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ORA Coordinator	:	Rick Tse

OFFICE OF RATEPAYER ADVOCATES
California Public Utilities Commission

PREPARED TESTIMONY ON PACIFIC GAS AND ELECTRIC COMPANY'S AND SOUTHERN CALIFORNIA EDISON COMPANY'S MEDIUM/HEAVY-DUTY FLEET CHARGING INFRASTRUCTURE AND COMMERCIAL ELECTRIC VEHICLE RATES PROGRAMS

San Francisco, California
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APPENDIX A – QUALIFICATIONS OF WITNESSES

MEMORANDUM

This report was prepared by the Office of Ratepayer Advocates ("ORA") in Application ("A.") 17-01-020 (Pacific and Electric Company) and A.17-01-021 (Southern California Edison Company). In this docket, the applicants request the Commission's approval to implement Medium/Heavy-duty fleet charging infrastructure and commercial electric vehicle rates programs pursuant to Senate Bill 350 ("SB 350"). In this report, ORA presents its analysis and recommendations associated with the applicants' requests.

Rick Tse served as ORA's project coordinator in this review, and is responsible for the overall coordination and preparation of all sections in this report. Nathan Chau, Benjamin Gutierrez, Tom Gariffo, and Rick Tse serve as ORA's witnesses and are responsible for different chapters of this report and their prepared qualifications and testimony are contained in this report.

ORA's legal counsel for this proceeding is Tovah Trimming.

EXECUTIVE SUMMARY

In accordance with Rule 13.8 of the California Public Utilities Commission ("CPUC" or "Commission"), Rules of Practice and Procedure, and the April 13, 2017 Scoping Memo and Ruling of Assigned Commissioner and Administrative Law Judges ("Scoping Memo"), the Office of Ratepayer Advocates ("ORA") submits this intervenor testimony on the standard review projects ("SRPs") proposals relating to fleet charging infrastructure and commercial electric vehicle rates filed by Pacific Gas and Electric Company ("PG&E") and Southern California Edison Company ("SCE") in Application ("A.") 17-01-020 and A.17-01-021, respectively.

PG&E proposes a five-year $210.8 million ("M") Fleet-ready Program to deploy make-ready infrastructure to support charging stations for non-light electric vehicles ("EV") in its service territory. PG&E would own, operate, and maintain the make-ready infrastructure. PG&E anticipates partnering with entities such as transit agencies, school districts, and delivery companies to electrify their respective combustion vehicle fleets.

Similarly, SCE proposes to deploy make-ready infrastructure to serve charging equipment for Medium/Heavy-duty ("MD/HD") electric vehicles ("EVs") for a five-year program at a cost of $553.8M. SCE proposes to model several aspects of its program after its Charge Ready Pilot for light-duty EV infrastructure. Participating customers will purchase charging equipment and be responsible for installing and maintaining the equipment as well as acquiring and maintaining eligible EVs.

SCE also proposes commercial EV rates for three different sizes of charging power levels. The rates will apply to new and existing EV customers including electric vehicles, vessels, trains, boats, or other equipment that are mobile sources of air pollution and greenhouse gas ("GHG") emissions. SCE proposed that its customers must agree to take service on an eligible Time-of-Use ("TOU") rate and participate in the program for five years.

ORA conducted an in-depth review and analysis of PG&E's and SCE's applications relating to fleet charging infrastructure and rates and provides the following recommendations, summarized below:

1) The Commission should approve PG&E's Fleet-ready Program as a phased pilot, not as a full-scale program as currently proposed. Given the uncertainty in the MD/HD market segment and the lack of learning in this area, PG&E

should not be authorized such a large amount of ratepayer funds ($210.8M) for full deployment.

2) The Commission should authorize $21.0M (or 10% of $210.8M) for the proposed pilot version of PG&E's Fleet-ready Program. PG&E should be allowed to file a new application for a full-scale Phase 2 of the program after PG&E collects a year's worth of data and learning from Phase 1 of the program.

3) The Commission should require a 25% target for disadvantaged communities, but allow PG&E to file a Tier 1 advice letter to seek relief from this obligation if the target cannot be met by year 4 of the 5-year program.

4) The Commission should reduce PG&E's cost-contingency request from 35% to 10%. PG&E's does not provide justifiable reasons for such a high contingency. PG&E's explanation that installing make-ready to support a wide array of electric technologies and different charging scenarios results in substantial cost variations is unfounded.

5) The Commission should approve SCE's MD/HD Charging Infrastructure Program as a phased pilot, akin to SCE's Charge Ready Pilot Program, with the intention of allowing full-scale deployment after one year of pilot implementation. Specifically, the Commission should authorize SCE's program at 10% the size of its proposed program, with a funding level of $55.4M (or 10% of $553.8M).

6) The Commission should reduce SCE's cost-contingency request from 35% to 10% for its MD/HD Charging Infrastructure Program. SCE's cost estimation already factors in a wide range of site configurations and attributes before adding on the 35% cost contingency, rendering it unreasonable.

7) The Commission should require a minimum of 10% of MD/HD charging sites for this SCE's pilot program, as recommended by ORA, be located in DACs.

8) The Commission should require SCE to establish a one-way balancing account for its Transportation Electrification Portfolio Balancing Account ("TEPBA") capped at the Commission's authorized funding level with no opportunity to request costs above the established cap at a later date, as proposed by SCE.

9) For SCE's Time-Of-Use-Electric Vehicle-7 ("TOU-EV-7") proposed rate for small commercial EV customers, the Commission should require the system-peak related transmission cost to be recovered by volumetric TOU rates. Doing so will encourage customers to charge in a manner that optimizes grid use.

List of ORA Witnesses and Respective Chapters

Chapter Number	Description	Witness
-	Executive Summary	Rick Tse
1	PG&E's Fleet-ready Program	Rick Tse
2	SCE's MD/HD Charging Infrastructure Program	Tom Gariffo
3	SCE's Commercial EV Rate Proposal	Nathan Chau and Ben Gutierrez

CHAPTER 1 : PG&E's FLEET-READY PROGRAM

I. BACKGROUND

PG&E proposes a $210.8M Fleet-ready Program to deploy make-ready infrastructure to support charging stations for non-light EVs[1] in its service territory. PG&E would own, operate, and maintain the make-ready infrastructure. PG&E anticipates partnering with entities such as transit agencies, school districts, and delivery companies to electrify their respective combustion vehicle fleets. To ensure commitment from participants and avoid stranded assets, PG&E will qualify customers based on their demonstrated commitments to 1) buy EV fleet and charging stations (i.e., purchase order), 2) provide PG&E certain vehicle and charging data, 3) maintain EV fleet and charging stations (i.e., maintenance contract), and 4) develop a long-term electrification plan for any requests to upsize infrastructure to accommodate future growth of transportation electrification ("TE").[2]

To forecast the number of sites in PG&E's service territory that would participate in the program, PG&E first developed a reference case EV adoption forecast for the non-light-duty sector by: developing a state-wide forecast;[3] estimating PG&E's share of each sector;[4] and determining the number of sites needed to support its forecast.[5] PG&E then estimated 788 sites that would require charging infrastructure, and has scaled its program to meet this level of vehicle adoption.

Additionally, PG&E proposes to provide $16M in financial incentives for disadvantaged communities ("DACs") and beach head sectors.[6] PG&E estimates that 25% of program participants will be in DACs. The program would offer a 75% rebate on Electric Vehicle Supply

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[1] PG&E defines non-light-duty electric vehicles as: Medium Duty: Light-heavy-duty trucks and Medium-duty trucks (EMFAC Categories LHD1, LHD2, and MDV); Heavy Duty: Trucks, Medium-heavy-duty trucks, Heavy-heavy-duty trucks, Buses, Commuter Bus, School and Other Bus (EMFAC Categories MHDT, HHDT, SBUS, UBUS, and OBUS); and Off-Road: Airport Ground Support Equipment, Port cargo handling equipment, Transport refrigeration units, Truck stop electrification, Forklifts (class 1), and Other non-light-duty vehicles. PG&E Testimony, Table 3-2, p. 3-9.

[2] PG&E Testimony, at p. 3-10.

[3] PG&E Testimony, Tables 3-3 and 3-4 at pp. 3-16 and 3-17.

[4] PG&E Testimony, Table 3-5 at p. 3-19.

[5] PG&E Testimony, Table 3-8 at p. 3-24.

[6] PG&E defines "beach head" sectors as sectors where developments are likely to promulgate EV innovation and accelerated deployment, PG&E Testimony, p. 3-33.

