Application No.: A.17-01-____

Exhibit No.: SCE-01

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SOUTHERN CALIFORNIA EDISON®

An *EDISON INTERNATIONAL*® Company

(U 338-E)

Testimony of Southern California Edison Company in Support of its Application of Southern California Edison Company (U 338-E) For Approval of its 2017 Transportation Electrification Proposals

Before the

Public Utilities Commission of the State of California

Rosemead, California

January 20, 2017

Testimony of Southern California Edison Company in Support of its Application of Southern California Edison Company (U 338-E) For Approval of its 2017 Transportation Electrification Proposals

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I.

INTRODUCTION

Southern California Edison (SCE) submits the following testimony in support of its Application for Approval of its 2017 Transportation Electrification Proposals (Application). SCE filed the Application pursuant to Commissioner Carla Peterman's September 14, 2016 Assigned Commissioner Ruling Regarding the Filing of Transportation Electrification Applications Pursuant to Senate Bill 350 (ACR).[1] In these documents, SCE describes its vision for transportation electrification (TE), which will reduce greenhouse gas (GHG) emissions and provide clean air and other benefits. SCE also proposes a portfolio of near-term, priority-review projects and longer-term, standard-review programs aimed at accelerating widespread TE adoption. Important elements of SCE's proposed portfolio of transportation electrification projects and programs include:

- Addressing key cost and complexity barriers associated with charging infrastructure for commercial (non-light-duty) electric vehicles (EVs) (including medium-duty, heavy-duty, and non-road vehicles used in goods and people movement), as well as EVs charging at homes and at urban, direct current fast charge (DCFC) stations;
- Proposing a new commercial EV rate structure to enable vehicle-grid integration and promote EV adoption;
- Collaborating with stakeholders from the private, non-profit, and public sectors that will provide expertise and funding for vehicles and charging equipment;
- Seeking to enhance third-party business models so that other market participants can successfully play a long-term role; and
- Prioritizing the needs of low-income and disadvantaged communities.

As summarized in Table I-1 below, SCE proposes three pilots aimed at accelerating light-duty EV adoption, two projects to promote electrification at the Port of Long Beach (POLB), one project to

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[1] Assigned Commissioner's Ruling Regarding the Filing of the Transportation Electrification Applications Pursuant to Senate Bill 350, issued September 14, 2016, in Rulemaking (R.) 13-11-007 (hereinafter "ACR").

accelerate electric transit bus adoption, one standard review program providing charging infrastructure for non-light-duty EVs, and one EV rate proposal to promote EV adoption.

Table I-1
SCE's TE Portfolio
(Millions, 2016 $, not loaded)

Priority Review Project	Estimated Cost
Residential Make-Ready	$4.00
EV Drive Rideshare Reward	$4.00
Urban DCFC Cluster	$3.98
Make Ready & Rebate for Transit Buses	$3.98
POLB, Rubber Tire Gantry Crane Electrification	$3.04
POLB, ITS Terminal Yard Tractor	$0.45
Priority Review Total	**$19.45**
Standard Review Programs	Estimated Cost
Medium and Heavy-Duty Vehicle Charging Infrastructure Program	$553.82
Commercial EV Rate Proposal	N/A
Standard Review Total	**$553.82**
Total TE Portfolio	**$573.27**

II.

VISION FOR TRANSPORTATION ELECTRIFICATION TO REDUCE EMISSIONS AND DRIVE INNOVATION

In 2016, California enacted Senate Bill (SB) 32, establishing an ambitious goal to reduce California's GHG emissions to 40 percent below 1990 levels by 2030.[2] Through this Application, SCE enthusiastically joins the State in supporting a clean energy future. 2030 is only 13 years away, and Southern California Edison feels a sense of tremendous urgency to facilitate widespread transportation electrification—transforming a transportation sector powered primarily by fossil fuels to one fueled by clean electric power—necessary for the state to meet its climate change goals. The state, the electricity industry, and multiple stakeholders must take significant action now[3] or time will quickly run out to achieve California's ambitious and laudable goals.[4]

In addition to reducing GHG emissions, broad-based transportation electrification is necessary for the state to reduce ground-level ozone, nitrogen oxide (NOx), and particulate emissions to improve air quality, especially in low- and moderate-income and disadvantaged communities.[5] Finally,

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[2] *See* SB No. 32, Chapter 249, An Act to add §38566 to the Health and Safety Code, relating to greenhouse gases. Approved by Governor September 8, 2016, filed with Secretary of State September 8, 2016.

[3] The Governor's Interagency Zero-Emission Vehicle (ZEV) Action Plan (2016 update) (*available at* https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf) includes over 190 actions needed by state agencies for electrification of transportation This action plan includes directives to the CPUC regarding expanding the utility role (e.g. new rates to mitigate or manage demand charges and increasing charging infrastructure, vehicle-grid integration, and mainstream consumer awareness of zero-emission vehicles). In addition, many other actions will be needed by other stakeholders to electrify transportation.

[4] Examples of these requirements and goals are SB 350 and SB 32, *available at* http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB350 and http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160SB32.

[5] *See* South Coast Air Quality Management District (SCAQMD), *Draft 2016 Air Quality Management Plan*, *available at* http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/DRAFT2016AQMP/draft2016aqmp-full.pdf?sfvrsn=2.

See also California Environmental Protection Agency (CalEPA) & the California Air Resources Board (CARB), *A New National Ambient Air Quality Standard (NAAQS) for Ozone* (2015), *available at* https://www.arb.ca.gov/newsrel/new_ozone_std_factsheet.pdf.

See also Trinity Consultants, *Implications of Revised Ozone NAAQS in the South Coast* (2016), *available at* http://www.wcsawma.org/wp-content/uploads/2016/07/Vineet-Masuraha-Trinity-WCS-Annaul-2016.pdf.

(Continued)

transportation electrification can benefit all consumers by spreading fixed costs across incremental load, thus putting downward pressure on electricity rates, improving system utilization, and integrating renewable energy by encouraging EV customers to charge their vehicles when renewable energy is more abundant and their load is less costly to serve.

SCE's plan to advance transportation electrification as set forth in its Application supports achieving high levels of electric vehicle adoption across multiple transportation sectors, including light-duty vehicles, commercial vehicles (non-light-duty, including medium- and heavy-duty trucks and buses), and seaports. Electrifying all segments of the transportation sector is essential, and the segments are in various stages of technological and market development. SCE's proposed portfolio of programs and pilots is tailored to support the phase that each segment is in currently. SCE's proposed programs will enable faster adoption of electric vehicles in new vehicle segments by providing utility distribution infrastructure, customer-side "make-ready" infrastructure,[6] rebates for charging stations, incentives to jump-start electric vehicle taxi and ridesharing, and a new rate to encourage fleet and away-from-home charging. Beyond the programs proposed in this application, SCE will enable EV fueling through

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See also SCAQMD, *National Ambient Air Quality Standards (NAAQS) and California Ambient Air Quality Standards (CAAQS) Attainment Status for South Coast Air Basin*, *available at* http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/naaqs-caaqs-feb2016.pdf?sfvrsn=2.

See also San Joaquin Valley Air Pollution Control District, *Proposed 2016 Plan for the 2008 8-Hour Ozone Standard* (2016), *available at* http://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2016/June/final/13.pdf.

Communities are considered disadvantaged communities if they are in the worst quartile of environmental and economic burden, as evaluated by the CalEPA using CalEnviroScreen (CES) 3.0. Freight corridors were identified by the Southern California Association of Governments in its 2016-2040 Regional Transportation Plan/Sustainable Communities Strategy. *See* Figures II-4 and II-5, *infra*.

[6] *See* Appendix B for a diagram of infrastructure defined as the "make-ready." Utility distribution infrastructure includes transformers, utility services, and meters. Customer-side make-ready infrastructure includes panels, conduit, and wiring up to the stub where the charging station is placed and associated infrastructure. SCE proposes to follow this model in the infrastructure pilots and programs proposed as part of its TE Portfolio.

delivery of increasingly clean power and integration of that power with EVs through the electric grid. The company will continue to enable EV market acceleration through its leading role on infrastructure deployment and continued facilitation of other aspects of the market.[7]

While SCE will play an important role in ensuring that electric fueling is clean, safe, reliable, and affordable, many other organizations, including state and local governments and environmental agencies, have important roles in the effort to move vehicle use to clean electricity by increasing customer awareness, helping EVs to become more affordable, and providing accessible charging and infrastructure. SCE looks forward to collaborating, coordinating, and cooperating with others to promote transportation electrification in California.

A. **California's GHG goals are some of the most ambitious in the world and require significant acceleration of transportation electrification.**

California's goals to reduce the state's total GHG emissions by 40 percent from 1990 levels by 2030 and 80 percent by 2050 are some of the most ambitious in the world and will be difficult to meet.[8] While California has reduced GHG emissions nine percent from their peak in 2004, meeting 2030 requirements and 2050 goals will require emissions reductions more than three times the annual rate achieved between 2004 and 2014, or the equivalent of eliminating emissions from 2.6 million homes

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[7] *See* Section II.E. *infra*, for information on potential future infrastructure programs, such as Charge Ready Phase 2, and potential facilitation roles for SCE.

[8] California and 12 other North American and European Governments announced on December 3, 2015, as part of the Conference of Parties (COP) 21 Climate Summit in Paris, that they will strive to make all passenger vehicle sales in their respective jurisdictions ZEVs as fast as possible, and no later than 2050. See ZEV Alliance Press Statement, *International Alliance Aims for All New Cars to be Zero-Emission by 2050* (Dec. 3, 2015), *available at* http://www.zevalliance.org/international-alliance-aims-for-all-new-cars-to-be-zero-emission-by-2050/. A few months prior, Governor Brown signed SB 350, which recognized that "[r]educing emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050 will require widespread transportation electrification." (Note that today's level of GHG emissions in California is the same as 1990 levels.) *See* Figure II-2. SB 350 also required the Commission to direct electrical corporations to file applications for programs and investments to accelerate widespread transportation electrification [in order] to reduce emissions and "reduce dependence on petroleum, meet air quality standards, achieve the goals set forth in the Charge Ahead California Initiative." In September 2016, Governor Brown also signed SB 32, which directs CARB to ensure that statewide greenhouse gas emissions are reduced to 40 percent below the 1990 level by 2030.

each year.[9] Given the amount of time needed to build infrastructure and change consumer behavior, acceleration of transportation electrification is critically important, as the next deadline (2030) is only 13 years away.

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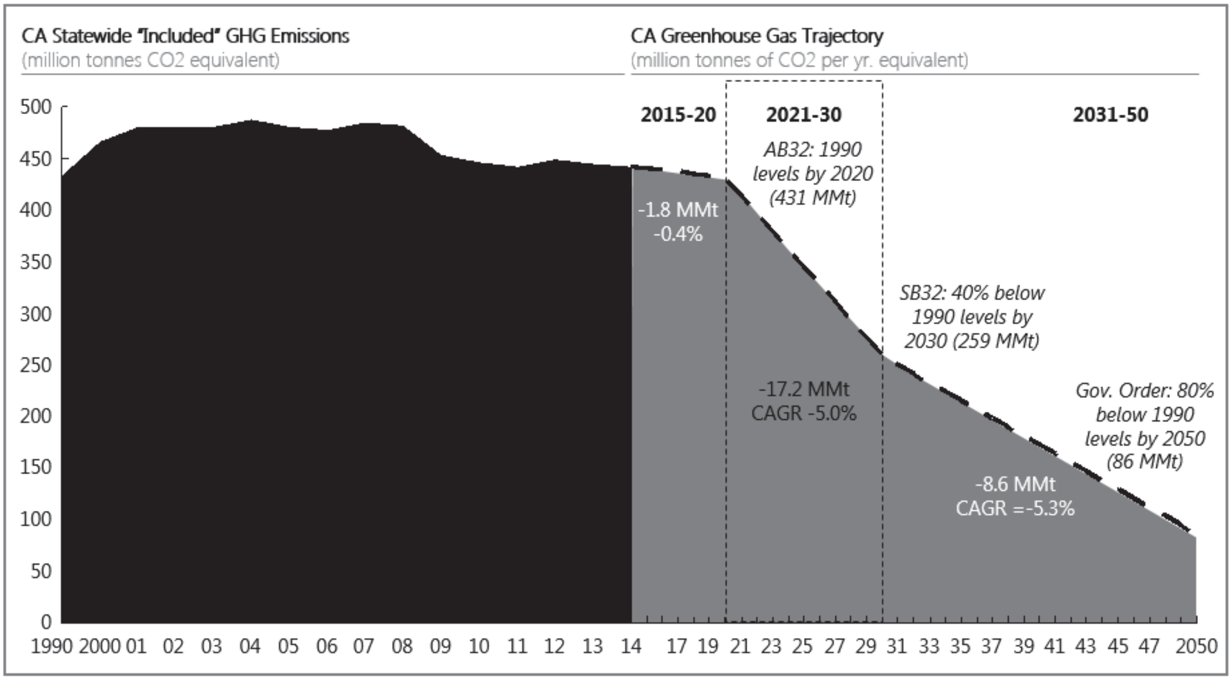
[9] *See* CARB's Assembly Bill (AB) 32 Fact sheet (Oct. 29, 2007), *available at* https://www.arb.ca.gov/cc/factsheets/1mmtconversion.pdf; *see also* U.S. Census. California households produce the equivalent of 5.2 million metric tons (MMT) of carbon dioxide (CO_2) emissions per year. Reducing statewide emissions at a rate of 17.2 MMT per year would require eliminating emissions from 2.6 million homes per year to keep pace, and emissions abatement goals cannot be achieved solely by eliminating emissions from all 13 million California households.

Figure II-1
Reaching GHG Targets Requires a Dramatic Increase in the Pace of GHG Emission Reductions[10]



Due to average vehicle life (11.4 years for passenger cars, 17.8 years for medium- or heavy-duty vehicles[11]), infrastructure must be in place now to start supporting EV purchases. Every time a vehicle is purchased, there is an opportunity to convert fossil-fuel-powered vehicles to clean vehicles. If that opportunity is missed, the vehicle will likely not be converted to a clean vehicle for another decade or more. Through this and future applications, SCE will describe a path forward and SCE's proposed role in coordinating with other sectors to eliminate barriers to EV adoption.

[10] *See* CARB's California GHG Emission Inventory – 2016 Edition, *available at* https://www.arb.ca.gov/cc/inventory/data/data.htm. Note: "Not specified" accounts for 0.8 percent in 2014; excludes 54 MMT CO2 equivalent, per AB32 definition (portion of transportation, industrial, military).

[11] U.S. Department of Transportation, Bureau of Transportation Statistics, *available at* http://www.rita.dot.gov/bts/sites/rita.dot.gov.bts/files/publications/national_transportation_statistics/html/table_01_26.html_mfd.

B. Transportation electrification as a solution

a) Transportation electrification represents the largest near-term opportunity to reduce GHG in California.

The transportation sector, including oil refineries, creates 50 percent of the GHG emissions in California,[12] and represents a significant opportunity for California to achieve its GHG goal. The California market represents more than half of all EV sales in the United States.[13] California's leadership in transportation electrification, coupled with CARB's analysis showing the transportation sector would be responsible for at least 35 percent of emission reductions in 2030, makes electrification in this sector an important place for the state to focus.[14]

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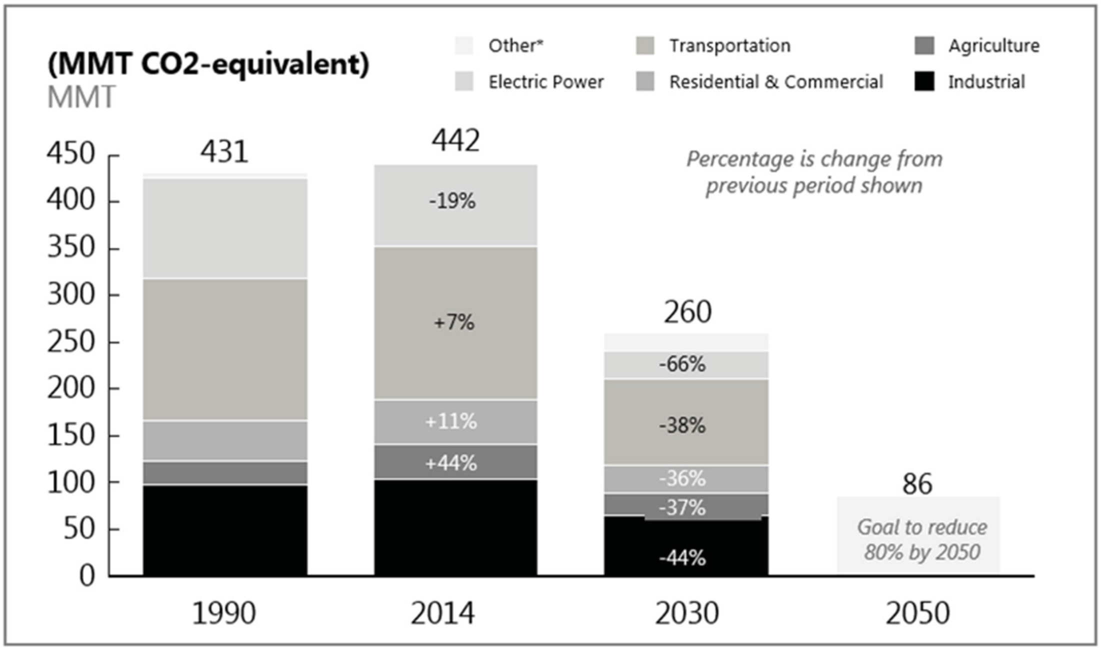
[12] The transportation sector is responsible for 36 percent of California's GHG emissions, nearly half of GHG emissions when you also consider the refining of oil into gasoline and diesel fuels in California, more than 80 percent of NOx, and over 90 percent of diesel particulates. *See* CARB's California GHG Emission Inventory – 2016 Edition, *available at* https://www.arb.ca.gov/cc/inventory/data/data.htm; CARB's Mobile Source Strategy, p. 20, *available at* https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc.pdf; and CARB's California GHG Inventory for 2000-2014, *available at* https://www.arb.ca.gov/cc/inventory/data/tables/ghg_inventory_scopingplan_2000-14.pdf.

[13] *See* California Plug-In Electric Vehicle Collaborative's Cumulative Sales, *available at* http://www.pevcollaborative.org/sites/all/themes/pev/files/10_oct_PEV_cumulative.pdf.

[14] The transportation sector accounts for 35 percent of emissions reductions according to both Alternatives 1 and 2 of CARB's Draft Scoping Plan (Dec. 1, 2016), *available at* https://www.arb.ca.gov/cc/scopingplan/scoping_plan_scenario_description2016-12-01.pdf. The transportation sector in this case does not include "upstream" sources of vehicle emissions (e.g., refineries, fuel extraction).

Figure II-2
California GHG Emissions by Sector[15]



California's electric power sector, which contributed roughly 20 percent of California's GHG emissions in 2014, has already reduced greenhouse gas emissions by 20 percent from 1990 levels. The electric power sector will further decrease emissions as it meets a 50 percent renewables portfolio standard (RPS) and as clean distributed energy resources (DERs) continue to be adopted by customers and are increasingly used to meet the electric grid's needs. California's low-emission electricity grid makes transportation electrification an attractive way to extend GHG-abatement opportunities, by targeting the largest emissions sector and providing additional abatement by reducing demand for refined oil. Because California's electric grid is relatively clean in comparison to other states, for each light-duty vehicle that is electrified about 70 percent of emissions is abated compared to the continued

[15] Source: Adapted from CARB's Draft Scoping Plan, *supra*, "Alt 1" case. In this scenario, the transportation section does not include emissions from the refining process, which are included in the industrial sector.

use of a comparable gasoline-fueled vehicle.[16] In addition, electric vehicles essentially become "cleaner" the longer they are in use, as the grid adds additional renewable resources and accordingly the fuel supply for EVs becomes cleaner over time.

While transportation electrification is expected to provide a large portion of GHG reductions, the amount of electric vehicles that need to be added onto the road is significant. Today there are roughly 80,000 light-duty EVs in SCE's service territory and almost zero non-light-duty EVs; by 2030, 1.9 million light-duty and 180,000 non-light-duty EVs will be needed.[17] Increasing the number of electric vehicles on the road more than 20 times in the next 13 years will require an active role from many players, including utilities.

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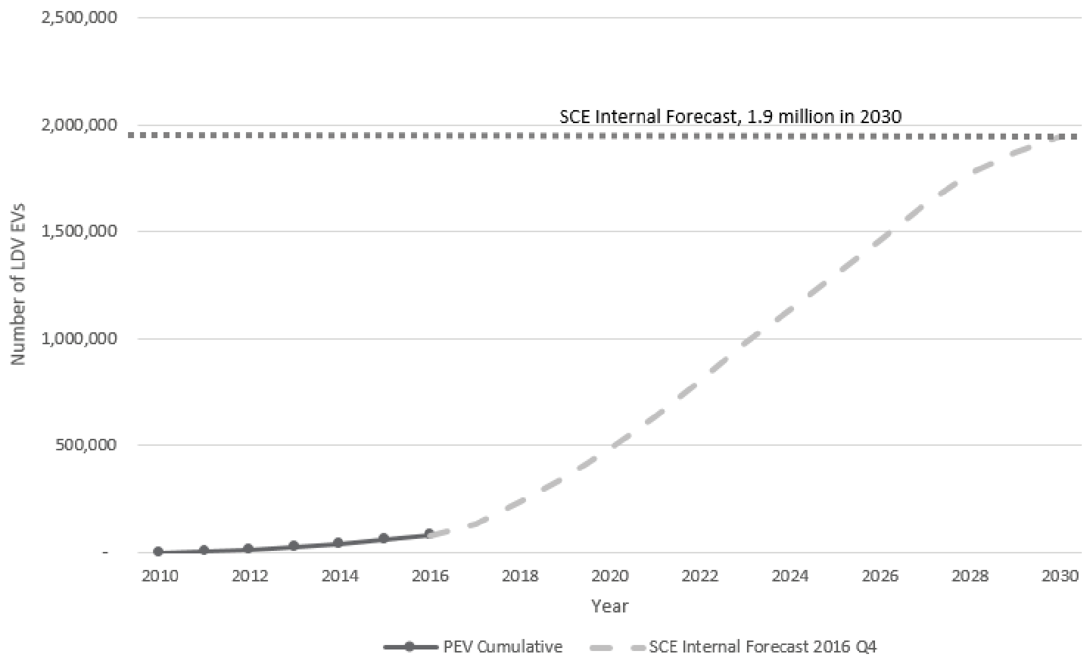
16 *See* Public Utilities Code §740.12(a)(1)(I). *See also* U. S Environmental Protection Agency's (EPA's) eGRID2014 GHG Annual Output Emission Rates, *available at* https://www.epa.gov/sites/production/files/2017-01/documents/egrid_ghgoutputrates.pdf.

17 EV Cumulative is derived from Polk's New Vehicle Registration and National Vehicle Population Profile, and represents the combined, cumulative number of battery electric vehicles and plug-in hybrid electric vehicles through 2016 Q3 in SCE service territory. The SCE Internal 2016 Q4 forecast is derived from Navigant's 2016 Q2 light-duty EV forecast and the *California Transportation Electrification Assessment, Phase 1: Final Report* (August 2014; updated September 2014), prepared by ICF International and Energy+Environmental Economics (E3) ("TEA Study") for medium-duty and heavy-duty vehicles and other non-road electric transportation.

Figure II-3 [18]

Light-Duty Vehicle Electrification Forecast to Achieve GHG Abatement Requirements in SCE Territory



b) Transportation electrification in non-light-duty segments has the potential to reduce criteria pollutants and improve air quality.

In addition to GHG emissions abatement, transportation electrification will help the state meet ground-level ozone, NOx, and particulate emissions reduction requirements.[19] NOx and reactive

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[18] *Id*.

[19] *See* SCAQMD's Draft 2016 Air Quality Management Plan, *available at* http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/2016-air-quality-management-plan/DRAFT2016AQMP/draft2016aqmp-full.pdf?sfvrsn=2; https://www.arb.ca.gov/newsrel/new_ozone_std_factsheet.pdf; http://www.wcsawma.org/wp-content/uploads/2016/07/Vineet-Masuraha-Trinity-WCS-Annaul-2016.pdf and http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/naaqs-caaqs-feb2016.pdf?sfvrsn=2http://www.valleyair.org/Board_meetings/GB/agenda_minutes/Agenda/2016/June/final/13.pdf. *See also* CARB, *Vision for Clean Air: A Framework for Air Quality and Climate Planning* (June 2012), pp. 16-19, *available at* http://www.arb.ca.gov/planning/vision/docs/vision_for_clean_air_public_review_draft.pdf. This study also found that meeting the 2023 and 2031 air quality attainment deadlines requires a faster shift to zero-emission transportation than meeting the state's greenhouse gas emission reduction goals.

organic gases contribute to the formation of harmful particulate matter in the atmosphere; both pollutants also react with sunlight to form smog (ground-level ozone).[20] The transportation sector emits 80 percent of NOx pollution and 95 percent of diesel particulates.[21] Electrification of the transportation sector, particularly medium- and heavy-duty vehicles, can help to reduce these smog-forming emissions and particulates. For example, medium- and heavy-duty EVs reduce smog-forming NOx emissions by up to 60 times more per kilowatt hour (kWh) than renewable generation or energy efficiency, and light-duty EVs reduce smog-forming NOx emissions eight times more per kWh.[22]

The federal Clean Air Act requires states to meet certain ozone requirements by 2023 and 2031.[23] The only two air basins in the nation that are in extreme ozone non-attainment are the South Coast Air Basin and the San Joaquin Valley Air Basin; SCE serves communities in both of these basins.[24] SCE will promote freight electrification in the Los Angeles Basin by supporting nascent electric medium- and heavy-duty and port technologies to improve air quality and spur innovation.

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[20] *See* EPA's Air Pollution Facts and Figures, *available at* https://www3.epa.gov/airnow/mediakits/ozone/facts.pdf.

[21] Diesel particulates are also a carcinogen according to World Health Organization (WHO). *See* WHO Press release No. 213 (June, 2012)*, available at* https://www.iarc.fr/en/media-centre/pr/2012/pdfs/pr213_E.pdf. *See also* Mobile Source Strategy Informational Update, p. 4 *available at* https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc.pdf at 5, which includes upstream emissions.

[22] *See* the *California Transportation Electrification Assessment, Phase 1: Final Report*, *supra*, *available at* http://www.caletc.com/wp-content/uploads/2016/08/CalETC_TEA_Phase_1-FINAL_Updated_092014.pdf: light-duty (Table 37, p. 69); heavy-duty (Table 49, p. 80), and upstream fuel emission factors (Table 32, p. 65). The analysis compares net NOx reductions per megajoule from electrifying a light-duty vehicle and heavy-duty vehicle with the NOx reductions per megajoule from the addition of zero-emission renewable energy or energy efficiency. The heavy-duty NOx reductions can vary widely by the type of vehicle (e.g., small truck, large truck, transit bus) and efficiency. These NOx numbers are conservative because they include out-of-basin NOx emissions from power plants.

[23] There are deadlines for attainment of several ambient air quality standards for several pollutants, including the 2032 deadline for ground-level ozone (formed by NOx and organic compounds in the atmosphere). Recently-adopted standards for ground-level ozone will require additional reductions of NOx by 2037. *See* SCAQMD, *National Ambient Air Quality Standards (NAAQS) and California Ambient Air Quality Standards (CAAQS) Attainment Status for South Coast Air Basin*, *available at* http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/naaqs-caaqs-feb2016.pdf?sfvrsn=2.

[24] *See* CARB, *Vision for Clean Air: A Framework for Air Quality and Climate Planning* (June 2012), pp. 16-19, *available at* http://www.arb.ca.gov/planning/vision/docs/vision_for_clean_air_public_review_draft.pdf. This study also found that meeting the 2023 and 2031 air quality attainment deadlines requires a faster shift to zero-emission transportation than meeting the state's greenhouse gas emission reduction goals.

In SCE's service territory, the communities most heavily impacted by air pollution from medium- and heavy-duty transportation are Disadvantaged Communities,[25] as defined by the Office of Environmental Health Hazard Assessment's (OEHHA's) California Communities Environmental Health's Screening Tool (CalEnviroScreen 3.0).[26] For example, cities and areas with large concentrations of warehouses and factories (e.g. Commerce, Industry, Compton, Paramount, South El Monte, Santa Fe Springs, Pomona, Ontario, Mira Loma, San Bernardino) are mostly disadvantaged communities. The Southern California Association of Governments has identified Interstates (I) 210, 10, 605, 710, 5 and 15 and State Routes (SR) 60, 103, and 91 as major freight corridors;[27] these corridors travel through many disadvantaged communities. In addition to the burden of increased air pollution, these communities also face challenges such as poverty, unemployment, educational attainment, linguistic isolation, and low infant birth rates.[28] To address this issue, SCE's proposal includes funding for electrification of medium- and heavy-duty vehicles and non-road equipment, the largest sources of air pollution.[29]

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25 SCE's service territory has approximately 45 percent of the disadvantaged communities in California based on CalEPA's CalEnviro Screen 3.0 and SCE's internal calculations. State laws targeting the importance of GHG reduction and air quality programs for disadvantaged communities as well as low- and moderate-income communities include AB 197, SB 1204, SB 1275, and SB 535, *available at* http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201520160AB197, http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1204, http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1275, and http://leginfo.ca.gov/pub/11-12/bill/sen/sb_0501-0550/sb_535_bill_20120930_chaptered.pdf.

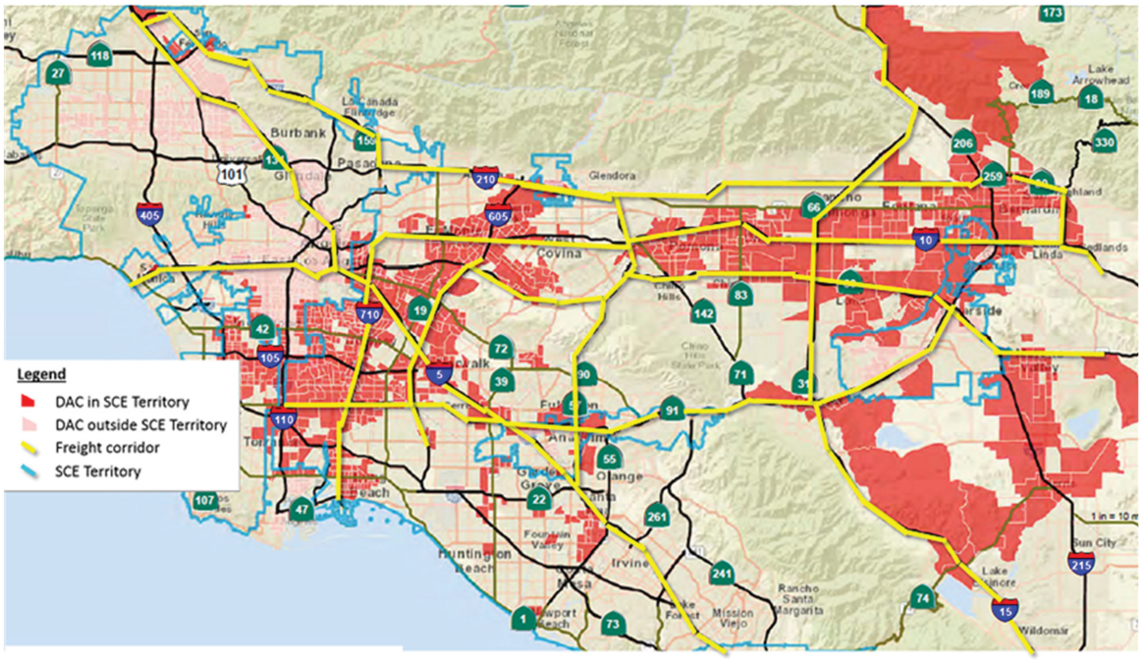
26 CalEnviroScreen 3.0 is a screening methodology, developed by the CalEPA, which can be used to help identify California communities that are disproportionately burdened by pollution and other socioeconomic factors, *available at* http://oehha.maps.arcgis.com/apps/webappviewer/index.html?id=4560cfbce7c745c299b2d0cbb07044f5.

27 *See* the Southern California Association of Governments, Goods Movement Transportation System Appendix (April 2016), p. 5, *available at* http://scagrtpscs.net/Documents/2016/final/f2016RTPSCS_GoodsMovement.pdf. These corridors travel through many disadvantaged communities.

28 *See* OEHHA, CalEnviroScreen, (Jan. 2017), *available at* http://oehha.ca.gov/media/downloads/calenviroscreen/report/ces3report.pdf.

29 *See* Figure II-5: Medium-Duty, Heavy-Duty and Non-Road Vehicles Contribute Significantly to NOx Emissions in Los Angeles County.

