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PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

AGENDA ID #16759

ENERGY DIVISION
RESOLUTION E-4951

September 13, 2018

R E S O L U T I O N

Resolution E-4951. Addressing proposals by San Diego Gas & Electric Company (SDG&E) for demand charge research plans pursuant to Decision (D.) 17-08-030.

PROPOSED OUTCOME:
- Approves, with modifications, SDG&E's proposed demand charge research plan. Directs SDG&E to perform parallel studies of its distribution and transmission demand charges based on an alternative cost classification methodology as described herein.

SAFETY CONSIDERATIONS:
- There is no impact on safety.

ESTIMATED COST:
- No incremental costs are identified.

By Advice Letter SDG&E 3166-E filed on December 21, 2017.

SUMMARY

This Resolution approves with modifications the proposed research plan submitted by SDG&E pursuant to Ordering Paragraphs (OPs) 33-35 of Decision (D.)17-08-030 (Decision). It directs SDG&E to perform parallel studies of: (1) distribution demand charges based on Equal Percentage of Marginal Cost ("EPMC") methodology, and (2) transmission demand charges based on research currently underway at the California Independent System Operator ("CAISO"). SDG&E is directed to file its distribution, transmission and generation demand

charge studies as supplemental testimony in its GRC Phase 2, and hold a workshop within 30 days of that filing, to discuss the results of its studies.

BACKGROUND

In August, 2017, the Commission issued D.17-08-030 in SDG&E's General Rate Case (GRC) Phase 2 proceeding, ordering SDG&E to perform studies of its distribution, transmission, and generation demand charges (OPs 33, 34, and 35). The Commission further ordered SDG&E to file a Tier 2 AL with a research plan for these studies, subject to Energy Division approval. SDG&E timely submitted AL 3166-E addressing the combined requirements of OPs 33-35, as follows:

> 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 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.
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> 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.
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> 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 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.

With respect to OP 33, SDG&E requested in A.15-04-012 to increase the proportion of non-coincident demand ("NCD") charges in its Medium and Large (M/L) Commercial & Industrial (C&I) rate schedules from 65% to 85%, with the balance consisting of coincident demand ("CD") charges. NCD charges apply to the customer's maximum 15-minute interval demand, regardless of when it occurs; CD charges apply only during peak time-of-use ("TOU") hours. The Commission declined to adopt SDG&E's proposal (or a subsequent proposal presented in joint testimony[1]). Instead, D.17-08-030 adopted a proposal by the Solar Energy Industries Association (SEIA) to decrease the proportion of NCD in M/L C&I rates from 65% to 39%. The rejected joint testimony proposal included a requirement that SDG&E perform 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."[2] Although the Commission declined to adopt the full suite of recommendations in the joint testimony, it did order the distribution study (OP 33).

With respect to OP 34, while acknowledging that transmission rates are FERC-jurisdictional, two parties to A.15-04-012 discussed transmission rates in their testimony[3] and asserted the relevance and importance of transmission rate design to State and Commission energy policy. As with distribution, in joint supplemental testimony, certain parties recommended a study of SDG&E transmission rate design, to be presented to FERC in conjunction with its next transmission rate case and made available in SDG&E's next GRC Phase 2 proceeding.[4] While declining to adopt the full suite of the joint testimony recommendations, D.17-08-030 directed SDG&E to perform the transmission study (OP 34).

[1] D.17-08-030 at 47.
[2] A.15-04-012, Exhibit JT-3.
[3] SEIA and City of San Diego.
[4] Scheduled for December 1, 2018.

With respect to OP 35, SDG&E proposed in A.15-04-012 to increase the proportion of coincident demand charges in its generation capacity cost recovery from the then current 50% to 70%, the balance being comprised of time-of-use (TOU) volumetric energy charges. While no party opposed this proposal, the Commission declined to adopt it, and required instead that SDG&E perform a study of the appropriate rate design for recovery of generation capacity costs from M/L C&I customers.