Equipment ("EVSE") costs to DACs for a total cost of up to $10M in incentives. PG&E identifies public transit buses and school buses as beach head sectors. PG&E proposes to provide eligible projects $15,000 towards the cost of an EVSE, or approximately 20% of the total charger cost[7] for 400 electric buses, which totals $6M in incentives. In addition, PG&E proposes to submit an annual report, with data on program deployment, site operation, and descriptive program information.[8]

II. SUMMARY OF RECOMMENDATIONS

1) The Commission should approve PG&E's Fleet-ready Program as a phased pilot, not as a full-scale program as currently proposed.

2) The Commission should authorize $21.0M (or 10% of $210.8M) for PG&E's Fleet-ready Pilot Program.

3) PG&E should site 25% of its make-ready installation in DACs unless it cannot meet this target by the end of year 4 of the program.

4) The Commission should reduce PG&E's cost-contingency request from 35% to 10%.

III. DISCUSSION

A. The Commission Should Approve PG&E's Proposed Fleet-ready Program as a Phased Pilot, not as a Full-Scale Program.

While ORA strongly supports the state's goal of increasing EV adoption in order to reduce that state's greenhouse gas emissions, PG&E's proposal to spend $210.8M ratepayer dollars in a highly evolving and uncertain market is unsound. It would be reasonable and prudent to test market demand and business viability prior to committing such a large investment upfront. The aim of the program to deploy as many as 788[9] make-ready sites to support charging in an emerging non-light duty EV sector represents a risk for ratepayers. As ORA stated in its protest, the MD/HD market segment is "largely nascent and faces a much greater magnitude of common market barriers, the largest being vehicle availability and cost."[10]

[7] PG&E Testimony, p. 3-35.

[8] PG&E Testimony, Table 3-15 at p. 3-46.

[9] PG&E Testimony, Table 3-8 at p. 3-24.

[10] ORA Protest in A.17-01-022, p. 4.

PG&E's strategy to avoid stranded assets and minimize ratepayers' risk is to impose a set of strict criteria in qualifying and selecting program participants.[11] Among other criteria, PG&E will require customers to demonstrate a commitment to buy and maintain a commercial EV fleet and charging stations.[12] In theory, this ensures some level of protection for ratepayers because a committed customer is less likely to back out of an agreement. But in reality, without a corresponding charging rate incentive, customers who find themselves paying high demand charges and whose fleet is largely inelastic to the time of charging may nonetheless curtail, if not completely abate EV operation, due to economics. Since PG&E did not propose any rate incentives or load management solutions[13] as it did for its priority-review projects ("PRPs"), the possibility of this occurring is very real. For example, a transit agency whose bus fleet has a certain in-service duty cycle would not be able to shift its charging to avoid costly demand charges. For these entities, without special charging rates, an EV fleet may or may not be a viable solution. The possibility of these entities defaulting, resulting in stranded assets, is a real and tangible concern. Therefore, PG&E's proposed discreet qualification and selection criteria provide no guarantee that PG&E's infrastructure will be fully utilized and not stranded, and does not necessarily minimize this ratepayer risk.

Further, similar to PG&E's Direct Current Fast Charge Program proposed in this proceeding, ratepayers are being exposed to significant risk because the EV market is generally nascent and in particular, charging behavior and actual market demand are not well understood. In light of this uncertainty, ORA raised concerns regarding PG&E's market forecast in its protest. ORA noted that "since the accuracy of PG&E's vehicle adoption forecast seems too uncertain at this time, as reflected by the extremely broad forecast, ORA believes further evaluation of adoption rates for the medium/heavy (MD/HD) sector should be conducted."[14] PG&E sized its $210.8M Fleet-ready Program based on California Energy Commission's ("CEC"), California Air Resources Board's ("CARB"), and independent market forecast studies.

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[11] PG&E Testimony, p. 3-10.

[12] PG&E Testimony, p. 3-10.

[13] PG&E proposes to utilize technology solutions, such as load management software and onsite battery storage in two of its three priority-review projects (MD/HD Fleet, and Idle-Reduction Demo), to avoid costly demand charges and lower charging costs to customers.

[14] ORA Protest in A.17-01-022, p. 4.

ORA conducted an in-depth review of one independent study conducted by ICF International, which PG&E used to support its forecast.[15] While ORA finds this study generally reasonable, there are concerns with how PG&E applied data from the study. The ICF study generated forecast data on non-light duty EV adoption for only three years: 2013, 2020, and 2030.[16] PG&E, however, proposes to implement its Fleet-ready Program for five years, starting in 2018 and extending into 2022. To fill in the gaps for in-between years where the ICF study did not provide forecast data, PG&E used a Compound Annual Growth Rate ("CAGR"). CAGR calculates the rate of growth between two data points in a given time period and is commonly-used to calculate growth rates of investment funds. For example, to calculate forecast data for in-between years, PG&E used the data in 2013 and 2020 (two data points that are available) to determine that period's growth rate and used it to project data across the period assuming a constant rate of growth.

However, CAGR has limitations and can be misleading. In particular, CAGR only looks at beginning and ending values and assumes a constant growth in between. But in reality, growth is seldom constant and often fluctuates. Further, ORA notes that the 2013's base year data used by PG&E is, in itself, a forecast calculated in 2012, resulting in values that are five years out-of-date. Thus, PG&E's use of this data and the CAGR metric to scope and size its five-year Fleet-ready Program may not accurately represent what is already a highly uncertain market.

Three of PG&E's proposed PRPs – the Electric School Bus Pilot, the MD/HD Fleet, and the Idle-Reduction Demo – already target this very same market segment. In ORA's Opening Brief on the PRPs, ORA recommended the Commission reject these three PRPs on the basis of an "unreasonable revenue requests that are inconsistent with the proposed project scope."[17] ORA also recommended that if the Commission decides to approve these PRPs, PG&E should use these pilots to develop learning for its Fleet-ready Program. To that end, ORA recommends that the Commission reduce the size of PG&E's Fleet-ready Program if the Commission approves PG&E's three related PRPs. PG&E should use a phased approach at 10% the size of

[15] ICF International California Transportation Electrification Assessment (TEA) Study, Phase 1: Final Report.

[16] ICF TEA Study, Tables 4, 8, and 12, at pp. 10, 15, and 19, respectively.

[17] ORA Opening Brief, p. 1.

its proposed Fleet-ready Program, with a funding level of $21M (or 10% of $210.8M) and for a one year duration. Upon completion of the PRPs, ORA recommends that the Commission require PG&E to file a Phase 2 application to request additional funding for full-scale deployment enabling PG&E to incorporate lessons-learned for an improved Fleet-ready Program. Phase 1 should reflect a year's worth of data collection and learning before a new application can be submitted. ORA's suggested approach is consistent with the Commission's guidance in its ruling to "encourage the utilities to target pilots and experiments in diverse market segments to gain experience to inform the eventual design of scaled programs."[18]

B. 25% of the Program Should be Targeted at DACs Unless this Target Cannot be Met in Year Four of the Program.

PG&E proposes a set-aside for DACs to ensure that the benefits of the Fleet-ready Program also accrue to DACs.[19] PG&E will provide financial support, in addition to the make-ready infrastructure, for the purchase of EV charging equipment. Customers in DACs will be eligible for a rebate to cover approximately 75 % of the charger. PG&E estimates that, as is representative of its customer base, 25% of program participants will be in DACs and requests a set-aside of $10M in expense to cover the projected rebate amounts below. PG&E also "requests flexibility to administer the DAC rebate portion as the market progresses."[20]

ORA supports PG&E's requests with some modification. Instead of allowing PG&E flexibility based on market progress, ORA recommends that PG&E have a target of 25% for program participants located in DACs, which as PG&E notes is representative of its customer base. However, since the benefits of reduced GHGs and criteria pollutants provides a broader public health and environmental benefit, if PG&E cannot meet its 25% goal and use the $10M set aside by the end of year 4 (of the 5 year program), PG&E may file a Tier 1 advice letter to be relieved of this obligation. The advice letter should include the current number of sites in DACs and percent of the $10M set aside spent. PG&E would then be free to approve sites outside of DACs and use the remainder of the unspent $10M.

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[18] Assigned Commissioner's Ruling Regarding the Filing of the Transportation Electrification Application pursuant to SB 350 issued September 2016, p. 19.

[19] PG&E Testimony, p. 3-33.

[20] PG&E Testimony, p. 3-33.