Figure II-4
Disadvantaged Communities are Heavily Impacted by Air Pollution from Freight Corridors[30]



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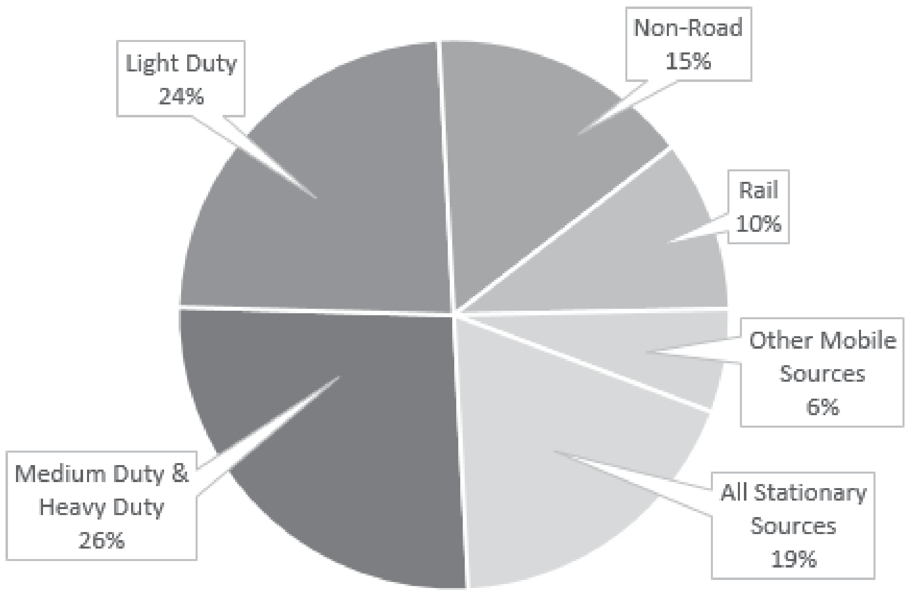
30 Communities are considered Disadvantaged Communities if they are in the worst quartile of environmental & economic burden, as evaluated by CalEPA using CES 3.0. Freight corridors are consistent with those identified by the Southern California Association of Governments in its 2016-2040 Regional Transportation Plan/ Sustainable Communities Strategy. A map of freight corridors, warehouses, and rail lines is available in the Southern California Association of Governments, Goods Movement Transportation System Appendix (April 2016), *available at* http://scagrtpscs.net/Documents/2016/final/f2016RTPSCS_GoodsMovement.pdf.

Figure II-5
Medium-Duty, Heavy-Duty and Non-Road Vehicles Contribute Significantly to NOx Emissions in Los Angeles County[31]



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c) Transportation electrification can help create downward pressure on rates.

As transportation electrification increases, it has the potential to lower the cost of electric service for electric customers by spreading fixed costs over a larger base of kWh sales. The overwhelming majority of the expected load opting to use the proposed, new EV rates will be incremental; customers at large will benefit from the proposed rate design by the newly attracted load's contribution to fixed cost recovery. SCE estimates that electrification of the medium-duty and heavy-duty market could put downward pressure on rates in the long term.

In addition, transportation electrification could improve integration of renewable generation by using time-of-use (TOU) rates as an incentive for load management.[32] SCE's proposed TE portfolio

[31] EPA National Emissions Inventory 2014 for Los Angeles County. Non-Road category includes forklifts, yard tractors, cranes, and transport refrigeration units.

encourages improved use of the electric system resulting from TOU price signals and other load-management strategies that encourage EV load to shift to hours of the day when there is excess generation on the grid.[33] At these times, load is less costly to serve, increasing downward pressure on costs, (and eventually rates). Additionally, at these times EV customers will help California use abundant renewable power, particularly when they are able to charge during periods of over-generation. Therefore, SCE's proposed EV rates will provide an incentive for charging vehicles at times when there is an abundance of clean (mostly solar) power on the grid. This is an additional benefit of SCEs proposed EV rate structure.

C. Transportation electrification has begun, but uptake is slow.

After more than five years of commercial availability, passenger EVs represent only three percent of total annual vehicle sales in California.[34] Despite the slow progress, some trends support growth potential.

Many factors impact the attractiveness of battery electric vehicles (BEVs) and plug-in hybrid electric vehicles (PHEVs). Light-duty electric vehicles have taken advantage of the rapid decline in lithium ion battery prices (~$1,000/kWh in 2010 to ~$350/kWh in 2015[35]) driven by the technology advances in batteries and economies of scale due to widespread manufacturing of these batteries.

Continued from the previous page

[32] The Natural Resources Defense Council's (NRDC's) recent report explains how TOU rates for EVs are an important tool to benefit utility customers through improved use of the electric system and integration of renewables. *See* Max Baumhefner & Roland Hwang, *Driving Out Pollution: How Utilities Can Accelerate the Market for Electric Vehicles*, NRDC p. 4-5 and 15-16, (June 2016), *available at* https://www.nrdc.org/resources/driving-out-pollution-how-utilities-can-accelerate-market-electric-vehicles.

[33] In PG&E's proceeding (A.15-02-009), the Commission found this benefit to be in the public interest. D.16-12-065, p. 19.

[34] Data from the Electric Power Research Institute (EPRI) on annual light-duty vehicle sales in California, based on registration data obtained through RL Polk, measured at the county level through the end of 2016 Q3. This data does not include pick-up trucks, vans, and sport-utility vehicles in the light-duty segment.

[35] McKinsey & Co., Bloomberg New Energy Finance, *An Integrated Perspective on the Future of Mobility*, (Oct. 2016), *available at* https://data.bloomberglp.com/bnef/sites/14/2016/10/BNEF_McKinsey_The-Future-of-Mobility_11-10-16.pdf.

Generation costs of renewable energy have also dropped rapidly, at an annual rate between 13 and 17 percent per year since 2009, and improved the economics of making abundant clean energy available to fuel transportation segments. The declining cost of solar generation is expected to continue at a rate of two percent per year through 2030.[36] As the electricity grid gets cleaner, the movement to electric vehicles further reduces GHG emissions.

Beyond trends in renewable cost, the growth in ride-sharing and autonomous operations may further accelerate transportation electrification. The compounding benefits from combining transportation electrification with ride-sharing and autonomous operations are just becoming evident. Taxi and ride-sharing vehicle miles may be ideal for electrification—typically, relatively short trips at relatively slow speeds with an abundance of stops and starts, and the potential to modify customer behavior to charge at lower-cost times in the day.[37] As a result, taxi and ride-sharing services may rely heavily on electric vehicles.[38] Autonomous electric vehicles will push these trends even further by making recharging easy—drop off the passenger, go recharge, and return for pick up—potentially allowing for grid location optimization. Taken together, electrifying taxi, ride-sharing, and autonomous operations could reduce gasoline and diesel demand 40-60 percent in large urban markets like Los Angeles over the next ten years, reducing pollution, increasing transportation accessibility, and improving grid utilization for customers.[39] As such, any comprehensive transportation electrification strategy in Southern California should consider taxi, ride-sharing, and autonomous vehicle electrification, which is why SCE has included a pilot program targeted at taxi and ride-sharing EVs.

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[36] IHS Energy, U.S. Wind and Solar PV Energy Price Outlook Update, June 2016.

[37] Mc. Kinsey & Co., Bloomberg New Energy Finance, *An Integrated Perspective on the Future of Mobility* (Oct. 2016), *available at* https://data.bloomberglp.com/bnef/sites/14/2016/10/BNEF_McKinsey_The-Future-of-Mobility_11-10-16.pdf.

[38] *Id.*

[39] *Id.*

D. <u>SCE will help to accelerate transportation electrification through programs proposed in this application.</u>

SCE supports the state's assessment that transportation electrification will be a large portion of the environmental solution in California, and SCE believes that utilities can be a driving force in making the changes necessary to increase EV adoption.

Utilities and other market participants can address many barriers that currently inhibit EV adoption. Electric utilities are especially well suited to address rate design, electricity delivery, infrastructure, and integration of EVs with the grid.[40] Utilities are well versed in developing rate structures, providing clean electricity, supporting customer adoption of new technologies (e.g., smart thermostats, solar rooftops, electric vehicles) and building infrastructure. In addition, utilities can help the state achieve its clean energy goals while helping to ensure accessibility to the technologies in disadvantaged and low- and moderate-income communities.[41] By focusing in these areas, electric utilities such as SCE can drive transportation electrification.

Electrifying all segments of transportation sector is essential to achieve the state's environmental goals, but they are in various stages of technological development. SCE's proposed portfolio of programs and pilots supports each stage of development and is tailored to support the phase that each segment is in currently. In the early market development stage, SCE will support well-designed pilots to reduce costs and develop policy incentives to drive adoption. When a segment is in the market transformation stage, SCE will provide large-scale programs that reduce cost barriers, such as make-ready infrastructure. When a segment is in the market growth stage, SCE will continue to provide clean power to fuel these vehicles.

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[40] SCE's current application focuses on rate design and infrastructure. SCE will consider other areas, such as battery end-of-life use, in potential future applications.

[41] For example, see the Governor's Interagency ZEV Action Plan goal to help residents of multi-unit dwellings be able to charge EVs. *See* Office of Governor Edmund G. Brown Jr., "2016 ZEV Action Plan," *available at* https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf, defining ZEVs to include hydrogen fuel cell electric vehicles (FCEVs) and plug-in electric vehicles (PEVs), which include both pure BEVs and PHEVs. *See also* ACR at Section 3.6.2.

Taking into account the barriers, utility capabilities, and phase of evolution for each transportation segment, SCE's proposed pilots and programs address barriers to transportation electrification.

- Light-duty vehicles:[42]
    - **Opportunity:** SCE forecasts light-duty vehicles to represent 86 percent of transportation-related GHG-emission reductions from the transportation sector by 2030.[43]
    - **Barriers:** With current incentives, EVs are cost competitive with traditional vehicles,[44] but public charging infrastructure is necessary to reduce range anxiety.[45] This is a fundamental problem, because availability of charging infrastructure stimulates demand for EVs.[46] This correlation is especially true for workplace

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[42] *See* Appendix C for descriptions of vehicle classes.

[43] Proportions based on internal analysis (see Appendix D) and the SCE 2016 Q4 forecast, which is derived from Navigant's 2016 Q2 light-duty EV forecast and ICF International and E3's Phase I TEA Study for medium-duty and heavy-duty vehicles and other non-road electric transportation.

[44] Mc. Kinsey & Co., Bloomberg New Energy Finance, *An Integrated Perspective on the Future of Mobility* (Oct. 2016), *available at* https://data.bloomberglp.com/bnef/sites/14/2016/10/BNEF_McKinsey_The-Future-of-Mobility_11-10-16.pdf.

[45] *See* National Research Council of the National Academies, *Overcoming Barriers to Electric-Vehicle Deployment: Interim Report*, (Feb. 2013), pp. 35-36, *available at* http://www.nap.edu/openbook.php?record_id=18320; *See also* ICF International Inc., *Bay Area Plug-In Electric Vehicle Readiness Plan: Background and Analysis*, pp. 9-10 (Dec. 2013), *available at* http://www.baaqmd.gov/~/media/files/strategic-incentives/ev-ready/bay-area-pev-readiness-plan-background-and-analysis-web-pdf.pdf?la=en.

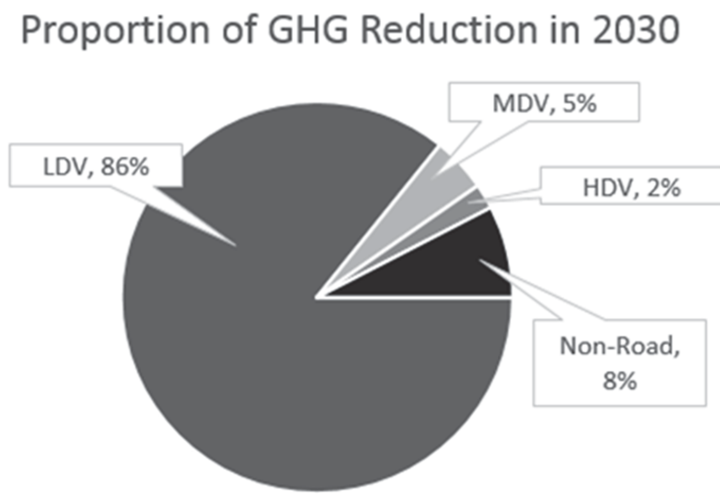
[46] A global study that examined the relationship between key variables (financial incentives, charging infrastructure, and presence of production facilities) and 30 national electric vehicle markets concluded that, of those variables, charging infrastructure was the best predictor of a country's EV market penetration. *See* William Sierzchula, et al., "The influence of financial incentives and other socio-economic factors on electric vehicle adoption," *Energy Policy*, vol. 68, May 2014, pp. 183-194 ("For charging infrastructure, holding all other factors constant, each additional station per 100,000 residents that a country added would increase its EV market share by 0.12 percent. This suggests that each charging station (per 100,000 residents) could have twice the impact on a country's EV market share than $1,000 in consumer financial incentives, albeit with different bearings on a nation's budget."). Abstract *available at* http://www.sciencedirect.com/science/article/pii/S0301421514000822.

charging.[47] Additionally, new modes of travelling, such as ridesharing and autonomous vehicles, may require different kinds of charging support, including DC fast charging.

- **Programs:** Given the need for additional infrastructure to reduce range anxiety and support new travel modes, SCE proposes a pilot program offering a rebate for residential at-home charging infrastructure, an EV rideshare driver reward, and clusters of multiple DCFC stations to service customers that are not able to charge at their residence or workplace. As almost half of the state's disadvantaged communities are within SCE's service territories, SCE will specifically target disadvantaged communities when implementing these programs.

[47] *See* Plug-in America for California Electric Transportation Coalition (CalETC), *Evaluating Methods to Encourage PEV Adoption,* pp 20-22, (Oct. 2016), *available at*: http://www.caletc.com/wp-content/uploads/2016/10/PIA-Incentive-Survey-Paper-CS5-final-cosmetic.pdf. *See also* "ChargePoint, *The Ratepayer Benefits of Electric Vehicle Charging*," (2017) *available at:* http://www.chargepoint.com/files/Ratepayer_Benefits_2017.pdf.

Figure II-6
GHG Abatement Opportunities by Transportation Sector[48]



- Medium-duty and heavy-duty vehicles (Class 2-7):[49]
  - **Opportunity:** Similar to light-duty vehicles, the total cost of ownership with incentives for medium-duty electric vehicles (excluding cost of charger and supporting infrastructure) is currently attractive,[50] despite low adoption to date. While the medium-, heavy-duty, and non-road sectors are small in proportion to light-duty vehicles, they will contribute a significant portion of GHG-reduction potential, a combined 15 percent of abatement by 2030.[51]

[48] Proportions based on internal analysis (see Appendix D) and the SCE 2016 Q4 forecast, which is derived from Navigant's 2016 Q2 light-duty EV forecast and ICF International and E3's Phase I TEA Study for medium-duty and heavy-duty vehicles and other non-road electric transportation.

[49] Includes Class 2 through 7 vehicle classes. *See* Appendix C for descriptions of vehicle classes.

[50] Mc. Kinsey & Co., Bloomberg New Energy Finance, *An Integrated Perspective on the Future of Mobility* (Oct. 2016), *available at* http://www.mckinsey.com/business-functions/sustainability-and-resource-productivity/our-insights/an-integrated-perspective-on-the-future-of-mobility.

[51] Proportions based on internal analysis (see Appendix D) and the SCE 2016 Q4 forecast, which is derived from Navigant's 2016 Q2 light-duty EV forecast and ICF International and E3's Phase I TEA Study for medium-duty and heavy-duty vehicles and other non-road electric transportation.

- **Barriers:** While commercially available, medium- and heavy-duty electric vehicle technology is nascent. Additionally, the charging infrastructure offerings are highly fragmented, expensive,[52] and lack standards.[53] Finally, rate structures with high demand charges can discourage some customers from electrifying vehicles.[54] These challenges add complexity to installation of infrastructure and adoption of electric technologies.
- **Programs:** To support this segment, SCE is focusing on lowering the customers' cost to charge (including infrastructure), helping to standardize charging technology, and proposing new rate designs to support EV charging.

- Heavy-duty vehicles (Class 8):[55]
  - **Opportunity:** Electrification of the heavy-duty vehicle segment is important to reduce criteria pollutants, such as NOx and particle pollution,[56] which cause smog and associated health issues. Medium- and heavy-duty vehicles alone contribute at least 26 percent of the daily NOx emissions in Los Angeles.[57]

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[52] *See* Calstart Inc., *Electric Truck and Bus Grid Integration Report*, p. 19 (Sept 2015), which found charging infrastructure up-front and installation costs to be expensive, *available at* http://www.calstart.org/Libraries/Publications/Electric_Truck_Bus_Grid_Integration_Opportunities_Challenges_Recommendations.sflb.ashx.

[53] These include Society of Automotive Engineers (SAE) International Standards J-2954, J-3068, and J-3105. *See* Dan Bowermaster*, U.S. DOE Electrification of Goods and People Movement Workshop, available at* http://steps.ucdavis.edu/wp-content/uploads/05-28-2016-Dan-Bowermaster-presentation-from-EPRI.pdf.

[54] *See* Calstart Inc., *Electric Truck and Bus Grid Integration Report*, p. 13-18 (Sept 2015), which found innovative electricity rates for electric trucks and buses are needed, *available at* http://www.calstart.org/Libraries/Publications/Electric_Truck_Bus_Grid_Integration_Opportunities_Challenges_Recommendations.sflb.ashx.

[55] For example, freight trucks, cement trucks, and large transit buses. *See* Appendix C for descriptions of vehicle classes.

[56] *See* EPA's Particulate Matter (PM) Pollution Fact Sheet, *available at* https://www.epa.gov/pm-pollution/particulate-matter-pm-basics. Particle pollution includes inhalable particles with diameters that are generally 10 micrometers and smaller (PM10) and fine inhalable particles with diameters that are generally 2.5 micrometers and smaller (PM2.5).

[57] EPA National Emissions Inventory 2014 for Los Angeles County. Information *available at* https://www.epa.gov/air-emissions-inventories/2014-national-emissions-inventory-nei-data.

- **Barriers:** The technologies available in this segment are very early stage and it is unclear which technologies will be adopted on a large scale.
- **Programs:** To drive vehicle and technology development in this market, SCE will support efforts to electrify freight transportation in the L.A. Basin.

- Non-road and material-handling equipment (e.g., electric forklifts, truck refrigeration units[58]):
  - **Opportunities**: Accelerating electrification of this segment is important to reduce criteria pollutants such as NOx and PM2.5, which cause smog and associated health issues.
  - **Barriers:** While electrified equipment in this segment is commercially available, barriers to increased adoption include lack of awareness and knowledge, the complexity of current charging infrastructure (installation and operations), and lack of more advanced charging technology (e.g., capable of receiving and responding to demand response (DR) or other load management tools that facilitate charging in a manner consistent with grid conditions).
  - **Solutions:** Infrastructure deployment and charging standardization will facilitate adoption of these technologies.
- Non-road equipment and ports:
  - **Opportunity:** Non-road infrastructure and port equipment play a key role in reducing air pollutants. Currently-available technologies include electric yard tractors, rubber-tire gantry cranes, and large port forklifts.
  - **Barriers:** The technologies available in this segment are very early stage.
  - **Programs:** To further adoption of these technologies, infrastructure deployment and charging standardization will be helpful.

[58] *See* Appendix C for descriptions of vehicle classes.

E. **Future actions by SCE and other parties will further transportation electrification in the state.**

This Application is an important step to facilitate transportation electrification, and SCE expects to propose additional programs and pilots in the future. The Southern California Association of Government's (SCAG's) Regional Transportation Plan calls for the deployment of zero-emission heavy-duty vehicles.[59] SCE will work closely with SCAG and other key stakeholders to support electrification of freight transportation originating from the ports of Long Beach and Los Angeles and travelling on the I-710 freeway.

SCE also intends to file a future application seeking CPUC approval of Phase 2 of its Charge Ready program,[60] which provides infrastructure and rebates to support charging stations in long-dwell locations including workplaces and multi-unit dwellings. Additionally, SCE sees opportunities to bring multiple market participants together to create EV salesforce training materials, address other market barriers, and create software applications to provide better information to the public on charging station availability. Finally, SCE will continue to work with government agencies on programs that need high levels of multi-party collaboration, such as efforts to electrify goods and people movement along the I-710 freeway.[61]

While utilities have an important and specific role to play in addressing these barriers, many other market participants need to help transform the transportation market. For example, vehicle manufacturers influence issues such as vehicle sales, operation, and charging standards. They will also be instrumental in increasing consumer awareness, providing innovative financing, continuing to lower vehicle costs, and adopting charging standards. Charging station manufacturers are essential to charging

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[59] *See* SCAG's 2016 Regional Transportation Plan, *Transportation/Goods Movement Appendix*, pp. 43-51, (April 2016), *available at* http://scagrtpscs.net/Documents/2016/final/f2016RTPSCS_GoodsMovement.pdf.

[60] SCE's Charge Ready program was proposed in A.14-10-014, and the Decision approving the Charge Ready Phase 1 Settlement required SCE to submit an application on its Phase 2 proposal in the event the second phase is warranted based on the results of the Phase 1 pilot report. D.16-01-023, Ordering Paragraph (OP) 9.

[61] *Id.* at p. 69.

infrastructure deployment. Finally, stakeholders will need to work together to provide information to consumers in a streamlined fashion to enroll in rebate and energy programs when purchasing an EV and understanding where charging infrastructure is located and when it is available.

State and local regulators and legislators also have a very important role to play in eliminating barriers to EV adoption. SCE commends the state for environmental actions taken to date, and is committed to facilitating the success of these measures. The state should continue providing incentives to ensure that EVs are cost competitive with traditional internal combustion engines. Additionally, incentives like high-occupancy vehicle (HOV) lane access and parking privileges are very high-value and very low-cost ways to encourage consumer adoption. The state can also set rules to expand electric vehicle adoption and increase access to recharging at state facilities. Local jurisdictions need to play a role too, ensuring that local siting and permitting is completed as quickly for new EV service as for new solar photovoltaic installations. The CPUC took an important step by requesting utility proposals and allowing priority review for key pilots. Promptly reviewing and approving this application and other applications for TE programs is imperative to enable the utilities to facilitate transportation electrification.

III.

SCE'S TRANSPORTATION ELECTRIFICATION PORTFOLIO

Electrification of all transportation sectors is necessary to meet the state's GHG and air-quality goals, and SCE has an important role to play in all market segments within its service territory. Because the light-duty, medium-duty, heavy-duty, and non-road segments of transportation are all in various stages of technological development and market maturity, there are different barriers to increased adoption in each segment.

SCE developed a portfolio of projects and programs addressing a variety of market segments and targeting the unique needs of SCE's customers. SCE's portfolio also establishes a mechanism for receiving valuable stakeholder input, and complies with the guidelines set forth in the ACR and Appendix A to the ACR.[62]

SCE's service territory contains the second busiest seaport in the country[63] and major manufacturing industries that drive large volumes of goods movement on the roads. While crucially important to the state and local economy, the goods movement industry is a major source of GHG emissions and air pollution. To tackle this important problem, SCE's portfolio contains a five-year program that will provide charging infrastructure needed to support medium- and heavy-duty vehicle electrification. SCE agrees with the ACR's finding that continuity is necessary[64] for emerging markets to transform and accelerate, and this five-year program provides that continuity to market participants. With this project, SCE will help the limited government and private funds go further. This form of public-private partnership leverages non-ratepayer funding as encouraged by the ACR,[65] and will lead to faster transformation of these markets.

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[62] ACR, pp.13-15 and A-1.

[63] *See* POLB Facts at a Glance, *available at* http://www.polb.com/about/facts.asp.

[64] ACR at 12.

[65] ACR at p. A2.

SCE is also proposing, as part of its portfolio, a short-, intermediate-, and long-term solution for commercial EV rate design to promote transportation electrification in California. Specifically, SCE proposes to establish three new, optional commercial rate schedules—EV-7, EV-8 and EV-9 (collectively, "New EV Rate Schedules")—which will have the same general structure but will apply to different sizes of customers for the exclusive purpose of charging EVs.

SCE's portfolio will collect valuable data regarding each proposed initiative, including deployment costs, TE load profiles, barriers to TE charging deployment, load management options, integration of renewable energy, impact of rates, and EV driver experiences. Data and lessons learned from SCE's existing TE pilots and the proposed portfolio will support the Commission in its efforts to integrate TE into the Integrated Resources Plan (IRP) process at some point in the future.[66]

SCE's TE portfolio will leverage lessons learned from on-going pilots such as:

- Charge Ready Pilot, including experience in deploying make-ready infrastructure for charging stations;
- TE Advisory Services, including experience in assisting business customers in adopting TE technologies;
- Market Education programs designed to develop awareness about EVs and the benefits of fueling from the grid; and
- SCE's workplace charging pilot designed to understand charging behavior, impact of DR, and pricing elasticity of demand.

To help address the light-duty EV market segments that were not included in the Charge Ready Pilot, and spur growth in non-light-duty TE segments like port equipment and buses, SCE is proposing the following priority review projects:

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[66] For more on SCE's comments regarding TE linking to the IRP, *see* R.16-02-007, SCE's informal comments on the CPUC staff concept paper for the IRP (Aug. 31, 2016) at pp. 2, 4, 9, 23, 25, 30, 33, 36, 37, 39 and 40, *available at* http://www.cpuc.ca.gov/WorkArea/DownloadAsset.aspx?id=6442451389.

- Rebates to support deployment of EV charging in single-family residences and multi-unit dwellings;
- Rewards to encourage EV ridesharing (to increase EV awareness, especially in disadvantaged communities);
- Urban direct current (DC) fast charging stations; and
- Make-ready infrastructure for electric buses operated by transit agencies, yard tractors, and rubber-tire gantry cranes at port terminals.

These proposed small-scale, short-term, priority-review projects are "non-controversial" as required by the ACR. SCE developed these pilots based on feedback from SCE's customers and industry stakeholders. The urban DCFC project will deploy a limited number of fast charging stations outside of the major highway corridors, in areas where EV drivers may not have access to home charging (e.g., near multi-unit dwellings). The rebate and infrastructure programs support accelerating transportation electrification in growing and new markets.

When implementing both the priority review and standard review projects and programs, SCE plans to address load management by working with customers, when appropriate, to understand their operational needs and help them select the right combination of charging infrastructure (speed and location) and cost-effective rate schedules. For some customers, DR and altered charging times may be challenging. In order to determine viability, SCE plans to learn from its commercial and industrial customers participating in DR events. SCE's proposed portfolio provides an opportunity to reduce fuel costs when charging in a manner consistent with electrical grid conditions. For example, customers participating in each of SCE's proposed initiatives will have the opportunity to take advantage of TOU rates, which offer less costly electricity when charging at off-peak times and include times when charging is less than $1.00 per gallon equivalent.[67]

[67] SCE's new rate proposal is eight cents per kWh off-peak, which is equivalent to about $0.80 per e-gallon according to the U.S. Department of Energy (DOE) e-gallon calculator, *available at* https://energy.gov/articles/egallon-what-it-and-why-it-s-important and https://energy.gov/sites/prod/files/2016/01/f28/eGallon%20methodology%20%28Updated%20January%202016%29.pdf.

SCE's proposed TE portfolio, coupled with its EV rate proposal, existing EV rates,[68] on-going education efforts,[69] and other existing or approved programs,[70] provide a comprehensive package of solutions to address important market barriers and enhance and accelerate existing efforts.

A. Priority Review Projects

1. Residential Make-Ready Rebate Pilot

a) Description

The Residential Make-Ready Rebate Pilot provides a rebate to residential customers living in single-family residences or multi-unit dwellings to install EV charging make-ready infrastructure, as explained below. The pilot complements, but does not duplicate, the existing Charge Ready Pilot Program by targeting residential customers.[71] The make-ready rebate will be offered in two tiers:

- Tier 1 Rebate: Residential customers who submit a proof of recent EV purchase or lease and agree to take service on a whole-house TOU rate plan (Schedule TOU-D or TOU-DT) for 24 months will be eligible to receive a rebate to offset (1) the costs of hiring a licensed electrical contractor to inspect their existing electric infrastructure and install a new circuit to recharge their new EV and (2) associated permitting costs.
- Tier 2 Rebate: Residential customers who submit a proof of recent EV purchase or lease and agree to take service on Schedule TOU-EV-1

[68] SCE's current EV rates include EV-1, EV-3, EV-4, ME, TOU-8 option A, TOU-D option A, and TOU-D option B. All current SCE Rate Schedules are *available at* http://on.sce.com/25KXt0T.

[69] Market education, including TE advisory services, as approved by D.16-01-023. Education and outreach, as approved by D.11-07-029.

[70] For example, checking transformers where EVs are located, posting circuit information for all of our 4600+ circuits, upcoming Low Carbon Fuel Standard program, the Electric Program Investment Charge (EPIC) program, and DR programs.

[71] Only non-residential customers are eligible for the Charge Ready Pilot Program. Schedule CRPP, Charge Ready Program Pilot, Definitions, and Subparagraph 1.a., *available at* https://www.sce.com/NR/sc3/tm2/pdf/ce361.pdf.

(separately-metered EV rate plan) for 24 months will be eligible to receive a rebate to offset (1) the costs of hiring a licensed electrical contractor to inspect their existing electric infrastructure and install a second panel and a new circuit to recharge their new EV and (2) associated permitting costs.

SCE will determine the rebate amounts by surveying service providers or through trade group studies. The rebate is intended to cover most standard costs incurred by customers to deploy a new circuit, new panel, or new meter socket.

b) Gaps and Customer Needs

Reliable access to daily charging is a critical driver to EV adoption, yet the cost of installing EV charging infrastructure may constitute a barrier for potential EV adopters.[72] Outside studies have found a need for incentives to address the cost of residential charging or programs to address the complexity of installing it.[73] In addition, most of SCE's residential EV customers choose to remain on a tiered rate schedule, usually Schedule D, rather than taking advantage of a TOU rate, which

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[72] While many jurisdictions have revised their building and electrical codes to require new residences to accommodate EV charging (e.g., sufficient panel capacity, separate 240v circuit), the cost of retrofitting existing buildings can be significant (e.g., new panel, trenching).

[73] A multi-state survey found that 22 percent of customers would not have purchased their EV without a home EV supply equipment (EVSE) subsidy, and another 39 percent said it was a very important part of the decision. *See* Idaho National Laboratory, Residential Charging Behavior in Response to Utility Experimental Rates in San Diego, 2015, *available at* http://avt.inel.gov/pdf/EVProj/ResChargingBehaviorInResponseToExperimentalRates.pdf. Plug-in America points out that utilities are well-positioned to help customers understand home charging options, costs, permitting and capacity requirements as well as offer rebates and programs to make a home EVSE installation easy, quick and inexpensive. *See* Evaluating Methods to Encourage Plug-in Electric Vehicle Adoption, October 2016, at 11 and 20, *available at* http://www.caletc.com/wp-content/uploads/2016/10/PIA-Incentive-Survey-Paper-CS5-final-cosmetic.pdf. *See also* Overcoming Barriers to Deployment of Plug-in EVs, 2015, National Academy of Sciences at 48-40, *available at* https://www.nap.edu/catalog/21725/overcoming-barriers-to-deployment-of-plug-in-electric-vehicles.

encourages off-peak charging[74] and would help many customers charge their EVs more cost-effectively.[75]

The customer cost of installing a new panel or meter socket to house a second meter for SCE's Schedule TOU-EV-1 may deter customers from adopting the separately-metered rate plan. General concerns about on-peak usage may also discourage customers from adopting a whole-house TOU rate plan.

Finally, EV customers may use an existing circuit to charge their EVs at Level 1 or attempt to install a Level 2 charging station by themselves without notifying the utility of the increased demand they will exert on the system, which could create potential safety concerns with the supporting grid[76] and their own electrical infrastructure.

c) Objective

The pilot aims to confirm customer interest in a home-charging program, validate cost assumptions, and evaluate EV customer satisfaction with TOU rates to prepare for a potential broader future phase.

d) Scope and Cost

(1) SCE Customer and Site Eligibility

The pilot is open on a first-come, first-served basis to residential customers who meet the following eligibility requirements. Eligible customers must:

- Have access to a dedicated parking space, either in a single-family residence or multi-unit dwelling within SCE's service territory,

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[74] SCE's load research consistently finds that EV residential customers on a separately-metered TOU rate plan (e.g., Schedule TOU-EV-1) charge nearly 90 percent of their usage during the off-peak period (Joint-IOU Electric Vehicle Load Research Report, December 30, 2016, p. 60).

[75] SCE's internal analysis found that about 75 percent of EV residential customers would benefit from switching to Schedule TOU-D.

[76] SCE can only verify the utility infrastructure (transformer, service) if it receives notification by customers of new charging locations.