SDG&E's Demand Charge Research Plan: Distribution

For distribution, the "research plan" attached to AL 3166-E proposes a 2-step approach:

- **Step 1: To examine the breakdown of distribution costs to identify what percentage of distribution costs are driven by capacity**. SDG&E's electric capital includes costs driven by capacity, reliability, safety and risk mitigation, policy mandates, new business, and other drivers. SDG&E proposes…to first identify the appropriate capacity costs…The capacity-driven projects will provide data [on] distribution facility additions designed by SDG&E to meet peak demand for that portion of the distribution system which serves customers located in the specific area. Given that the capacity-driven projects are…driven by peak demand at the circuit/substation level, SDG&E proposes to limit the allocation of costs to an on-peak demand charge to the costs of capacity-related projects."

- **Step 2: To examine demands by customer class, circuit, and substation**: "This will indicate which circuits and substations peak within or outside the peak hours…SDG&E will determine [based on hourly load data from 2014 to 2016] the percentages of circuits and substations that peaked during the system peak period (4-9 pm) and noncoincident hours' time frames…In this study, SDG&E proposes to use the load information…in the Effective Demand Factor ("EDF") methodology which will inform the study on each customer classes' contribution to circuit and substation peaks.[5]

[5] SDG&E AL 3166-E, Attachment A ("Demand Charge Research Plan"), p.6.

SDG&E's Demand Charge Research Plan: Transmission

For transmission, the research plan attached to AL 3166-E proposes a 2-step approach, summarized as follows:

- **Step 1**: A determination of the percentage of transmission costs driven by capacity or peak needs, using transmission project costs from the most recently filed transmission rate case.[6]

- **Step 2**: Examine customer class load at the system level that occurs within and outside the peak period. SDG&E proposes to use hourly data from 2014 through 2016 for:

    - Maximum demand by customer class, with dates and times;
    - Maximum system peak with dates and times for each year.

SDG&E's Demand Charge Research Plan: Generation

SDG&E proposes to use a Loss of Load Event ("LOLE") methodology for the allocation of generation capacity costs to the peak period. However, SDG&E recognizes that "…going forward, ramping and integration of renewables may affect future capacity investment analysis." Further, SDG&E states that generation capacity costs that are "driven by peak needs during the on-peak period will be considered for allocation to an on-peak demand charge with the remaining capacity costs to be considered for allocation to volumetric energy charges during other TOU periods…"[7]

In compliance with OP 35, SDG&E will also "examine whether a shorter duration period [for] assessing generation capacity peak-related demand charges should be established, relative to …[the] 4 pm to 9 pm…"[8]

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[6] *Id.* p.8.
[7] *Id.* pp.9-10.
[8] *Id.*

NOTICE

Notice of AL 3166-E was made by publication in the Commission's Daily Calendar. SDG&E states that a copy was mailed and distributed in accordance with General Order (GO) 96-B.

PROTESTS

AL 3166-E was protested by the Office of Ratepayers Advocate (ORA) on January 10, 2018. SDG&E responded to the protest by ORA in a letter dated January 18, 2018.

ORA's Protest

ORA's protest centers on the possibility of bias in the characterization of cost data in Step 1 of SDG&E's distribution research plan:

> One significant area of disagreement ORA had with SDG&E, throughout the preparation of this research plan, is the necessity of analyzing cost data as part of the plan.…ORA is concerned that SDG&E may be overly motivated to produce a research product that will justify recovering the vast majority of the demand-related revenue requirement through non-coincident demand charges.

Specifically, ORA notes that, in meetings with ORA and other parties, SDG&E asserted that "only 3% of distribution system capital additions are associated with load additions [i.e., are capacity related]". ORA also cites to SDG&E's AL, which claims that "costs driven by other reasons would then not be eligible for allocation to a peak demand charge and as a result [should] be allocated to non-coincident demand."[9] Under these assumptions, at most only 3% of distribution costs would be subject to CD (peak-related) charges.

[9] ORA Protest, January 10, 2018, p.2.

In its comments attached to both the AL and ORA's protest, ORA stated: "Allocating all costs that are not triggered by load growth [i.e. capacity] to non-coincident demand is wrong…non-coincident demand is a measure of load and not a catch-all for any cost that cannot be associated with load growth."[10]

While the above ORA concerns focus on distribution, ORA raises similar concerns over SDG&E's proposed attempts to parse transmission investments into capacity-related and non-capacity-related buckets. ORA's protest also points out that transmission investments attributed to reliability should be considered at least in part capacity-related, as well as certain policy-driven or economically-driven projects.