C. The Commission Should Reduce PG&E's Cost-Contingency From 35% to 10%.

PG&E's requested cost-contingency of 35% in its revenue requirement for the Fleet-ready Program is too high and should be reduced.[21] PG&E justifies this request on the basis that there are many cost variables and, therefore, cost contingencies are needed to address potential cost variations and cost overruns. On March 21, 2017, ORA submitted a data request[22] asking PG&E to further explain why it needs a 35% cost-contingency for its Fleet-ready Program. PG&E referred to its testimony which merely states that in order "to address the variations in cost, PG&E has included an overall 35 percent contingency on the EV service connection and supply infrastructure work."[23] PG&E further explains in its data response that because it provides make-ready to support a wide array of electric technologies and different charging scenarios, that this would result in substantial cost variations. For example, "PG&E estimated site costs for 18 different charging scenarios for its Fleet-Ready Program, and could provide make-ready infrastructure for over 10 different electric technologies."[24]

ORA disagrees with PG&E's explanation that installing make-ready infrastructure to support a wide array of charging scenarios is what drives cost variations. In determining overall program cost, PG&E estimates what it would cost to install each type of installation separately. For example, PG&E estimates installation costs for medium-duty trucks, heavy-duty trucks, and school buses separately.[25] Therefore, the wide array of scenarios that PG&E referred to is already accounted for in the overall program cost and does not explain the need for a large contingency. Further, PG&E cites the Association for the Advancement of Cost Engineering's ("AACE")[26] cost estimate classification system to justify its large contingency request.[27] PG&E

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[21] PG&E Testimony, p. 4-13.

[22] ORA Data Request No. ORA-A1701022-PGE-01, Question 4b.

[23] PG&E Testimony, p. 3-30.

[24] PG&E Response to ORA's Data Request No. ORA-A1701022-PGE-01 (March 21, 2017).

[25] PG&E's Detailed Cost Summary Workpaper Supporting Chapter 3 for MD Truck, HD (Truck and Transit) and HD School Bus.

[26] AACE (Association for the Advancement of Cost Engineering) is a recognized technical authority in cost and schedule management for programs, projects, products, assets, and services (http://web.aacei.org/).

[27] PG&E Response to ORA Data Request No. ORA-A1701022-PGE-01 Question 4a.

states that its request is "consistent with a Class 4 estimate,"[28] which has a contingency range of 20 to 50%.[29] While AACE's system may be a valid tool to use for estimating costs in common Engineering Procurement and Construction projects, PG&E's Fleet-ready Program is atypical and unlike traditional infrastructure projects where robust data and statistics can be drawn from to inform reasonable estimates. Therefore, PG&E lacks a solid basis to rely on this system to justify its request for a large cost-contingency.

PG&E's request is also not supported by Commission decisions addressing the issue of reasonable cost contingencies. The Commission issued Decision ("D.") 10-04-028[30] authorizing PG&E to install fuel cell projects, in which PG&E's capital cost contingency was deemed unreasonably high. The Commission found that "the contingency rates proposed by PG&E and SCE are significantly higher than other contingency rates, generally in the 5 to 8% range, previously approved by the Commission."[31] Further, the Commission found that "approval of large contingencies for capital costs sends an improper incentive to the utilities and vendors that they can enhance the project scope within the limits of the contingencies."[32]

A large contingency also reflects the fact that the project scope is too unrefined. In D.10-04-028, the Commission reduced PG&E's capital cost contingency rate to 5 to 10 % consistent with prior Commission decisions.[33] Consistent with these Commission decisions, ORA recommends the Commission approve a 10% contingency for PG&E's Fleet-ready Program, for both capital costs and expenses. This comports with D.10-04-028 as well as what it generally allows for in utilities' infrastructure projects.[34]

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[28] PG&E Testimony, p. 3-30.

[29] PG&E Testimony, p. 3-30.

[30] D.10-04-028 issued in April 2010 authorized PG&E and SCE to install fuel cell generating facilities at several University of California and California State University campuses.

[31] D.10-04-028, p. 18 (citing D.06-11-048 at 21-22 and fn. 12).

[32] D.10-04-028, p. 19.

[33] D.10-04-028, p. 19.

[34] The CPUC generally adopts 10 to 15% cost contingencies for infrastructure projects. *See, e.g.,*

D.16-12-065, Conclusion of Law #18; D.13-03-032, p. 69 ("As we have done in prior decisions, we adopt a 10 percent contingency amount for Transmission and Distribution aspects of the approved pilots in this decision.") (footnoting D.12-11-051, p. 247).

IV. CONCLUSION

To protect ratepayers from the risk of overinvestment at the early stages of a developing market, the Commission should approve PG&E's Fleet-ready Program as a phased pilot. In addition, the project cost should be limited to $21.0M, or 10% of PG&E's proposed costs. Regarding DACs, PG&E should aim to implement 25% of the program in DACs, and only be relieved of this obligation if the target cannot be met by the end of year 4 of the 5-year program. Lastly, for consistency with other Commission decisions and in consideration of the wide variation in program costs already taken into account by PG&E, the Commission should authorize a 10% cost-contingency.

CHAPTER 2 : SCE'S MEDIUM/HEAVY-DUTY CHARGING INFRASTRUCTURE PROGRAM

I. BACKGROUND

Southern California Edison Company ("SCE") proposes to provide make-ready electric infrastructure to serve charging equipment for Medium/Heavy-duty ("MD/HD") vehicles.35 SCE proposes to model several aspects of its program after its Charge Ready Pilot for light-duty infrastructure, but notes that charging the non-light-duty segment may require significantly higher levels of kilowatt ("kW") demand that is in turn more expensive. Participating customers will purchase the electric vehicle supply equipment ("EVSE") and be responsible for installing and maintaining it as well as acquiring and maintaining the EV.[36] Customers must agree to take service on an eligible time-of-use ("TOU") rate and participate in the pilot for five years.[37]

SCE intends to form an advisory board to provide guidance on program implementation, and provide quarterly status reports. SCE will also provide information in its annual SB 350 portfolio report and in a project close out report.[38]

SCE also proposes to provide a rebate to cover 100% of the base cost of the EVSE and installation for eligible customers. To qualify for the program and rebate, the EVSE must meet certain technical standards and energy efficiency recommendations and be listed by a nationally recognized testing laboratory.[39] For those customers without standardized EVSE, SCE will work with the customer to determine if it can provide the make-ready infrastructure, but will not provide a rebate on the EVSE.[40]

II. SUMMARY OF RECOMMENDATIONS

1) The Commission should approve SCE's MD/HD Charging Infrastructure Program as a phased pilot and allow SCE to file a Phase application upon completion of Phase 1. The scope of Phase 1 should be 10% the size of the program as proposed, with a funding level of $55.4 million.

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[35] SCE Testimony, p. 52.

[36] Class 2-8 trucks as well as non-road cargo handling equipment and buses are eligible, as detailed in Appendix C of SCE's Testimony, at pp. C-1.

[37] SCE Testimony, p. 55.

[38] SCE Testimony, p. 98.

[39] SCE Testimony, p. 55.

[40] SCE Testimony, p. 55.

2) The Commission should require SCE to establish a one-way balancing account capped at the Commission's authorized funding level.

3) The Commission should reduce SCE's cost-contingency request from 35% to 10% for its MD/HD Charging Infrastructure Program.

III. DISCUSSION

A. The Commission Should Approve SCE's Proposed MD/HD Vehicle Charging Infrastructure Program as a Pilot, not as a Full-Scale Program.

ORA supports the effort to increase EV adoption in order to further the state's GHG emissions reductions goals. However, SCE's $553.82 ("M") funding proposal exposes ratepayers to unreasonable risk due to the potential for stranded assets resulting from a developing EV market sector. In D.16-01-023, which established SCE's first major Charge Ready Pilot Program ("CRPP"), many parties asserted that EV charging is still poorly understood and that implementation of the charging program should be carefully considered over multiple phases.[41] At a funding level of $22M,[42] the Commission determined that "12 months should provide adequate data for pilot evaluation" and the Commission therefore "modif[ied] the Proposed Settlement to require that SCE file and serve a pilot report to provide Phase 1 data, and recommend any necessary changes to Phase 2, after at least 12 months of program implementation, and at least 1,000 charging station installations."[43] As of the CRPP's 5th advisory board meeting on May 19, 2017, SCE had completed construction for only 16 charging stations, and verified deployment of only 2 charging stations.[44]

SCE states that its MD/HD Vehicle Charging Infrastructure Program "follows the model developed for the Charge Ready pilot program, where SCE deploys owns, and maintains the infrastructure needed to serve charging equipment for in-scope vehicles (up to and including the

[41] D.16-01-023, p. 4 ("SCE states that the initial pilot will allow it to test several key assumptions prior to undertaking a full program in Phase 2. Specifically, SCE plans to validate its cost estimates and program incentives, identify and address field deployment issues, and refine its market education strategies"); *see id.* at p. 29 ("[T]he benefit of a pilot and phased approach is to enable analysis of the program, and determine whether full-scale deployment is warranted, and in what form…the Commission must be able to evaluate the reasonableness of Phase 2, which will largely hinge on the results of Phase 1.").