- Obtain property owner approval to install the new electric infrastructure to charge their EV,
- Provide proof of recent purchase or lease and registration of a light-duty electric vehicle (on-road vehicle registered with the California Department of Motor Vehicles at the SCE customer address),
- Provide a receipt from a licensed electrical contractor for deploying a new circuit (for the Tier 1 Rebate) and for the installation of a new panel or meter socket to house SCE's meter for Schedule TOU-EV-1 (for the Tier 2 Rebate), together with a copy of all permits required by the relevant authority having jurisdiction,[77]
- Agree to take service on Schedule TOU-D or TOU-DT for 24 months when applying for the Tier 1 Rebate and Schedule TOU-EV-1 for 24 months when applying for the Tier 2 Rebate, and
- Agree that SCE may conduct random spot checks at the customer residence to confirm that the work was performed.

SCE estimates that approximately 5,000 SCE residential customers could participate in the proposed Residential Make-Ready Rebate Pilot.

(2) Qualified Vendors, Products, and Services

SCE plans to accept receipts from electrical contractors holding a valid C-10 license for eligible work and receipts from the relevant authority having jurisdiction for the required permits. SCE will not establish charging station requirements as customers may charge at Level 1 with

[77] Customers may obtain in-scope services prior to acquiring an EV, but may only receive the proposed rebate after providing proof of purchase or lease and registration of a light-duty electric vehicle.

a standard 120v outlet or at Level 2 with a charging station; the rebate will not cover any costs related to charging equipment.

(3) Customer Engagement and Enrollment

SCE plans to leverage multiple communication channels to develop customer awareness about the pilot, including online advertising to target customers interested in EVs or charging equipment. SCE may also engage with EV dealers to promote the pilot at the point of sale. SCE may leverage the online Clean Fuel Reward program to reach potential participants. SCE will direct interested customers to an online landing page to obtain information about the pilot and to a customer portal to apply for the rebate. As part of its education and outreach efforts, SCE will specifically target customers in disadvantaged communities to invite them to participate in the pilot.

(4) Management and Execution

SCE's Customer Programs and Services (CP&S) organization, in close collaboration with the Transportation Electrification Program Management organization in SCE's Transmission and Distribution (T&D) group, will implement and execute this pilot.

(5) Data Collection and Reporting

SCE proposes to report a number of metrics in connection with the pilot, including:

- Volume of participants by segment (single-family residence, multi-unit dwelling, and disadvantaged community),
- Volume of unserved customers if the pilot's budget is fully expended during the pilot's duration and not all applicants are served,
- Electrical work and permitting costs,
- Customer preference between whole-house TOU rate and separately-metered TOU rate,
- Load profiles, including adherence to off-peak periods, and
- Customer satisfaction with the pilot and with TOU rate plans.

(6) Costs

The total estimated cost of the pilot is $4 million. The pilot's budget includes the cost of the make-ready rebates, enrollment and rebate processing (including compliance verification), and education and outreach to potential participating customers.

e) Duration

Planning implementation of the pilot requires approximately six months. The pilot is estimated to run for approximately twelve months following the pilot's launch (or until funding has been exhausted, if sooner).

f) Benefits

The pilot provides many potential customer benefits. It supports EV adoption, as purchasing or leasing an EV will be a verified requirement. The same requirement also limits the risk of stranded assets.

The pilot improves safety by incentivizing customers to use the services of a licensed electric contractor and install a new circuit. This prevents EV owners from plugging their vehicles into an existing outlet without a professional inspection and improves the safety of EV charging. The pilot also helps SCE identify new EV charging locations for participating customers, allowing SCE to conduct system checks and grid reinforcements according to its standards and procedures.

The pilot potentially increases grid reliability by encouraging adoption of residential TOU rates, which improves vehicle-grid integration by promoting off-peak charging and minimizes potential impacts from EV charging.

2. EV Driver Rideshare Reward Pilot

a) Description

The EV Driver Rideshare Reward Pilot provides a monetary reward to rideshare or taxicab drivers who use an EV and exceed a specified number of rides during a given time period.[78]

[78] Actual requirements will be described in the implementation advice letter.

SCE has already engaged with leading rideshare providers to discuss the feasibility of the proposed pilot. SCE plans to work with interested rideshare companies to administer the pilot, determine reward requirements, and develop communications to drivers while ensuring compliance with privacy and confidentiality requirements.

b) Gaps and Customer Needs

Rideshare popularity has exploded across the country and surpasses taxi services in many cities,[79] providing on average more than 30 million rides per month.[80] Yet very few drivers use an EV to provide rideshare services.

c) Objective

The EV Driver Rideshare Reward is designed to encourage EV adoption by rideshare drivers and increase EV-miles traveled within SCE's service territory, in support of state energy and clean air policy requirements and goals. The pilot will also evaluate the charging needs of EV rideshare drivers.

d) Scope and Cost

(1) Customer Eligibility

Eligible drivers must:

- Qualify as residential SCE customers,
- Provide proof of their personal vehicle as defined by CPUC Decision D.16-12-037[81] (e.g., registration from the California Department of Motor Vehicles at the SCE customer address for an on-road light-duty EV)

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[79] *See* Certify Inc., *Sharing the Road: Business Travelers Increasingly Choose Uber*, *available at* http://www.certify.com/infograph-sharing-the-road.aspx.

[80] *Id*.

[81] In this decision, the Commission adopts and interprets the definition of a personal vehicle as a vehicle that fits into any of the following four categories: 1) owned; 2) leased; 3) rented for a term that does not exceed 30 days; or 4) otherwise authorized for use by the participating driver.

- Complete the number of required rideshare trips in a given week or month,[82] as demonstrated by rideshare or taxicab services participating in the pilot.

(2) Qualified Vendors, Products, and Services

Rideshare or taxicab organizations licensed by the Commission may participate in the pilot. SCE plans to develop standard terms and conditions for these organizations to provide relevant data for SCE to verify eligibility of customers, process rewards, and report to the Commission and stakeholders, as described below.

(3) Customer Engagement and Enrollment

SCE plans to leverage multiple communication channels to develop customer awareness about the pilot, including online advertising to target customers interested in EVs and rideshare services. SCE also intends to work with rideshare services to reach existing drivers and with EV dealers to promote the pilot at the point of sale. Finally, SCE may leverage the online Clean Fuel Reward program[83] and work with third-party low-income purchase incentives (e.g., CARB's Enhanced Fleet Modernization Program and Plus Up Pilot Project[84]) to reach potential participants. Interested customers will be directed to an online landing page to obtain information about the pilot and to a customer portal to apply for the reward. As part of its education and outreach efforts, SCE plans to target customers in disadvantaged communities to participate in the pilot.

(4) Management and Execution

SCE's CP&S organization will implement and manage the pilot.

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82 SCE will work with rideshare companies to determine these requirements.

83 SCE's Clean Fuel Reward program for residential EV owners launches in 2017 and is SCE's version of the Low Carbon Fuel Standard rewards that electric distribution utilities provide to customers.

84 Information on these programs are available at https://www.arb.ca.gov/msprog/aqip/efmp/efmp.htm and https://www.arb.ca.gov/newsrel/efmp_plus_up.pdf.

(5) Data Collection and Reporting

SCE will report a number of metrics in connection with the pilot, including:

- Volume of participants by vehicle type and by community (disadvantaged and non-disadvantaged communities),
- Survey results from participants, including benefits and challenges of using an EV for rideshare services,
- Volume and amounts of rewards issued, and
- Miles traveled.

(6) Costs

The total estimated cost of the Rebate Pilot is $4 million. The pilot's budget includes the cost of rewards, enrollment, and rebate processing (including compliance verification), and education and outreach to potential participating customers.

e) Duration

Planning implementation will take approximately six months and the program will run for approximately 12 months following the pilot's launch or until funding has been exhausted, whichever is sooner.[85]

f) Benefits

The pilot promotes the use of EVs in rideshare services, increases EV miles traveled, and introduces more passengers to the experience of riding in an EV. The pilot may incent SCE's customers to purchase, lease or rent new and used EVs or mobilize already owned EVs to participate in the rideshare economy. Ride-sharing services expect to cover 40 percent of the vehicle miles travelled in high-density urban markets and 10 percent of the vehicle miles travelled in less dense

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[85] Program length depends on the number of EV drivers participating in rideshare programs receiving reward payments.

markets by 2025.[86] SCE's proposed pilot will help to leverage these benefits and learn more about this new market. The pilot project also has many potential environmental benefits, such as replacing gasoline-fueled trips with zero-emissions miles. This conversion to EVs reduces pollutants and GHG emissions.

3. Urban DCFC Clusters Pilot

a) Description

The Urban DCFC Clusters Pilot proposes to deploy and operate five DCFC sites, clustered in urban areas. Each site may include up to five dual-port charging stations, for up to 50 DCFC ports total.

SCE intends to install, own, and maintain make-ready infrastructure at participating customer sites. Participating customers will have the opportunity to select DCFC charging stations qualified by SCE and receive a rebate to cover the base cost of charging stations deployed through the pilot, including hardware and installation. Participating customers will be required to provide public access to the charging stations deployed through the pilot, but can determine EV charging fees at their discretion.

SCE intends to promote the pilot with potential participating customers, such as cities, public parking lot operators, and EV service providers, and invite them to participate in this effort.

b) Gaps and Customer Needs

DCFC has seen limited urban deployment and tends to support long distance travel near highways (e.g., National Alternative Fuels Corridors from the US Department of Transportation, West Coast Electric Highway (WCEH) and the CEC DCFC for California's North-South Corridors (GFO-15-601)).[87] According to the DOE Alternative Fuels Data Center, 77 percent of

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[86] McKinsey & Co., Bloomberg New Energy Finance, *An Integrated Perspective on the Future of Mobility*, (Oct. 2016), *available at* https://data.bloomberglp.com/bnef/sites/14/2016/10/BNEF_McKinsey_The-Future-of-Mobility_11-10-16.pdf .

[87] *See* Green Car Congress, *available at* http://www.greencarcongress.com/2016/11/20161103-fhwa.html and http://westcoastgreenhighway.com/electrichighway.htm and http://insideevs.com/california-awards-8-9-million-for-completion-of-fast-charge-corridor/.

the 370 DCFC stations in SCE's territory are located within 0.5 miles of a major highway.[88] If available in urban areas, DCFC could help residential customers without access to overnight off-street parking or home charging adopt an EV and quickly charge it near their homes.[89] Lack of overnight or home charging is especially problematic for customers in multi-unit dwellings, who could benefit from this pilot. DCFC located in densely-populated areas away from highway corridors could also prove useful for EV drivers participating in rideshare programs.

c) Objective

The pilot will determine interest in DCFC in urban areas and evaluate charging behaviors of end-users.

d) Scope and Cost

(1) Customer Eligibility

Eligible customers must:

- Qualify as non-residential customer,
- Own or lease the participating site, or be the customer of record associated with the premises meter (likely the property management company or the building owner or tenant), where the charging stations will be deployed,
- Provide agreement by the participating site's owner to grant SCE appropriate real property rights and continuous access to the

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[88] SCE mapped the 144 DCFC sites (370 ports in total) as listed on the DOE Alternative Fuels Data Center (AFDC) database that are in SCE territory. *See* Electric Vehicle Charging Station locations, *available at* http://www.afdc.energy.gov/fuels/electricity_locations.html. SCE determined 107 sites (283 ports) are less than one-half mile from a major highway.

[89] Z. Tweed, *Fast Charging Key to Electric Vehicle Adoption, Study Finds*, (Nov. 2013), *available at* http://www.greentechmedia.com/articles/read/fast-charging-key-to-electric-vehicle-adoption-study-finds;

M. Kane, *NRG Analyzes 10 EVgo Freedom Sites: Fast Charging Preferred 12 to 1 Over L2*, (Nov. 2015), *available at* http://insideevs.com/nrg-analyzes-10-evgo-freedom-sites-fast-charging-preferred-12-1-l2/.

customer participant site infrastructure installed, owned, and maintained by SCE,

- Commit to and provide acceptable proof of qualified charging station purchase (together with the price paid for the purchase) prior to deployment by SCE,
- Agree to take service on an eligible TOU rate and participate in applicable DR program(s), and
- Agree to participate in the pilot for five years, including maintaining the charging stations in working order and contracting with a qualified EV charging network service providers to provide transactional data to SCE.

(2) Site Eligibility

Eligible sites must:

- Provide public access during normal operation hours,
- Be located in urban areas, near residential neighborhoods, as determined by SCE, and
- Include an appropriate location within the site to deploy charging stations in a cost-effective manner (based on factors such as proximity to transformers, length of trenching, available T&D capacity, and ease of access for EV drivers), as determined by SCE in its sole discretion, but subject to the participating customer's agreement.

(3) Qualified Vendors, Products, and Services

SCE plans to follow an approach similar to the Charge Ready Pilot Program to qualify vendors, charging stations and network services.[90] All DCFC stations must meet various technical standards and energy efficiency recommendations (e.g., SAE Standards J1772, J2894, J2836, and J28479) and must be listed by a nationally recognized testing laboratory. All DCFC stations must be DR capable (i.e., capable of receiving and executing real-time instructions to throttle or modify end-user pricing of EV charging load).

(4) Customer Engagement and Enrollment

SCE intends to target non-residential customers that may meet the pilot's requirements through low-cost channels such as emails and other customer communications by SCE's Business Customer Division. SCE will also solicit expertise and proposals from EV service providers on potentially eligible sites. Non-solicited customers will also have the opportunity to apply to the pilot, which SCE will promote on its website.

(5) Management and Execution

SCE's CP&S organization will implement and execute the project. The Transportation Electrification Program Management organization in SCE's T&D group will manage site evaluation and construction. SCE's Business Customer Division will handle all aspects of customer management and collaborate with service providers and additional stakeholders.

(6) Data Collection and Reporting

SCE proposes to report a number of metrics in connection with the pilot, including:

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90 SCE will issue a Request for Information (RFI) to all charging equipment vendors known to SCE (over 50 charging equipment vendors were contacted as part of the Charge Ready Pilot Program). The RFI will include commercial requirements for the vendors (e.g., current C-10 Electrical Contractor License) and technical requirements for the charging equipment and network services (e.g., listing by a nationally recognized testing laboratory). Any vendors and charging equipment that meet such requirements will be qualified by SCE and will appear on the pilot's Approved Package List (APL). Customers participating in the pilot may select any charging equipment appearing on the APL.

- Number of charging events, times, duration,
- Load profiles and adherence to off-peak periods, and
- DR event participation levels.

(7) Costs

The pilot's total estimated costs are $3.9 million.

b) Duration

Planning and implementation (enrollment and deployment) for the Urban DCFC Clusters Pilot requires approximately 12 months. Data collection will require 12 months at each site with an additional three months of review and reporting.

c) Benefits

The pilot provides new charging options in certain urban areas for EV drivers, while requiring participation in a DR program, which limits grid impacts. DR is a preferred resource for meeting new generation capacity demand in California under the state's Energy Action Plans.[91]

The pilot also offers potential environmental benefits. The pilot aims to increase EV adoption, which potentially increases alternative fuels, improves air quality, and reduces GHG emissions.

4. Electric Transit Bus Make-Ready Program

a) Description

The Electric Transit Bus Make-Ready Program will deploy make-ready infrastructure to serve in-depot and on-route charging equipment for electric commuter buses operating in SCE's service territory. SCE will also provide a rebate to participating customers to cover the cost of the charging equipment and its installation.

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[91] *See* California Energy Commission (CEC) Staff Report, *Implementing California's Loading Order for Electricity Resources*, (July 2005), *available at* http://www.energy.ca.gov/2005publications/CEC-400-2005-043/CEC-400-2005-043.PDF. *See also* State of California, Energy Action Plan, adopted May 8, 2003, *available at* http://www.energy.ca.gov/energy_action_plan/2003-05-08_ACTION_PLAN.PDF.

b) Gaps and Customer Needs

Electric bus technology is maturing with a number of companies offering a range of commercially available vehicles suited to the needs of transit agencies, with standard-based charging systems. However, the costs and complexities associated with electric buses are significant. From siting and deploying charging infrastructure to operational impacts (e.g., downtime for charging, training maintenance technicians), transit agencies must overcome new challenges when they convert to electric fleets.

c) Objective

The objective of the program is to deploy make-ready infrastructure and provide charging station rebates to serve electric transit bus charging and help transit agencies expand the number of electric buses in operation in SCE's service territory.

d) Scope and Cost

(1) Customer Eligibility

The program is open on a first-come, first-served basis to non-residential customers meeting the following requirements. Eligible customers must:

- Qualify as a government transit agency,
- Own or lease the participating site, or be the customer of record associated with the premises meter (likely the property management company or the building owner or tenant), where the charging equipment for the buses would be deployed,
- Provide agreement by the participating site's owner to grant SCE appropriate real property rights and continuous access to the customer participant site infrastructure,
- Acquire at least one new electric or plug-in hybrid bus used to provide transit service to the public,

- Commit to and provide acceptable proof of qualified charging equipment and vehicle purchase (together with actual pricing information) prior to deployment by SCE,
- Agree to take service on an eligible TOU rate, and
- Agree to participate in the pilot for its entire duration, including maintaining the charging equipment in working order and participating in surveys and data collection.

(2) Site Eligibility

Eligible sites must:

- Be located in SCE's service territory,
- Serve as the charging location for qualified vehicles and equipment,
- Install at least one qualified charging station, and
- Include an appropriate location within the site to deploy charging equipment in a cost-effective manner (based on factors such as proximity to transformers, length of trenching, available T&D capacity), as determined by SCE in its sole discretion, but subject to the participating customer's agreement.

(3) Qualified Vendors, Products, and Services

To qualify for the program and the rebate, charging equipment must meet various technical standards and energy efficiency recommendations (e.g., SAE Standards J1772, J2894, J2836, and J28479; Title 20) and be listed by a nationally recognized testing laboratory.

(4) Customer Engagement and Enrollment

SCE will target transit agencies operating in its service territory and solicit them for participation in the program through SCE's Business Customer Division.

(5) Management and Execution

The program will be implemented and executed by SCE's CP&S organization. The Transportation Electrification Program Management organization in SCE's T&D group will manage site evaluation and construction. SCE's Business Customer Division will handle all aspects of customer engagement and management.

(6) Data Collection and Reporting

Upon completion of the program, SCE will issue a close-out report to identify actual costs incurred in deploying in-scope electric infrastructure.

(7) Costs

SCE estimates that the program will cost $4M to complete, including deployment costs to serve up to 20 charge ports and customer rebates to offset the costs of qualified charging equipment and installation.

e) Duration

SCE estimates that the program will take approximately 12 months from launch to complete.

f) Benefits

The program will help increase adoption of electric commuter buses by transit agencies. It will ensure system safety and reliability, as SCE will work closely with participating customers to site, size, and deploy electric infrastructure in accordance with SCE's T&D standards and applicable building and electrical codes, using licensed contractors.

A typical diesel-powered commuter bus emits 2,000 g/mile of CO_2 or roughly 80 metric tons per year plus 0.4 metric tons of NOx and .0064 metric tons of PM from its tailpipe during its lifetime.[92] Each new fully electric bus will reduce GHG and pollutant emissions by 100 percent throughout its lifetime.

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92 Assumes average grams per mile results from Altoona testing of New Flyer and Daimler 40-ft transit buses as published by MJ Bradley, *available at*

(Continued)

5. **Port of Long Beach Rubber Tire Gantry Crane Electrification Project**

a) Description

The Rubber Tire Gantry (RTG) Crane Project will deploy make-ready infrastructure to serve nine cranes at SSA Marine Terminal J at the POLB, currently fueled by diesel engines. SCE proposes to provide the electrical infrastructure to support the electric cranes and the POLB will secure funding from other sources (e.g., SCAQMD and the CEC) for the conversion costs of switching from diesel to electric power.[93] RTG cranes are the second largest source of NOx emissions at the terminal and the technology could have a significant impact on emissions if adopted by other port operators in California. Traditional RTG cranes have electric lift and propulsion drives, with electric energy generated by on-board diesel reciprocating engines. SCE's proposed project will support a customer pilot for a grid-connected electric conversion system that removes the diesel engine and adds power transformation and electronics fed by a motorized electric cable mechanism. The cable connects to a stationary grid connect mechanism which allows the RTG crane to disconnect from the cable when it has to transfer to the maintenance shop. The grid connect mechanism ties to a high voltage utility connection (4,000 volts).

b) Gaps and Customer Needs

The POLB's Clean Air Action plan sets aggressive goals[94] and POLB has expressed interest in accelerating some of the TE technology deployment, including RTG cranes if SCE is authorized to deploy the supporting electric infrastructure.

Continued from the previous page

http://mjbradley.com/sites/dAefault/files/CNG%20Diesel%20Hybrid%20Comparison%20FINAL%2005nov13.pdf.

[93] The SSA Terminal and POLB will fund the electric conversion of the initial nine RTG cranes. Converting each crane to electric power is estimated to cost $600,000 and the total estimated project cost is $5.4 million.

[94] Port of Long Beach and the Port of Los Angeles adopted a Clean Air Action Plan in 2006 and updated it in 2010, *See* San Pedro Bay Ports Clean Air Action Plan 2010 Update, *available at* http://www.cleanairactionplan.org/documents/2010-final-clean-air-action-plan-update.pdf. The Plan is being

(Continued)

c) Objective

The project will support SSA Marine Terminal J at the POLB in accelerating the conversion of the port's current RTG cranes to electric power by deploying the electric infrastructure necessary to serve the new electric RTG cranes.

d) Scope and Cost

SCE proposes to design, own, install, and maintain the electric infrastructure serving the RTGs, including two new substations near the RTG runs to convert the 12 RPM/volt (kV) power. SCE will not design or deploy electric infrastructure until the customer has secured the required funding and ordered electric RTG cranes.

(1) Qualified Vendors, Products, and Services

As SCE is not providing a rebate for the charging equipment in this particular project, SSA Marine Terminal J—not SCE—will qualify vendors, products, and services.

(2) Management and Execution

SCE's Business Customer Division, in close collaboration with the Transportation Electrification Program Management organization in SCE's T&D group, will implement and execute this project.

(3) Reporting

Upon completion of the project, SCE proposes to issue a close-out report to identify actual costs incurred.

(4) Costs

The total estimated costs for this project are $3 million for the deployment of electric infrastructure.

Continued from the previous page

updated in 2017. Draft discussion Document, *available at* http://www.cleanairactionplan.org/wp-content/uploads/2016/11/CAAP-2017-Draft-Discussion-Document-FINAL.pdf.

e) Duration

SCE estimates the project will take approximately 12 months to complete.

f) Benefits

The project accelerates electrification of a key transportation segment in SCE's service territory. If the project is successful, it could lead to electrification of additional RTG cranes at the POLB and by other port operators in California.

This project offers many potential environmental benefits. The ACR recognizes the potential for improvement in this transportation segment, stating, "[m]obile emission sources at ports and truck stops located in the service territories of the large three electric utilities are a concentrated source of emissions that could be well served with targeted programs."[95] There are 64 RTGs at the POLB, a significant source of criteria pollutant emissions.[96] The mean annual NOx emissions from these 64 cranes is 111.3 tons.[97] The combined mean PM10 and PM2.5 emissions is 2.1 tons. The mean carbon dioxide equivalent (CO_{2e}) emissions for the 64 cranes is 11,776 tons.[98]

If this electric technology is adopted at all three major ports in California (Oakland, Los Angeles, and Long Beach), it could reduce 708 tons of NOx, 35 tons of particulate matter, and 24,780 tons of CO2 annually, which would be equivalent to reducing more than five percent of non-road diesel NOx and PM emissions in Los Angeles County.[99] Accelerating TE adoption at POLB improves air quality and reduces GHG emissions for all neighboring communities. These communities immediately surrounding the POLB are considered disadvantaged communities as defined by CalEPA.[100]

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[95] ACR at p. 23.

[96] POLB, Air Emissions Inventory 2002-2015, *available at* www.polb.com/emissions.

[97] *Id*.

[98] *Id*.

[99] U.S. Environmental Protection Agency, National Emissions Inventory 2014, non-road equipment diesel in Los Angeles County.

[100] *See* CalEniroScreen map, *available at* http://oehha.maps.arcgis.com/apps/webappviewer/index.html?id=4560cfbce7c745c299b2d0cbb07044f5.

Finally, the project carries limited risks of long-term stranded assets, as SCE will not break ground on the project until the customer has ordered the RTG cranes and committed to operate them for a minimum of ten years from completion of infrastructure.

6. POLB ITS Terminal Yard Tractor Project

a) Description

The yard tractor project will deploy make-ready infrastructure to serve the International Transportation Service (ITS) Terminal's fleet of yard tractors, currently fueled by diesel engines.

b) Gaps and Customer Needs

The POLB Clean Air Action plan sets aggressive goals,[101] and POLB has expressed interest in accelerating some of the TE technology deployment, including yard tractors, which move intermodal containers around the facility, if SCE is authorized to deploy the supporting electric infrastructure. The ITS Terminal currently has a fleet of 120 diesel-powered yard tractors at the POLB that it would like to convert to electric power. The ITS Terminal is attempting to secure funding from SCAQMD for 68 yard tractors, but not for the supporting electric infrastructure. Other port terminal operators in California may follow.

c) Objective

This project's objective is to deploy the electric infrastructure necessary to serve charging stations for new electric yard tractors. The project will support the ITS Terminal's evaluation of electric yard tractors and help accelerate their deployment.

d) Scope and Cost

The ITS Terminal has two areas where yard tractors are parked; the main area accommodates 100 tractors and a second, smaller area accommodates 24 tractors. ITS Management has

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[101] POLB and the Port of Los Angeles adopted a Clean Air Action Plan in 2006 and updated it in 2010. *See* http://www.cleanairactionplan.org/documents/2010-final-clean-air-action-plan-update.pdf. The Plan is being updated in 2017. For a discussion draft, see http://www.cleanairactionplan.org/wp-content/uploads/2016/11/CAAP-2017-Draft-Discussion-Document-FINAL.pdf.

selected this second area for the pilot. SCE will design, deploy, own, and maintain the electric infrastructure serving the charging stations for the ITS Terminal's electric tractors, including 24 charging points on the west side of Pier G with service from Pier Substation.

To accommodate the estimated load for all 24 charging points, SCE needs to upgrade its distribution infrastructure, including additional pad mounted switches, capacitor bank, and transformers.

1) *Qualified Vendors, Products, and Services:* SCE will not establish technical requirements on charging equipment as SCE will not provide a rebate to cover its costs.

2) *Management and Execution:* The project will be implemented and executed by SCE's Business Customer Division, in close collaboration with the Transportation Electrification Program Management organization in SCE's T&D group and SCE's Advanced Technology Organization.

3) *Reporting:* Upon completion of the project, SCE will issue a close-out report to identify actual costs incurred.

4) *Costs:* The total estimated costs for this project are $0.5 million for the deployment of the infrastructure.

e) Duration

SCE estimates that designing and deploying the infrastructure will require about 12 months.

f) Benefits

The project accelerates electrification of a key transportation segment in SCE's service territory, with potential for additional future conversion of yard tractors.

On average, the yard tractors annually produce five pounds of particulate matter and 341 pounds of NOx). Converting yard tractors to an electric drivetrain[102] will improve air quality

[102] The group of components that deliver power to the driving wheels.

and reduce GHG emissions for all neighboring communities, in particular for disadvantaged communities, as they are the most severely impacted by current levels of pollution and GHG emissions.

7. Priority Review Projects Cost Summary

Table III-2 below summarizes the costs for the projects proposed for Commission priority review.

Table III-2
Priority Review Projects Total Costs
(Millions, 2016 $, not loaded)

Priority Review Project	Estimated Cost
Residential Make-Ready	$4.00
EV Drive Rideshare Reward	$4.00
Urban DCFC Cluster	$3.98
Make Ready & Rebate for Transit Buses	$3.98
POLB, Rubber Tire Gantry Crane Electrification	$3.04
POLB, ITS Terminal Yard Tractor	$0.45
Priority Review Total	**$19.45**

The six proposed projects are an innovative response to the utility's new TE role. These efforts help inform future TE programs to further transform TE markets. Moreover, SCE's proposed new commercial EV rate incents customers to adopt these TE technologies and charge at times that avoid capacity constraints. These projects meet the requirements of Commission priority review by being under $4 million, 12 months or less in duration, and noncontroversial.

B. Standard Review Programs

SCE proposes a Medium- and Heavy-Duty Vehicle Charging Infrastructure Program and a new commercial EV rate design for standard Commission review. The infrastructure program targets key transportation segments, including good movements and mass transit, through the electrification of medium-duty and heavy-duty vehicles and non-road equipment. The new commercial EV rate structure will use up-to-date time-of-use periods and have a five-year introductory period during which SCE will not assess monthly demand charges; rather, customers' bill will consist primarily of volumetric energy charges. Demand charges will be phased in over a five-year period. The proposed rates and infrastructure program support the goals of SB 350 by accelerating widespread TE.

1. Medium- and Heavy-Duty Vehicle Charging Infrastructure Program

a) Description

The Medium- and Heavy-Duty Vehicle Charging Infrastructure Program follows the model developed for the Charge Ready pilot program, where SCE deploys, owns, and maintains the electric infrastructure needed to serve charging equipment for in-scope vehicles[103] (up to and including the make-ready stubs). Through this program, SCE plans to install a separately-metered circuit together with utility transformer upgrades, service drop, panel, trenching, wiring, conduit, and step-down transformer, as needed. SCE also plans to provide a rebate to cover the costs of charging equipment that meets SCE's requirements and its installation. SCE also plans to follow the base cost methodology developed for the Charge Ready Pilot Program to set the rebate amounts.[104] Participating customers will be responsible for procuring charging station equipment and installation (and paying any costs in excess of the rebate amount) and for maintaining the equipment in working order for the duration of the program.

b) Gaps and Customer Needs

The demand (kW) needed to charge or power medium- and heavy-duty vehicles is significantly higher than for light-duty vehicles. Charging equipment in the non-light-duty segment needs to be able to deliver electricity up to 75 times the rate of a normal light-duty vehicle.[105]

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[103] *See* Appendix C for eligible vehicles.

[104] SCE will establish an RFI process to qualify vendors and charging equipment that meet SCE's requirements. Vendors will be required to provide pricing information for each of the models they submit. SCE may supplement the pricing information through additional market research. SCE will identify various charging equipment categories to determine the base cost. Among qualified equipment, the model that provides the best value within each charging equipment category will set the base cost for the category.

[105] For example, BYD Auto Co., Ltd. (BYD) yard trucks charge at 200 kW, while many light-duty EVs charge at home at 1.4 kW.

Consequently, the cost of the electric infrastructure to serve the charging equipment (or propulsion systems) is more expensive. According to a recent CALSTART survey of medium-duty and heavy-duty fleet owners,[106] upfront costs are the primary barrier preventing fleets from adopting electric technologies. Similarly, ICF International and E3 also found that the cost and complexity of charging infrastructure is a significant barrier in the non-light duty EV markets that utilities could address.[107] High demand from large batteries and time-sensitive duty cycles also create multiple complexities for determining charging needs, siting, and connecting to the electrical system. A recent report by Union of Concerned Scientists and Greenlining Institute found large potential for the emerging electric bus and truck industry.[108] SCE's proposal will incent customers who are interested in adopting electric vehicle technology but may not otherwise electrify, absent this funding.

c) Objective

The program supports the acceleration of widespread TE for goods movement and mass transit by mitigating the cost and complexity of deploying charging equipment for medium- and heavy-duty vehicles for participating customers.

Providing the charging infrastructure reduces two major barriers to TE adoption in non-light-duty market segments—the burden of upfront costs, and the complexity of installing charging infrastructure. Overcoming these barriers incents adoption of TE technologies, eliminates the

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[106] Because medium- and heavy-duty vehicles are contained as fleets, charging infrastructure is an upfront cost that is required before vehicles can operate. Participants in CALSTART's Commercial Electric Vehicle Working Group (CEVWG) described charging difficulties as a key barrier to expanded adoption of electric vehicle technologies. *See* Calstart's Electric Truck and Bus Grid Integration Report, Sept 2015, *available at* http://www.calstart.org/Libraries/Publications/Electric_Truck_Bus_Grid_Integration_Opportunities_Challenges_Recommendations.sflb.ashx.

[107] *See* ICF International and E3's TEA Study Phase 3A (Jan. 2016), pp. 44-45, *available at* http://www.caletc.com/wp-content/uploads/2016/08/California-Transportation-Electrification-Assessment-Phase-3-Part-A-1.pdf.

[108] This report found a potential technology and business case for incenting electric buses and trucks as well as large environmental and job benefits especially in low-income and disadvantaged communities. *See Delivering Opportunity: How Electric Buses and Trucks Can Create Jobs and Improve Public Health Benefits* (Oct. 2016), prepared by Union of Concerned Scientists and Greenlining Institute, *available at* http://www.ucsusa.org/clean-vehicles/electric-vehicles/freight-electrification#.WHpg0SbTmpo.

use of fossil fuels, and decreases emissions of air pollutants that directly affect the communities located along goods movement and mass transit routes.