For generation, ORA's protest observes:

> …how the costs should be recovered in rates, and whether some costs should be recovered in demand charges, or fully in time-differentiated volumetric energy charge[s], should be determined in rate design proceedings… .The [SDG&E] research plan is not explicit on what are 'the remaining capacity costs' that are not peak-demand related.[11]

In summary, ORA questions the proposed use of cost data in SDG&E's distribution and transmission research plans, and states that partitioning costs into capacity-related and non-capacity-related categories requires more thorough vetting and analysis by parties in a GRC phase 2 setting.[12]

SDG&E's Reply to ORA's Protest

SDG&E's reply to ORA's protest expressed concerns about ORA's contention that the distribution study focus solely on the load at circuits and substations, and exclude consideration of cost drivers.

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[10] ORA detailed comments attached to its Protest to AL 3166-E, p.1.
[11] *Id*. p.4.
[12] *Id.* p.1.

> SDG&E believes such a change would result in an overly narrow examination of the available data and result in a missed opportunity to better understand the relationship between load and its impact on potential cost drivers at different levels of the system.[13]

Further, SDG&E's Reply claims:

> To determine an appropriate allocation of distribution costs to be recovered between the two charges, it is necessary to know (i) the percentage of distribution costs driven by "capacity", and (ii) the portion of total distribution costs driven by other reasons. It is reasonable to include cost information in order to determine the portion of these costs are appropriately allocated between the two demand charges.[14] Without analyzing distribution cost data, SDG&E would be challenged to fulfill the Decision's explicit directive to examine appropriate allocation of distribution costs between demand charges.[15]

DISCUSSION

Step 1: Determination of Distribution and Transmission Capacity Costs

While we understand and accept the logic in SDG&E's two-step approach to analysis of its demand charge rate designs for distribution and transmission, we also share ORA's concern about possible bias[16] in SDG&E's Step 1 (determining which investments are "capacity-related"). Additionally, we question whether SDG&E's proposed approach is sufficiently broad to capture the role of coincident peak demand in cost causation.

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[13] SDG&E Reply, January 18, 2018, p.3.
[14] SDG&E's Reply states that it is applying the same logic to transmission cost data as part of the Demand Charge Study Research Plan.
[15] *Id.*
[16] Per ORA's Protest (p.1): *"ORA is concerned that SDG&E may be overly motivated to produce a research product that will justify recovering the vast majority of the demand-related revenue requirement through non-coincident demand charges."*

SDG&E proposes to start by identifying "the appropriate distribution capacity costs from the various drivers [capacity, reliability, safety and risk mitigation, policy mandates, new business…] justifying the distribution project costs."[17] Under its proposal, Step 1 will "examine the breakdown of distribution costs to identify what percentage of distribution costs are driven by 'capacity'".[18] SDG&E proposes to limit cost allocation to an on-peak demand charge to capacity-related project costs, and proposes a similar approach for transmission costs.

We find that SDG&E's proposed partition of distribution projects and transmission costs into capacity-related and non-capacity-related buckets may be overly restrictive for the purpose of these studies. Moreover, we agree with ORA that T&D investments related to reliability, policy mandates, and economic efficiencies may be partially peak-load-related.

Further, we find that the proposed Step 1 classification of T&D costs solely by cost-driver is likely to be subjective and thus subject to bias as ORA alludes to in its protest. Here we point to relevant guidance in a footnote in D.18-05-040:

> A cost-causation study of transmission must recognize that transmission facilities must be sized to accommodate maximum expected power flow, and will help ensure that, even in cases where peak demand is not the primary driver, analysis of the investments will have a peak demand-related component.[19]

While this footnote addresses transmission, we find it relevant to distribution as well: For distribution, as well as transmission, even when peak demand is not the primary cost driver, it may be a secondary cost driver as facilities must be sized to accommodate the maximum expected power flow. We direct SDG&E to be

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17 AL 3166-E, Attachment A, ("Demand Charge Research Plan"), p.6.
18 Attachment A to AL 3166-E.
19 Excerpt from footnote 433, p.114, D.18-05-040.

cognizant of this principle and ensure that it is reflected in all of its transmission and distribution demand charge studies.