[42] D.16-01-023, OP 1.

[43] D.16-01-023, p. 24.

[44] Charge Ready Advisory Board meeting slides, May 19, 2017; p. 7 ("Charge Ready Advisory Board 5th Meeting_rev5_05182017.pdf").

make-ready stubs)."[45] But unlike CRPP's widely supported multi-party settlement agreement allowing SCE recovery of $22M from ratepayers for "a 12-month pilot deploying 1,500 EV charging stations intended to test key assumptions,"[46] SCE's MD/HD Charging Infrastructure Program represents a massive scale-up to electrify MD/HD transportation across SCE's entire service territory.

CRPP was originally proposed by SCE with two phases, a pilot Phase 1 and a scale up in Phase 2 that would take the knowledge gained from Phase 1's 1,500 charging station installations to inform a further deployment of "up to 30,000 EV charging stations."[47] The instant program reads much like the CRPP's proposed Phase 2 minus the learning from a Phase 1. In addition, unlike the Commission's determination in the CRPP proceeding that a Phase 2 scale-up needed to be a separate application informed by the results of Phase 1, approval of SCE's massive MD/HD proposal here would be by a single application absent any further review by the Commission or interested parties.

The basic design aspects of CRPP, such as SCE installing and owning EVSE make-ready infrastructure, site hosts owning the EVSEs, and SCE providing a rebate for EVSE purchase, are broadly favored by parties, allowing for the settlement to be made with relatively little deliberation. This is also why the basic design of the MD/HD Vehicle Charging Infrastructure program may seem acceptable at first glance. But the light-duty charging stations installed under CRPP are only now just beginning to see use from drivers. There has not been enough time for results to come in on CRPP and for data from this sample to be analyzed and digested regarding light-duty EVs, and MD/HD EVs may experience vastly different charger utilization.

In its testimony on the MD/HD Vehicle Charging Infrastructure Program, SCE addresses stranded assets only in terms of customers participating in the program, by requiring them to "utilize and maintain charging equipment" and demonstrate "that they have secured appropriate funding and have placed a firm order for charging equipment acceptable to SCE."[48] There is no consideration of an EVSE site being a stranded asset because it goes unused by drivers. But

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[45] SCE Testimony, p. 52.

[46] D.16-01-023, p. 4.

[47] D.16-01-023, p. 4.

[48] SCE Testimony, p. 100.

because SCE will be allowed to include capital expenditures[49] and charging station rebates[50] in its rate base if the program is authorized as proposed, SCE will receive a 7.9% rate of return on these investments regardless of how much they are actually used to charge EVs. As such, SCE does not have "skin in the game" monetarily when it comes to EVSEs actually getting used.

SCE does not require a showing by participants that a site will actually be patronized by EV drivers, and SCE's testimony does not present any data or describe general institutional knowledge of how to site a charging station that receives traffic. Completed pilot programs and analysis of the data they generate on successfully electrifying the various transportation sectors would enable both of these commonsense measures. Without this fundamental data, participating customers may be burdened with maintaining infrastructure that generate no income, SCE ratepayers may be subsidizing millions of dollars' worth of infrastructure that provide little or no benefit, and Californians may not get the GHG reductions intended by SB 350. Additionally, failure of an EV charging program on a large enough scale would threaten California's leadership in transportation electrification in the country along with support for transportation electrification in general.

In light of these unknowns, ORA recommends that the Commission approve SCE's MD/HD Vehicle Charging Infrastructure Program at a size commensurate with a robust first phase pilot program, akin to the CRPP Phase 1, with the intention of a scaling up in the second phase following the collection of one year's worth of pilot data on electrification of the MD/HD transportation sector. A proven small-scale program will provide confidence and assurance that larger scale transportation electrification will ultimately provide benefits beginning in 2019 than a potentially ineffective program beginning in 2018. Thus, ORA recommends that the Commission only authorize a Phase 1 of the MD/HD Vehicle Charging Infrastructure Program at 10% the size of SCE's proposed program, with a funding level of $55.4M (or 10% of $553.8M), a required one year duration, and similar reporting and oversight requirements as the CRPP. SCE should be permitted to submit a Phase 2 application after the completion of Phase 1 and CRPP Phase 1.

[49] SCE Testimony, p. 102.

[50] SCE Testimony, p. 107.

B. SCE's 35% cost contingency is unnecessary and duplicative given its cost estimation methodology.

In its testimony, SCE states that it includes a 35% contingency in its cost estimates because "each customer site is unique with many factors influencing costs."[51] There is no disputing the fact that each site installation is unique and will have differing attributes contributing to costs including "customer planning, engineering, construction (including trenching) labor, and materials,"[52] and that, because SCE will be responding to applications from customers rather than actively selecting ideal sites for cost, there is further uncertainty about the kinds of challenges presented by sites in the applicant pool.

However, in workpapers provided by SCE to ORA in response to data requests, it is clear that SCE's cost estimation already factors in a wide range of site possibilities in terms of these attributes before adding on the 35% cost contingency.[53] The workpapers contain detailed examination of granular factors contributing to a range of customer-side site sizes and complexities, as should be expected for an investor-owned utility's due diligence for programs of this scale and importance to the state.[54] The workpapers also estimate the incremental number of sites that can be expected to be added in SCE's service territory each year from 2019 through 2023, with an estimated site complexity distribution.[55] Given this estimation methodology, SCE's remaining uncertainty in terms of "customer planning, engineering, construction (including trenching) labor, and materials" would seemingly have to come from the data and assumptions used here to estimate its funding request.

Because of this, two possible conclusions can be made regarding SCE's inclusion of a 35% cost contingency, which represents $97.7M[56] of its funding request. First, it can be

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[51] SCE Testimony, p. 57.

[52] SCE Testimony, p. 57.

[53] SCE Response to ORA Data Request 1, A.17-01-021 ORA-SCE-001 Q.01a-d, Attachment 3: MD-HD Cost Estimate Infrastructure ORA.xlsx, "Aggregate Costs" tab, cells I9-I18.

[54] SCE response to ORA data request 1, A.17-01-021 ORA-SCE-001 Q.01a-d, Attachment 1: MD-HD Cost Estimate Site Infrastructure ORA.xlsx, entire spreadsheet.

[55] SCE response to ORA data request 1, A.17-01-021 ORA-SCE-001 Q.01a-d, Attachment 3: MD-HD Cost Estimate Infrastructure ORA.xlsx, "Aggregate Costs" tab, cells F29-I96.

[56] SCE response to ORA data request 1, A.17-01-021 ORA-SCE-001 Q.01a-d, Attachment 3: MD-HD Cost Estimate Infrastructure ORA.xlsx, "Aggregate Costs" tab (forecasts total costs due to contingency for SCE-side capital costs in cell I11 as $51,718,733 and customer-site capital costs as $46,010,701, which sum to $97,729,433).

concluded that SCE already has done an adequate job forecasting the cost of the MD/HD Vehicle Charging Infrastructure Program, which would justify only a small fraction of the $97.7 million in order to account for true randomness. Cost contingencies for projects aimed at supporting the development of emerging technologies have been considered by the Commission in the past, in a proceeding involving utility-owned fuel cells that featured similar claims to those leveled here. The proposed capital cost contingencies addressed in D.10-04-028 were under 35% and still the Commission agreed they were "significantly higher than other contingency rates, generally in the 5 to 8 percentage range, previously approved by the Commission."[57] In that proceeding, SCE argued that its fuel cell program needed a high contingency "to cover scope modifications required during the final development and engineering phase of the project, and to accommodate site specific construction and design requirements,"[58] and "that its 'Fuel Cell Program is in the conceptual design phase which means that a larger contingency is required'".[59]

A second conclusion is that the high cost contingency may be representative of the uncertainty behind SCE's data and assumptions employed in its cost estimate to the extent that they predict it may need as much as $97.7 million more for the program, meaning the 35% cost contingency represents a margin of error. If this is the case, it further demonstrates the argument in subsection A of this testimony, such that the current state of data and understanding of viable EV charging sites is still too immature for investor-owned utility projects at a scale that could put at risk hundreds of millions of dollars in ratepayer funds.

Regarding the first point, for the purposes of the instant proceeding, EVSE installations are well beyond a conceptual phase, and the range of construction, engineering, labor, and materials are essentially understood; the only significant unknown in installing EV chargers are site-specific variables. As such, if SCE's estimation methodology can be considered sufficient, then it would be appropriate to apply a 10% cost contingency rather than 35%. Thus, ORA recommends that the Commission require SCE to apply a 10% contingency to cost estimates for the MD/HD Vehicle Charging Infrastructure Program, consistent with previous decisions on cost contingencies for transmission and distribution infrastructure.[60]

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[57] D.10-04-028, p. 18.