By covering the cost of electrical infrastructure and providing a rebate on the charging equipment and its installation[109] for participating customers, the program aims to remove a significant barrier to widespread deployment of charging equipment in SCE's service territory. SCE also plans to work closely with participating customers to inform their decision-making and guide them throughout the complex deployment process while meeting customer operational needs and managing potential grid impacts.

d) Program Scope and Cost

(1) Customer Eligibility

Eligible customers must:

- Qualify as a non-residential customer,
- Own or lease the participating site, or be the customer of record associated with the premises meter (likely the property management company or the building owner or tenant), where the charging equipment would be deployed,
- Provide agreement by the participating site’s owner to grant SCE appropriate real property rights and continuous access to the customer participant site infrastructure,
- Agree to participate in SCE surveys and data collection,
- Commit to and provide acceptable proof of qualified charging station purchase (together with actual pricing information) prior to deployment by SCE,

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[109] Customers will be responsible for all operational costs relating to the charging equipment, including maintenance and repair, and the cost of energy. In addition, customers will be responsible for the costs of acquiring and maintaining eligible electric vehicles.

- Agree to take service on an eligible TOU rate, and
- Agree to participate in the pilot for five years, including maintaining the charging equipment in working order.

(1) Site Eligibility

Eligible sites must:

- Be located in SCE's service territory,
- Serve as the charging location for in-scope vehicles and equipment,[110] and
- Include an appropriate location within the site to deploy charging equipment in a cost-effective manner (based on factors such as proximity to transformers, length of trenching, and available T&D capacity), as determined by SCE in its sole discretion, but subject to the participating customer's agreement.

(2) Qualified Vendors, Products and Services

To qualify for the program and the rebate, charging equipment must meet various technical standards and energy efficiency recommendations (e.g., SAE Standards J1772, J2894, J2836, and J28479; Title 20) and be listed by a nationally recognized testing laboratory. For those segments where no charging equipment meets established standards, SCE plans to work with customers to evaluate the equipment that meets the customer's needs. If SCE approves the proposed equipment, the customer would be authorized to participate in the program, but would be solely responsible for the cost of the charging equipment and its installation.

[110] Examples of eligible vehicles include Class 2-8 trucks (e.g., step vans, refuse trucks, drayage trucks, delivery vehicles), non-road cargo handling equipment (e.g., forklifts, yard tractors, top loaders, side pickers), transport refrigeration units (e.g., semi and bobtail trailers), and buses (e.g., shuttle, transit, school). *See* Appendix C for a more detailed description of electric vehicle technologies eligible for the program.

(3) Customer Engagement and Enrollment

SCE aims to target non-residential customers that may meet the program's requirements and solicit them for participation in the program through SCE's Business Customer Division. Non-solicited customers may also apply to the program, which SCE plans to promote on its website.

(4) Management and Execution

The program will be implemented and executed by SCE's CP&S organization. SCE plans to form a Project Management Office (PMO) to execute the program. The PMO would be responsible for planning the implementation of the program, working across SCE functions and coordinating execution among vendors and contractors hired for the program. In particular, the Transportation Electrification Program Management organization in SCE's T&D group would manage site evaluation and construction. SCE's Business Customer Division would handle all aspects of customer engagement and management. The PMO would ensure that the program is executed on time and on budget and leverage project management best practices, including the active maintenance and review of issue logs, risk logs, and action item logs. The PMO would also prepare regular reports and provide status updates on the program's implementation. These reports would identify various milestones and metrics, including accomplishments during the relevant reporting period, deployment progress, and financials.

(5) Advisory Board

As with the Charge Ready Pilot Program, SCE intends to form an advisory board with customers and industry stakeholders to provide input, guidance, and suggestions on the execution and improvement of the program. Establishing this type of forum has been very valuable to support SCE's programs by allowing board members to provide useful feedback, helping SCE improve the programs' processes, and promoting transparency about the programs' implementation.

(6) Data Collection and Reporting

SCE proposes to provide quarterly status reports to the Commission's Energy Division and other stakeholders. The proposed reports will evaluate: (i) customer interest and satisfaction; (ii) processes such as procuring deployment services, time, and costs; and (iii) post-deployment impacts. The status reports will also include updates about progress, achievements, and lessons learned executing the program. The status reports may also include recommendations from the Advisory Board to improve the program. SCE further proposes to include program information in its annual report.

(7) Costs

SCE's cost estimate relies on the TE adoption forecast (See Appendix D for details). Actual costs will vary based on market development.

- Customer-side costs - SCE developed cost estimates in consultation with internal subject matter experts, external electrical contractors, and using published costs from EPRI to estimate the customer-side costs. These costs include customer planning, engineering, construction (including trenching) labor, and materials. Since each customer site is unique with many factors influencing costs, SCE includes a 35 percent contingency in its cost estimates.
- Rebate - The proposed rebate amounts cover 100 percent of the base cost of the charging equipment and its installation. Charging equipment in each of these vehicle segments is at different stages of market maturity and standardization. SCE is coordinating with EPRI to evaluate vendors and charging systems.
- Other Capitalized Costs - Other capitalized costs include easement-related expenses, charging equipment testing to verify that charging stations meet requirements of the program, and all capitalized labor.
- Labor – The forecast labor associated with the program will ramp up to roughly 7.2 new full-time equivalent employees or

contractors in the Business Customer and CP&S divisions. An additional 21.7 new full-time equivalent employees or contractors need to be added to the Transportation Electrification Project Management organization to facilitate the design and construction of each participating customer site.

- Other non-labor - Other non-labor operation and maintenance (O&M) expenses include the development of back-office software to manage the program, preparation of quarterly status reports, and maintenance of the electric infrastructure deployed through the program on the customer-side of the meter.

Table III-3
Annual Program Costs
(Thousands, 2016 $, not loaded)

O&M	Yr1	Yr2	Yr3	Yr4	Yr5	**Total**
Program Labor	884	816	850	986	1,062	**4,598**
Other non-Labor	4,334	2,694	2,842	3,431	4,227	**17,527**
Total O&M	**5,218**	**3,510**	**3,692**	**4,417**	**5,289**	**22,125**
Capital	Yr1	Yr2	Yr3	Yr4	Yr5	**Total**
Utility Costs	31,094	36,148	39,973	48,882	60,974	**217,071**
Site costs	34,372	40,087	43,226	52,650	65,414	**235,749**
Capitalized Labor	1,796	1,656	1,725	2,001	2,156	**9,334**
Rebate	10,815	12,410	12,726	15,161	18,432	**69,544**
Total Capital	**78,076**	**90,301**	**97,650**	**118,695**	**146,976**	**531,698**
						$ 553,823

(8) Duration

Due to lead-time implementing the program, enrolling customers, and deploying infrastructure, SCE is requesting approval for a five-year program. A five-year program provides market players and customers with the visibility needed to manage the significant expense of vehicle acquisition into their budgets. The program also allows customers who purchase vehicles that require long-lead manufacture times to participate in the program. For example, transit agencies phase in their vehicle purchases over several years, because of manufacturing and financial constraints.

(9) Program Benefits

The program supports the acceleration of widespread TE by deploying critical electric infrastructure for government, commercial, and industrial customers, providing incentives to adopt TE technologies within the proposed program duration rather than in a more distant future. With the proposed scale, the program will support innovation and the TE market in general, while the utility remains neutral to market and technology developments.

SCE designed the program to provide benefits for the customers and communities we serve, as discussed in more detail in Section IV of this testimony. These include:

- *Improved safety* – SCE's program will follow standard T&D practices and procedures and will be performed safely, and to code, by SCE employees or by certified and licensed contractors.
- *Benefits accrue to disadvantaged communities* – Warehouses, distribution facilities, manufacturing sites and goods movement corridors in SCE's territory are located within or adjacent to disadvantaged communities.[111] Therefore, targeting these sites and removing the pollution from the gasoline- and diesel-powered vehicles serving these sites will primarily benefit the local communities.
- *Innovation* – SCE's proposed approach supports the Commission's interest in innovation[112] and enables numerous third-party charging equipment suppliers to provide qualified charging equipment and services to participating customers. This approach will encourage the charging market to innovate hardware, propose new business

[111] *See* Figure II-4.

[112] D.16-12-065, Finding of Fact (FOF) 27 at p. 75.

- models and allow SCE to collect valuable data around customer usage, needs, and load requirements.
- *Environmental and other air quality benefits* – Increased TE adoption and fueling from the grid will provide additional benefits to the entire Southern California region by reducing GHGs and improving air quality. Based on SCE's vehicle forecast, SCE estimates that by 2030 a net 19.2 million metric tons of GHG could be reduced statewide from the transportation sector through electric conversion.[113] In addition to GHG reductions, electric heavy-duty Class 8 trucks are 83 percent cleaner than the cleanest natural gas engines.[114] Achieving the forecasted adoption of all of medium-duty, heavy-duty, and non-road vehicles could reduce NOx emission by a cumulative 6.7 tons per day.

2. New EV Rate Design Proposal

In this chapter, SCE proposes a short-, intermediate-, and long-term solution for commercial EV rates to promote transportation electrification in California. Specifically, SCE proposes to establish the New EV Rates, which will have the same general structure but will apply to different sizes of customers for the exclusive purpose of charging EVs.[115] The proposed rate schedules will use

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[113] *See* Appendix D.

[114] Compares the 0.02 grams per brake horsepower-hour (g/bhp-hr) Low-NOx engine with the modeled 0.004593 grams per kilowatt hour (g/kWh) of NOx from electric generation in the South Coast Air Basin using SCE's production simulation model. At 1.341 horsepower per kWh, emissions from power plants resulting from EV charging would emit an equivalent of 0.003425 g/bhp-hr.

[115] SCE currently offers two commercial EV rates that SCE does not seek to modify here – Schedule TOU-EV-3, *available at* https://www.sce.com/NR/sc3/tm2/pdf/ce116-12.pdf and Schedule TOU-EV-4, *available at* https://www.sce.com/NR/sc3/tm2/pdf/ce141-12.pdf. SCE has a pending advice letter (Advice Letter 3402-E, filed May 5, 2016, *available at* https://www.sce.com/NR/sc3/tm2/pdf/3402-E.pdf) proposing to establish a Schedule TOU-EV-6 for customers with demand of greater than 500 kW. The shorthand Schedule names used in this testimony – EV-7, EV-8, and EV-9 – will ultimately be modified to conform to the nomenclature of SCE's other TOU-EV rate schedules.

up-to-date, TOU periods that will offer more accurate price signals to reflect system grid conditions, and these TOU periods will be set consistent with the Commission's recent guidance in this area. The New EV Rates will have a five-year introductory period after implementation during which SCE will not assess monthly demand charges; rather, customers' bills will consist primarily of volumetric energy charges. After the five-year introductory period, SCE will introduce demand charges and phase them in over a five-year intermediate period. Then, at the end of the tenth year, the rate schedules will reflect stable demand charges that will be lower than what new EV customers would pay on their otherwise applicable (non-EV) commercial rates today.

The benefits of the New EV Rates include (a) reduced distribution-related demand charges relative to the current EV and non-EV rates; (b) attractive volumetric rates during daytime super-off-peak periods and overnight; and (c) lower summer season charges to mitigate seasonal bill volatility.

Section III.B.2.a) describes who will be eligible for the advantageous rates, how the TOU periods and other components of the rates will be designed, and the way in which the rate structures will change over a 10-year period as the EV market is anticipated to grow. Section III.B.2.b) explains why the rate designs described in Section III.B.2.a) are reasonable. Section III.B.2.c) discusses how the collective projected incremental load of customers to be served on the new EV rate schedules will make a positive "contribution to margin," a standard approach previously used in the context of Economic Development Rates (EDRs), to provide a rate incentive to customers to increase electric load while ensuring that nonparticipating customers also benefit.

a) <u>Description of the New EV Rates</u>

The New EV Rates, like all optional rates that SCE offers, are designed on a "revenue-neutral" basis, meaning that the optional rates are designed to recover the same amount of total revenues as the "base" or "default" rates would collect. (In this context, the "base" or "default" rates for these EV customers are the general service rates.) To design the optional rates, SCE assumes that all customers in a given class[116] take service on each optional rate and then SCE establishes rate levels to recover the total assigned revenue requirement for the class. In this sense, customers availing themselves of optional rates are not receiving a "discount" relative to what is "owed" to the utility; rather, they are choosing an optional rate that results in a lower bill because of the customers' specific load shape and usage patterns.

(1) Eligibility

The New EV Rates will be available to commercial customers exclusively for the purpose of charging electric vehicles, and the demand thresholds for eligibility on each new rate schedule will be as follows:

TOU-EV-7: Monthly maximum demand of 20 kW and under.

TOU-EV-8: Monthly maximum demand of 21 kW to 500 kW.

TOU-EV-9: Monthly maximum demand above 500 kW.

SCE proposes to modify its Rule 1 definition of electric vehicles to be consistent with the broader applicability set forth in the ACR inviting the new rate proposals.[117] While the rates SCE proposes are primarily intended to promote new EV adoption, they should also be available to existing EV customers to avoid any risk of providing an unintended competitive advantage to a specific entity or technology. The new rates will be available to customers with all types of electric vehicles, vessels, trains, boats, or other equipment (*e.g.*, aircraft, forklifts, port equipment) that are

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116 By "class," SCE refers to small commercial, medium and large commercial, and industrial customers, for example.

117 ACR, p. 21: "[T]he utilities should modify the definition of eligible types of customer loads for existing electric vehicle-specific rates to comport with the definition [from SB 350] of TE." The statutory definition of "transportation electrification," codified in Public Utilities Code §237.5, is "the use of electricity from external sources of electrical power, including the electrical grid, for all or part of vehicles, vessels, trains, boats, or other equipment that are mobile sources of air pollution and greenhouse gases and the related programs and charging and propulsion infrastructure investments to enable and encourage this use of electricity."

mobile sources of air pollution and GHG emissions.[118] Specific examples include transit buses, drayage, vocational, short-haul fleets, port applications, ground equipment supporting goods movement, ground support equipment at airports, and long-haul truck stop applications to minimize the idling of diesel engines.

(2) Term of the New EV Rates

SCE does not propose a specific commencement date for the New EV Rates. When the Commission issues a decision approving the New EV Rates, SCE will assess the time it will take to market the new rates to potential customers through customized rate comparisons and projected bill savings to facilitate informed decision-making with a goal to begin offering the rates within a reasonable time after the Commission's decision. The five-year introductory "demand charge-free" period mentioned above will commence *at the same time for all eligible customers*. That is, individual customers will not have customized ten-year rate periods. For example, if the New EV Rates open on January 1, 2018, a customer taking service on one of the new rates in the summer of 2020 will have approximately 2.5 years left before it must begin paying demand charges.[119] In the intermediate five-year period, the T&D demand charges will increase year over year as set forth in Section III.B.2.a)(6)(ii), below. In the post-ten-year period, the demand charges will stabilize to reflect a more mature EV market but will remain lower than customers' demand charges on otherwise applicable general service rates.

(3) TOU Periods

Figure III-7, below, depicts SCE's proposed TOU periods for the New EV Rates, which feature a winter super-off-peak period of 8:00 a.m. to 4:00 p.m. every day, and a summer

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[118] EV customers will also be eligible to take service on SCE's Real Time Pricing (RTP) rate intended for customers with flexible loads that can take advantage of hourly pricing signals, as proposed in SCE's 2016 RDW application (A.16-09-003).

[119] This treatment reflects SCE's desire to avoid costly and confusing grandfathering or vintaging rate treatments for individual EV customers.

off-peak period for all hours except from 4:00 p.m. to 9:00 p.m. These new time periods will encourage charging during longer periods of time when system demands and energy prices are lower.

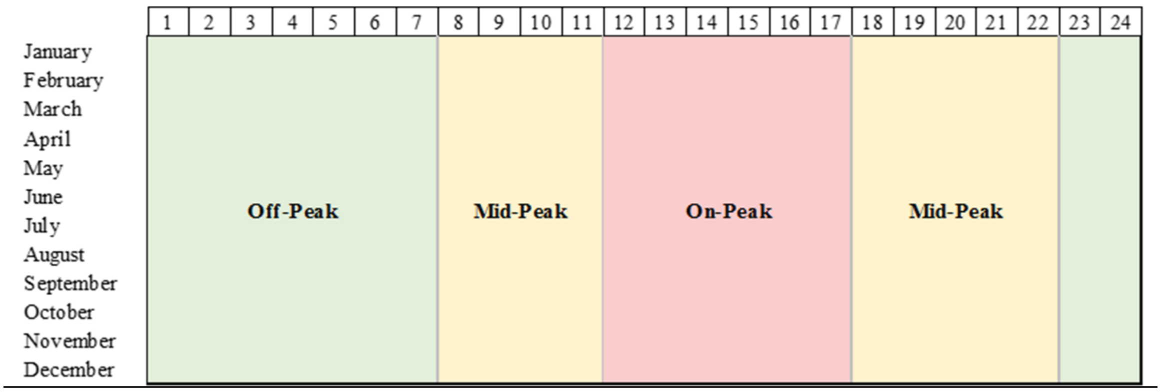
Figure III-7
Proposed TOU Weekday Periods for New V Rates (Hour Beginning)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January February March April May	**Off-Peak**							**Super-Off-Peak**								**Mid-Peak**					**Off-Peak**			
June July August September	**Off-Peak**															**On-Peak**					**Off-Peak**			
October November December	**Off-Peak**							**Super-Off-Peak**								**Mid-Peak**					**Off-Peak**			

The TOU periods proposed above are consistent with what SCE has proposed for its *default* (as opposed to optional) commercial rate schedules in its pending rate design window (RDW) application, A.16-09-003.[120] Figure III-8, below, depicts SCE's current TOU periods.

[120] Although SCE aims to have its RDW application resolved by August of 2017, its TOU period proposals for the New EV Rates are not contingent on prior approval of the RDW proposals (and in that sense can be viewed as a "stand alone" proposal). To the extent the litigated result of that proceeding differs from the TOU periods proposed here, SCE reserves the right to seek consistent treatment in the appropriate forum, but it does not make its proposal here contingent on a specific deadline to be met in the RDW application proceeding.

Figure III-8
Current Weekday TOU Periods for Existing EV Rate Schedules
(Hour Beginning)



The TOU period proposals are reasonable for reasons discussed in Section III.B.2.b), below, and in Appendix E (page E-35).

(4) <u>Customer (Fixed) Charges</u>

The New EV Rates will have monthly customer charges that are equal to the customer charges in the EV customers' then-current otherwise applicable tariffs.

(5) <u>Energy Rates</u>

For the introductory five-year period, SCE proposes that the New EV Rates be structured to recover all generation- and distribution-related costs through seasonal TOU Energy Charges on a cents-per-kWh basis.[121] (Transmission-related costs will be recovered through non-seasonal and non-TOU Energy Charges on a cent-per-kWh basis.) Every year, when SCE implements its Energy Resource Recovery Account (ERRA)-related rate changes (generally on January 1 of a given year), it will update the TOU Energy Charges to reflect changes in SCE's revenue requirements and sales forecasts. For the intermediate period (years 6 through 10), the energy rates will be reduced—all else held consistent—as demand charges increase annually as described in the next

[121] Costs for Public Purpose Programs, Nuclear Decommissioning, New System Generation, Department of Water Resources Bonds, and the Public Utilities Commission Reimbursement Fee will continue to be collected on a non-time-differentiated cent-per-kWh basis, or as amended in future proceedings.

section. The New EV Rates will be subject to updates made to TOU periods as long as the New EV rates remain open to customers.

(6) Demand Charges

(a) Overview of Demand Charge Terminology

Demand charges are used to recover the capacity-related portion of SCE's delivery and generation costs. For most commercial and industrial customers, SCE's generation capacity-related costs are collected through a time-related demand (TRD) charge that is billed based on the customer's maximum demand during the on- and mid-peak periods in a given month. However, SCE's existing EV Rates (TOU-EV-3 and TOU-EV-4) collect these TRD charges through time-differentiated volumetric energy charges. SCE's New EV Rates maintain this approach of collecting generation capacity-related costs. For most commercial and industrial customers, distribution capacity-related and transmission capacity-related costs are collected through a facilities-related demand (FRD) charge that is *not* differentiated by TOU period or by season and is billed based on the customer's maximum demand at any point in a given month. With this overview in mind, the next section describes how FRD charges will be treated in the New EV Rates.[122]

(b) Demand Charges for the New EV Rates

(i) Introductory Period (Years 1 through 5)

For the introductory five-year period, the New EV Rates will not have any demand charges. Revenues will be collected largely via TOU volumetric energy charges with some contribution from customer charges.

(ii) Intermediate Period (Years 6 through 10)

In years 6 through 10, SCE proposes to initiate and then increase the FRD charge to collect distribution capacity-related costs by 10 percent each year until the beginning of year 11, at which time the distribution component of the FRD will collect a maximum of

[122] SCE plans to propose changes to the FRD charges of the general service rates in the future to be consistent with this proposed treatment.

60 percent of all distribution capacity costs. The remaining 40 percent of distribution capacity costs will be collected via TOU energy charges. SCE also proposes to initiate in year 6 an FRD charge to collect transmission capacity costs that would increase by about 17 percent each year until the beginning of year 11, at which time the transmission component of the FRD would collect 100 percent of transmission capacity costs. As both of these FRD Charges increase, it will result in commensurate *decreases* to the T&D Energy rates. The New EV Rates will not have any TRD Charges (conventionally used to collect generation capacity charges in the general service otherwise applicable tariffs (OATs)).

(iii) Long-Term Rate Structure (Year 11 and Beyond)

The long-term rate structure for the New EV Rates (*i.e.*, after the tenth year) will continue to have up-to-date TOU periods, TOU volumetric energy rates, an FRD charge that collects 60 percent of all distribution capacity costs (with the balance of distribution capacity costs recovered in TOU volumetric energy rates) and 100 percent of all transmission capacity costs, and no TRD Charges.

(c) Treatment of Demand Charges For Multiple-Meter Premises

SCE's current commercial EV rate schedules, TOU-EV-3 and TOU-EV-4, have a feature that prevents customers from paying separate demand charges for both the EV load and the separately metered non-EV load on the same premises.[123] Thus, TOU-EV-3 and TOU-EV-4 customers with a "host" (non-EV) account on the same premises that is served on a demand-metered general service account will not pay the EV account's FRD Charge in a given month if the customer's maximum demand on the host account is higher than the maximum demand on the EV account. (If the converse is true, *i.e.*, the EV account's maximum demand is higher than the host account's maximum demand, the EV account's FRD Charge would be calculated as the difference between the EV maximum demand and the host account maximum demand only.)

[123] SCE Advice Letter 1238-E, "Establishment of Schedule TOU-EV-4, General Service TOU, EV Charging, Demand Metered," filed June 5, 1997, *available at* https://www.sce.com/NR/sc3/tm2/pdf/1238-E.pdf. This provision was later extended to Schedule TOU-EV-3, Option B, in SCE's 2013 RDW Application, A.13-12-015.

SCE does not propose to make this feature available to customers served on the New EV Rates, as this feature was initially introduced as an additional incentive to encourage customers to be early adopters of EV technology in the 1990s. At the time this advantageous feature was established, EV charging was expected to occur in the off-peak hours and thus demands would not be coincident with the General Service account load located on the same premise. If EV charging occurred during off-peak hours, it was appropriate to provide this FRD discount treatment to help incent adoption. However, developments over the last decade have changed charging behavior drastically. The former assumption that EV users charge off peak, especially for C&I customers, is no longer true. SCE has observed a steady increase in EV charging in periods where General Service customers most frequently peak. Additionally, the New EV Rates' off- and super-off-peak periods further raise the likelihood of EV charging occurring coincidentally with General Service loads. This can mean higher peak demands placed on the system, and can result in the need for incremental capital to serve these new loads. Allowing the demand charge forgiveness to continue for the proposed New EV Rates would mean EV customers would potentially avoid paying their fair share for SCE's distribution system, and that can create an unacceptable cost-shift to non-EV customers.[124]

(7) Summary of Rate Changes Over The Introductory and Intermediate Periods and the Long-Term Period

Figure III-9, below, provides a comparison of energy charges for (1) current Schedule TOU-EV-4,[125] and (2) the New TOU-EV-8 Rate (for customers with monthly demands of 21-500 kW) over the introductory (3) intermediate, and (4) long-term periods. The change in the energy rates for the New EV-8 Rate reflects the changes over time in the FRD charges. Figure III-9 illustrates the material changes made to the current TOU-EV-4 tariff in terms of the timing of TOU on-peak periods compared to the New TOU-EV-8 Rate, by simplifying the number of periods to only two

[124] For customers on Schedules TOU-EV-3 and TOU-EV-4 who are currently enjoying this dual-meter/single-demand-charge feature, SCE may, in the appropriate proceeding, choose to grandfather this rate feature for only these customers when and if they take service on the New EV Rates.

[125] The New TOU-EV-8 is comparable in size to the currently existing Schedule TOU-EV-4.

in the summer and by adding an SOP period in the winter. It also shows that as FRD charges are introduced and increase, the volumetric TOU rates decrease. Also, note that the color codes used here are defined in Figure III-7 above.

Figure III-9
Comparison of Energy Charge Changes As FRD Increases (Hours Beginning)

Currently Effective TOU-EV-4, Weekdays ($15/kW FRD Charge)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January February March April May	**7 ¢/kWh**							**8 ¢/kWh**				**9 ¢/kWh**						**8 ¢/kWh**						
June July August September	**6 ¢/kWh**							**9 ¢/kWh**				**25 ¢/kWh**						**9 ¢/kWh**						
October November December	**7 ¢/kWh**							**8 ¢/kWh**				**9 ¢/kWh**						**8 ¢/kWh**						

Schedule TOU-EV-8 Introductory Period, Years 1-5 ($0/kW FRD Charge)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January February March April May	**13 ¢/kWh**							**8 ¢/kWh**								**26 ¢/kWh**					**13 ¢/kWh**			
June July August September	**13 ¢/kWh**															**37 ¢/kWh**					**13 ¢/kWh**			
October November December	**13 ¢/kWh**							**8 ¢/kWh**								**26 ¢/kWh**					**13 ¢/kWh**			

Schedule TOU-EV-8 Intermediate Period, Year 7 ($3/kW FRD Charge)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January February March April May	**12 ¢/kWh**							**7 ¢/kWh**								**24 ¢/kWh**					**12 ¢/kWh**			
June July August September	**12 ¢/kWh**															**33 ¢/kWh**					**12 ¢/kWh**			
October November December	**12 ¢/kWh**							**7 ¢/kWh**								**24 ¢/kWh**					**12 ¢/kWh**			

Schedule TOU-EV-8 Long-Term Period, Year 11 ($9/kW FRD Charge)

	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January February March April May	**11 ¢/kWh**							**6 ¢/kWh**								**21 ¢/kWh**					**11 ¢/kWh**			
June July August September	**11 ¢/kWh**															**24 ¢/kWh**					**11 ¢/kWh**			
October November December	**11 ¢/kWh**							**6 ¢/kWh**								**21 ¢/kWh**					**11 ¢/kWh**			

b) SCE's EV Rate Structure Proposals Are Reasonable

The ACR noted that "[a]t the workshops and in their comments, some of the parties indicated that rate design tools, such as demand charges, may result in a disincentive to use electricity as transportation fuel."[126] This is particularly true for customers with low overall energy usage but periodic spikes in demand. The ACR invited proposals to change IOU rate structures, "including demand charges" while keeping in mind that "simply shifting costs to other ratepayer classes does not comport with cost causation rate design principles and may not be a viable solution."[127] SCE's New EV Rates strike the appropriate balance for reasons explained in this section and in Section C, below.

(1) SCE's Currently Effective EV Rate Schedules Are Outdated

The current EV rates applicable to medium- and heavy-duty loads are similar to the standard General Service rates (TOU-GS-2 specifically), which consist of demand, energy, and customer charges, except that generation energy and capacity costs are recovered entirely through TOU volumetric energy charges with no TRD charges. However, the time-of-use periods for the current EV rates reflect the long-standing, but now outdated, summer weekday on-peak period from noon to 6:00 p.m.

Historically, the challenge with EV pricing design has been maintaining the principle of cost causation (*i.e.*, assigning the appropriate costs to the customers who cause the utility to incur those costs), while sending a clear pricing signal that encourages transportation electrification and charging behaviors that are best for the electric grid. The existing EV tariffs generally confine the lowest-cost charging periods to late-night hours, but such rate designs can be costly for certain electric transportation technologies that must be charged during more the expensive daytime periods. As discussed further in Section B.3, below, these challenges can be somewhat alleviated by using updated

[126] ACR, p. 20.

[127] *Id*.

TOU periods for new EV load, consistent with what as SCE has proposed in its pending RDW application seeking a change to the default TOU periods for all commercial customers.[128]

(2) Lower Demand Charges Will Attract EV Load

The proposed EV rates complement the programs proposed in this Application by addressing a key barrier to entry for many customers considering EV technologies. Recovering nearly all costs from EV customers through volumetric rates for a five-year introductory period is an effective way to accelerate transportation electrification because this relieves early EV adopters from having to pay an FRD charge, which has historically been seen as a barrier to EV adoption. Gradually phasing in FRD charges (and removing the TRD charges that normally are assessed on general service accounts) will allow customers to gain knowledge and experience regarding demand charges and load management. The two-step approach to the rate (no demand charges, then increasing step-ups over five years) balances the need for a favorable charging rate with the goal of minimizing impacts to non-participating customers. The gradual phase-in is also appropriate given that SCE expects EV customers' load factors to improve over time.

The Commission recognized the benefits of temporarily eliminating demand charges in Resolution E-4514, when it adopted a special pilot rate for government agencies during the first three years of electric bus charging.[129] Under the pilot rate adopted in that resolution, transit agencies were able to take service on a small commercial customer volumetric rate for a period of three years. The Commission determined that temporarily eliminating demand charges for a defined period balanced the goal of encouraging electric bus adoption while not unduly providing an advantage to any particular electric transit battery technology or energy storage strategy.[130] Here, SCE similarly

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[128] *See* Appendix E for SCE's testimony in the RDW application (A.16-09-003), which is incorporated herein by reference for justification of the TOU periods *and* the proposal to collect 60 percent of distribution costs through the FRD Charge (with the balance of costs collected via time-differentiated energy rates).

[129] SCE proposed the pilot rate in Advice Letter (AL) 2699-E-A, filed November 19, 2012, *available at* https://www.sce.com/NR/sc3/tm2/pdf/2699-E-A.pdf.

[130] Resolution E-4514, p. 7. SCE filed AL 2699-E on February 13, 2012, requesting that the Commission approve its proposal to extend the applicability of Schedule TOU-8, Option A to customers charging zero
(Continued)

strives to strike that balance by reducing the burden demand charges can place on early stage deployments, adjusting the TOU period definitions, and gradually returning to a rate structure with energy and FRD charges. SCE's previous pilot rate successfully allowed customers time to refine operations and expand their fleets, while maintaining a reasonable average rate. Unfortunately, the pilot rate did not address how customers would gradually return to a traditional rate structure with demand and energy charges at the conclusion of the pilot. This created uncertainty, making it difficult for customers to plan future deployments. Thus, SCE designed the phase-in or "intermediate" period, in the latter five years of the New EV Rates, to remove the uncertainty experienced in the pilot rate.

The volumetric rate can be especially beneficial to participating customers in the early low-load-factor stages of EV deployments, where certain EV technologies may be disadvantaged by energy pricing that incorporates demand charges based on the highest occurring peak demand within each billing period. Lack of customer understanding of demand charges often compounds this structural disadvantage. SCE's proposed temporary "demand charge free" period allows customers to adopt new technologies and develop demand management strategies, while not overburdening the competitiveness of technologies with different charging patterns.

(3) <u>The Proposed TOU Periods Will Give the Right Price Signals at the Right Times</u>

The ACR stated that "[r]ate 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 T&D levels."[131] The updated TOU periods accomplish these objectives by offering a

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Continued from the previous page

emissions electric buses. Rather than place these customers on Schedule TOU-8, Option A, this Resolution directed SCE to extend the eligibility of TOU-GS-1, for a period of three years, to government agencies that had purchased or obtained zero-emissions electric buses. SCE subsequently filed AL 2699-E-A in compliance with Resolution E-4514, and replaces AL 2699-E in its entirety.

[131] ACR, p. 20.

super off-peak period in the winter months from 8:00 a.m. – 4:00 p.m. when renewable generation is high and net system demand is low. The introduction of a new on-peak period that reflects the new peak system conditions will help alleviate capacity constraints at the distribution levels.

The new TOU periods retain the current summer and winter seasons, with the summer season starting on June 1st and ending September 30th and the balance of the year comprising the winter season. During the summer season, weekdays are divided into an on-peak and an off-peak period. Winter weekdays and weekends are divided in to three time-of-use periods, including a super-off-peak period. The super-off-peak period was created to capture the low-cost pricing in the middle of the day, which reflects the abundance of renewable energy relative to demand that can occur in winter months. Summer weekends consist of a mid-peak and an off-peak period.