In addition, while we accept SDG&E's distribution and transmission demand charge research plans, we direct certain modifications and additional data to serve as the basis for parallel studies, as follows: (1) Use of equal percentage of marginal cost ("EPMC")[20] for distribution, and (2) Analysis of cost causation now being undertaken by the California Independent System Operator ("CAISO") for transmission. These additional analyses are described below.
Finally, we also note that both steps of the study SDG&E proposes to undertake are related to direction established in the Distribution Resource Planning proceeding (R.14-08-013). Specifically, SDG&E is required to produce a Grid Needs Assessment ("GNA") reflecting future distribution grid needs, including capacity needs, as well as a Distribution Deferral Opportunity Report ("DDOR") reflecting which grid needs are potentially deferrable by DERs (D.18-02-004, OP 2d). SDG&E is required to ensure that the information it presents in its GRC testimony is consistent with that year's GNA and DDOR or to explain any justifiable discrepancies (D.18-02-004, OP 2h).

To promote transparency and facilitate the efficient achievement of those requirements, we direct SDG&E to provide an explanation of the relationship between the data, methodology, and results of its study of distribution capacity costs and the methodology and results of its GNA and DDOR within the report results submitted as testimony in its GRC, as well as a part of a public workshop as directed herein.

Use of EPMC for Distribution

The Commission uses EPMC methodology to separate distribution costs into customer-related and demand-related components for ratemaking purposes. Under EPMC, all distribution is related either to providing customers access to the grid, or to serving their aggregated demand. D.17-08-030 adopted a revenue

[20] The Commission has used EPMC to allocate distribution costs to customer classes since (at least) D.89-12-057.

allocation settlement for SDG&E which resulted in approximately 26% of SDG&E distribution revenue being attributed to customer access and 74% associated with serving demand.[21]

Accordingly, as an alternate to its proposed Step 1 for distribution, SDG&E is directed to prepare a second version of its distribution demand charge study, based on the assumption that 74% of its distribution costs are demand-related. These demand-related costs should then be partitioned into coincident peak maximum demand-related costs, and non-coincident peak related costs, using SDG&E's proposed Step 2 circuit and substation load analysis, modified as proposed by ORA and as discussed below.

In summary, SDG&E should file two studies in parallel for distribution: (1) A study that follows SDG&E's research plan as submitted; and (2) A second study that bypasses SDG&E's proposed Step 1, and based on an EPMC approach, partitions the 74% of distribution costs that are demand-related into coincident peak maximum-demand related costs and non-coincident peak-related costs, based on circuit and substation loads.

Use of CAISO Transmission Cost Findings

The California Independent System Operator (CAISO) currently is conducting a "Stakeholder Initiative" to review its Transmission Access Charge (TAC) structure. As part of this initiative, CAISO released a "Straw Proposal" which discussed a "hybrid approach" to transmission rates, in which a fixed percentage of transmission revenues would be considered usage related, and recovered via volumetric rates, and the remainder recovered via demand charge rates. Initially, CAISO posited that a 50/50 split could be a possible outcome. Subsequently, CAISO published a "Revised Straw Proposal" in April 2018 and a

[21] The 26% weighting of distribution revenues to customer access is based on the average of the Rental method weighting (28%) and the NCO method weighting (24%). These weightings are in turn derived from SDG&E's calculations submitted in the fixed charge phase of PG&E's GRC Phase 2 (A.16-06-013), Supplement To Fixed Cost Report And Comments On Alternative Methodologies.

"Second Revised Straw Proposal" in June, 2018.[22] While it has refined its calculations, these CAISO reports maintain approximately a 50/50 split between peak-related and non-peak-related cost components.