[58] D.10-04-028, p. 18.

[59] D.10-04-028, p. 18.

[60] *See* D.16-12-065, Conclusion of Law 18; *see also* D.13-03-032, p. 69 ("As we have done in prior

C. There Should be a Set Aside for Disadvantaged Communities.

ORA agrees with SCE that a MD/HD Vehicle Infrastructure Charging Program will benefit disadvantage communities ("DACs"). Heavily trafficked freight corridors run through many of Southern California's DACs, as identified by CalEnviroScreen 3.0.[61] DACs also surround the ports of Los Angeles and Long Beach, which together make up one of the busiest sites for shipping and warehousing in the country. Based on SCE's assertion that its "service territory has approximately 45 percent of the disadvantaged communities in California,"[62] this program, if successful ,will almost certainly help to alleviate the air pollution these communities face as a result of their proximity to the movement of goods along DACs freight corridors. Thus, transportation electrification measures should offer benefits to DACs as economic resources, exposure to evolving EV charging technology and greenhouse gas reduction. As such, ORA recommends that a minimum percentage of EV charging site installations be located in DACs or at business entities that primarily serve DACs. ORA further recommends that a minimum of 10% of MD/HD charging sites for this pilot program be located in DACs, consistent with the programmatic structure adapted in SCE's CRPP.[63] Given that the prevalence of MD/HD vehicle activity in DACs has already been acknowledged by SCE and ORA, SCE should be able to meet this minimum requirement.[64]

D. The Transportation Electrification Portfolio Balancing Account should be a one-way balancing account with a cap and no opportunity to seek additional ratepayer funding beyond that cap.

SCE proposes a one-way balancing account for its Transportation Electrification Portfolio Balancing Account ("TEPBA"). SCE requests that if the Commission approves the scope of the MD/HD Vehicle Charging Infrastructure Program that the actual incurred costs, as long as consistent with the adopted scope of activities and within cost levels adopted by the

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decisions, we adopt a 10 percent contingency amount for Transmission and Distribution aspects of the approved pilots in this decision.") (footnoting D.12-11-051, p. 247).

[61] SCE Testimony, p. 13.

[62] SCE Testimony, p. 13, fn. 25.

[63] D. 16-01-023, p. 39 ("The Proposed Settlement states that SCE plans to deploy at least 10% of charging stations in disadvantaged communities as identified by CalEPA's CalEnviroScreen tool.").

[64] SCE Testimony, pp. 13-15, 95-96.

Commission, be deemed reasonable and therefore no after-the-fact reasonableness review is necessary. SCE also requests that if actual costs exceed the forecast, or if the actual scope of activities changes from what the Commission has approved, then SCE would be permitted to file an application or other appropriate regulatory procedural mechanism to request approval of the activities and recovery of the additional costs through a traditional after-the-fact reasonableness review.

ORA agrees that a one-way balancing account should be approved, capped at the amount authorized by the Commission. However, given the already large scope and high costs of this program, ORA opposes SCE's request to file an additional application or other procedural mechanism to seek recovery of costs over the cap or an after-the-fact review of unapproved activities if SCE's program as proposed in its application is approved.

CHAPTER 3 : SCE'S PROPOSED SMALL COMMERCIAL EV RATES

I. BACKGROUND

This chapter addresses Southern California Edison's ("SCE's") proposed Time-of-Use ("TOU") electric vehicle ("EV") rate called the Time-of-Use-Electric Vehicle-7 ("TOU-EV-7") rate for small commercial EV customers.[65] SCE's TOU-EV-7 is modeled after a standard TOU rate and includes two customer choices regarding demand charges. SCE proposes an Option A which is a TOU rate with no demand charge and an Option B which includes a demand charge and lower volumetric energy rates. Customers would be able to choose between Options A or B under which their separately-metered EVs would be billed. Option B's non-coincident demand charge ("NCD charge") is designed to recover what SCE classifies as the "grid-related" (or "facilities-related") portion of distribution capacity costs and 100% of transmission costs.[66]

SCE's proposal to recover all SCE's asserted transmission costs via a NCD charge in Option B should be rejected. Instead, the portion of transmission costs that are determined "peak-related" should be transferred to TOU rates for recovery to send more efficient price signals concerning use of the transmission system. Recovering 100% of transmission costs through a NCD charge as SCE proposes does not send meaningful price signals during peak transmission system usage or encourage customers to charge vehicles in a manner that optimizes the use of the grid. SCE's proposal erroneously assumes that none of the transmission costs are system peak-related. The Commission should adopt SCE's TOU-EV-7 Option A as proposed and modify Option B's demand charge level at 44% of the current level of the NCD charge contained in Time-of-Use-Electric Vehicle-3 ("EV-TOU-3") Option B tariff.[67]

A reduced demand charge also will benefit customers as they engage in EV charging to the extent that they avoid charging during the generation system peak. ORA's proposal is also consistent with the guidance put forth in the Assigned Commissioner's Ruling ("ACR") of Commissioner Peterman, issued on September 14, 2016, as discussed below. Though this

[65] Customers with demands below 20kW.

[66] SCE Testimony, p. 67.

[67] This is equivalent to 40% of distribution costs and 100% of transmission costs being included in the NCD charge. SCE's proposal is to recover 60% of combined distribution and transmission capacity costs through the NCD charge. See section III.A for further details.

recommendation could apply to all of SCE's proposed EV tariffs in this proceeding, ORA limits its analysis in this testimony to the small commercial EV tariff only.

SCE proposes three commercial EV rates as part of the company's standard review portion of its Transportation Electrification ("TE") application (A.17-01-020). In this chapter, ORA limits its focus to SCE's proposal for small commercial customers, as reflected in Schedule EV-TOU-7.[68]

SCE proposes Schedule EV-TOU-7 Options A and B which are TOU rates with a customer charge equal to the customer charge in the otherwise applicable general service ("GS") rate ("TOU-GS-1") and in the commercial EV rate EV-TOU-3. The customer charge for TOU-GS-1 and EV-TOU-2 is $0.777/day ($24.087 for a 31-day month).[69] In addition to the flat customer charge, EV-TOU-7-B would include a non-coincident peak ("NCP") demand charge[70] that is evaluated based on a customer's highest 15 minute interval of demand during each month regardless of when it occurs.[71] As previously mentioned, Option A would not feature a NCD charge.

SCE proposes to exempt customers of Option B from the NCD charge for the first five years of implementation because SCE expects that it will take time for EV customers to acclimate to this kind of charge. After the five year introductory period, SCE will introduce the charge in year 6 and gradually increase recovery of distribution and transmission capacity costs until the demand charge reaches its full value in year 11.[72] These increases in the NCP demand charge would be accompanied by decreases to the volumetric TOU component. Additionally, the rate is calibrated to the TOU periods that the company proposed in its 2017 Rate Design Window ("RDW").[73] This TOU configuration, if approved, would feature a 4pm to 9pm peak period and a winter super off-peak period of 8 am to 4 pm.[74] To mitigate seasonal bill volatility,

[68] ORA does not specifically address SCE's EV rate proposals for the larger commercial customers.

[69] SCE Testimony, p. 65; Schedule TOU-GS-1: Time-of-Use General Service; Schedule TOU-EV-3: General Service Time-of-Use, Electric Vehicle Charging.

[70] NCP demand charge, NCD charge and FRD charge are used interchangeably in this chapter.

[71] SCE Testimony, p. 66 (and verified with SCE by phone call).

[72] SCE Testimony, pp. 66-67 (phasing in of demand charges).

[73] SCE Testimony, p. 61 (The TOU periods also adopt a four month summer of June–September, as SCE proposed in its 2017 RDW).

[74] SCE Testimony, p.64.

SCE proposes that some of the summer TOU costs be recovered via winter rates.[75] SCE's proposed rates would have a low super off-peak rate (e.g. ¢8.49/kilowatt-hour ("kWh") for Option A or ¢6.94/kWh for Option B)[76]. Option B's NCD charge is 40% less than the NCD charges in other small commercial rates.[77]

II. SUMMARY OF RECOMMENDATIONS

ORA conducted review and analysis of SCE's proposed rates, and recommends that the system-peak related transmission costs be recovered by volumetric TOU rates for the TOU-EV-7 rate.