The new TOU periods encourage EV charging during periods of lower system net load, which have become lower-cost time periods when wholesale electricity prices are at their lowest. In addition, these new TOU periods will not unduly disadvantage charging during the hours that fall outside these periods. The resulting benefits of reduced carbon emissions, lower charging costs, and more effective use of generation oversupply, particularly from renewable energy generation, would accrue to both participating and non-participating customers.[132] Therefore, multiple parties will be better off and the benefits will help meet the California GHG goals.[133] SCE's proposed TOU periods in this proceeding are identical to those that are pending in SCE's RDW application (A.16-09-003). On January 19, 2017, the Commission voted to approve the ALJ's PD in R.15-12-012, *Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for*

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132 For example, *see* rates discussion beginning on page 25 in the CPUC's Energy Division Staff White Paper, *Beyond 33% Renewables: Grid Integration Policy for a Low-Carbon Future*, *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/Beyond33PercentRenewables_GridIntegrationPolicy_Final.pdf.

133 *See* R.15-12-012, Administrative Law Judge (ALJ) McKinney's Proposed Decision (PD) Adopting Policy Guidelines to Assess Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments, Revision 2, issued January 17, 2017 (the original version of the PD was issued November 1, 2016), *available at* http://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M172/K517/172517222.PDF, Appendix 2, p. 4.

Future Time-of-Use Rates and Energy Resource Contract Payments (TOU-OIR Decision),[134] which proposed a framework, including guiding principles, for designing, implementing, and modifying the time intervals reflected in time-of-use rates. SCE's proposal here is consistent with the guiding principles of that proposed decision.

SCE's New EV Rates align price signals with SCE's highest and lowest marginal cost hours and account for EV customers' preferences and ability to respond, two key principles outlined in the TOU-OIR Decision.[135] Moreover, it is the first of SCE's "menu of TOU rate options [designed] to provide rate choices [that] address [both] different customer profiles and needs…and grid needs."[136] Specifically, SCE's New EV Rates offer meaningful off-peak and super-off peak rates when energy prices are lowest. As the Commission observed in the TOU-OIR Decision:

> The deployment of grid-connected and behind-the-meter solar has increased the availability of energy during the afternoon and decreased the load on the grid. As a result, the peak periods, in terms of grid needs and cost, have shifted to later in the day. In addition, on spring days with low demand and high solar generation, there is a risk that there will be excess generation available, leading to curtailment of renewables and other resources.[137]

Consistent with the ACR's guidance,[138] the New EV Rates are designed to encourage charging at the time periods of the day when such incremental load through charging of batteries will minimize the risk of curtailment of renewable energy. The New EV Rates will also help resolve potential capacity constraints at the distribution level by encouraging conservation during hours of highest electric demand.[139] Customers with EV technologies such as mass transit, DC fast charging, and fleet operations should be well positioned to take advantage of the new lower-cost periods.

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[134] *See* D.17-01-006. The Commission voted to approve Revision 2 of the PD (see *id*.) on January 19, 2017; however, as of the date of SCE's filing of this Application, D.17-01-006 has not yet been served by the Commission.

[135] *See generally,* TOU-OIR Decision, pp.7-9.

[136] *Id*. at 8.

[137] *Id*. at 5.

[138] ACR, p. 20.

[139] *See* TOU-OIR Decision, p. 4.

(4) SCE's Rate Design is Innovative and Consistent with Cost-Causation

SCE's proposed approach to designing generation charges, to some extent, follows current EV rate design practice by recovering Marginal Generation Capacity Costs (MGCC) through TOU energy charges instead of through summer TOU TRD charges. However, the New EV Rates depart from current practice by employing Flexible Capacity marginal cost (Flex Capacity) as a cost element, which is consistent with SCE's proposal in its pending RDW application to redefine the MGCC driver to include the consideration of Flex Capacity. Including Flex Capacity distributes MGCC over *every month of the year* rather than concentrating MGCC recovery in the summer months. This change reduces upward pressure on *summer* on-peak TOU energy charges, which helps alleviate seasonal bill volatility.[140] By incorporating these features and updated TOU periods in the proposed New EV Rates, SCE aligns previously competing objectives of cost causation and EV pricing signals.

Another innovative feature of the New EV Rates is that the FRD Charge after going through the five-year intermediate period will reflect only 60 percent (rather than 100 percent) of distribution costs, with the balance of distribution costs recovered via energy charges. This approach is sensible because SCE's recent cost studies determined that distribution-related costs *do* vary by time of day. Traditionally, distribution-related costs have been recovered through FRD charges assessed on a customer's maximum recorded peak demand within a monthly billing period *regardless* of the time of day when that peak demand occurred. Therefore, a customer who experiences a peak demand at 1:00 a.m., when the system demand is relatively low and the load is less costly to serve, pays the same demand charge as a customer whose peak demand occurs at 6:00 p.m., which is at or near the time of circuit peak demand when load is most costly to serve. Under SCE's FRD charge proposal, EV customers who peak at 1:00 a.m. and EV customers who peak at 6:00 p.m. will pay the same FRD demand charge for the *fixed* portions of distribution system costs. However, the EV customer whose usage peaks at 6:00 p.m will—appropriately—pay higher energy rates for the peak load-related costs it

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[140] *See* Appendix E, Section III.C.2.c., for additional discussion on this.

imposes on the distribution system at that expensive time. For more detail about why the 60/40 split of distribution-related costs is reasonable, see Chapter III.D of the testimony from SCE's 2016 RDW application, which is provided as Appendix E to this testimony.

(5) The New EV Rates Will Provide Meaningful Bill Savings

To compute average expected bill savings anticipated to be achieved under the new EV-8 rate, Table III-4, below compares bills for EV customers served on Schedule TOU-EV-4[141] to bills for customers served on the New TOU-EV-8 rate and bills on a future TOU-GS-3 rate. SCE assumes that its future Schedule TOU-GS-3 will also reflect demand charges set to recover 60 percent of distribution costs in an FRD given that this is SCE's long-term vision for its general service rate structures.

Table III-4
Anticipated Annual Average Bills Under Various Rate Schedules

	Current TOU-GS-3	Current TOU-EV-4	Future TOU-GS-3	Introductory New TOU-EV-8 Rate	Proposed Final TOU-EV-8 (Year 11) Rates
Estimated Medium Duty EV Load (21kW - 500kW)	$93,208	$82,040	$89,997	$63,343	$75,995

The New TOU-EV-8 rate is projected to provide 30 percent lower bills for medium duty vehicles (on average) and 15 percent lower bills for heavy-duty vehicles relative to their respective OATs.[142] These bill savings will help defray the cost of customers' investments in EVs.

The overall benefit for customers on the New EV Rates is greater than the benefits currently enjoyed by customers taking service under the existing EV rates. In particular, the

[141] SCE is furnishing this rate comparison for Schedule TOU-EV-4 because it covers the largest percentage of customers eligible for the current, and future, TOU-EV rate that governs demands 21 kW to 500 kW.

[142] We are using the plural "OATs" because TOU-EV-8 applies to customers whose loads under the general service OATs could qualify the customer for TOU-GS-2 or TOU-GS-3 depending on the load.

proposed EV rates will provide a greater benefit to customers with daytime charging profiles should they shift their load to match the super-off-peak period in the winter (moving from nighttime to the middle of the day). Load management will remain a priority for commercial EV customers to optimize their benefits on the proposed TOU EV Rates. As demand charges are phased in after the initial five years, load management will become more important as a tool to mitigate the effect of demand charges.

(6) The New EV Load Will Put Downward Pressure on Non-Participating Customers' Rates

As discussed in more detail in Section III.B.2.c), below, the New EV Rates will provide a positive Contribution to Margin (CTM) in each year. Because the overwhelming majority of the expected load on the new EV rates will be incremental and provides a positive CTM, all customers will benefit through downward pressure on rates resulting from the incremental load's contribution to fixed cost recovery. The Commission has used similar reasoning to identify overall customer benefits resulting from EDRs.[143]

c) Customers Served on the New EV Rates Will Provide Positive Contribution to Margin

(1) Development of Price Floor

D.96-08-025 authorized SCE's EDR to provide rate incentives to SCE's commercial customers to retain, expand, or to locate new load within SCE's service territory. In D.96-08-025 and subsequent decisions, the Commission found EDR tariffs to be in the public interest because they attracted incremental load or expanded existing load in a utility's service territory, while providing a net benefit to other customers through a positive CTM.[144]

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143 EDRs provide discounted prices to attract, retain, and expand load, as long as the price offered to participating customers still provides a positive contribution to margin. EDRs have been approved in the following decisions: D.05-09-018, D.06-05-042, D.07-09-016, D.07-11-052, D.10-06-015, and D.13-10-019.

144 *See* D.13-10-019, p. 16: "Successful Economic Development projects benefit ratepayers directly by increasing the revenues available to contribute to the utilities' fixed costs of doing business, thus lowering rates to other customers. Ratepayers also benefit since offering a discount tariff rate helps to retain, expand or attract customers who would otherwise relocate or not come to the utilities' service territory absent the incentive. In essence, the discount rate ensures that there is a positive CTM, meaning that they are still contributing."

Relatively recently, in D.13-10-019, the Commission adopted a price floor (in the EDR context) consisting of the marginal cost of distribution, the marginal cost of generation energy and the sum of non-bypassable charges.[145] By incorporating marginal distribution and generation costs, as well as non-bypassable charges, the price floor ensures that participating customers pay at least the marginal costs for service plus non-bypassable charges. D.13-10-019 also recognized that in some instances, negative contributions to margin could occur, but that these occurrences can be minimized by using a Price Floor that includes short-term marginal costs, sets marginal generation capacity cost at zero, and annually updates non-bypassable charges to reasonably protect against negative CTM.[146] By analogy to the EDR price floor, when the New TOU-EV Rate is applied to the participating customers' specific usage patterns, the resulting bills should be greater than the bills that result from applying the same usage pattern to all of the components of the price floor as defined above. To the extent the EV customer's bill is above the Price Floor, that customer is providing positive CTM.

There is precedent to set the MGCC to zero in the Price Floor. In D.13-10-019, in Finding of Fact 23, the Commission found that setting the marginal generation capacity cost to zero for the term of the EDR contract was reasonable in light of the fact that PG&E was then, as SCE is now, over-procured in generation capacity for the foreseeable future. A similar rationale is applied by SCE in this testimony.

(2) <u>CTM Analysis Results</u>

SCE's CTM analysis compares the revenues provided by customers served on the New EV Rates to the Price Floor. An analysis for the TOU-EV-8 rate covering the

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[145] Non-Bypassable Charges include: Transmission, Public Purpose Program, Nuclear Decommissioning, Competition Transition, New System Generation, Department of Water Resources Bond, and Power Cost Indifference Amount Charges. Price floors are established to ensure that the minimum rate for any customer must reflect the marginal cost of providing service and the payment of all NBCs. The definitions of CTM and Price Floor used in this application were adopted in D.13-10-019. CTM is the difference between the average rate paid by the customer and the Price Floor, where the Price Floor consists of the marginal costs of distribution, generation energy, and all non-bypassable charges.

[146] D.13-10-019, p. 30.

introductory period, the intermediate period, and the post-10-year (final) EV rates shows that the proposed EV Rate produces revenues in excess of the Price Floor (and thus contributes to a positive CTM), which averages 8.1 ¢/kWh from 2019 through 2030. Figure III-10 shows the results of SCE's CTM analysis for years 1-12.

Figure III-10
Estimated CTM ($/kWh) Produced By TOU-EV-8 Over Years 1 – 12
(On A Program Basis)

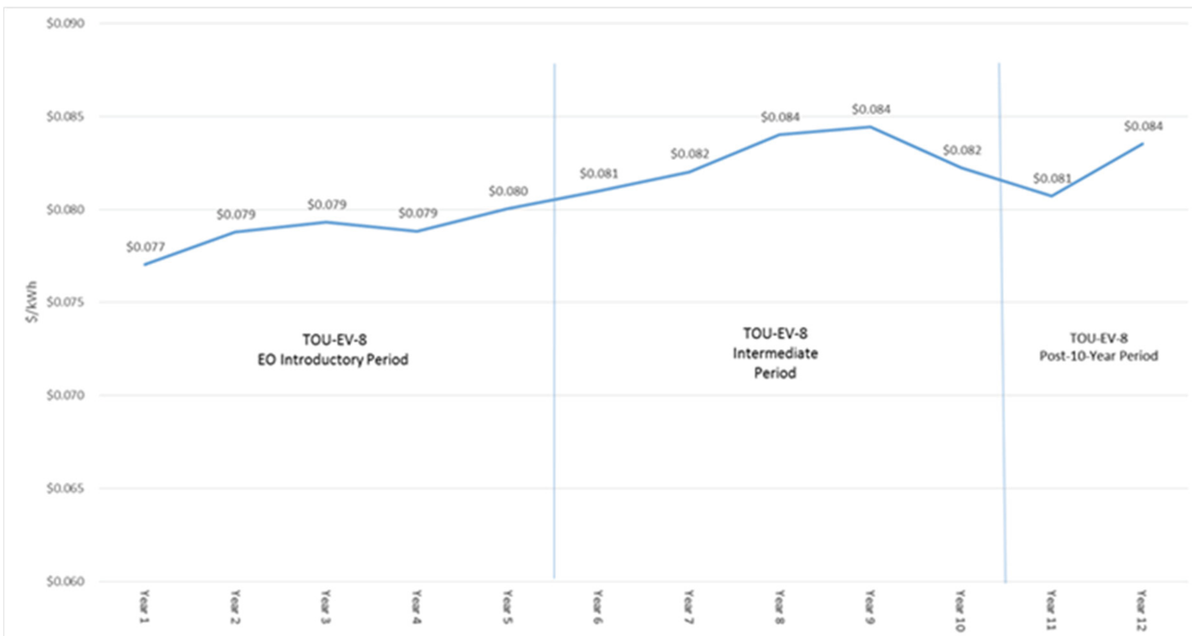
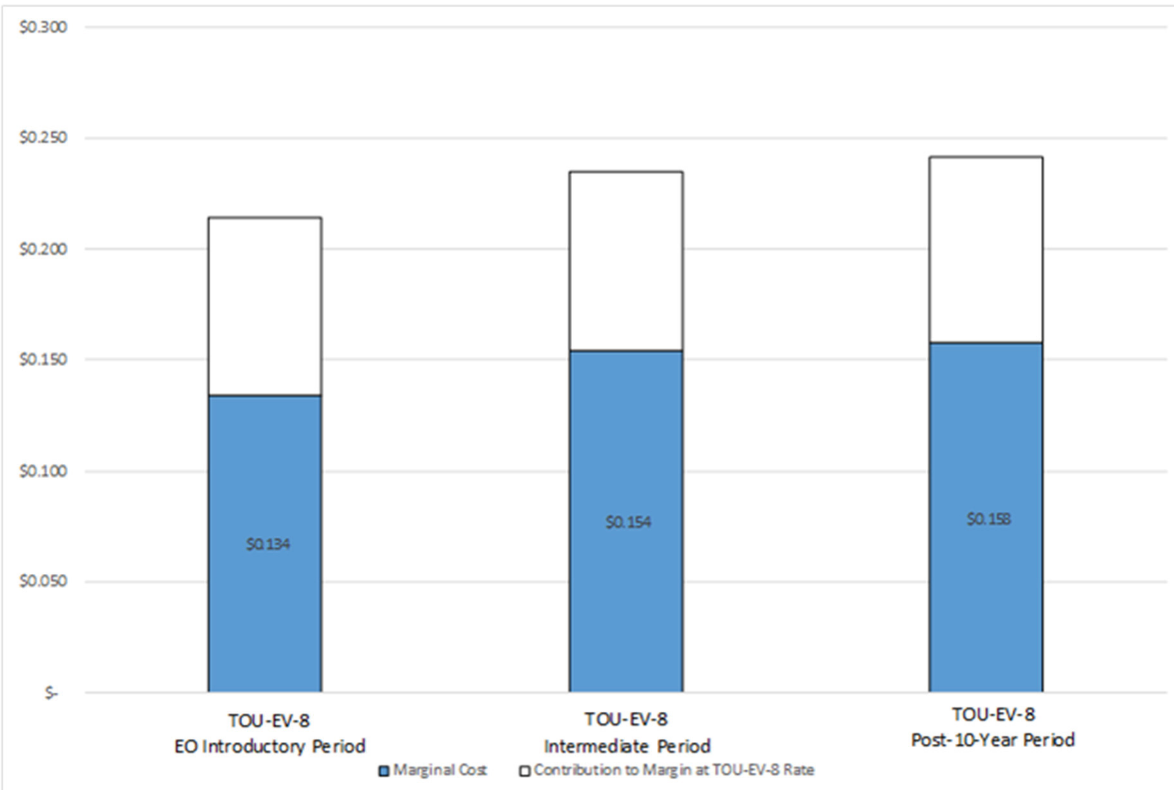


Figure III-11, below, illustrates the Price Floor and the average TOU-EV-8 Rate in 2019, 2026 and 2031 in order to demonstrate the resulting CTM values in $/kWh in each of those years.

Figure III-11
Price Floor and CTM ($/kWh) for 2019, 2026, and 2031
(On A Program Basis)



To develop this CTM analysis, SCE utilized the adoption and energy consumption "In-Between Case" forecast of the electrified medium duty (MD) and heavy duty (HD) transportation sectors from 2019 through 2031 developed in the TEA Study Phase 3A.[147] SCE's CTM analysis also included the simplifying assumption that 50 percent of the MD and HD customer load responded to the TOU rates, while the other 50 percent of MD and HD customer load displayed the assumed charging and discharging behavior that would have occurred without TOU differentiated rates. The MD and HD load shapes that SCE used for the CTM analysis were also sourced from the TEA Study. SCE utilized an internal forecast of marginal power prices, capacity costs, T&D costs, non-

[147] ICF International and E3's TEA Study Phase 3A (Jan. 2016), *available at* http://www.caletc.com/wp-content/uploads/2016/08/California-Transportation-Electrification-Assessment-Phase-3-Part-A-1.pdf.

bypassable charges, and incremental TE program costs to develop the price floor from 2019 through 2031.

SCE's proposed New EV Rates include all of the risk mitigation features outlined by the Commission in approving previous EDR programs. SCE also appropriately measures the CTM over the ten-year duration of the all-volumetric and the combined FRD/volumetric rate periods rather than in each year[148]. In certain situations, the erratic load pattern that can result from testing and limited vehicle use in the early stages of deployment may falsely indicate negative CTM when measured annually in the early years. All loads that are associated with the New EV Rates on a portfolio basis are included in the CTM analyses above.

3. Standard Review Cost Summary

In Table III-5 below, SCE shows the summary of costs for the proposed EV rate and standard review program.

Table III-5
Standard Review Program Total Costs
(Millions, 2016 $, not loaded)

Standard Review Programs	Estimated Cost
Medium and Heavy-Duty Vehicle Charging Infrastructure Program	$553.82
Commercial EV Rate Proposal	N/A
Standard Review Total	**$553.82**

C. Other Terms Applicable to SCE's TE Portfolio

SCE may procure certain products and services from third parties to implement the proposed TE portfolio following a competitive Request for Proposal (RFP) process, subject to SCE's Women Minority Disabled Veteran Business Enterprise (WMDVBE) requirements.

148 The Commission adopted that portfolio approach to its determination of CTM with respect to PG&E's EDR in D.13-10-019, p. 38.

If applying for a rebate, customers will be required to represent that the rebate amount does not exceed the actual net costs of the qualified products and services, after deduction of any other rebates or incentives offered by third parties.

IV.

SCE's PORTFOLIO FOLLOWS THE ACR's GUIDELINES

As demonstrated below, SCE's transportation electrification portfolio conforms to the guidelines established in Commissioner Peterman's September 14, 2016 ACR.[149]

A. SCE's portfolio fits with the CPUC and IOU core competencies and capabilities.

SCE's portfolio focuses on SCE's core competencies—delivering safe, reliable, affordable, and clean electricity to our customers and managing effective customer programs. For the programs requiring construction, SCE will work closely with customers, creating safe, cost-effective interconnection with the distribution grid, testing technologies and new grid strategies.

SCE's market-neutral approach enables third-party businesses throughout the TE ecosystem to focus on their respective core competencies, including providing TE charging equipment and services, communications technology, and networks to support vehicle-grid integration.

B. SCE's portfolio addresses the multiple goals of widespread TE.

SCE presents an innovative TE portfolio that mixes short-term pilot projects and longer-term initiatives to achieve the multiple objectives outlined in SB 350, namely to reduce dependence on petroleum, meet air quality standards, lower GHG emissions, and achieve the goals set forth in the Charge Ahead California Initiative in California's Health and Safety Code.[150] As described above, SCE's portfolio addresses every major market segment of transportation[151] and targets critical barriers to widespread adoption of transportation electrification, while also recognizing, and reserving, an important role for third-party market participants.

The new IRP effort, required by SB 350,[152] is currently unable to specify the scope or size of utility TE programs and related electrical infrastructure necessary to secure the GHG reductions required

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[149] ACR, pp. 15-16.

[150] Pub. Util. Code §740.12(a)(1)(A) – (B); Health & Safety Code §44258.

[151] *See* Appendix C (showing light, medium, and heavy-duty vehicles, port and material handling equipment).

[152] *See* SB 350 (amending Pub. Util. Code §701.1 and adding §§454.51 and 454.52).

by SB 32 and SB 350.[153] SCE's portfolio will provide meaningful data and analyses that will inform future IRP processes, leading to the eventual integration of utility applications for transportation electrification programs into the IRP.

C. SCE's portfolio is consistent with Commissioner-identified priority projects.

SCE's proposed TE portfolio aligns with Commissioner-identified priority projects:[154]

- Rate Design: SCE's proposed EV rate design addresses demand charges and encourages TE charging at times that maximize the use of renewable energy.
- Sector Focus: SCE's proposed TE portfolio complements existing light-duty EV programs (Residential Make-Ready Rebate, EV Driver Rideshare Reward, and Urban DCFC Clusters) and supports electrification of transit fleet, port, and other medium- and heavy-duty vehicles.
- Education and Outreach: SCE's TE portfolio includes education and outreach efforts to support enrollment in the proposed initiatives and does not propose any standalone education and outreach program.
- Previous Pilots: SCE has developed comprehensive experience through the Charge Ready Pilot Program, the Workplace Charging DR Pilot, and the Smart Charging Pilot. SCE has identified throughout this testimony lessons learned from these pilots (e.g., managing DR events for EVs through the Workplace Charging DR Pilot, program design through the Charge Ready Pilot Program) that SCE considered in developing the proposals in this application.

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[153] SB 32 requires a reduction in GHG emissions to 40 percent below 1990 levels by 2030. SB 350 recognized that "[r]educing emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050 will require widespread transportation electrification." SB 350 set an RPS goal of 50 percent, and a goal to double energy efficiency in existing end-uses of electricity and natural gas by 2030. SB 350 also provided direction to the Commission with regard to the expansion of transportation electrification programs and investments.

[154] ACR, pp. 20-25.

D. SCE's portfolio aligns with local, regional, and broader state policies.

SCE's portfolio aligns with and supports local, regional, and broader state policies for reducing petroleum use, air pollutants, and GHG emissions because transportation electrification is necessary to achieve these requirements and goals. Examples of the major policies and electrification initiatives that SCE's TE portfolio supports include:

- Executive Order B-16-2012,[155] which calls for an 80 percent reduction in GHG emissions from the transportation sector by 2050, infrastructure in place to support one million zero-emission vehicles by 2020, 1.5 million zero-emission vehicles on California roads by 2025, and implementation of an Interagency ZEV Action Plan[156] (updated in 2016) for agencies such as the CPUC, CARB, and the CEC,
- California's efforts to meet National Ambient Air Quality Standard deadlines and the California Clean Air Act,[157]
- The State Alternative Fuels Plan adopted by the CEC and CARB, which sets a goal of increasing non-petroleum fuel to 20 percent of on-road demand by 2020 and 30 percent in 2030, adopted pursuant to AB 1007,[158]
- SB 1274 "California Charge Ahead Initiative," which increases customer access to EVs by creating vehicle rebates and financing for low- and moderate-income consumers,[159]

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[155] *See* Exec. Order No. B-16-2012 (Mar. 23, 2012), *available at* http://gov.ca.gov/news.php?id=17472.

[156] *See* Office of Governor Edmund G. Brown Jr., *2016 ZEV Action Plan*, *available at* https://www.gov.ca.gov/docs/2016_ZEV_Action_Plan.pdf, defining ZEVs to include hydrogen FCEVs and PEVs, which include both pure BEVs and PHEVs.

[157] *See* SCAQMD, *National Ambient Air Quality Standards (NAAQS) and California Ambient Air Quality Standards (CAAQS) Attainment Status for South Coast Air Basin*, *available at* http://www.aqmd.gov/docs/default-source/clean-air-plans/air-quality-management-plans/naaqs-caaqs-feb2016.pdf?sfvrsn=2. *See also* CARB, *Mobile Source Strategy* (May 2016), pp.20-23, *available at*: https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc.pdf.

[158] *See* CARB & CEC, *State Alternative Fuels Plan*, p. 36 (Dec. 2007), *available at* http://www.energy.ca.gov/2007publications/CEC-600-2007-011/CEC-600-2007-011-CMF.PDF.

[159] *See* SB 1275, *available at* http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1275 (establishing a state goal to have one million zero-emission and near-zero-emission vehicles on the roads by 2023; SB 1275 also
(Continued)

and SB 1204 "CA Clean Truck, Bus, and Off-Road Vehicle and Equipment Technology Program," which equips medium- and heavy-duty vehicles with clean technologies,[160] and

- California's Sustainable Freight Strategy, which establishes clear targets to improve freight efficiency, transition to zero-emission technologies and increase the competitiveness of California's freight system, developed pursuant to Governor Brown's Executive Order B-32-2015.[161]

To ensure alignment and support, SCE actively sought feedback from public agencies (federal, state, regional, and local), as well as stakeholders from the private and non-profit sectors. On December 9, 2016, SCE invited over 150 participants to a workshop to share details about the SCE's TE plans and solicit feedback on the proposed TE portfolio.[162]

Based on extensive feedback from public agencies, SCE designed its portfolio to maximize its support of public agencies' environmental requirements by focusing on a range of transportation segments. Several aspects of SCE's portfolio are designed to help local and regional transit and rideshare agencies accelerate TE. By providing make-ready infrastructure and charging station rebates, SCE's portfolio enables state and air district funding programs to focus on the incremental cost of electrifying vehicles. SCE also proposes pilots and programs to electrify the POLB and goods movement.

Continued from the previous page

calls for increased access to zero- and near-zero-emission vehicles for disadvantaged, low-, and moderate-income communities).

160 *See* SB 1204, *available at* http://leginfo.legislature.ca.gov/faces/billNavClient.xhtml?bill_id=201320140SB1204 (creating a grant program at CARB for zero- and near-zero-emission truck, bus, and non-road vehicles, with priority for certain projects, including projects that benefit disadvantaged communities).

161 Exec. Order No. B-32-2015 (July 7, 2015), *available at* https://www.gov.ca.gov/news.php?id=19046.

162 Over 75 participants attended, representing over 45 different private, non-profit, and public sector entities.

E. <u>SCE's portfolio promotes safety.</u>

SCE's portfolio promotes customer and worker safety. For instance, the proposed Residential Make-Ready Rebate Pilot provides financial incentives to pay for make-ready infrastructure installed by a licensed electrical contractor and for the applicable permits, which promotes safety practices. SCE will also leverage the expertise of its Advanced Technology Pomona Lab to evaluate charging equipment and ensure safe connection to the grid.

F. <u>SCE's portfolio leverages non-utility funding.</u>

California agencies provide important, but limited, funds for the purchase of zero-emission and near-zero-emission trucks and buses.[163] However, not enough public funding appears to be available for deploying charging infrastructure.[164] SCE's portfolio provides funding for make-ready infrastructure and, in some cases, charging station rebates, which together will complement public funding targeting the incremental cost of electrifying vehicles and support acceleration of TE by mitigating cost barriers to adoption. SCE will also encourage participating customers to apply for available third-party funding.

G. <u>A vehicle-grid integration communication standard is not necessary for SCE's portfolio.</u>

The majority of SCE's portfolio is for the electric delivery, service, and drayage truck markets as well as electric shuttles, buses, forklifts, yard trucks, and truck refrigeration units. Unlike light-duty

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[163] The IRS provides tax credits up to $7,500 for smaller electric trucks and shuttles with gross vehicle weights of up to 14,000 pounds. See 26 U.S.C. § 30D(b). For vehicles with gross vehicle weight greater than 14,000 pounds, the following programs provide funding (however, they are regularly oversubscribed): (1) CARB's Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project (HVIP); (2) CARB's Low Carbon Transportation (LCT) programs (information *available at* https://www.californiahvip.org/ and https://www.arb.ca.gov/msprog/aqip/fundplan/fundplan); (3) CEC's Alternative and Renewable Fuels and Vehicle Technology (ARFVT) program (*available at* http://www.energy.ca.gov/drive/); (4) SCAQMD's Carl Moyer program (*available at* http://www.aqmd.gov/home/programs/business/business-detail?title=heavy-duty-engines).

[164] Existing funds for TE infrastructure are limited. The federal tax credit for EV infrastructure has expired. (*See* 26 U.S.C. § 30D(e)). The HVIP program does not fund infrastructure. The LCT, ARFVT, and SCAQMD grant programs will fund charging infrastructure, but these programs are primarily focused on paying the incremental cost of the vehicle. In addition, funding for the LCT program depends on both legislative appropriations and funds from uncertain cap-and-trade auction revenues.

vehicles, these other segments may not support existing DC or AC charging standards.[165] Currently, only EVs and DC fast chargers using the Society of Automotive Engineer's Combined Charging System (CCS) support International Orgainzation for Standardization and International Electrotechnical Commission (ISO/IEC) 15118 communications signals. Other DCFC standards such as CHAdeMO, BYD, and Tesla do not support ISO/IEC 15118.[166] The electric truck, bus, forklift, and truck refrigeration unit markets also include smaller vehicles that can charge at Level 2 AC using the SAE J1722 connector standard, while fleet charging includes conductive and inductive in-route charging using overhead or in-ground connectors when the bus or truck is parked. Where standards development activities are occurring related to some of these non-light-duty segments (e.g., SAE J3105 overhead conductive charging, SAE J3068 three-phase AC charging, SAE J2954 inductive charging, etc.),[167] the focus is on connectors, power levels, and interoperability as opposed to higher level communications and grid support functions or support for ISO/IEC 15118.[168]

The ISO/IEC 15118 standard only applies to communications between the EV and EVSE. It is not an end-to-end solution that can send a signal from the EV to the grid.[169] Further, rather than directly

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[165] CARB, "DRAFT Technology Assessment: Medium- and Heavy- Duty Battery Electric Trucks and Buses" (Oct. 2015), pp. III-5 and III-6, *available at* https://www.arb.ca.gov/msprog/tech/techreport/bev_tech_report.pdf.

[166] Ignacio Martin Jimenez et al., *IA-HEV Task 20 "Quick Charging Technology" Final Report 2012-2015,* pp. 18-19, *available at* http://www.ieahev.org/assets/1/7/IEA_Final_Report_Task_20.pdf.

[167] Electric Vehicle Power Transfer System Using a Mechanized Coupler, SAE International, *available at* http://standards.sae.org/wip/j3105/; Electric Vehicle Power Transfer System Using a Three-Phase Capable Coupler, SAE International, *available at* http://standards.sae.org/wip/j3068/; Wireless Power Transfer for Light-Duty Plug-In / Electric Vehicles and Alignment Methodology, SAE International, *available at* http://standards.sae.org/wip/j2954/.

[168] *See* Committee on Overcoming Barriers to Electric-Vehicle Deployment, *Overcoming Barriers to Electric-Vehicle Deployment: Interim Report* (2013), pp. 35-36, *available at* http://www.nap.edu/openbook.php?record_id=18320.

[169] Sunil M. Chhaya, *Vehicle-Grid Integration to Enable Customer-Centric Innovation with Speed, Scale, and Flexibility*, Electric Power Research Institute (Dec. 7, 2016), slide 6, *available at* http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN214650_20161207T082714_VehicleGrid_Integration_To_Enalbe_CustomerCentric_Innovation_wi.pdf.

managing these vehicles, SCE recommends utilizing aggregators or local management systems that can manage charging based on customer or operator needs and program terms and conditions. Accordingly, if ISO/IEC 15118 is required, SCE's event signals (or measurements, prices, etc.) will first be sent to a management system, which will have to decrypt, translate, and encrypt the signal. The management system will then send the signal to each charging station (most likely using a variety of standard or proprietary protocols), which SCE will then need to decrypt, translate into ISO/IEC 15118, and encrypt to be sent to each vehicle. This will require SCE and other stakeholders to ensure that the appropriate functionality is present in each protocol (mapping) and to develop many gateways that can translate from a variety of protocols into ISO/IEC 15118.[170] SCE would also need to validate through testing and piloting that the systems conform to important requirements such as cyber-security. To reduce costs and provide choice to customers, SCE's portfolio does not require charging stations with ISO/IEC 15118 communications signals for load management. Instead, SCE proposes to address vehicle-grid integration for fleets with proposed TOU rates,[171] DR functionality, and data collection, to evaluate the various market segments and use cases.