As with distribution, SDG&E should file two studies in parallel for transmission: (1) A study that follows SDG&E's research plan as submitted; and (2) A second study that (a) bypasses SDG&E's proposed Step 1 and incorporates CAISO's proposed 50% demand-related percentage for transmission, and (b) partitions the roughly 50% of transmission costs that are demand-related into coincident peak maximum demand-related and non-coincident peak related costs, based on a modified Step 2 load analysis. Should CAISO update its 50/50 split between usage-related and transmission-related transmission costs, SDG&E should incorporate CAISO's updated percentages into it alternate transmission demand charge study.[23]

<u>Step 2</u>: Load Data Analysis for Distribution and Transmission

We find SDG&E's Step 2 distribution load analysis reasonable and approve it with two modifications described below:

According to SDG&E, Step 2 (for distribution) will examine demands by customer class, circuit, and substation to determine which circuits and substations peak within or outside the peak hours. SDG&E proposes to use the load information "in the Effective Demand Factor ("EDF") methodology which will inform the study on each customer class' contribution to circuit and substation peaks."[24]

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[22] The June 2018 "Second Revised Straw Proposal" calls for a Draft Final Proposal in September 2018, and a Final Proposal to be presented to CAISO's Board of Governors in February 2019.
[23] Our intent here is not to require SDG&E to follow CAISO's methodology in detail, but to simply begin with CAISO's proposed split between peak and non-peak cost components, as a useful bookend to SDG&E's preferred approach as presented in AL 3166-E.
[24] SDG&E Demand Charge Research Plan, Attachment A to AL 3166-E, pp. 5-6.

SDG&E's research plan states: "SDG&E will determine [based on hourly load data from 2014 to 2016] the percentages of circuits and substations that peaked during the system peak period (4-9 pm) and non-coincident hours' time frames." However, as ORA observes in comments attached to the AL, "These percentages do not appear to be weighted by the peak load on each substation and [circuit], but should be."[25] We agree with ORA's concern, and direct SDG&E to weight its coincident and non-coincident percentages by the peak loads on each circuit and substation.[26]

The second modification concerns the use of EDFs. We accept the use of EDFs as a general matter in the determination of appropriate demand charges for the Medium and Large C&I customer class. However, we find value in developing a parallel analysis that uses uniform EDFs for SDG&E's distribution system as a whole, and direct SDG&E to do so. This would shed light on cost causation (coincident vs. non-coincident demand) for the 74% of SDG&E's distribution system that is demand driven, in accordance with EPMC methodology.

For transmission load modeling (Step 2), we find SDG&E's description[27] vague, and require SDG&E to provide more detail and transparency into this part of its proposal in a workshop as directed herein.

SDG&E's Generation Demand Charge Research Plan

As stated in SDG&E's research plan:

> Generation capacity costs that are determined to be driven by peak needs during the on-peak period will be considered for allocation to an on-peak demand charge with the remaining capacity costs to be considered for allocation to volumetric energy charges during other TOU periods…

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[25] ORA detailed comments attached to its Protest to AL 3166-E, page 3.
[26] SDG&E's Reply states (p.3) "SDG&E will work with ORA to ensure their concern about the weighting circuit and substation peaks when analyzing load data is addressed in the study."
[27] SDG&E Demand Charge Research Plan, Attachment A to AL 3166-E, p. 9

SDG&E's research plan does not state how SDG&E intends to determine which costs are driven by peak needs during the on-peak period. Further, as ORA's comments state: "The [SDG&E] research plan is not explicit on what are 'the remaining capacity costs' that are not peak-demand related."[28]

Further, SDG&E's generation research plan does not specify what data and analysis is needed to examine whether a shorter duration (e.g., two-hour) period for assessing generation capacity peak-related demand charges should be established, within the recently adopted 4 pm to 9 pm peak period. Indeed, based on SDG&E's statement: "… SDG&E does not foresee a need to change TOU periods as part of its 2019 GRC Phase 2,"[29] SDG&E appears to misunderstand the origin of this aspect of OP 35. In citing to D.14-12-080, D.17-08-030 addresses these concerns with SDG&E's current methodology for assessing peak-related demand charges:

> 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 ([D.14-12-080] Finding of Fact 12).
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> In this [generation demand charge] 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.

D.17-08-030 provides further clarification of this issue:

[28] ORA comments attached to AL 3166-E, p.3.
[29] Research plan, p.10.