III. DISCUSSION

The ACR sets forth guiding principles for TE planning, the type of TE applications that should be filed, and the criteria that these applications must meet. The ACR referenced the following concerns and guidelines concerning TE rate design:[78]

a. EV rates should address some parties' concerns that demand charges discourage the use of electricity as a transportation fuel.

b. Consistent with Public Utilities Code § 740.12(a)(1), EV rate design should reasonably afford customers the opportunity to reduce fuel costs who charge EVs in a manner consistent with electrical grid conditions. A provision in Senate Bill ("SB") 350 observes that deploying EV charging infrastructure "should provide the opportunity to access electricity as a fuel that is cleaner and less costly than gasoline or other fossil fuels in public and private locations."

c. Shifting costs to other ratepayer classes does not comport with cost causation rate design.

d. Rate design proposals should encourage TE charging to maximize the use of renewable energy or to charge at times that resolve conflicting capacity constraints at the transmission and distribution levels.

ORA commends SCE for formulating a proposal that include features intended to address customer needs. SCE's proposal is a step in the right direction in designing a rate that

[75] 50% of summer costs have been shifted to winter.

[76] In Year 11, SCE's response to ORA's data request 2, question 1 (i.e. rate design workpaper), Appendix tab.

[77] The demand charge for TOU-EV-7 rises to $5.85/kW in year 11, compared to $9.74/kW for EV-TOU-3. See SCE's response to ORA's data request 2, question 1 (i.e. rate design workpaper).

[78] ACR, pp. 20, 21.

incorporates the up-to-date grid conditions while also being palatable to customers. These features include Option A, phase-in of the demand charge in Option B, moderation of summer rates, and calibration of the rates to new TOU periods generally address the main rate design-related provisions of the ACR. However, SCE's rate proposal still falls short in two principal matters. First, recovering all transmission costs in the NCD charge in Option B does not align with cost causation principles. Second, Option B will not encourage TE charging that necessarily resolves capacity constraints at the transmission level given that customers' coincident demands may be very different from their NCDs.

A. SCE's NCD Charge is Artificially High and Should be Modified to Promote Efficient Use of the Grid and Non-Peak EV Charging.

SCE's proposal of the NCD charge in Option B results in the recovery of 40% of SCE's distribution demand costs and 100% of SCE's transmission costs via the NCD charge by year 11. SCE asserts that it is appropriate to collect 40% of its calculated distribution demand costs because SCE argues that this amount reflects the costs of the distribution system that SCE deems "grid-related" (i.e., have little correlation with peak demand). The other 60%, which SCE considers "peak-related," is time-differentiated based on SCE's peak load risk factor ("PLRF") method and is collected via volumetric TOU rates.[79] In contrast, SCE does not propose to split transmission capacity costs into similar grid-related and peak-related categories but rather proposes to collect 100% of transmission costs via the NCD charge.[80] The NCD charge would be introduced in year 6 at 16.67% of SCE's estimated full costs and would gradually ramp up to full costs by year 11.[81] Illustrative rates for TOU-EV-7 are displayed in the table below.[82]

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[79] The PLRF method was first proposed by SCE in its 2017 RDW proposing TOU periods for non-residential customers. As explained in SCE's RDW filing, this method uses the triggers defined by distribution planners to identify specific capacity needs, also known as planning thresholds, to allocate peak-driven capacity costs to each hour of the year. It does so by identifying the hours in which a distribution circuit may exceed the trigger. SCE A.16-09-003, Opening Testimony, pp. 38-39. ORA is not determining in this proceeding whether there is solid theoretical support for SCE's calculation and partition of distribution capacity costs but merely outlines how the costs are folded in to rates depending on how they are classified.

[80] SCE Response to ORA's Data Request No. 2, Question 1.

[81] *Ibid.*

[82] By year 11, the size of the NCD charge will amount to 60% of the combined total of distribution and transmission capacity costs. A.17-01-021 ORA-SCE-002 Q.10 a-b. Year 11 rates were constructed

Table 3.1: SCE's Illustrative TOU-EV-7 Rates Following the 6 Year Phase-In of the NCD (Facilities Related Demand Charge ("FRD")) Charge.

TOU-EV-7 (Option B)						
Energy Charge - $/kWh	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
Summer Season						
On-Peak	$ 0.35465	$ 0.34749	$ 0.34034	$ 0.33318	$ 0.32603	$ 0.31888
Mid-peak	$ 0.19926	$ 0.19211	$ 0.18495	$ 0.17780	$ 0.17064	$ 0.16349
Off-Peak	$ 0.12464	$ 0.12005	$ 0.11545	$ 0.11086	$ 0.10626	$ 0.10167
Winter Season						
Mid-peak	$ 0.24490	$ 0.23775	$ 0.23059	$ 0.22344	$ 0.21629	$ 0.20913
Off-Peak	$ 0.12507	$ 0.12047	$ 0.11588	$ 0.11128	$ 0.10669	$ 0.10209
Super-Off-Peak	$ 0.08183	$ 0.07935	$ 0.07687	$ 0.07439	$ 0.07191	$ 0.06943
FRD - $/kW	$ 0.97494	$ 1.94988	$ 2.92481	$ 3.89975	$ 4.87469	$ 5.84963
Customer Charge - $/day	$ 0.77700	$ 0.77700	$ 0.77700	$ 0.77700	$ 0.77700	$ 0.77700

following SCE's instructions in its response to ORA's DR 5, Question #1a. The table assumes no changes in revenue.

ORA supports SCE's proposal to recover peak-related costs via TOU rates but does not support SCE's proposal to include all transmission costs in its NCD or FRD charge.[83] Customers should be charged appropriately for their contributions to coincident peak demand, which drive incremental capacity investments. ORA does not see justification for SCE's asymmetric treatment of transmission costs compared to distribution costs. Given that a significant portion of the transmission system is sized to meet system coincident peak demand, SCE should treat how it recovers such costs in a manner consistent with its treatment of distribution capacity costs.[84] Therefore, the revenues collected via the FRD charge should be reduced by an amount equal to the portion of transmission costs that are considered peak-related.

B. SCE's Proposal to Include 100% of Transmission Costs in the Demand Charge Does Not Follow Cost Causation Principles and the Demand Charge Should be Reduced.

SCE's FRD charge design is an inefficient way of recovering transmission capacity costs because it will not encourage the deferral of infrastructure investments intended to address system peak loads. Additionally, SCE's charge is not an effective tool to encourage customers to use less energy on peak because the charge is assessed on a customer's maximum *non-coincident demand* even though a significant portion of the transmission system is sized to meet system coincident peak demand.

The Commission has concluded that transmission costs are inherently time-dependent (i.e., peak-related) in a number of past decisions. In its decision approving PG&E's Option R tariff, the Commission found that the "need for additional generation, transmission, and primary distribution capacity are driven by customer' coincident peak demand."[85] This conclusion was reiterated in the TOU Order Instituting Rulemaking, D.17-01-006, which established guidelines for developing and evaluating TOU periods.[86] While marginal generation costs (consisting of

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[83] SCE Testimony, p. 66.

[84] SCE determined that 60% of distribution capacity costs are peak-related and 40% of such costs are grid-related. SCE allocates the peak-related distribution capacity costs to the volumetric TOU energy rates and grid-related costs to the FRD or demand charge.

[85] D.14-12-080, Findings of Fact 8

[86] General principle 2 provides that "Base TOU periods should be based on utility-specific marginal costs, rather than on a statewide load assessment. This marginal cost analysis should use marginal generation cost, consisting of marginal energy costs and marginal generation capacity costs. Going forward, the IOUs should include information on marginal distribution costs that contribute to peak load costs and TOU information filed or adopted in FERC transmission rate proceedings. Use of marginal distribution

marginal energy costs and marginal generation capacity costs) constitute the primary basis for setting TOU periods, the decision also recognizes that other aspects of the utility functions are inherently time-dependent. This same Decision ordered the investor-owned utilities to include in their respective General Rate Case ("GRC") filings information on marginal transmission costs that contribute to peak load costs and TOU information filed or adopted in Federal Energy Regulatory Commission ("FERC") transmission rate proceedings.[87] The Commission again relied on this guidance when issuing its Proposed Decision in SDG&E's GRC Phase 2.[88]

In its original testimony in its 2017 RDW updating the TOU periods for non-residential customers, SCE identified all of its sub-transmission assets as being *100% peak-related*.[89] Therefore the transmission system, which is located closer to the generation resources and experiences peak demands that are much closer to the system coincident peak, is likely to exhibit costs that are highly peak-related. Though SCE did not initially consider transmission costs in developing its TOU periods in the 2017 Rate RDW, SCE later acknowledged in its rebuttal testimony that the transmission system serves to accommodate peak demand, stating:[90]

> SCE maintains that the transmission system performs two important functions by serving as both: (1) a peak capacity resource needed to accommodate peak demand under normal operating and contingency scenarios, and (2) a grid or network resource that permits the flow of energy from supply to load in a manner that optimizes the overall system costs (experienced as marginal energy prices) at different load centers on the network.

