Exhibit SDG&E-2 must be implemented by San Diego Gas & Electric Company in its Release 2 advice letter.

16. The Year 3 Medium/Large Commercial and Industrial and Schedule PA-T-1 monthly service fee rate design set forth in Exhibit SDG&E-2 must be implemented by San Diego Gas & Electric Company in its advice letter to implement the January 1, 2019 rate change.

17. The allocation of 61 percent of time-related distribution costs to peak-related demand charges for Schedules AL-TOU and A6-TOU and to on-peak energy charges for Schedule DG-R must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

18. San Diego Gas & Electric Company must include at least one rate option available to each non-residential rate class (except streetlighting) that exempts usage during the March and April super-off-peak daytime hours adopted herein from distribution demand charges in its Release 2 advice letter.

19. The Year 1 substation rate design proposal set forth in Exhibit JT-1 must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

20. The Year 2 substation rate design proposal set forth in Exhibit JT-1 must be implemented by San Diego Gas & Electric Company in its Release 2 advice letter.

21. The Year 3 substation rate design proposal set forth in Exhibit JT-1must be implemented by San Diego Gas & Electric Company in its advice letter to implement the January 1, 2019 rate change.

22. The alternative Medium/Large Commercial and Industrial "cost-based" rate option set forth in Exhibit SDG&E-2 (at CS-49 and 50) must be implemented by San Diego Gas & Electric Company in its Release 2 advice letter.

23. Changes to Schedule DG-R resulting from Schedule AL-TOU must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter.

24. The agricultural customer rate design proposals set forth in Exhibit JT-2, the agricultural customer optional rate, and the proposal to eliminate on-peak TOU period options in Schedule PA-T-1 must be implemented by San Diego Gas & Electric Company in its Release 1 advice letter with a January 1, 2018 effective date.

25. The streetlighting rates set forth in Exhibit SDG&E-12, as well as the modifications to Schedule LS-1 as described in Exhibit SDG&E-2, modified to allow waiver of the transfer payment for customers served as Class C customers for more than 15 years, must be implemented by San Diego Gas & Electric Company in its Release 2 advice letter.

26. San Diego Gas & Electric Company must implement a wattage-based dimmable streetlight rate option, as proposed by California City-County Streetlight Association, a $8,000/city up-front participation payment, and a memorandum account as part of its Release 3 advice letter.

27. San Diego Gas & Electric Company must implement the ancillary device rate option with a $3.18 monthly service fee, plus monthly fees of $0.10 for implementation costs and $0.45 for ongoing maintenance, and a memorandum account as part of its Release 3 advice letter.

28. Moving cost recovery of the California Solar Initiative and the Self-Generation Incentive Program costs to the Public Purpose Program rate, as set forth in Exhibits SDG&E-1 and SDG&E-11 must be implemented by San Diego Gas & Electric Company in its Release 2 advice letter.

29. After performing appropriate education and outreach to the affected customers, San Diego Gas & Electric Company must eliminate the legacy rate schedules as described in Exhibit SDG&E-2 in its Release 2 advice letter.

30. The motion to adopt the Settlement Agreement Between San Diego Gas & Electric Company and San Diego Public Schools is denied.

31. San Diego Gas & Electric Company must file a Tier 2 Advice Letter within 30 days of the effective date of this decision to extend the Decision 17-01-006 Eligibility Grace Period for schools by eight months, to August 31, 2018, and the interconnection on file date for schools to March 31, 2017.

32. San Diego Gas & Electric Company must update the critical event period annually by filing a Tier 2 Advice Letter based on a loss of load analysis of the San Diego Greater Reliability area and the San Diego sub-area similar to the one performed in support of Chart RBA-11 in Exhibit SDG&E-3 that demonstrates a substantial change in the Relative Loss of Load Expectation for San Diego Gas & Electric Company's local capacity areas. The Advice Letter should be served on the service lists of this proceeding and Application 17-01-012 et al.

33. San Diego Gas & Electric Company must conduct a study to examine the appropriate allocation of distribution costs between noncoincident demand charges and system peak demand charges and whether a shorter duration peak demand period for assessing coincident peak-related demand charges should be established, relative to the adopted time-of-use period, to be included in the next San Diego Gas & Electric Company Phase 2 General Rate Case. San Diego Gas

& Electric Company must consult with parties to this proceeding in preparing its research plan for the study, and file the research plan as a Tier 2 Advice Letter within 120 days of the effective date of this decision.

34. San Diego Gas & Electric Company must conduct a study to examine the appropriate allocation of transmission costs between noncoincident demand charges and system peak demand charges to be filed at the Federal Energy Regulatory Commission prior to the next San Diego Gas & Electric Company Phase 2 General Rate Case. San Diego Gas & Electric Company must consult with parties to this proceeding in preparing its research plan for the study, and file the research plan as a Tier 2 Advice Letter within 120 days of the effective date of this decision.

35. San Diego Gas & Electric Company must conduct a study to examine the appropriate allocation of generation capacity costs between volumetric and peak demand charges to be included in the next San Diego Gas & Electric Company Phase 2 General Rate Case. San Diego Gas & Electric Company must consult with parties to this proceeding in preparing its research plan for the study, and file the research plan as a Tier 2 Advice Letter within 120 days of the effective date of this decision.

36. San Diego Gas & Electric Company must file a Tier 2 Advice Letter within 30 days of the effective date of this decision to modify the eligibility language in its small commercial tariff to offer a three-year temporary exemption on the small commercial load limit to current small commercial accounts with electric vehicle fleet charging that comprises at least 50 percent of the customer's maximum load.

37. San Diego Gas & Electric Company must file an application for approval of its 2019 sales forecast (normally a part of the General Rate Case Phase 2 application) no later than March 1, 2018.

38. San Diego Gas & Electric Company must file an application for approval of its 2019 General Rate Case Phase 2 application (except for sales forecasts), including the studies required by Ordering Paragraphs 33, 34, and 35, no later than December 1, 2018.

39. Application 15-04-012 is closed.

This order is effective today.

Dated _____, at San Francisco, California.