> 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.[30]

In summary, OP 35 is not requesting a re-examination of SDG&E's TOU periods as SDG&E's research plan seems to suggest. Rather, it asks SDG&E to examine whether a *separate*, shorter period (perhaps 2 hours) would be appropriate to more accurately hone in on when the actual summer peak is most likely to occur, <u>solely for the purpose of a more accurate assessment of peak-related demand charges (for generation capacity only)</u>. We direct SDG&E to revise its generation demand charge research plan to address the issue of whether a shorter peak capacity period is more in line with actual cost causation.

As with SDG&E's proposed transmission load modeling, we find SDG&E's description of its generation demand research plan lacking in specificity as described above. We therefore approve this proposal as modified herein, and direct SDG&E to hold a workshop as described below.

Need for a Workshop

As discussed above, we are not satisfied that SDG&E's transmission and generation demand charge research plans are complete or accurate. Further, we have directed major augmentations to SDG&E's demand charge research plans. To provide methodological clarity and ensure that the directives of this Resolution are being carried out, we direct SDG&E to work with Energy Division to schedule a workshop within 30 days of SDG&E's filing its demand charge

[30] See D.17-08-030, footnote 31, p.51.

studies[31]. In this workshop, SDG&E shall present its findings for distribution, transmission, and generation, based on its preferred methodologies and the alternate approaches directed herein, along with a detailed description of the methodologies it followed in reaching these findings.

COMMENTS

Public Utilities Code Section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review and comment prior to a vote of the Commission. Section 311(g)(2) provides that this 30-day period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

FINDINGS

1. Decision 17-08-030 Ordering Paragraphs 33-35 ordered SDG&E to perform studies of the appropriate demand charges in its medium and large commercial and industrial rates for distribution, transmission, and generation, respectively.

2. SDG&E's AL 3166-E complies with the requirements of OPs 33-35.

3. SDG&E's proposed two-step demand charge research plan for each of distribution and transmission, with the modifications required herein, is reasonable.

[31] Assuming SDG&E files its GRC Phase 2 on schedule (December 1, 2018), we expect SDG&E to file these studies before February 1, 2019, and Energy Division should hold a workshop on these studies no later than February 28, 2019.

4. In its alternate demand charge studies, SDG&E should bypass the detailed cost analysis proposed in Step 1 of its research plan, as it is not necessary for the purpose of the distribution and transmission demand charge studies required by OPs 33 and 34.

5. The Commission has used "Equal Percent of Marginal Cost" ("EPMC") methodology to partition distribution costs into customer-related and demand-related components for ratemaking purposes going back to D.89-12-057.

6. SDG&E should apply the EPMC methodology to marginal customer and distribution costs and billing determinants adopted in D.17-08-030.

7. SDG&E should develop an alternate demand charge study for distribution that bypasses the proposed Step 1 and incorporates 26% of distribution revenue attributed to customer access and 74% to serving demand, consistent with the revenue allocation settlement in D.17-08-030.

8. SDG&E's use of the EDF methodology to inform each customer class' contribution to circuit and substation peaks is reasonable, however, SDG&E should implement ORA's proposed load-weighted EDFs for greater accuracy.

9. The process of classifying distribution and transmission projects by cost-causation is subjective to some degree and could be subject to bias.

10. Distribution and transmission projects may have multiple cost drivers. SDG&E's alternate demand charge studies should reflect the fact that capacity may be the primary or secondary cost driver given that all T&D projects must be sized to meet the maximum power flow on those facilities.

11. SDG&E's alternate demand charge studies should reflect the fact that distribution and transmission investments related to reliability, policy

mandates, and economic efficiencies may be partially peak-demand-related.

12. SDG&E's proposed partition of distribution and transmission projects into capacity-related and non-capacity-related buckets may be overly restrictive for the purpose of the demand charge studies required by OPs 33 and 34.

13. SDG&E's alternate transmission demand charge study should incorporate the "hybrid approach" to transmission rates set forth in the straw proposal in CAISO's TAC Initiative, in which transmission revenues are split 50/50 between usage related (recovered via volumetric rates) and peak-related (recovered via peak-related demand charges).