Vehicle-grid integration (VGI) communication standards are complex with a large number of possible end-to-end solutions (from EV to grid) involving different standards, platforms, and 20 or more possible criteria for evaluating them.[172] In the recent Rule 21 Smart Inverter Working Group efforts,

[170] *See* Rich Scholer, *CPUC Meeting: VGI Standards Summary* (Dec. 7, 2016), slide 14, *available at* http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN214651_20161207T082913_CPUC_Meeting_VGI_Standards_Summary.pdf.

[171] For additional details regarding SCE's commercial EV rate proposal, see Chapter III, *supra*.

[172] Ignacio Martin Jimenez et al., *IA-HEV Task 20 "Quick Charging Technology" Final Report 2012-2015*, p. 11, n. 2, *available at* http://www.ieahev.org/assets/1/7/IEA_Final_Report_Task_20.pdf (indicating that Tesla's DC chargers are proprietary).

See Committee on Overcoming Barriers to Electric-Vehicle Deployment, *Overcoming Barriers to Electric-Vehicle Deployment: Interim Report* (2013), pp. 35-36, *available at* http://www.nap.edu/openbook.php?record_id=18320. Also, SCE's internal analysis found that about 75 percent of EV residential customers would benefit from switching to Schedule TOU-D. The PUC-CEC-ISO workshop on this topic has begun to illustrate this with a partial list of end-to-end VGI communication solutions and criteria.

(Continued)

only the IOU interfaces (IEEE 2030.5 as the default protocol) and desired functionalities were defined, rather than defining edge communication networks and protocols.[173] For this reason, SCE supports the Energy Division proposal for a VGI working group in 2017 to develop high-level criteria, analyze the possible end-to-end communication solutions based on these criteria, develop technical specifications as needed, and make recommendations.[174] A VGI working group will help industry to accelerate vehicle-grid integration solutions for the many diverse use cases for charging all types of EVs.

H. SCE's portfolio provides utility incentives

In response to the utility incentive structure issue raised by the ACR,[175] SCE requests to treat the rebates proposed in the TE Portfolio as regulatory assets, as further described below. Five of the programs in SCE's TE Portfolio contain a request to spend funds on infrastructure, on which SCE would earn a rate of return. In order to further incent utility programs and services that will increase EV

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See Sunil M. Chhaya, *Vehicle-Grid Integration to Enable Customer-Centric Innovation with Speed, Scale, and Flexibility*, Electric Power Research Institute (Dec. 7, 2016), slide 6, *available at* http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN214650_20161207T082714_VehicleGrid_Integration_To_Enalbe_CustomerCentric_Innovation_wi.pdf.

See Rich Scholer, *CPUC Meeting: VGI Standards Summary* (Dec. 7, 2016), slide 14, *available at* http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN214651_20161207T082913_CPUC_Meeting_VGI_Standards_Summary.pdf.

[173] *See* CEC & CPUC, *Recommendations for Utility Communications with Distributed Energy Resource Systems with Smart Inverters* (Feb. 28, 2015), *available at* http://www.energy.ca.gov/electricity_analysis/rule21/documents/SIWG_Phase_2_Communications_Recommendations_for_CPUC.pdf.

[174] Sunil M. Chhaya, *Vehicle-Grid Integration to Enable Customer-Centric Innovation with Speed, Scale, and Flexibility*, Electric Power Research Institute (Dec. 7, 2016), *available at* http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN214650_20161207T082714_VehicleGrid_Integration_To_Enalbe_CustomerCentric_Innovation_wi.pdf;

CEC & CPUC, *Vehicle-Grid Integration Communications Standards*, Joint Agency Workshop (Dec. 7, 2016), *available at*: http://docketpublic.energy.ca.gov/PublicDocuments/16-TRAN-01/TN214649_20161207T080617_VehicleGrid_Integration_Communications_Standards.pdf.

[175] ACR, pp. 29-31(explaining the issue of misaligned incentives for utilities seeking to accelerate TE.

adoption on which the utilities do not typically earn a rate of return, SCE requests that the Commission treat the proposed rebates as regulatory assets.

I. <u>SCE's portfolio proposes four pilots and two customer programs for priority review and a five-year program and innovative rate design for standard review.</u>

SCE proposes six programs for priority review. The estimated total cost of these priority review pilots and projects is $19.45 million (see Table III-2 for a cost summary), which is under the Commission's proposed $20 million cap. SCE expects to execute these pilots and projects in approximately 12 months. SCE also proposes a five-year program and an innovative rate design to incent TE adoption for standard Commission review.

J. <u>SCE's portfolio provides anonymous and aggregated data for evaluation.</u>

SCE plans to report anonymous and aggregated data to the Commission and interested stakeholders annually. SCE also proposes to provide final close-out reports once each initiative concludes. These annual reports and final close-out reports will inform future Commission policy and help guide the design of future utility transportation electrification programs.

K. <u>SCE's TE Portfolio Meets the Requirements of Appendix A in the Assigned Commissioner Ruling (ACR)</u>

The ACR requires the utility applications to comply with statutory guidelines.[176] Appendix A summarizes how SCE's portfolio of pilot projects and programs meet these statutory and regulatory requirements. SCE's portfolio meets the ACR's requirements because it:

1. <u>Fulfills the Legislature's Findings and Declarations in §740.12(a)(1)</u>

§740.12(a)(1) describes "widespread transportation electrification" as including the following:

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[176] *Id.* at 13-14.

- Advanced clean vehicles and fuels are needed to reduce petroleum use, to meet air quality standards, to improve public health, and to achieve greenhouse gas emissions reduction goals;
- Achieving the goals of the Charge Ahead California Initiative;
- Requiring increased access for disadvantaged communities, low and moderate income communities, and other consumers of zero-emission and near-zero-emission vehicles and increased use of those vehicles;
- Reducing emissions of greenhouse gases to 40 percent below 1990 levels by 2030 and to 80 percent below 1990 levels by 2050 will require widespread TE;
- Requiring electrical corporations to increase access to the use of electricity as a transportation fuel; and
- Stimulating innovation and competition, enable consumer options in charging equipment and services, attract private capital investments, and create high-quality jobs for Californians where technologically feasible[177]

§740.12(a)(1) finds that "[d]eploying electric vehicles should assist in grid management, integrating generation from eligible renewable energy resources, and reducing fuel costs for vehicle drivers who charge in a manner consistent with electrical grid conditions."[178] Further, it finds that "[d]eploying electric vehicle charging infrastructure should facilitate increased sales of electric vehicles by making charging easily accessible and 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."[179]

SCE's TE portfolio is consistent with the findings in §740.12(a)(1) because:

[177] *See* Pub. Util. Code §740.12(a)(1).

[178] *Id.*

[179] *Id.*

a) SCE's Portfolio Benefits Local Communities

SCE's portfolio benefits local communities by improving air quality and reducing GHG emissions, consistent with the new, more stringent federal standards.[180] This is especially important for residents in SCE's eight non-attainment districts, including the very populous South Coast, Ventura, and San Joaquin air districts.[181] In addition, SCE's portfolio contains several projects and programs designed to benefit EV ridesharing, electric shuttles, and electric buses.

For each electric mile driven, an EV reduces emissions contributing to GHGs by approximately 70 percent, ozone-forming air pollutants by 85 percent, and petroleum use by 100 percent compared to tailpipe, power plant, refinery, and other upstream emissions from gasoline-powered vehicles.[182] These benefits increase when charging is managed to optimize grid utilization or integrate renewable energy generation, and further increase over time as the grid becomes cleaner with more renewable generation coming online in the future.

The GHG reduction and energy security benefits of light-duty EVs when monetized are conservatively estimated to be over $2,000 per EV over its lifetime.[183] The GHG reduction and energy security benefits of electric light and heavy-duty vehicles, buses, forklifts and transport refrigeration units when monetized are conservatively estimated to be over $3,400, $49,600,

[180] The CEC and CARB, in response to AB 2076 and AB 1007, adopted the goal of increasing non-petroleum fuel to 20% of on-road demand by 2020 and 30% in 2030. *See* CARB & CEC, *State Alternative Fuels Plan, Commission Report*, p. 6 (Dec. 2007), *available at* http://www.energy.ca.gov/2007publications/CEC-600-2007-011/CEC-600-2007-011-CMF.PDF.

[181] *See* e.g., R.13-11-007, Comments of SCAQMD Staff in Response to Order Instituting Rulemaking and Scoping Memo, filed September 4, 2014, pp. 3-5; *See also* CARB, *California Local Air District Directory*, *available at* http://www.arb.ca.gov/capcoa/roster.htm (identifying: SCAQMD; San Joaquin Valley Unified Air Pollution Control District (APCD); Antelope Valley Air Quality Management District (AQMD); Eastern Kern APCD; Great Basin Unified APCD; Mojave Desert AQMD; Santa Barbara County APCD; and Ventura County APCD).

[182] Pub. Util. Code §740.12(a)(I).

[183] *See* ICF International & Energy & Environmental Economics, *California Transportation Electrification Assessment, Phase 2: Grid* Impacts, Figure 20, for information on the net benefits of reducing greenhouse gases and petroleum and Section 5, pp. 46-54, for inputs to Figure 20. Available at http://www.caletc.com/wp-content/uploads/2016/08/CalETC_TEA_Phase_2_Final_10-23-14.pdf.

$5,200, and $1,500 respectively over their lifetimes.[184] The monetary value of criteria pollution reduction for electric cars, light-trucks, forklifts, truck stops and truck refrigeration units is also substantial.[185] The Commission and state legislature have recognized these additional customer benefits.[186]

b) Disadvantaged Communities Benefit from Expanded EV Markets and Charging Infrastructure

As discussed in Section II, above, disadvantaged communities in SCE's service territory are heavily impacted by the pollution resulting from medium- and heavy-duty vehicle traffic. Accelerating TE adoption, especially in fleets of trucks, shuttles, buses, and non-road equipment at ports, factories, and warehouses, will contribute to improving air quality in disadvantaged communities, as these communities are usually located near sites and roadways where such vehicles operate. Both the ACR and state laws, such as SB 1204, recognize this benefit to disadvantaged communities.[187] Improving air quality and reducing GHG emissions are important goals of SB 350,[188] but they are

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184 *See* "California Transportation Electrification Assessment; Phase 3A: Final Report," Figures 4-2, 4-3, 4-4 and 4-6, respectively for information on the net benefits of reducing GHG and petroleum, and pp. 53-56 for inputs to these figures. *Available at* http://www.caletc.com/wp-content/uploads/2016/09/California-Transportation-Electrification-Assessment-Phase-3-Part-A.pdf.

185 For information on the net benefits of reducing NOx, PM, and volatile organic compounds from these technologies, *see* ICF International & Energy & Environmental Economics, *California Transportation Electrification Assessment; Phase 1: Final Report*, Chapter 3 (Sept. 2014), *available at* http://www.caletc.com/wp-content/uploads/2016/08/CalETC_TEA_Phase_1-FINAL_Updated_092014.pdf.

186 D.11-07-29, p. 68 (discussing that it is essential to accelerate EV adoption to support reduction of greenhouse gas emissions and meet other state and national goals); EV programs and policies must be in the ratepayer's interests as defined in Cal. Pub. Util. Code § 740.8: "direct benefits that are specific to ratepayers in the form of safer, more reliable, or less costly … electrical service … and activities that benefit ratepayers and that promote energy efficiency, reduction of health and environmental impacts from air pollution, and greenhouse gas emissions related to electricity … production and use, and increased use of alternative fuels." *Id.* at 67, n. 37 (citing Pub. Util. Code § 740.8).

187 ACR at pp. 5,21-22; *See* SB 1204 (creating a grant program at CARB for zero- and near-zero emission truck, bus, and non-road vehicle and priority to be given to certain projects, including projects that benefit disadvantaged communities).

188 Pub. Util. Code §740.12.

especially critical for these communities disproportionately affected by polluted transportation corridors and the negative environmental consequences of gasoline- and diesel-powered vehicles.

c) SCE's Portfolio Create Jobs in the Community and Provides Opportunities for SCE's Suppliers, Including Diverse Business Enterprises

SCE anticipates its portfolio could potentially create many jobs for electricians, engineers, and construction workers.[189] SCE plans to contract for many of the required services, potentially including engineering, design, and construction. SCE participates in the Commission's voluntary supplier diversity program (Commission General Order 156), which sets a goal of procuring 21.5 percent of the company's annual spend on goods and services from WMDVBEs.[190]

d) SCE's Portfolio Supports Reliable Electric Service by Addressing Current and Future Grid Problems

SCE's portfolio focuses on providing reliable electric service, enhanced resource utilization, and optimized grid operation. The Residential Make-Ready Rebate Pilot ensures that the neighborhood grid and the customer infrastructure are evaluated for participating EV customers. The pilot also requires all customers to take service on a residential TOU rate schedule.[191]

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[189] Sara Chandler et al., *Delivering Opportunity: How Electric Buses and Trucks Can Create Jobs and Improve Public Health in California*, Union of Concerned Scientists (Oct. 2016), *available at* http://www.ucsusa.org/sites/default/files/attach/2016/10/UCS-Electric-Buses-Report.pdf (describing the job potential for electric trucks and buses). Two other studies found light duty EVs result in net job and economic benefits to California. *See* David Roland-Holst, *Plug-in Electric Vehicle Deployment in California: An Economic Assessment* (Sept 2012), *available at* http://www.caletc.com/wp-content/uploads/2016/08/ETC_PEV_RH_Final120920.pdf; *See also* Marc Melaina et al., National Economic Value Assessment of Plug-in Electric Vehicles, National Renewable Energy Laboratory (Dec. 2016), *available at* http://www.nrel.gov/docs/fy17osti/66980.pdf.

[190] *See* SCE's General Order (GO) 156 Report, *Supplier Diversity 2015 Annual Report/2016 Annual Plan* (May 2016), *available at* http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/About_Us/Business_and_Community_Outreach/GO_156_Reports/2014(1)/R0907027%20OIR%20to%20Amend%20GO156%20-%20SCE%202015%20Annual%20WMDVBE%20Rpt%20and%202016%20Annual%20Plan%20-%20Southern%20California%20Edison%20Company.pdf.

[191] Compared to tiered domestic rates, the net benefits of TOU rates per EV are about $1,400 higher because they encourage off-peak charging. *See* ICF International & Energy & Environmental Economics, *California Transportation Electrification Assessment, Phase 2: Grid Impacts*, p. 19 (Oct. 23, 2014), *available at* http://www.caletc.com/wp-content/uploads/2016/08/CalETC_TEA_Phase_2_Final_10-23-14.pdf.

The proposed commercial rate design addresses grid problems by incentivizing charging during the day when generation oversupply may occur. Daytime charging of EVs (e.g. workplaces, fleet vehicles) may absorb excess solar generation and reduce the evening ramp of residential load.

e) SCE's Portfolio Is Designed to Increase Access to Charging Infrastructure

SCE's portfolio is designed to address existing barriers that currently limit TE adoption. SCE's proposed pilots, projects, and program specifically target barriers, such as insufficient EV infrastructure away from home, cost of charging infrastructure, and traditional utility rate structures. Eliminating these barriers should help improve access to charging infrastructure. (For additional details on existing barriers, see Section II – Vision, *barriers.*)

f) SCE's Portfolio Contains Measurable Monitoring and Evaluation Criteria

Each proposed initiative in SCE's portfolio contains the following elements: objective, scope, cost, estimated duration, and anticipated benefits. These elements provides the foundation for measurable monitoring and evaluation criteria. In addition, SCE also proposes to report on a number of metrics related to implementation and execution of the portfolio. For further details on reporting see the subsections on data collection and reporting in Chapter II for each of the priority and standard review projects and programs.

2. SCE's Portfolio Seeks to Minimize Costs and Maximize Benefits

SCE designed its proposed portfolio to minimize costs and maximize benefits. For example, SCE proposes to source relevant products and services through a competitive request for proposal (RFP) process to select vendors and contractors. When providing a rebate on charging equipment in any of the proposed pilots and programs, SCE will follow the base cost methodology developed for the Charge Ready program to minimize costs while meeting the needs of participating customers.[192]

[192] SCE mapped the 144 DCFC sites (370 ports in total) as listed on the Department of Energy's Alternative Fuels Data Center (*available at* http://www.afdc.energy.gov/fuels/electricity_locations.html), that are in SCE territory. SCE determined 107 sites (283 ports) are less than one-half mile from a major highway.

The proposed portfolio will maximize benefits from TE by requiring that customers participating in the proposed programs take service on a TOU rate plan, which incents charging in a manner consistent with grid conditions. In addition, the proposed new EV rate design encourages EV charging during periods of electricity over-generation.

3. <u>SCE's Portfolio Contains Specified Cost Recovery Mechanism</u>

SCE proposes a balancing account to record and recover portfolio costs for the pilots and programs. These costs would be transferred to the Base Revenue Requirement Balancing Account (BRBBA) on an annual basis and costs would be reviewed as part of SCE's annual April 1 ERRA Review proceeding. Additional cost recovery details are provided in Section V.

4. <u>SCE's Portfolio Fairly Competes with Non-Utility Enterprises</u>

In its proposed portfolio, SCE intends to follow the same market neutral approach demonstrated with the Charge Ready Pilot Program. This approach consists of deploying electric infrastructure that the utility owns and maintains while participating customers (site hosts) select, own, operate, and maintain qualified charging equipment. When qualifying charging equipment, SCE plans to rely on adopted efficiency and safety standards to define its requirements and accept a large number of vendors and charging equipment models. Participating customers, not SCE, ultimately select the qualified charging equipment needed for their operations.

5. <u>SCE's Portfolio Contains Trackable Performance Accountability Measures</u>

SCE proposes to prepare annual reports to provide status updates on portfolio implementation to the Commission and interested stakeholders. The annual reports will provide a high-level summary for each initiative, the amount of funds expended to date, and the status of each pilot, project, and program.

More information is needed to inform a variety of transportation issues (future areas for utility programs, customer acceptance of vehicle-grid integration, etc.). In addition to providing annual reports, SCE also proposes to provide a close-out report on every project and program completed during the previous year. Each such report will provide a comprehensive description of the completed initiative, including findings, lessons learned, and metrics.

6. SCE's Portfolio is in the Interests of Ratepayers Per §740.8

SB 350 modified Public Utilities Code §740.8 to require demonstration of both of the following types of ratepayer benefits:

- Safer, more reliable, or less costly gas or electrical service, consistent with §451, including electrical service that is safer, more reliable, or less costly due to either improved use of the electric system or improved integration of renewable energy generation.
- And any one of the following:
  - Improvement in energy efficiency of travel.
  - Reduction of health and environmental impacts from air pollution
  - Reduction of greenhouse gas emissions related to electricity and natural gas production and use.
  - Increased use of alternative fuels.
  - Creating high-quality jobs or other economic benefits, including in disadvantaged communities identified pursuant to §39711 of the Health and Safety Code.[193]

SCE's TE portfolio meets these requirements for both types of ratepayer benefits identified in §740.8. As identified in Section III, the proposed initiatives contribute to safer, more reliable, or less costly gas or electrical service[194] through either improved use of the electric system or improved integration of renewable energy generation.[195] In addition, the proposed initiatives contribute

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[193] Pub. Util. Code § 740.8.

[194] The Natural Resources Defense Council's recent report shows how well-managed EVs benefit all utility customers through improved use of the electric system and integration of renewables. *See* Max Baumhefner & Roland Hwang, *Driving Out Pollution: How Utilities Can Accelerate the Market for Electric Vehicles*, NRDC (June 16, 2016), *available at* https://www.nrdc.org/resources/driving-out-pollution-how-utilities-can-accelerate-market-electric-vehicles.

[195] For example, SCE's standard review programs support TE adoption by proposing a new commercial EV rate structure, expanding the infrastructure for the goods movement and medium- and heavy-duty transportation segments, while also requiring participants to use low-cost vehicle-grid integration solutions such as TOU
(Continued)

to supporting TE adoption and will help displace diesel or gasoline petroleum usage with electricity, resulting in environmental and societal benefits consistent with §740.8.[196]

7. SCE's Portfolio Avoids Long-Term Stranded Assets

SCE will seek to avoid long-term stranded assets by requiring customers to utilize and maintain charging equipment deployed through the TE Portfolio. In addition, SCE will not break ground at any sites until participating customers have demonstrated to SCE that they have secured appropriate funding and have placed a firm order for charging equipment acceptable to SCE. SCE's TE Portfolio also limits the risk of technology obsolescence by deploying make-ready infrastructure (i.e., charging technology-agnostic electric infrastructure).

L. Priority Review Project Regulatory Requirements

The ACR defines priority review projects as being:

> "[N]on-controversial in nature, and limited to no more than $4 million in costs per project with a total funding limit of $20 million for each utility. The priority review projects and investments can be of a short duration (up to one year)."[197]

All six of SCE's proposed pilots and projects are noncontroversial, seek new and innovative solutions to accelerate TE adoption, and reflect stakeholder feedback.

The estimated total cost of the pilots and projects proposed for priority review is $19.45 million, under the Commission's cap of $20 million, with each initiative below the ACR's $4 million threshold. Finally, the estimated duration for each initiative is about twelve months.

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rates, DR functionality, and data collection to improve renewables integration and grid reliability. DR for fleets has many variations (e.g., DR at the building, circuit, kiosk, or charging station level) that can ramp up or ramp down charging to improve renewables integration or meet local or system grid conditions.

[196] *See* Appendix D.

[197] ACR, pp. 31-32.

V.

COST RECOVERY

A. Description of the Transportation Electrification Portfolio Balancing Account (TEPBA)

SCE requests Commission authorization to establish the Transportation Electrification Portfolio Balancing Account (TEPBA) to record the actual TE Portfolio revenue requirements each month, effective upon Commission approval of this application. Each month, SCE will record the actual O&M expenses, payroll taxes, and capital revenue requirement (i.e., depreciation, return on rate base, property taxes, and incomes taxes) in the TEPBA associated with the activities as approved by the Commission for the TE Portfolio pilot projects and standard review programs. The TEPBA will account for and record the revenue requirements for each of the six priority review projects and standard review program.

SCE proposes to include in distribution rates a forecast annual revenue requirement effective January 1 of each year, for at least five years,[198] or until the TEPBA-related costs are included in a future general rate case (GRC). To help ensure that customers only pay the actual TE Portfolio revenue requirements, SCE proposes to transfer the revenue requirement recorded in the TEPBA to the distribution sub-account of the BRRBA on an annual basis. Using this approach, any difference between the forecast TE Portfolio revenue requirements included in rate levels and the actual recorded TE Portfolio revenue requirements will be trued up in the BRRBA. This proposed ratemaking provides that no more and no less than the reasonable revenue requirements associated with the TE Portfolio activities will ultimately be collected from customers. Any over-collection recorded in the BRRBA at the end of each year will be refunded to customers in the subsequent year. Similarly, any under-collection recorded in the BRRBA at the end of each year will be recovered from customers in the subsequent year.

[198] The ACR requests that standard review projects not exceed five years. ACR, Appendix A, at p. A2.

As described below, each month, SCE will record into the TEPBA O&M expense and capital-related revenue requirements.

1. O&M Expenses

SCE proposes to record the incremental O&M costs for the pilots and programs to the TEPBA, tracked separately by program. O&M expenses will include such items as the incremental labor associated with the staffing requirements to manage the pilot projects and programs, applicable labor loadings, as well as certain non-labor expenses.

2. Capital Revenue Requirements

The capital-related revenue requirements (i.e., depreciation, property, income taxes, and return calculated at the authorized rate of return on rate base) associated with the priority review and standard review program capital additions will be recorded in the TEPBA.[199] SCE will use the most recent authorized rate of return on rate base, currently set at 7.90 percent consistent with Commission D.12-12-034. SCE will continue to record entries in the TEPBA until the conclusion of the five-year program, at which time the on-going capital-related revenue requirements will be included in SCE's GRC revenue requirement, most likely beginning January 1, 2024.

B. Proposed Reasonableness Review of TE Portfolio Expenditures

Assuming the Commission approves the scope of each of SCE's six proposed priority review projects and the standard review program, SCE requests that the actual incurred costs, as long as consistent with the adopted scope of activities and within cost levels adopted by the Commission, be deemed reasonable and therefore no after-the-fact reasonableness review is necessary. If actual costs exceed the forecast, or if the actual scope of activities changes from what the Commission has approved, then SCE would 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.

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[199] The capital additions will include Allowance for Funds Used during Construction (AFUDC) and other applicable overheads.

SCE will record revenue requirements for each individual pilot and program in the TEPBA. SCE proposes that the Commission review the recorded operation of the TEPBA in SCE's annual ERRA review applications. This review of the TEPBA will ensure that all entries to the balancing account are stated correctly and are consistent and compliant with Commission decision(s). Commission review should be limited to ensuring all recorded costs are associated with the activities as defined and within the cost levels approved by the Commission in this proceeding.

1. Cost Deflation for Reasonableness Determination

Because actual O&M expenses and direct capital expenditures[200] will be recorded in nominal dollars in years beyond the 2017 Application time frame, even for one year pilots, these costs must be deflated back to 2016$ for price increases expected in future years. SCE proposes to deflate the recorded capital and O&M costs in nominal dollars by the same inflation indexes used to escalate costs from constant 2016$ to nominal for forecasting. SCE proposes to use two deflation factors: Handy-Whitman Capital Cost Index for capital and IHS Global Insight O&M Cost Index for O&M. In the ERRA Review Proceeding following completion of the programs, SCE plans to include testimony supporting the reasonableness of the O&M and capital expenditures spent on implementing the TE Portfolio. SCE will use the actual, published inflation indexes to deflate nominal costs back to constant 2016$ to compare actual O&M expenses and direct capital expenditures to the forecast spend as adopted by the Commission.

C. Forecast of TE Portfolio Revenue Requirements

Table V-6 below presents SCE forecast 2019-2023 revenue requirements associated with the TE Portfolio's pilots and programs.

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[200] Direct capital expenditures refers to project-related spend, controllable by program managers, and does not include AFUDC or overhead loaders.

Table V-6
Forecast of SCE's TE Portfolio Revenue Requirements
(Thousands, Nominal, with loaders)

Summary of Earnings	2019	2020	2021	2022	2023
Operating Revenues	**15,711**	**22,919**	**42,013**	**62,939**	**88,713**
Operating Expenses					
O&M	11,489	3,967	4,276	5,243	6,431
Uncollectibles	37	55	100	150	211
Franchise Requirements	143	208	382	572	807
Total Operating Expenses	**11,669**	**4,230**	**4,759**	**5,965**	**7,449**
Depreciation	**2,717**	**8,114**	**13,762**	**20,439**	**28,874**
Property Taxes	–	1,758	2,923	4,253	5,900
Payroll Taxes	95	69	73	87	97
Taxes Based on Income	(6,709)	(2,959)	1,031	3,870	7,102
Total Taxes	**(6,614)**	**(1,132)**	**4,028**	**8,211**	**13,099**
Total Operating Expenses and Taxes	**7,772**	**11,213**	**22,548**	**34,615**	**49,421**
Net Operating Revenue	**7,939**	**11,706**	**19,465**	**28,324**	**39,292**
Rate Base (Weighted Average)	100,518	148,220	246,464	358,637	497,503
Rate of Return	7.90%	7.90%	7.90%	7.90%	7.90%

Beginning in 2019, SCE requests to include in distribution rate levels a forecast TE Portfolio revenue requirement annually until the time the costs are included in a GRC request. The annual revenue requirement associated with the 2019-2023 TE Portfolio forecast revenue requirements will be consolidated and made when all other previously authorized revenue changes are reflected in rates, consistent with current standard practice.

To determine the TE Portfolio revenue requirement to be included in distribution rates the following year, SCE proposes to file an annual advice letter. Similar to the approach approved by the Commission in SCE's Charge Ready Application, SCE proposes to file this advice letter in November each year. In these annual advice letters, SCE will update the TE Portfolio revenue requirement to reflect the prior year's recorded capital expenditures, any forecast capital expenditure changes in the following year, and the most recently adopted rate of return on rate base, franchise fees and uncollectible rates and tax rates. Upon Commission approval of this advice letter, SCE plans to consolidate the changes in its distribution rates to reflect these TE Portfolio revenue requirements in conjunction with other rate changes in its January 1 rate change filing.

1. Capital Expenditures

The forecast revenue requirements shown in Table V-6 above were derived based on the estimated capital expenditures of $546 million (constant 2016$), as supported in Chapter III. Table V-7 below shows the estimated direct capital expenditures escalated for each calendar year. The total estimated nominal expenditures of $660 million include applicable overheads,[201] and are forecast to close to plant-in-service (i.e., rate base) as the assets are placed in service.

2. Capital Additions and Plant-In-Service

SCE does not include capital expenditures in rate base until the assets are ready for service. This accounting is prescribe by the Federal Energy Regulatory Commission (FERC) Uniform System of Accounts (USoA). Capital expenditures when incurred are originally accounted for in the FERC Account 107, Construction Work In Progress (CWIP). During the period that capital costs reside in CWIP, they are not included in rate base and instead accrue AFUDC. The AFUDC rate is based on a prescribed formula in FERC USoA and represents construction financing costs.

When the assets are ready for service, the cumulative costs, including AFUDC, are transferred from FERC Account 107 to FERC Account 106, Completed Construction Not Classified or FERC Account 101, Electric Plant in Service. These cumulative transfers are called Capital Additions. At this same time, AFUDC accruals are stopped, depreciation begins, and the cumulative balance is included in rate base.

For purposes of forecasting capital for the TE Program, SCE has assumed that AFUDC accrual will be zero. However, on a recorded basis, the TEPBA will reflect actual recorded revenue requirements, including all applicable overheads and AFUDC, if incurred.

[201] The forecast capital expenditures as presented in Table V-7 include a composite overhead loader of 5.0 percent.

Table V-7
Summary of SCE's TE Portfolio, Annual Capital Expenditures
(Thousands, Nominal, with loaders)

Summary of Capital Expenditures						
Capital	**2019**	**2020**	**2021**	**2022**	**2023**	**Total**
Direct Expenditures	92,224	90,301	97,650	118,695	146,976	545,846
Escalation	7,316	10,263	14,507	21,909	32,543	86,538
Overhead Loader	4,178	4,337	4,877	6,132	7,850	27,375
Total Expenditures	**103,718**	**104,901**	**117,034**	**146,736**	**187,370**	**659,759**

D. Depreciation Expense and Accumulated Depreciation

The total annual forecast depreciation expense over the period 2019-2023 is shown in Table V-7 above. SCE has divided the Capital Additions into two categories: (1) utility-side infrastructure that includes line transformers, services, meters, and easements; and (2) customer-side infrastructure that includes the panel, conduit, wiring, and "make-ready" stub. For purposes of estimating depreciation expense for this TE Portfolio, SCE used a composite of authorized depreciation rates from its 2015 GRC to apply to the utility-side infrastructure that has been previously been authorized rates and used proposed rates for the customer-side infrastructure as shown in Table V-8 below.

For assets that SCE already has established depreciation rates, SCE proposes to use those rates authorized in its most recent GRC. If depreciation rates change in subsequent GRCs while the TEPBA is still in effect, SCE proposes to update the depreciation rates for this program to match the authorized rates on the same effective date as the final GRC decision.

Table V-8
Depreciation Rates

Depreciation Rates & Parameters					
FERC Account	**Description**	**Life**	**Remaining Life**	**Net Salvage %**	**Depreciation Rate[1]**
368	Line Transformer	33	25	(20%)	3.93%
369	Distribution Services	45	33	(100%)	4.34%
368 & 369	Composite	44	32	(91%)	4.29%
370	Meters	20	18	(5%)	5.30%
371	Customer-Side Infrastructure	45	45	(100%)	4.44%

1) Represent 2015 GRC Authorized Rates

1. Line Transformers, Services and Conductor, Meter, Easements

This category includes estimated costs for assets, including transformer, services and conductor, meter, and easements. For forecasting purposes, a composite rate of 4.29 percent is used based on specific Commission-authorized depreciation rates.

2. Customer-Side Panel and Wiring

This category includes the installation of the panel and wiring components from the meter to the charging station. SCE plans to record these costs to FERC Plant Account 371, Installations on Customers' Premises. SCE has no current investment in the Account, and no current authorized depreciation rate. SCE proposes to use the same depreciation rate of 4.44 percent used in the FERC Plant Account 369, Services.