Based on this assertion, SCE presents three different methods for dividing the transmission cost between peak-related and grid-related costs, summarized briefly below:[91]

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and transmission cost information in setting future Base TOU periods will be addressed in individual IOU rate proceedings" D.17-01-006, p. 7.

[87] *Ibid*.

[88] A.15-04-012.

[89] SCE states: "Because sub-transmission assets are generally planned to consider peak load needs, all CPUC-jurisdictional costs are categorized as part of the *peak capacity* component of design demand marginal costs." A.16-09-003, *Testimony of Southern California Edison Company in Support of its Application for Approval of its 2016 Rate Design Window Proposals*, 1 September 2016, p. 35.

[90] A.16-09-003, *Rebuttal Testimony of Southern California Edison Company*, 9 June 2017, p. 13.

[91] *Ibid*, p. 14, fn. 29.

- Method #1: Uses the amount that the maximum monthly peak demand over a year exceeds the annual *average* monthly peak demand[92] to determine the costs split (results in a 30% peak/70% grid split).

- Method #2: Uses the amount that the maximum monthly peak demand over a year exceeds the annual *minimum* monthly peak demand to determine the costs split (results in 40% peak/60% grid).

- Method #3: Categorizes SCE's transmission costs FERC filings into peak-related and grid-related components (only pertaining to load growth-related costs) and sums the costs (results in 50% peak/50% grid).

SCE recommends that the Commission endorse its method #1 for the purpose of establishing new TOU periods for non-residential customers, in which 30% of transmission costs would be allocated to TOU periods and recovered in volumetric TOU rate, and the remaining 70% would be recovered through rate elements that are not TOU-differentiated. On the other end, the Solar Energy Industries Association's ("SEIA") testimony advocates including 100% of transmission costs in TOU rates, i.e., categorizing 100% of these costs as peak-related. The disparity in these positions illustrates that, while parties now generally agree that some portion of transmission costs are inherently time-dependent, they disagree on how to properly assign them.

Clearly, there is some portion of transmission costs that are time-related. Accordingly, it would be problematic to collect costs that are driven by peak demand through a charge that is assessed based on a customer's maximum *non-coincident peak* demand. Under SCE's rate design, a customer whose usage peaks at times when there is surplus transmission capacity would be charged the same level of demand charges as another customer who places the same demand on the system when there is constrained transmission capacity.

The Commission has a long-established policy of aligning rates with marginal costs and cost-causation. With regards to NCD charges, the Commission has ruled in D.14-12-080, stating that "[w]e have previously found that non-coincident demand charges do not align with cost-causation for primary distribution, transmission, nor generation capacity costs."[93] In addition, D.14-12-080 found that "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

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[92] (Max Monthly demand-average monthly demand)/ or Max Demand/Avg. Demand – 1.

[93] D.14-12-080, Finding of Fact 8.

individual customers during *coincident peaks* rather than each customer's single highest interval of demand during peak time of use billing hours."[94]

SCE should reduce the peak-related transmission costs collected via the NCD charge, and move them to the volumetric TOU component. Because use of the transmission system to meet peak needs during the off-peak or super off-peak periods is limited, recovery of peak-related transmission costs through TOU rates should not increase the off-peak rates or the super off-peak rates much or at all.[95] ORA's modification to SCE's proposal will appropriately charge customers for their contribution to coincident peak, which drives a significant portion in transmission capacity investments.

Parties disagree about how to bifurcate transmission capacity costs as either peak-related or grid-related. There is still ongoing investigation of this issue and ultimately it will be litigated in SCE's 2017 RDW.[96] Until this issue is resolved in A.16-09-003, it is unclear how much the NCD charge should be reduced. Accordingly, ORA does not make any specific endorsement on how to properly split and assign transmission costs,[97] but as an interim solution, it would be reasonable to propose that SCE recover 50% of SCE's reported transmission costs in the NCD charge and 50% in the TOU component. This 50/50 split reflects a reasonable middle-ground approach between SCE's and SEIA's recommendations[98] and can serve as an interim solution until these issues are resolved in SCE's 2017 RDW (A.16-09-003).

ORA's recommendation of a 50/50 split for transmission costs results in an NCD charge that is approximately 44% of the current EV-TOU-3 Option B demand charge. In contrast,

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[94] D.14-12-080, Finding of Fact 9 (emphasis added).

[95] SEIA's testimony in the 2017 RDW allocates a significant portion of transmission costs, perhaps as high as 50%, to the summer "off-peak" (according to SCE's definition, not SEIA's, i.e. 2-4pm) whereas the rest are in the summer peak. However given the large number of summer off-peak hours, the increase in off-peak rates is likely to be small. SCE's rebuttal testimony allocates most of the transmission costs to the summer and winter peaks, although there is a small percentage (perhaps 10%) occurring during the summer and winter off-peak periods. Neither proposal allocates any costs to the winter super off-peak period. A.16-09-003, *Prepared Direct Testimony of R. Thomas Beach on Behalf of the SEIA*, p. ii; A.16-09-003, *Rebuttal Testimony of SCE*, pp. 24–25.

[96] Hearings are scheduled for August 7–11, 2016 and a Final Decision is scheduled for February 2018.

[97] Table 3-2 Assumes equal cents per kWh recovery of the portion of transmission costs not included in the FRD charge. However, the rates in table 3-2 are intended for illustrative purposes only to illustrate the impact of ORA's recommendation on the demand charge and conceptually demonstrate how it impacts the volumetric energy rates. Therefore the peak period rates are probably higher than what is presented while the super off-peak rates are probably lower than what is presented.

[98] D.14-12-080, pp. 21-22.

SCE's proposal to recover 40% of distribution costs plus 100% of transmission costs through the NCD charge results in an NCD charge that is 60% the size of its current EV-TOU-3 NCD charge.[99] The Commission should set SCE's Option B NCD charge at 44% of its current EV-TOU-3 NCD charge in order to encourage more efficient use of the grid.[100] This modification effectively reduces the full NCD charge that customers would see in year 11 from $5.85/kW to $4.30/kW (Reducing it by 26.5%).[101] An illustrative example of this rate is provided in table 3.2 below.

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[99] I.e., 60.06% of $9.74/kW is $5.85/kW. SCE Response to ORA's DR 2, Q #1a.

[100] SCE's current FERC rates are set to expire December 31, 2017. If SCE proposes to recover 100% of transmission costs through demand charges at the FERC and it is approved, this would mean that only 17.6% of distribution costs should be recovered through the demand charge in order to keep the overall level at 44%.

[101] Based on SCE's March 2017 rate design workpaper and not on their June updates to rates. ORA essentially used the assumptions shown in SCE's response to ORA's DR #5, Q1 which yield the demand charge in year 11 ("Appendix B" tab, rate TOU-EV-7 Option B). ORA then switched the "Transmission (Energy Only)?" field to "Yes" to subtract out the transmission costs. $5.85 – $3.09 = $2.76 in transmission costs. ORA then added 50% of transmission costs back into the distribution-only demand charge ($2.76 + $1.55 = $4.31/kW). A.17-01-021 ORA-SCE-002 Q.01 Attachment TE Application EV Rates – Workpaper.

Table 3.2: ORA's Illustrative TOU-EV-7 Rates with NCD Charge that Recovers 44% of Combined Distribution and Transmission Costs

TOU-EV-7 (Option B)						
Energy Charge - $/kWh	Year 6	Year 7	Year 8	Year 9	Year 10	Year 11
Summer Season						
On-Peak	$ 0.3559	$ 0.3500	$ 0.3441	$ 0.3381	$ 0.3322	$ 0.3263
Mid-peak	$ 0.2005	$ 0.1946	$ 0.1887	$ 0.1828	$ 0.1768	$ 0.1709
Off-Peak	$ 0.1259	$ 0.1225	$ 0.1192	$ 0.1158	$ 0.1125	$ 0.1091
Winter Season						
Mid-peak	$ 0.2461	$ 0.2402	$ 0.2343	$ 0.2284	$ 0.2225	$ 0.2166
Off-Peak	$ 0.1263	$ 0.1230	$ 0.1196	$ 0.1162	$ 0.1129	$ 0.1095
Super-Off-Peak	$ 0.0831	$ 0.0818	$ 0.0806	$ 0.0794	$ 0.0781	$ 0.0769
FRD – kW	$ 0.72	$ 1.43	$ 2.15	$ 2.87	$ 3.59	$ 4.30
Customer Charge - $/day	$ 0.7770	$ 0.7770	$ 0.7770	$ 0.7770	$ 0.7770	$ 0.7770

Reducing the demand charge will also reduce overall costs of EV charging during off peak periods by reducing the rates for off-peak or super off-peak EV charging. This makes the rate structure align better with utility operations and costs, and will encourage EV charging during the off-peak and super off-peak periods.