14. SDG&E's research plan should be modified by providing sufficient detail as to how to use Step 2 transmission load data to separate demand-related costs into peak-related and non-coincident demand charge components, and should be modified and presented in a workshop in its GRC Phase II.

15. As a part of the distribution-related demand charge study results submitted as testimony and presented in a workshop in its GRC Phase II, SDG&E should include an explanation of the relationship between the data, methodology and results used its demand charge study and the data, methodology and results of its Grid Needs Assessment and Distribution Deferral Opportunity Report conducted pursuant to Decision 18-02-004, Ordering Paragraph 2.

16. SDG&E's proposal to use a "Loss of Load Event (LOLE)" methodology to allocate generation capacity costs to the peak period is reasonable.

17. SDG&E's research plan should be modified by providing sufficient detail as to how to separate generation capacity costs into peak-related and non-peak related components, and the extent to which ramping and integration of renewables will affect future capacity investments.

18. SDG&E AL 3166-E omits the data necessary to examine whether a shorter duration period for assessing generation capacity peak-related demand charges should be established within the recently adopted 4 pm to 9 pm peak period.

<u>THEREFORE IT IS ORDERED THAT:</u>

1. SDG&E shall modify the studies presented in AL 3166-E and file them as supplemental testimony in its GRC Phase 2 proceeding within 60 days of filing its Application.[32] SDG&E shall modify these studies by providing the following supplemental information:
    a. How its transmission studies use its load data to separate demand-related transmission costs into peak-related and non-coincident demand charge components.
    b. How its generation study models ramping and renewables integration, and how it separates generation capacity costs into peak-related and non-peak related components.
    c. The data and analysis SDG&E used to examine whether a shorter duration period for assessing generation capacity peak-related demand charges should be established within the recently adopted 4 pm to 9 pm peak period.
    d. How the data, methodology, and results of its distribution demand charge studies relate to the data, methodology and results of its Grid Needs Assessment and Distribution Deferral Opportunity Reports.

2. SDG&E shall conduct an alternate distribution demand charge study, filed concurrently with its proposed distribution demand charge study in AL 3166-E, with the following parameters:
    a. SDG&E shall use the EPMC-based attribution of 74% of distribution costs as demand-related as the starting point, bypassing SDG&E's

[32] SDG&E's next GRC Phase 2 Application is now scheduled for December 1, 2018. OP 34 requires SDG&E to file its transmission study *at FERC* before that date.

proposed Step 1 distribution cost analysis and proceeding directly to its Step 2 load analysis.

   b. SDG&E shall provide that up to 74% of distribution cost could be subject to recovery in a peak-related demand charge, depending on the outcome of SDG&E's Step 2 load analysis.

3. SDG&E shall conduct an alternate transmission demand charge study, filed concurrently with its proposed transmission demand charge study, with the following revised parameters:
   a. SDG&E shall use the CAISO's attribution of a fixed percentage of transmission costs as demand-related as the starting point, bypassing SDG&E's proposed Step 1 transmission cost analysis and proceeding directly to its Step 2 load analysis.
   b. SDG&E's alternate study shall assume that 50% of transmission cost is demand-related per CAISO's January 11, 2018 "Straw Proposal" in its Transmission Access Charge Structure stakeholder initiative, subject to any updates to CAISO's TAC proposal as they become available.
   c. SDG&E's alternate study shall assume recovery of up to 50% of transmission costs in a peak-related demand charge, depending on the outcome of SDG&E's Step 2 load analysis.

4. SDG&E shall present both its preferred transmission demand charge study, and the alternate transmission study ordered above, at FERC, pursuant to OP 34 of D.17-08-030.

5. SDG&E shall hold a publically noticed workshop within 30 days of the filing of its supplemental testimony as directed herein, to present its preferred and alternate demand charge methodologies, its findings for all of the studies directed in OPs 33-35, and the relationship between the data, methodology, and results of those studies and the data, methodology, and results of its Grid Needs Assessment and Distribution Deferral Opportunity Report.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on September 13, 2018; the following Commissioners voting favorably thereon:

ALICE STEBBINS
Executive Director