3. Charging Stations Rebates

The Residential Make-Ready Pilot, the Electric Transit Bus Make-Ready Pilot, and the Medium-Duty and Heavy-Duty Vehicle Charging Infrastructure Program involve SCE providing a rebate to customer participants for charging station equipment that the customer participant will own, maintain, and operate. SCE's cost for the charging station is the rebate that SCE will provide to the customer participant. SCE proposes to amortize these costs as a regulatory asset over the expected ten-year life of the charging station. Although SCE will not own the assets, the rebates will constitute a significant portion of the cost of the charging station. The program requires the charging stations to remain in place and in working order for at least ten years to ensure the associated benefits accrue to customers. Because the utility's investment in the charging stations is necessary for the entire new infrastructure to function, that investment should be recoverable from customers over time, as the benefits of the entire new investment accrue. It would be appropriate, and consistent with cost-of-service ratemaking principles, to allocate this cost over the estimated life of the charging station. Thus, customers benefitting from the service of the charging station will be allocated a portion of the cost. This treatment has the added benefit of spreading out the cost of the charging stations over a longer period, rather than full recovery as an expense in the year incurred. The regulatory asset treatment is also consistent with Commission precedent. In D.14-03-021, the Commission concluded that costs for infrastructure not owned by the utility can be treated as a regulatory asset, included in rate base, and recovered through amortization.[202] This regulatory asset treatment is consistent with the ACR's invitation to propose utility incentives to invest in TE.[203]

E. Rate of Return

As authorized in D.12-12-034, SCE calculated the rate of return on rate base using SCE's current authorized rate of return of 7.90 percent.

F. O&M Expenses

SCE's forecasted revenue requirements are derived based on the O&M expenses as supported in summarized in Table V-8 above. O&M labor expenses include all applicable overheads.[204]

G. Income Taxes

SCE estimates income taxes according to the rules and methods adopted in its latest GRC. Specifically, in computing depreciation on SCE-owned property, SCE uses the twenty-year Modified Accelerated Cost Recovery System (MACRS) tax life for federal purposes and a 30-year life, straight-line method for computing state tax depreciation. Deferred taxes are estimated as required by the normalization rules of the Internal Revenue Code (IRC) for SCE-owned property, subject to the MACRS under IRC, Section 168. SCE computes tax basis by removing any recorded AFUDC costs and replacing it with tax capitalized interest following the rules of IRC, Section 263A. SCE computes tax expense using the applicable federal corporate tax rate of 35 percent for each year and an apportioned state corporate tax rate, as applicable.

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[202] D.14-03-021, p. 77, OP8.

[203] ACR, p. 31.

[204] The forecast revenue requirements as presented in Table V-8 include a composite benefit labor loader of 7.13%.

H. Franchise Fees and Uncollectibles

Franchise Fees and Uncollectible (FF&U) expenses are calculated as a function of the revenue requirement, using the FF&U factors authorized in SCE's latest GRC. The current authorized rates are 0.9095 percent for Franchise Fees and 0.238 percent for uncollectibles, as adopted in SCE's 2015 GRC.

Appendix A

Witness Qualifications

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF CAROLINE CHOI

Q. Please state your name and business address for the record.

A. My name is Caroline Choi, and my business address is 1515 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am currently the Senior Vice President of Regulatory Affairs. I am responsible for regulatory policy and affairs, regulatory operations and environmental affairs.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree from Dartmouth College. Prior to my current position, I was the vice president, Energy & Environmental Policy at Southern California Edison; in that position, I was responsible for analyzing federal and state energy and environmental policies and proposals, and developing environmental- and energy-related regulatory strategies. Prior to joining SCE in 2012, I was the executive director of Environmental Services & Strategy at Progress Energy, where I was responsible for leading environmental permitting, compliance and policy.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-01 entitled *Testimony in Support of SCE's 2017 Transportation Electrification Proposals*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF LAURA RENGER

Q. Please state your name and business address for the record.

A. My name is Laura Renger, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am the Principal Manager of Air and Climate Policy at Southern California Edsion. I lead a team responsible for SCE's air quality, climate change and transportation electrification policy. I have held this position since January 4, 2016.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor of Arts degree from Occidental College and a Juris Doctorate from Columbia University. Prior to my present position, I was a Senior Attorney in the Law Department at Southern California Edison. In that position, I represented SCE in environmental matters and on transmission licensing projects before the California Public Utilities Commission. Prior to my position in the SCE Law Department I was an attorney at O'Melveny and Myers LLP. I have not previously testified before the California Public Utilities Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-01, entitled *Testimony in Support of SCE's 2017 Transportation Electrification Proposals*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF MATTHEW D. SHERIFF

Q. Please state your name and business address for the record.

A. My name is Matthew David Sheriff, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company (SCE).

A. I am currently Senior Project Manager in SCE's CPUC Revenue Requirements and Tariffs Department. As such, I am primarily responsible for preparation of SCE's Consolidated Revenue Requirements showing and forecasting SCE's system average rate.

Q. Briefly describe your educational and professional background.

A. I graduated from the University of Maryland Baltimore County in May of 1995 with a Bachelors of Arts Degree in Political Science. For the next seven years I worked at several venture-backed new media startups in marketing and business development roles. In August of 2002, I returned to graduate school to earn a Master of Business Administration (MBA) from the University of Southern California. Shortly after graduation, I worked for Raytheon Inc. as a senior financial analyst responsible for balance sheet and cash flow forecasting. In April of 2007, I began to work for Southern California Edison Company as Senior Financial Analyst in the Financial Planning and Analysis group of the Treasurer's department. In this role as a financial subject matter expert, I prepared cost-effectiveness analysis in support of applications before the CPUC, including SmartConnect®, SONGS High Pressure Turbine and sale of SCE's interest in Four Corners. I was promoted to senior project manager while in this department. I started in my current position in January of 2014. I have previously testified before the California Public Utilities Commission.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-01, entitled *Testimony in Support of SCE's 2017 Transportation Electrification Proposals*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF ROBERT A. THOMAS

Q. Please state your name and business address for the record.

A. My name is Robert Thomas, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Manager of the Rate Design Group in the Regulatory Affairs Department at Southern California Edison Company. In this position, I am responsible for development of SCE's rate designs. I have held this position since November 20, 2006.

Q. Briefly describe your educational and professional background.

A. I hold a Bachelor's of Science and Engineering from the University of Arizona, a Masters in Business Administration from California State Polytechnic University, Pomona and a Professional Engineering License in Mechanical Engineering. Prior to my present position, my responsibilities have included Manager of the Analysis and Program Support Group, within SCE's Business Customer Division, where I was responsible for providing complex customer specific rate and financial analyses involving self-generation, load growth, contract rates, and hourly pricing options. Prior to this position, I was the SCE's Program Manager for the Self Generation Incentive Program. In this position, I was responsible for all aspects of the program to include dispute resolution, processing applications, program promotion and was SCE's lead representative on the Working Group.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor portions of Exhibit SCE-01, entitled *Testimony in Support of SCE's 2017 Transportation Electrification Proposals*, as identified in the Table of Contents thereto.

Q. Was this material prepared by you or under your supervision?

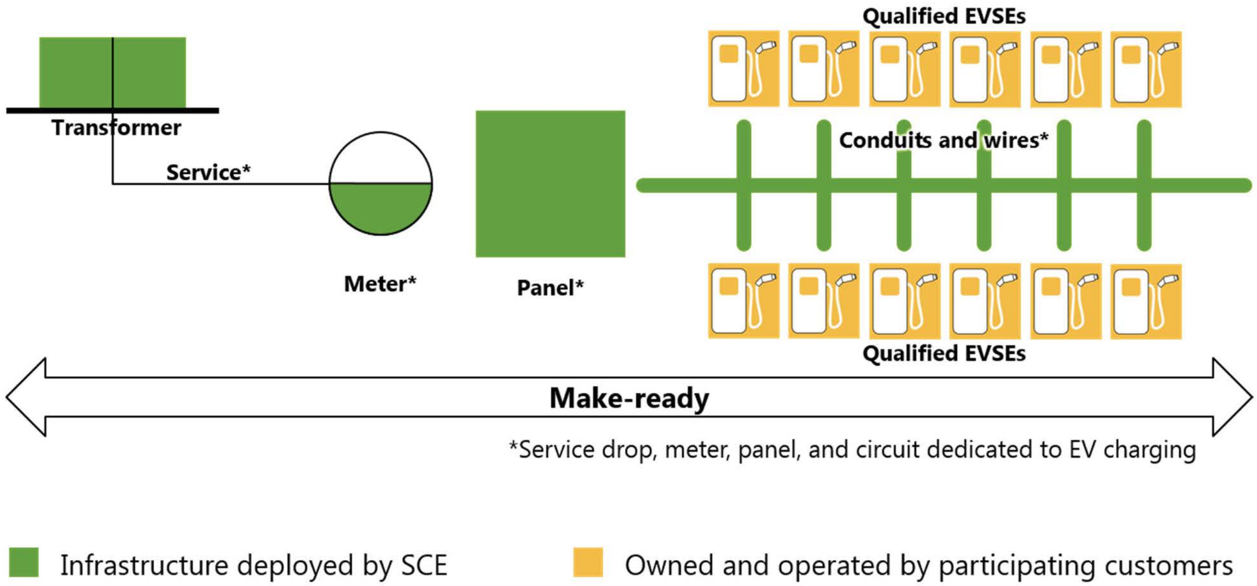
A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?
A. Yes, I do.
Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?
A. Yes, it does.
Q. Does this conclude your qualifications and prepared testimony?
A. Yes, it does.

Appendix B

Diagram of Charge Ready Infrastructure

Make-Ready Infrastructure Overview



Appendix C

Eligible Vehicle Classes

Eligible Electric vehicle class descriptions

Class	Weight	Examples	SCE Designated Segment
Class 1	Less than 6,000 lbs	Passenger car, minivan, SUV, small pickup truck	Light-duty
Class 2	6,001 to 10,000 lbs	Cargo van, passenger van, step-van, large pickup truck	Medium-duty
Class 3	10,001 to 14,000 lbs	Walk-in van, box truck, city delivery truck	Medium-duty
Class 4	14,001 to 16,000 lbs	Large walk-in van, large city delivery truck	Heavy-duty
Class 5	16,001 to 19,500 lbs	Bucket truck, extra-large walk-in van, extra-large city delivery truck, shuttle bus	Heavy-duty
Class 6	19,501 to 26,000 lbs	Beverage delivery trucks, single-axle truck, school bus, rack truck	Heavy-duty
Class 7	26,001 to 33,000 lbs	Refuse truck, city transit bus, tractor trailer truck	Heavy-duty
Class 8	Greater than 33,000 lbs	Large transit bus, tractor trailer truck, cement truck, dump truck, sleeper cab truck	Heavy-duty
Other/Non-Road	N/A	• Forklift (Class 1 – electric rider or Class 2 – narrow aisle replacing Class 4 - Counterbalanced internal combustion engine rider with solid tires, Class 5 - Counterbalanced internal combustion engine rider with pneumatic tires), • Electric container handling equipment (side-picker, top-loader, rubber-tire gantry crane, ship-to-shore crane, yard tractor), • electrified truck-stop parking, • electric transport refrigeration unit (TRU) • electric ground support equipment (e.g., airports, warehouses, factories)	Non-road

Appendix D

SCE EV Forecast

<u>**SCE EV Forecast and GHG Calculation Methodology**</u>

SCE's electric vehicle adoption forecast used two different sources—one source for the light-duty vehicle segment and a different source for the non-light duty vehicle segments (including medium-duty, heavy-duty and non-road vehicles). SCE herein describes the methodology used for each forecast and compares both forecast results to forecasts already released by the California Energy Commission (CEC) and the California Air Resources Board (CARB).[1] Table 1 shows sources for each of the forecasts compared.

Table 1 - Forecast Sources

TE Forecasts	Light-Duty Vehicles	Medium-Duty plus Heavy-Duty Vehicles
CARB Cleaner Tech and Expanded ZEV	CARB	CARB
CEC IEPR	CEC	N/A
SCE TE Forecast	Navigant Conservative Scenario	California Transportation Electrification Assessment Phase I: In-Between Forecast (TEA Study)

CARB established a web database called EMFAC to provide public access to commonly used emissions and emission rates data for vehicles. The EMFAC database categorizes vehicles in California into 37 different vehicle IDs (See Table 3). Industry reports often combine these categories into four groups; light-duty, medium-duty, heavy-duty, and non-road. However, the grouping of EMFAC IDs is not standardized across studies. SCE worked with both CARB and CEC to understand their work and establish consistent terminology between all forecasts. SCE used the vehicle counts provided by EMFAC, but mapped the EMFAC categories in CARB's forecast to align with SCE's different vehicle forecasts (Navigant and the TEA Study) for the comparisons detailed below.

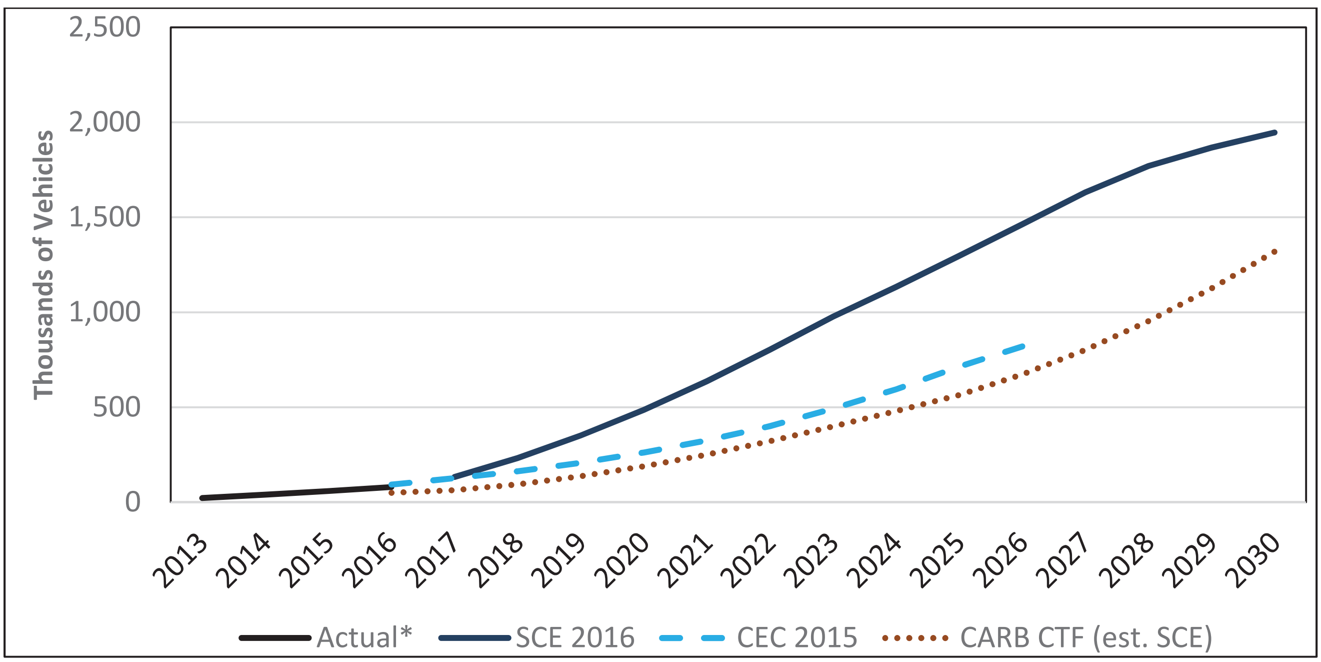
[1] CARB provided documentation from its Passenger Vehicle Module (PVM) and Heavy-Duty Vehicle (HDV) Module from Vision 2.1, CARB's multi-pollutant scenario planning tool. More information on CARB scenarios is in chapters 6, 7, and 11 of the 2016 Mobile Source Strategy, *available at* https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc.pdf.

Light-Duty Vehicles

SCE obtained three forecasts from Navigant (conservative, base, and high), specific to SCE's territory. The forecasts contain EMFAC categories for light-duty automobiles (LDA) and light-duty trucks (LDT1, LDT2). These forecasts were adjusted downward by approximately 20,000 to align with historical adoption numbers through 2016 using Polk/DMV registration data. SCE's Q4 2016 forecast is the resulting adjusted conservative case from Navigant.

Figure 1 below compares the light-duty forecasts in SCE's territory for LDA, LDT1, and LDT2 vehicle segments of CARB's Cleaner Technologies and Fuels scenario,[2] CEC's Medium IEPR forecast for SCE Planning Area, and SCE's Q4 2016 forecast.

Figure 1 - Comparison of Light-Duty EV Forecasts



Medium-Duty, Heavy-Duty and Non-Road

For all non-light-duty EV forecasts (See Figures 8 and 9), SCE used Phase 1 of ICF International and Energy+Environmental Economics's Transportation Electrification

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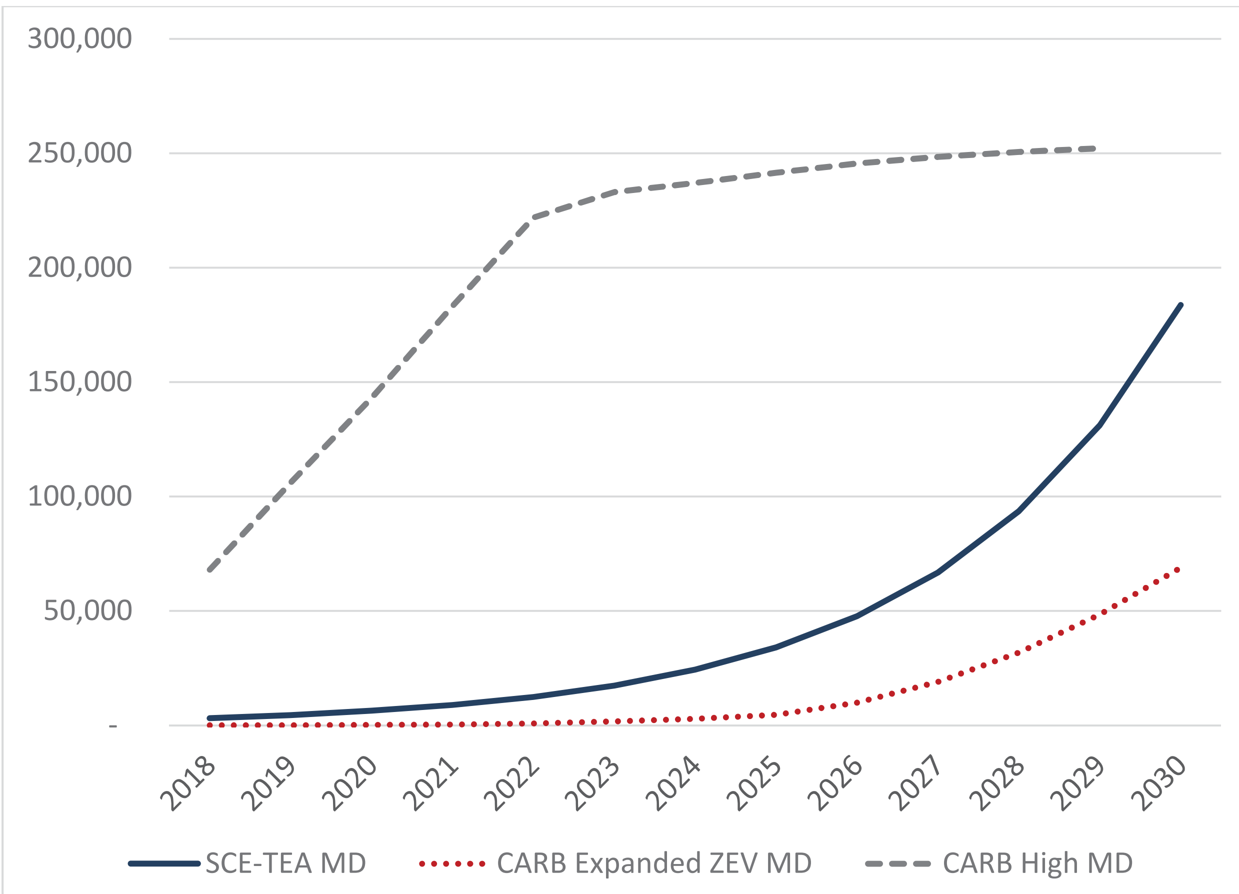
[2] Approximately 38 percent of California forecasts are assumed to be in SCE's service territory. Based on historical adoption data, SCE has adopted approximately 38 to 39 percent share of California's annual vehicle sales (all fuel types, light-duty) in the last five years.

Assessment report (TEA Study) in-between forecast.[3]

The medium-duty vehicle segment forecast (Figure 8) is based on an ICF-developed penetration of three EMFAC vehicle classes—including light-heavy-duty trucks (LHD1 and LHD2) and medium-duty vehicles (MDV)—for the TEA study. ICF extracted vehicle populations from EMFAC and estimated annual new vehicles sales. Vehicle retirement was based on survivability profiles extracted from EMFAC.

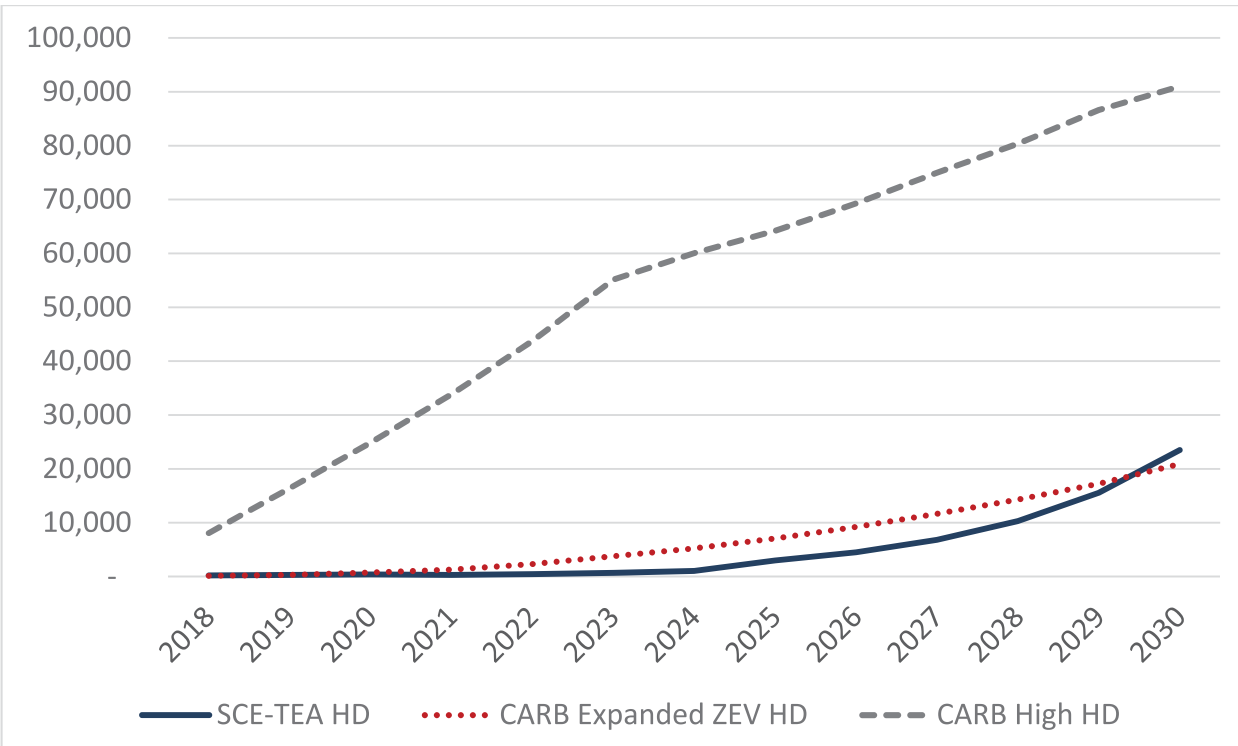
Figure 2 – California Medium-Duty Vehicle Comparison to CARB Clean Technologies and Fuels and Expanded Zero Emission Scenario



[3] See ICF International, California Transportation Electrification Assessment Phase 1: Final Report, p. 15, Table 8 (Sept. 2014), available at http://www.caletc.com/wp-content/uploads/2016/08/CalETC_TEA_Phase_1-FINAL_Updated_092014.pdf.

The forecast of heavy-duty vehicles is based on an ICF-developed adoption of 23 EMFAC vehicle classes—including medium-heavy-duty trucks (T6 categories), heavy-heavy-duty trucks (T7 categories), and buses (BUS categories) in the TEA study. ICF extracted vehicle populations from EMFAC and estimated annual new vehicles sales. Vehicle retirement was accounted for based on survivability profiles extracted from EMFAC.

Figure 3 – California Heavy-Duty Vehicle Comparison to CARB Expanded Zero Emission Scenario



For both medium-duty and heavy-duty categories, SCE used the "in between" case. Because TEA Study data is presented at the California level, SCE applied a 38% scaling factor for each grouping derived from SCE's share of commercial and industrial activity.

To create the CARB lines in Figures 8 and 9, SCE worked with CARB, utilizing the VISION 2.1 model, and obtained annual forecasts of the Cleaner Technologies and Fuels Expanded ZEV scenario from each of the EMFAC vehicle categories. These categories were regrouped into medium-duty and heavy-duty groups to match the TEA study, as shown in Table 3 below.

Because California is in the beginning stages of TE adoption, forecast accuracy is challenging. However, using California's emissions requirements we can determine bookends (high and low bounding cases) for different adoption scenarios. Such bookends are helpful in providing context for forecasts. Figure 2 and Figure 3 show a potential high EV scenario using data from the Mobile Source Strategy, based on combining their zero-emission vehicle and low-NOx standard (or better) USEPA phase 2 GHG wedges.[4]

SCE also includes non-road vehicles in its forecast assumptions for the programs in this application. Non-road vehicles includes forklifts, cranes, yard tractors, and airport ground support equipment. Table 9 shows forecast numbers for SCE in each vehicle category.

Table 2 - Medium-Duty, Heavy-Duty and Non-Road Population Forecast

TEA Study SCE Total Annual Population		2018	2019	2020	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
Forklifts	Class 1 + 2	8,142	8,600	9,083	9,523	9,985	10,469	10,977	11,509	12,068	12,653	13,266	13,910	14,584
Forklifts	Class 3	8,965	9,306	9,660	9,980	10,309	10,650	11,002	11,365	11,741	12,129	12,530	12,944	13,371
Truck Stop Electrification (Spaces)		133	171	219	230	241	253	266	279	292	307	322	337	354
Transport Refrigeration Units		1,506	1,859	2,296	2,652	3,064	3,540	4,089	4,724	5,457	6,304	7,282	8,412	9,718
Port Cargo Handling Equipment	Yard Tractors	82	98	115	129	146	165	186	209	236	266	300	338	381
	Forklifts	31	38	44	49	54	60	67	74	82	91	101	113	125
	Cranes	10	12	14	16	18	20	22	25	28	31	35	40	44
Airport GSE		28	32	36	38	40	42	44	46	49	51	54	57	59
Medium-Duty Vehicles		441	633	910	1,275	1,786	2,502	3,506	4,912	6,883	9,644	13,512	18,932	26,526
Heavy-Duty Vehicles		101	108	116	162	227	318	447	626	878	1,231	1,726	2,420	3,393
		19,439	**20,857**	**22,493**	**24,054**	**25,871**	**28,019**	**30,605**	**33,770**	**37,713**	**42,707**	**49,128**	**57,502**	**68,558**

[4] See California Air Resources Board, *Mobile Source Strategy*, p. 81, Figures 16 & 17 (May 2016), *available at* https://www.arb.ca.gov/planning/sip/2016sip/2016mobsrc.pdf. The Mobile Source Strategy details CARB's medium- and heavy-duty vehicle forecast populations by the NOx emission abatement standard that each vehicle achieves (e.g., Pre-2007 Standard, 2007-2009 Standard, 2010 Standard, USEPA GHG Phase 2, Battery Electric, Hydrogen). According to the Mobile Source Strategy, "[t]o meet the 2030 GHG emissions and petroleum reductions targets statewide, low-NOx trucks will need to use renewable fuels." (*Id.* at 79.) CARB has not identified how the state will generate enough renewable diesel and natural gas to fuel all of these vehicles, while also not precluding electric trucks and similar vehicles that exceed the low-NOx standard. EV technologies exceed the GHG emissions reductions, petroleum reduction, and NOx emissions reductions on a per-mile basis compared to diesel and natural gas engines. Therefore, the portion of the population represented by Low-NOx diesel and natural gas vehicles in the Mobile Source Strategy could be replaced by BEVs or PHEVs in order to meet California's environmental requirements.

Table 3 - EMFAC Vehicle ID and Description

EMFAC Vehicle ID	Description
LDA	Light-Duty Automobiles (i.e. Passenger Cars)
LDT1	Light-Duty Trucks (0-3,750 lbs GVWR)
LDT2	Light-Duty Trucks (3,751-5,750 lbs GVWR)
MDV	Medium-Duty Trucks (5,751-8,500 lbs GVWR)
UBUS	Urban Buses
SBUS	School Buses
OBUS	Other Buses
LHD1	Light-Heavy-Duty Trucks (GVWR 8501-10000 lbs)
LHD2	Light-Heavy-Duty Trucks (GVWR 10001-14000 lbs)
T6 Ag	Medium-Heavy Duty Diesel Agriculture Truck
T6 CAIRP heavy	Medium-Heavy Duty Diesel CA International Registration Plan Truck with GVWR>26000 lbs
T6 CAIRP small	Medium-Heavy Duty Diesel CA International Registration Plan Truck with GVWR<=26000 lbs
T6 instate	Medium-Heavy Duty Diesel instate construction Truck with GVWR>26000 lbs
T6 instate	Medium-Heavy Duty Diesel instate construction Truck with GVWR<=26000 lbs
T6 instate heavy	Medium-Heavy Duty Diesel instate Truck with GVWR>26000 lbs
T6 instate small	Medium-Heavy Duty Diesel instate Truck with GVWR<=26000 lbs
T6 OOS heavy	Medium-Heavy Duty Diesel Out-of-state Truck with GVWR>26000 lbs
T6 OOS small	Medium-Heavy Duty Diesel Out-of-state Truck with GVWR<=26000 lbs
T6 Public	Medium-Heavy Duty Diesel Public Fleet Truck
T6 utility	Medium-Heavy Duty Diesel Utility Fleet Truck
T6TS	Medium-Heavy Duty Gasoline Truck
T7 Ag	Heavy-Heavy Duty Diesel Agriculture Truck
T7 CAIRP	Heavy-Heavy Duty Diesel CA International Registration Plan Truck
T7 CAIRP	Heavy-Heavy Duty Diesel CA International Registration Plan Construction Truck
T7 NNOOS	Heavy-Heavy Duty Diesel Non-Neighboring Out-of-state Truck
T7 NOOS	Heavy-Heavy Duty Diesel Neighboring Out-of-state Truck
T7 other port	Heavy-Heavy Duty Diesel Drayage Truck at Other Facilities
T7 POAK	Heavy-Heavy Duty Diesel Drayage Truck in Bay Area
T7 POLA	Heavy-Heavy Duty Diesel Drayage Truck near South Coast
T7 Public	Heavy-Heavy Duty Diesel Public Fleet Truck
T7 Single	Heavy-Heavy Duty Diesel Single Unit Truck
T7 single	Heavy-Heavy Duty Diesel Single Unit Construction Truck
T7 SWCV	Heavy-Heavy Duty Diesel Solid Waste Collection Truck
T7 tractor	Heavy-Heavy Duty Diesel Tractor Truck
T7 tractor	Heavy-Heavy Duty Diesel Tractor Construction Truck
T7 utility	Heavy-Heavy Duty Diesel Utility Fleet Truck
T7IS	Heavy-Heavy Duty Gasoline Truck

GHG Reduction Comparison

SCE compared an analysis of CO_2 reduction from CARB-forecasted light-, medium-, and heavy-duty vehicle forecasts with those from SCE's forecasts described above. SCE used the methodology from the CARB Low Carbon Fuel Standard to calculate net GHG reductions from EVs. The results of the calculations are detailed below.

SCE compared California 2030 emissions and emission intensities between the TE forecasts in CARB's Cleaner Technologies and Fuels and Expanded Zero-Emission Scenarios and SCE's internal TE forecast. SCE ran the 2030 expected loads from each of these forecasts separately through SCE's internal PLEXOS production simulation model to determine economic electricity dispatch and associated emission intensities of electricity generation to serve electric vehicles.

SCE used Equation 1, below, from CARB's Low Carbon Fuel Standard (LCFS) to compare million metric tons (MMT) of CO_2 between the SCE and CARB TE forecasts above (Figures 7, 8 and 9).[5] The CARB formula (slightly modified to obtain units in MMT instead of grams) calculates total net emissions stemming from the electric sector's generation offset by decreased emissions from the transportation sector. Table 4 lists the definition and sources for each variable.

Equation 1 - LCFS Net Emission Formula

$$\frac{\mathrm{Credits}_i^{XD}}{\mathrm{Deficits}_i^{XD}}(\mathrm{MMT}) = \left[\left(\mathrm{CI}_{\mathrm{standard}}^{XD} - \mathrm{CI}_{\mathrm{reported}}^{XD}\right) \mathrm{x}\ \mathrm{E}_{\mathrm{displaced}}^{XD}\ \mathrm{x}\ \mathrm{C}\right] * 1\mathrm{x}10^{-12}$$

[5] Reference LCFS regulation p. 43 (California Code of Regulations Section 95486).