C. ORA's Proposal Aligns with the ACR's Directions.

ORA's recommended rate proposal is more closely aligned with the ACR's cost-causation principles than SCE's and also reduces some of the cost barriers that SCE's rate proposal creates. The ACR cited parties' concerns that demand charges discourage the use of electricity as a transportation fuel. To address the ACR's direction, SCE proposes to have a smaller demand charge than what would otherwise apply on a standard commercial rate. SCE's rate proposal should be further improved by removing the peak-related transmission costs from the NCD, which effectively reduces the charge by about 26.5%.

Reducing the demand charge will also have the benefit of promoting more off-peak or super off-peak EV charging,[102] which will lower overall costs of customer EV charging and defer utility capacity investments. ORA's proposed peak and mid-peak rates will deter charging during high-cost hours and thus provide grid benefits by resolving conflicting capacity constraints at the transmission and distribution levels and maximize the use of renewable energy. Thus, ORA's modification is consistent with the provisions codified by Public Utilities Code § 740.12(a)(1)(G) and (I), which require that deploying EVs should assist in grid management[103] and that customers should have access to electricity as a fuel that is cleaner and less costly than gasoline. ORA's proposal will provide customers opportunities to realize significant fuel costs savings to the extent that they charge in a manner consistent with electrical grid conditions.

The low super off peak rate of about 8 cents should provide plenty of opportunities to realize fuel savings. A recent analysis conducted by the Rocky Mountain Institute for EVgo finds that charging per kWh should not be more than $0.29/kWh for EV charging to be cost-competitive with gasoline.[104] ORA's proposed modification will promote timely achievement of SB 350's aggressive goal of putting 1.5 million zero emission vehicles on California roads by 2024.

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[102] Higher demand charges increase the average price per kWh. If the costs formerly included in the demand charge are predominantly assigned to the on-peak period, this gives customer an opportunity to avoid them by charging off-peak.

[103] I.e., integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions.

[104] EVGO Fleet & Tariff Analysis Phase 1 Public Version RMI, p. 1.

IV. CONCLUSION

For the foregoing reasons, the Commission should adopt ORA's proposal which retains customer choice, better aligns rates with costs and is more customer-friendly than SCE's rate proposals.

APPENDIX A

QUALIFICAITONS OF WITNESSES

QUALIFICATIONS AND PREPARED TESTIMONY

OF

RICKEY K. TSE

Q1. Please state your name, business address, and position with the California Public Utilities Commission.

A1. My name is Rickey Kit Tse and my business address is 505 Van Ness Avenue, San Francisco, CA 94102. I am a Senior Utilities Engineer in the Energy Safety and Infrastructure Branch of the Office of Ratepayer Advocates.

Q2. Please summarize your educational background.

A2. I attended the University of California at Davis. I graduated in 1999 with a Bachelor of Science degree in mechanical engineering.

Q3. Briefly describe you professional experience.

A3. After graduating in 1999, I started my professional career at AT&T (then Pacific Bell) as an engineer in the construction and engineering department designing telecom network in support of high-speed DSL (Digital Subscriber Line) service. My core responsibilities included facilities design, permitting, construction oversight, and budget management. I spent about three years in the telecommunications industry before joining a consulting firm as a civil engineer associate working on hydrology designs for small commercial developments. In 2003, I started my career with the California Public Utilities Commission as a utilities engineer in the Safety and Enforcement Division (formerly CPSD). I spent the next 13 years working on enforcement matters related to General Order 167 to ensure California power plants comply with the Commission's operation and maintenance standards. My responsibilities revolved around conducting outage inspections, compliance audits, and incident investigations. I'm a licensed professional engineer and am technically-versed in power generation, transmission, and distribution. In 2016, I joined the Office of Ratepayer Advocates in charge of the transportation electrification application proceeding pursuant to Senate Bill 350.

Q4. What is your responsibility in this proceeding?

A4. I am sponsoring Chapter 1 of this prepared testimony on PG&E's Fleet-ready Program.

Q5. Does this conclude your prepared testimony?

A5. Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

THOMAS GARIFFO

Q1. Please state your name, business address, and position with the California Public Utilities Commission.

A1. My name is Thomas Gariffo and my business address is 505 Van Ness Avenue, San Francisco, CA 94102. I am a Public Utilities Regulatory Analyst in the Electricity Planning and Policy Branch of the Office of Ratepayer Advocates.

Q2. Please summarize your educational background.

A2. I have a Master's Degree in Public Policy with honors from the Luskin School of Public Affairs at UCLA, where I focused primarily on fields regarding environmental, technology, and energy policy. Prior to UCLA, I received a Bachelor's Degree in Political Science from UC Berkeley with a focus on political communications and a Minor in Public Policy from the Goldman School of Public Policy.

Q3. Briefly describe you professional experience.

A3. I have worked as an analyst for the Office of Ratepayer advocates for two years on climate change programs such as transportation electrification and electric vehicle initiatives, but also including the Low Carbon Fuel Standards, cap-and-trade, energy storage, research and development funding, and renewable portfolio standards. Before that, I interned at the Luskin Center for Innovation as research assistant to the director, researching electric vehicle policies.

Q4. What is your responsibility in this proceeding?

A4. I am sponsoring Chapter 2.

Q5. Does this conclude your prepared testimony?

A5. Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

BENJAMIN GUTIERREZ

Q1. Please state your name, business address, and position with the California Public Utilities Commission.

A1. My name is Benjamin Gutierrez and my business address is 505 Van Ness Avenue, San Francisco, CA 94102. I am a Public Utilities Regulatory Analyst in the Electricity Pricing and Public Programs Branch of the Office of Ratepayer Advocates.

Q2. Please summarize your educational background.

A2. I have a Bachelor of Arts in Environmental Science and Public Policy from Harvard University, Cambridge, MA.

Q3. Briefly describe you professional experience.

A3. I have been employed by the Office of Ratepayer Advocates (ORA) for twenty-two months, and I have submitted testimony on various marginal costs in San Diego Gas and Electric's General Rate Case ("GRC") Phase 2, Pacific Gas and Electric Company's GRC Phase 2, participated in the design of the investor-owned utilities' Opt-In and Default Time-Of-Use ("TOU") pilots through the TOU Working Group and participated in the TOU OIR proceeding. Prior to working for ORA, I worked as a Clean Energy Coordinator and Philanthropy Coordinator for nearly two years for the Malaysian nonprofit organization Land Empowerment Animals People (LEAP). During this time, I contributed research and writing on the costs and resource availabilities of renewable energy and fossil fuel technologies in the Malaysian state of Sabah, among other duties.

Q4. What is your responsibility in this proceeding?

A4. I am sponsoring Chapter 3 – "SCE's Proposed Small Commercial EV Rates."

Q5. Does this conclude your prepared testimony?

A5. Yes, it does.

QUALIFICATIONS AND PREPARED TESTIMONY

OF

NATHAN CHAU

Q1. Please state your name, business address, and position with the California Public Utilities Commission.

A1. My name is Nathan Chau and my business address is 505 Van Ness Avenue, San Francisco, CA 94102. I am an analyst in the Electric Pricing and Customer Programs Branch of the Office of Ratepayer Advocates.

Q2. Please summarize your educational background.

A2. I attended the University of the Pacific. I graduated in 2014 with a bachelor of science in applied economics. Coursework included areas of microeconomics, finance, statistics, calculus, econometrics and industrial economics which I find relevant to this proceeding.

Q3. Briefly describe you professional experience.

A3. I started work at the Commission in 2015. Since then, I have written testimony for San Diego Gas & Electric Company's and Pacific Gas and Electric Company's general rate case Phase 2 proceedings Application ("A.")15-04-012 and A.16-06-013 respectively on marginal cost, and rate design matters. I have also written comments and testimony pertaining to the Time-of-Use Order Instituting Rulemaking (R.15-12-012) and Residential Rate Reform Order Instituting Rulemaking (R.12-06-013). Additionally, I have provided analytical support for Southern California Edison Company's Rate Design Window Proceedings A.16-09-003 and A.17-04-015.

Q4. What is your responsibility in this proceeding?

A4. I am sponsoring Chapter 3 of this prepared testimony on SCE's Small Commercial Electric Vehicle Rates.

Q5. Does this conclude your prepared testimony?

A5. Yes, it does.