Table 4 - CARB Low Carbon Fuel Standard Emissions Savings: Inputs Summary

Variable	Definition	Unit	Source
CI (Carbon Intensity) Standard	Transportation Gas Intensity (Average Carbon Intensity of Gas or Diesel).	g/MJ	CARB LCFS[6]
CI (Carbon Intensity) Reported	Electric Carbon Intensity.	g/MJ	Production Simulation Model[7]
E Displaced	E Displaced = E_i x EER E_i = TE Forecast (kWh) EER = Dimensionless Energy Economic Ratio relative to gas or diesel fuel	kWh	Ei = TE Forecast 1. CARB EER = From CARB LCFS 2. SCE TE Forecast
C	Convert MJ into kWh	3.6	N/A
$1x10^{-12}$	Convert grams to million metric tons	$1x10^{-12}$	N/A

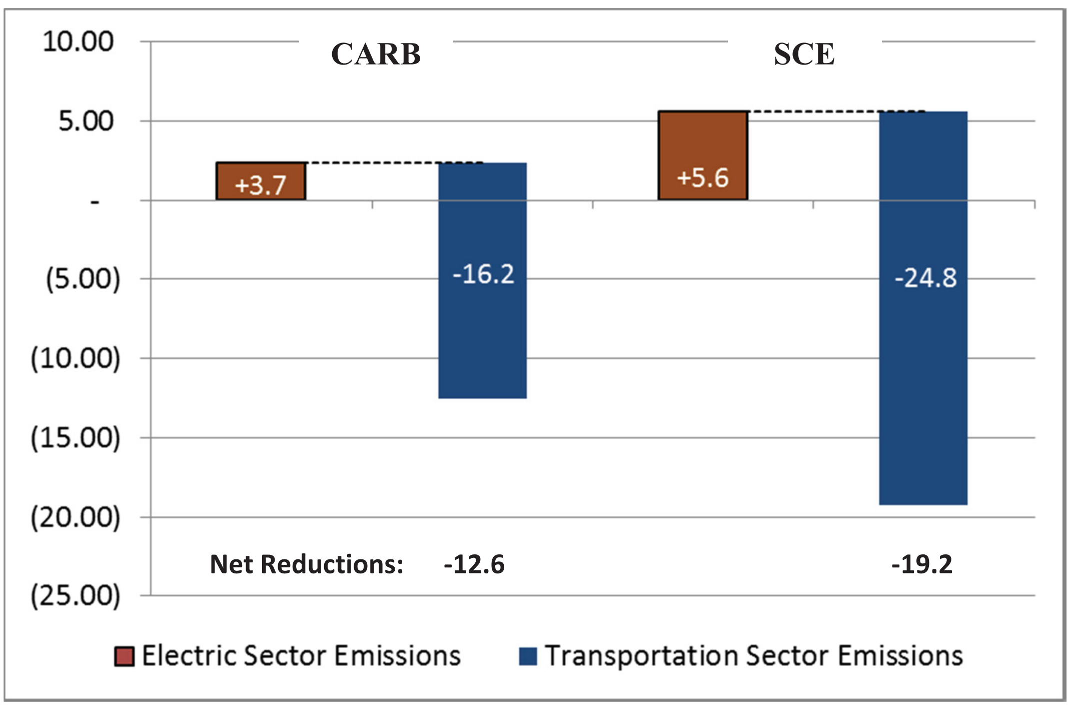
SCE's forecast shows additional CO_2 emission reductions, compared to CARB's forecast.

[6] The transportation sector's carbon intensity is approximately 96 g/MJ and 98 g/MJ for light-duty and combined medium-duty and heavy-duty vehicles.

[7] Based on SCE's production simulation model, the California marginal electric sector's carbon intensity in 2030 to serve all associated EV load is 73.8 g/MJ.

Figure *4* shows increased emissions from the electric sector in both the CARB and SCE scenarios (3.7 MMT and 5.6 MMT respectively), as well as decreased emissions in the transportation sector (16.2 MMT and 24.8 MMT respectively). The combined results equal total emissions reduced for each forecast. The CARB Cleaner Technologies and Fuels and Expanded Zero Emission Scenarios shows approximately 12.6 MMT of CO_2 reduced, while SCE's internal forecast shows approximately 19.2 MMT reduced. The difference in CO_2 emissions reduced is 6.7 MMT, or 53 percent.

Figure 4 - California 2030 Emissions from Transportation versus Electric Sector



Appendix E

Rate Appendix

Testimony of Southern California Edison Company (U 338-E) in Support of its Application For Approval of its 2016 Rate Design Window Proposals

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III.

MARGINAL COST STUDIES

A. Marginal Cost Overview

1. Marginal Cost Principles

The Commission's reliance on marginal cost principles for revenue allocation and rate design is long-standing and based on well-founded economic principles. Marginal costs reflect the change in costs incurred (or avoided), to serve a small increment (or decrement) in demand for utility services. Allocating the authorized revenue requirement based on marginal costs provides an economically-efficient price signal, which enables and encourages customers to make consumption decisions to use electricity efficiently and to make appropriate choices when purchasing electrical equipment and appliances. When utility electric rates are not based on marginal costs, economic theory dictates that users of utility services may inefficiently over- or under-consume electric products and services.

The Commission has reasoned that the theory behind the use of marginal costs in utility rate design is that they "provide a better price signal to customers of the impact of their consumption decisions on the utility cost of providing service on a prospective basis and [will hopefully] induce [the customers] to be more efficient."[25] It follows that marginal costs should be used to identify the hourly patterns in utility costs and form the basis for TOU periods and prices. Properly-set forward-looking TOU periods and prices will incentivize customers to reduce their usage during the on-peak periods in which costs are generally high, and to increase usage during the off-peak (or super-off-peak) periods in which costs are generally low.

In this application, SCE proposes new TOU pricing periods based on an updated marginal cost analysis of generation energy and capacity costs, as well as an assessment of the time-differentiation of certain distribution system costs. These proposed changes include:

[25] D.92-12-057, p. 234.

1. Hourly generation energy costs that reflect the influx of RPS resources. Consistent with basic principles of supply and demand, SCE's lowest marginal costs for energy are expected when "net system demand" is low (e.g., when overall electricity demand is low while the supply of must-take renewable power is high). Conversely, SCE's highest marginal costs for energy are expected when the demand for electricity is high and the production of RPS resources is low.
2. Hourly generation capacity costs that reflect both peak and flexible capacity requirements. Generation capacity costs have historically correlated with the "peak" system demand conditions caused primarily by large air-conditioning loads during hot summer afternoons. Today, those costs are also influenced by the need for flexible capacity to meet year-round daily ramping conditions (specifically for the late afternoon/early evening ramp). The influx of renewable resources has also pushed the incremental need for capacity to hours later in the day, when solar power generation begins to wane.
3. The deployment of system-wide "smart" meters allows SCE to incorporate time-dependent costs drivers of the distribution system into TOU rate components. While load research samples have historically provided the ability to account for coincidence with distribution system peak loads in the rate group revenue allocation process, system-wide "smart" meter deployment, along with the mandatory TOU rate requirement, allows for these time-differentiated elements to be incorporated into the overall individual customer rate designs, improving individual customer rate equity.

2. <u>Methodology for Aggregating Studies</u>

In initial comments on the TOU OIR, several parties recommended that marginal cost studies, typically provided in GRC Phase 2s, should be used to support the development of "Target Time

Periods (TTP)."[26] To facilitate comparisons, the Energy Division provided templates for marginal cost studies, which expressed marginal generation energy costs and marginal generation capacity costs in dollars-per-kilowatt-per-hour ($/kWh) summed for each hour in the year, and aggregated the results in a "heat map"[27] that averaged the costs in each hour, in each month. The results of the marginal cost studies described in this chapter and in Chapter IV use the Energy Division's template and are all shown in Pacific Prevailing, or Clock, Time (PPT).

SCE's marginal cost aggregation model is publicly available online at: http://www3.sce.com/law/cpucproceedings.nsf/vwSearchProceedings?SearchView&Query=A.16-09-XXX&SearchMax=1000&Key1=1&Key2=25.

In this chapter, SCE describes the assumptions and inputs used to determine the annual generation capacity and distribution system marginal costs and their hourly distributions, and in the case of generation energy, hourly marginal energy costs. Those values form the basis for each of the charts and graphs in this testimony. SCE's model allows all other users to modify certain assumptions and inputs in the aggregation model to evaluate the impact of such changes on the distribution of hourly marginal costs. Instructions on how to use the model are included in the first tab of the Excel-based model.

3. Use of 2024 Data

SCE developed its marginal cost studies using forecasts of supply-and-demand conditions expected in 2024. Consistent with parties' recommendations in the TOU OIR and similar to the language in Public Utilities Code Section 745(c)(3), which directs the Commission to "strive" for

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[26] The May 3, 2016 Scoping Memo and Ruling (May 3, 2016 Ruling) in the TOU-OIR defines TTP as the periods during which it would be helpful to the California power grid for customers to modify their level of energy use. The Ruling goes on to state that the TTP should be used as the starting point for utility-specific proposals. *See* May 3, 2016 Ruling at p. 2.

[27] The heat maps included in testimony display a color scheme that reflects the 90th percentile of the average hourly value (load or cost, respectively) in red, the 50th percentile of the average hourly value in yellow, and the 10th percentile of the average hourly value in green.

residential TOU periods that are appropriate for at least the following five years.[28] TOU periods should be stable for a period of at least six years. To ensure that price signals remain appropriate, TOU periods must be set based on expected conditions in the future and should have sufficient duration to provide stability over reasonable planning periods for SCE and its customers. The conditions that have caused concerns with the current TOU periods, specifically the impact on IOU load profiles of the statutory increases in the RPS targets from 20% in 2013[29] to 33% in 2020, will only intensify as California moves to 40% by 2024 and 50% RPS by 2030, all while behind-the-meter (BTM) DG continues to grow. The approximate midpoint between the requirements of 33% RPS (in 2020) and 50% RPS (in 2030), is 2024, which is also five years after the expected 2019 transition of residential customers to default TOU rates. That is an appropriate year to use in the marginal cost analyses for setting standard TOU periods from late 2018 through 2024 and beyond.[30]

B. The Net Load

The net-load curve is transforming the way that the CAISO manages the supply and demand of electricity during different times of the day. In addition to fundamentally changing system grid needs, the increased penetration of renewable generation has, and will continue to, dramatically change the utilities' cost drivers. SCE expects that the need to meet the evolving net system loads will cause the following changes to its hourly marginal costs:

- Negative or zero bound *marginal energy prices* are expected during hours of low demand and high solar production, typically mid-day in the spring and winter months.
- *Flexible resource capacity* will have to be made available and kept in reserve to meet ramp imbalance needs as solar production tapers off during the late afternoon hours.

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[28] Finding of Fact 126 of D.15-07-001, at page 319, states that this statute "… encourages the Commission to approve TOU periods 'that are appropriate for at least the following five years.'"

[29] SBX1-2

[30] In the TOU OIR, the IOUs were asked to provide marginal generation cost studies for the year 2021. While the data and analysis presented in this testimony and used to inform SCE's proposal reflect 2024 forecasts, SCE's marginal cost aggregation tool includes marginal cost studies for the year 2021. The differences in the marginal cost studies for 2021 and 2024 for the purposes of TOU-period determination are not significant.

- Net *system peak capacity* requirements will shift to later in the day due to the combined effect of solar production going offline and increasing demand in the evening hours.
- Increased penetration of Distributed Energy Resources (DERs) on distribution circuits will change the use of the distribution system and therefore the drivers of *marginal distribution* costs. Future distribution systems will need to allow for the bi-directional flow of energy to and from customers and provide sufficient capacity to meet time-sensitive peak needs on circuits. Increased BTM DG is expected to shift the need for peak capacity on the distribution system later in the day, resulting in "mini-duck" curves on individual distribution circuits.

Figure III-2, below, is a heat map that shows 2024 forecast average hourly net load on SCE's system for each hour of the day for each month and for weekdays and weekends. The colors indicate the hours where the net load is highest in red, lowest in green, and mid-range in yellow.

Figure III-2
SCE 2024 Forecast Average Hourly Net Load (MW)

Weekdays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	8,420	7,695	7,458	7,409	7,682	8,621	10,169	10,452	8,559	7,601	6,989	6,632	6,383	6,582	7,004	7,885	10,504	13,610	13,059	12,755	11,978	11,491	11,023	9,488
February	8,409	7,696	7,550	7,466	7,802	8,686	10,083	9,687	8,192	7,419	7,066	6,872	6,688	6,970	7,187	7,621	9,135	12,661	12,836	12,630	11,956	11,431	10,915	9,428
March	8,216	7,398	7,128	7,043	7,288	8,084	9,238	8,577	6,865	5,863	5,286	4,903	4,631	4,854	5,491	6,289	7,453	9,784	11,383	12,117	11,720	11,280	10,770	9,246
April	8,411	7,644	7,445	7,347	7,586	8,238	8,735	7,526	6,177	5,444	5,002	4,761	4,568	4,914	5,535	6,338	7,416	9,341	10,206	11,727	11,937	11,572	11,040	9,516
May	8,724	7,915	7,668	7,530	7,770	8,359	8,389	7,259	6,562	6,042	5,802	5,709	5,669	6,049	6,663	7,439	8,287	9,988	10,066	11,512	12,059	11,871	11,399	9,845
June	9,512	8,671	8,365	8,268	8,492	8,923	8,636	7,700	7,133	6,737	6,535	6,474	6,365	6,755	7,524	8,471	9,483	11,404	11,418	12,997	13,237	13,159	12,491	10,714
July	10,644	9,623	9,236	9,082	9,281	9,749	9,643	8,599	8,297	8,193	8,433	8,806	9,212	10,114	11,155	12,198	13,219	14,812	14,230	14,984	15,079	14,882	14,048	12,126
August	11,046	10,041	9,630	9,442	9,620	10,225	10,553	9,416	8,796	8,599	8,792	9,220	9,700	10,665	11,840	13,081	14,254	15,849	15,537	16,000	15,850	15,226	14,319	12,451
September	10,384	9,385	8,936	8,837	9,069	9,785	10,695	9,744	8,481	8,140	8,163	8,392	8,882	9,963	11,169	12,555	13,877	15,665	15,971	16,269	15,467	14,449	13,516	11,687
October	8,781	7,989	7,776	7,737	7,955	8,741	9,958	9,412	7,509	6,885	6,658	6,593	6,774	7,510	8,370	9,487	10,656	12,934	13,047	13,228	12,755	12,060	11,442	9,819
November	8,405	7,715	7,509	7,518	7,763	8,538	9,769	9,344	7,886	7,154	6,895	6,742	6,753	7,267	7,966	9,182	11,884	14,218	13,417	12,902	12,051	11,447	10,932	9,426
December	8,669	7,870	7,683	7,594	7,772	8,610	10,023	10,269	8,725	7,806	7,290	7,123	6,924	7,021	7,353	8,362	11,167	14,004	13,338	13,133	12,412	12,014	11,481	9,937

Weekends and Holidays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	8,021	7,404	7,152	6,982	7,006	7,290	7,759	7,539	6,047	5,503	5,060	4,832	4,602	4,631	5,057	5,852	8,973	10,685	11,173	10,960	10,404	9,978	9,574	8,496
February	7,904	7,360	7,231	7,053	7,208	7,463	7,846	7,077	6,017	5,605	5,479	5,201	5,078	5,289	5,445	5,896	7,868	9,985	11,043	10,951	10,467	10,016	9,466	8,385
March	7,429	6,867	6,733	6,499	6,534	6,883	7,114	5,929	4,529	3,834	3,386	3,166	2,940	3,071	3,590	4,398	6,192	7,337	9,709	10,498	10,249	9,973	9,499	8,345
April	7,644	7,038	6,888	6,742	6,809	6,980	6,605	4,991	3,832	3,293	2,984	2,771	2,647	2,887	3,333	4,019	5,701	6,256	7,957	9,548	9,989	9,801	9,425	8,338
May	8,040	7,357	7,068	6,818	6,849	6,914	6,192	4,834	4,348	3,981	3,784	3,760	3,716	3,939	4,429	5,042	6,456	6,783	7,729	9,354	10,011	9,920	9,547	8,507
June	8,722	8,082	7,749	7,477	7,462	7,477	6,481	5,177	4,764	4,597	4,473	4,419	4,309	4,438	4,917	5,651	7,305	7,870	8,910	10,738	11,123	11,154	10,554	9,149
July	9,531	8,788	8,382	8,180	8,122	8,038	7,214	5,856	5,620	5,444	5,622	5,966	6,289	6,805	7,498	8,193	9,728	10,077	10,703	11,813	12,082	12,037	11,456	10,189
August	10,254	9,431	8,978	8,695	8,587	8,627	8,239	6,716	6,087	5,962	6,231	6,679	7,153	7,918	8,875	9,855	11,415	11,708	12,426	13,269	13,401	13,029	12,210	10,737
September	9,523	8,718	8,293	8,149	8,123	8,218	8,139	6,900	5,853	5,642	5,863	6,248	6,740	7,522	8,497	9,563	11,285	11,839	13,360	13,785	13,149	12,282	11,433	10,130
October	8,189	7,526	7,326	7,217	7,145	7,359	7,655	6,747	5,206	4,799	4,651	4,659	4,831	5,367	6,083	7,105	8,935	10,024	11,151	11,422	11,068	10,437	9,854	8,664
November	7,513	6,884	6,679	6,619	6,769	7,047	7,378	6,551	5,422	4,852	4,725	4,545	4,476	4,783	5,410	6,581	9,944	10,945	11,169	10,949	10,348	9,769	9,331	8,221
December	8,228	7,534	7,309	7,178	7,179	7,463	8,005	7,755	6,636	6,002	5,645	5,462	5,219	5,153	5,421	6,469	9,898	11,511	11,707	11,586	11,071	10,759	10,158	8,899

C. Marginal Generation Energy and Capacity Costs[31]

The Commission's long-standing policy of developing marginal generation costs uses the deferral value[32] of a combustion turbine (CT) generator as a proxy for estimating the avoided cost of capacity, or marginal generation capacity cost (MGCC), and a system market energy price for estimating the avoided cost of energy, or marginal energy cost (MEC). This is an appropriate approach in California's current hybrid market, where energy procurement is transacted largely through market transactions, and capacity requirements are met through a combination of utility long-term procurement and annual resource adequacy (RA) requirements.

The MECs and system peak-related MGCCs were developed using methodologies similar to those typically used in SCE's GRC Phase 2 applications. In this instance, the marginal generation cost analysis should be expanded to account for ramp-related marginal capacity costs. SCE has developed a methodology, consistent with the methodology introduced in the TOU OIR and the principles established in the CAISO Flexible Resource Adequacy Criteria Must Offer Obligation (FRAC-MOO) proceeding, to functionalize the marginal capacity costs between system peak and ramp requirements, and to determine the hourly allocation of ramp-related marginal capacity costs. The following sections describe in more detail how these types of marginal generation costs are developed.

1. Marginal Energy Costs

a) Methodology and Data Sources

MECs equal the hourly long-term marginal wholesale CAISO market-clearing price. SCE develops a wholesale marginal energy price forecast using the PLEXOS production

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[31] The marginal generation costs presented in this application are largely consistent with those SCE presented in its July 11, 2016 Amended Response to the ALJ's March 17, 2016 Ruling Requesting Additional TOU Period Forecast Analysis with the following exceptions: SCE's generation capacity LOLE analysis was updated to correct a minor error, and SCE's generation capacity flex analysis was updated to move a portion of the costs from the third hour to the second hour of the ramp.

[32] That is, the annual cost of acquiring CT capacity in a single year is the full lifecycle cost of a CT (with replacement) procured at the beginning of the year, minus the full cost of a CT procured at the beginning of the next year. This is calculated using the real economic carrying charge (RECC) methodology.

simulation model. The PLEXOS model used in the price forecast is a California-only nodal model based on the Full Network Model (FNM) published by the CAISO on a regular basis. The PLEXOS model contains the following inputs:

- Gross load projections, which include the effects of on-site load impacts due to DERs, including DR, energy efficiency (EE), and DG such as rooftop solar, based on both SCE's internal load forecast and the California Energy Commission's (CEC)[33] forecast developed in the Integrated Energy Policy Report (IEPR) proceeding[34];
- Natural gas price forecasts for each "hub" based on SCE's internal forecasts, which SCE updates on a regular basis;
- Greenhouse Gas (GHG) compliance cost forecasts based on SCE's internal forecasts, which SCE updates on a regular basis;
- Transmission line and interface limitations based on the transmission capability of the interties and the CAISO Full Network Model;
- RPS trajectory for major Load Serving Entities (LSEs) including SCE, PG&E and SDG&E based on the RPS calculator;
- Generation profiles for the IOUs' RPS-eligible wind and solar resources based on the RPS calculator;

The forecast energy prices consist of the costs of incremental fuel, variable operation and maintenance (O&M), GHG compliance, startup, and no-load fuel costs. The energy prices include the costs related to congestion and line losses.

SCE uses PLEXOS, a commercial software program with a mixed integer programming (MIP) optimization engine, to perform the fundamental market simulations and model the CAISO day-ahead market auction. PLEXIS models the commitment and dispatch of available

[33] The CEC forecast is the mid-case and mid-AAEE adopted in the 2015 IEPR forecast.

[34] SCE uses IEPR forecasts for the rest of the state, and an internal forecast for SCE's planning area.

generation resources to meet demand and reserve requirements at least cost subject to transmission and individual generation resource constraints. The forecasted hourly energy prices from the simulations reflect the level of hourly net load served by dispatchable generation resources and their production cost.[35]

b) **Key Assumptions**

SCE's proposed MECs are consistent with those presented in SCE's July 11, 2016 Amended Response to the Administrative Law Judge's March 17, 2016 Ruling Requiring Additional TOU Period Forecast Analysis in the TOU OIR ("Amended Response"). As described in the Amended Response, the PLEXOS Model includes the following assumptions:

- 95% of renewable generation is scheduled in the CAISO day-ahead market;
- Economic curtailment of wind and solar generation is allowed by modeling a price-sensitive bid price;
- California exports during periods of over-generation are allowed by modeling price-sensitive loads at major intertie locations.

c) **Results**

The following heat maps reflect the average MEC in each hour of each month.

[35] Renewable generation resources including small-hydro, geothermal and biomass are self-scheduled. Price sensitive bids are created for wind and solar generation to allow for economic curtailment.

Figure III-3
SCE 2024 Forecast Average Hourly Marginal Energy Costs ($/kWh)

Weekdays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.049	0.048	0.047	0.047	0.048	0.050	0.058	0.062	0.049	0.046	0.045	0.044	0.041	0.042	0.043	0.046	0.057	0.081	0.077	0.071	0.063	0.060	0.055	0.051
February	0.048	0.047	0.047	0.047	0.048	0.050	0.059	0.053	0.047	0.044	0.043	0.043	0.042	0.042	0.043	0.044	0.049	0.067	0.076	0.073	0.065	0.060	0.054	0.050
March	0.047	0.046	0.046	0.046	0.046	0.047	0.052	0.049	0.045	0.040	0.037	0.032	0.027	0.030	0.038	0.040	0.042	0.050	0.062	0.079	0.069	0.061	0.056	0.049
April	0.046	0.044	0.044	0.044	0.045	0.047	0.051	0.044	0.040	0.035	0.032	0.030	0.028	0.029	0.036	0.038	0.040	0.044	0.050	0.069	0.071	0.058	0.052	0.047
May	0.046	0.045	0.044	0.044	0.045	0.047	0.047	0.043	0.039	0.037	0.037	0.037	0.036	0.037	0.038	0.040	0.041	0.045	0.047	0.063	0.071	0.062	0.054	0.048
June	0.047	0.045	0.045	0.045	0.046	0.047	0.046	0.042	0.039	0.038	0.038	0.039	0.038	0.039	0.040	0.042	0.044	0.050	0.048	0.065	0.074	0.070	0.057	0.049
July	0.049	0.046	0.045	0.045	0.045	0.047	0.046	0.043	0.040	0.041	0.042	0.044	0.046	0.049	0.053	0.056	0.060	0.073	0.059	0.096	0.079	0.070	0.060	0.053
August	0.049	0.047	0.046	0.046	0.046	0.048	0.050	0.045	0.043	0.042	0.042	0.043	0.044	0.046	0.049	0.053	0.060	0.074	0.065	0.092	0.080	0.067	0.059	0.053
September	0.049	0.047	0.046	0.046	0.046	0.049	0.055	0.049	0.044	0.042	0.042	0.042	0.043	0.045	0.048	0.050	0.057	0.073	0.090	0.106	0.074	0.062	0.057	0.051
October	0.048	0.047	0.046	0.046	0.046	0.048	0.054	0.054	0.045	0.042	0.041	0.041	0.042	0.043	0.045	0.046	0.048	0.062	0.073	0.079	0.067	0.060	0.056	0.050
November	0.049	0.047	0.047	0.047	0.047	0.049	0.055	0.050	0.046	0.044	0.044	0.043	0.043	0.044	0.045	0.048	0.061	0.089	0.076	0.068	0.063	0.059	0.054	0.050
December	0.050	0.048	0.048	0.048	0.048	0.050	0.057	0.057	0.049	0.047	0.046	0.046	0.045	0.045	0.046	0.048	0.060	0.084	0.077	0.073	0.066	0.062	0.059	0.052

Weekends and Holidays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.048	0.048	0.047	0.047	0.047	0.048	0.049	0.049	0.044	0.038	0.040	0.036	0.034	0.031	0.032	0.042	0.050	0.068	0.068	0.068	0.061	0.057	0.054	0.050
February	0.048	0.048	0.047	0.048	0.048	0.048	0.050	0.047	0.043	0.036	0.040	0.037	0.033	0.036	0.040	0.042	0.046	0.056	0.065	0.068	0.060	0.056	0.056	0.051
March	0.047	0.046	0.046	0.046	0.046	0.046	0.047	0.045	0.038	0.020	0.013	0.006	0.008	0.007	0.011	0.030	0.037	0.046	0.056	0.068	0.063	0.059	0.057	0.050
April	0.046	0.045	0.045	0.045	0.045	0.046	0.045	0.040	0.028	0.019	0.015	0.015	0.008	0.008	0.013	0.017	0.027	0.042	0.046	0.058	0.062	0.059	0.055	0.049
May	0.046	0.045	0.045	0.045	0.045	0.046	0.044	0.034	0.018	0.021	0.017	0.019	0.018	0.010	0.014	0.027	0.036	0.041	0.044	0.055	0.063	0.058	0.053	0.048
June	0.047	0.045	0.045	0.045	0.045	0.046	0.044	0.033	0.019	0.020	0.027	0.026	0.024	0.031	0.037	0.039	0.041	0.045	0.046	0.057	0.064	0.065	0.058	0.049
July	0.049	0.047	0.046	0.045	0.045	0.045	0.044	0.036	0.027	0.034	0.036	0.038	0.039	0.041	0.044	0.045	0.045	0.049	0.052	0.068	0.068	0.065	0.058	0.050
August	0.049	0.047	0.047	0.047	0.047	0.047	0.047	0.042	0.036	0.034	0.034	0.038	0.039	0.041	0.043	0.044	0.046	0.052	0.054	0.071	0.073	0.066	0.061	0.051
September	0.048	0.047	0.047	0.046	0.046	0.047	0.047	0.044	0.032	0.020	0.027	0.032	0.034	0.040	0.042	0.044	0.047	0.056	0.066	0.084	0.070	0.061	0.057	0.050
October	0.048	0.047	0.047	0.047	0.047	0.048	0.049	0.047	0.040	0.035	0.029	0.035	0.039	0.041	0.041	0.043	0.046	0.058	0.071	0.082	0.064	0.058	0.055	0.049
November	0.049	0.048	0.048	0.048	0.048	0.048	0.050	0.047	0.043	0.040	0.037	0.035	0.032	0.035	0.040	0.045	0.054	0.081	0.071	0.066	0.060	0.058	0.054	0.050
December	0.051	0.049	0.048	0.048	0.048	0.048	0.050	0.049	0.044	0.039	0.042	0.042	0.041	0.041	0.042	0.045	0.054	0.076	0.069	0.070	0.062	0.062	0.057	0.051

2. Marginal Generation Capacity Costs

As described in Chapter II and Section A of this chapter, marginal generation capacity costs (MGCC) have historically reflected the capacity cost of meeting system peak conditions. However, as intermittent renewable energy resource penetration has expanded throughout California, multiple parties have identified the need to enhance the Resource Adequacy (RA) program, or the system capacity framework, to include physical attributes for "flexible capacity."[36]

As the electric system evolves and California progresses towards its 50% RPS requirement, the need for flexible capacity will increase and require the utilities to assess the costs directly associated with the procurement of flexible capacity. For this reason, flexible capacity costs should be recognized as a cost driver relevant to TOU-period and TOU-price determinations, and these

[36] The Commission formally adopted a policy framework for incorporating flexible capacity needs as a part of the local capacity requirements for LSEs in 2013, and began including flexible capacity requirements in the 2015 RA Program.

costs should be determined by a marginal cost methodology consistent with the framework adopted in the CPUC's RA program.

In this section, SCE first describes the methodology for quantifying the annual marginal generation capacity cost. This annual marginal generation capacity cost is then allocated to each hour using the Loss of Load Expectation (LOLE) probability to estimate the hourly capacity costs associated with meeting system peak demand. Lastly, SCE explains how the traditional marginal generation capacity cost methodology has been expanded to account for the marginal costs associated with flexible capacity.

a) **Proxy Resource and Valuation**

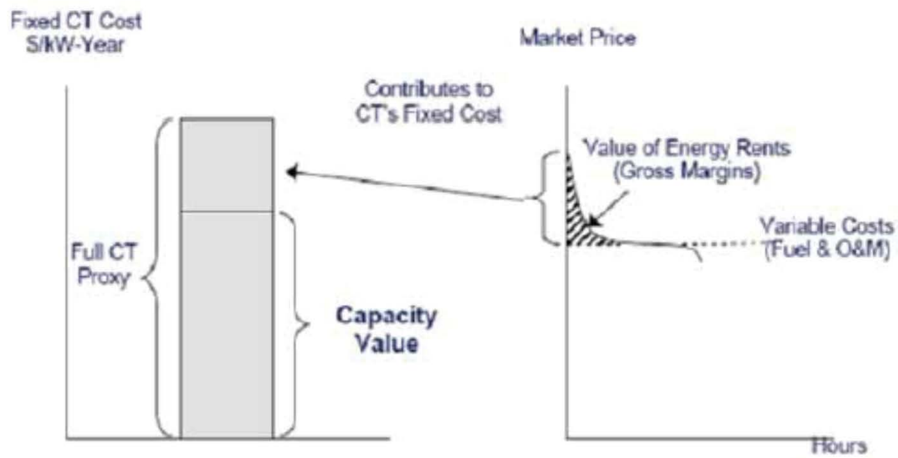
SCE bases the MGCC on the deferral value of a new build CT proxy resource.[37] The proxy is the estimated installed cost (in $/kW) for a new SCE-owned generation unit in the Southern California region, including all permitting, financing, development costs and inflation during the construction period. The annualized cost ($/kW-yr.) is then calculated using the RECC methodology, to which fixed O&M costs and property taxes are added to get the total annualized MGCC.

Due to the separation of capacity and energy prices, the CT proxy cost must be adjusted for any energy rents forecast to be obtained in the market in order to avoid overstating the isolated capacity value of the CT proxy. Energy rents are the operating profits that a proxy CT is able to earn from energy-related market awards when market prices are above the CT's variable operating costs, which principally consist of fuel, emission costs, and variable O&M. Because these energy rents reduce the CT's fixed costs that need to be recovered in capacity markets, energy rents are also known as energy-related capital costs (ERCC). For example, if the marginal energy price forecast is $90 per MWh, but the variable operating cost of a CT proxy is $60 per MWh for that same hour, then the CT

[37] This is typically thought of as the long-run value of capacity, while the short-run value of capacity represents the present day value of RA capacity. SCE has traditionally used the long-run value of capacity to determine revenue allocation and to set rates.

would realize a $30 per MWh contribution to its fixed costs and the value of energy rents (or ERCC) would be subtracted from the full CT proxy. The figure below illustrates this calculation.

Figure III-4
CT-Proxy Valuation



Following this approach, the annualized value of 30 years of energy rent revenues is divided by the CT's name plate capacity, which will give an energy rent value in $/kW-year. That value is then subtracted from the CT proxy's capacity value.

CTs have historically been the generators used to provide marginal system capacity. As the need for flexible, marginal capacity increases, CTs should continue to be considered the generator of choice for this exercise due to their relatively-low marginal cost, ability for fast dispatch, fast start-up times, and ramping capabilities.

The long-run value of capacity is typically used to quantify the cost associated with the need for an additional MW of capacity needed to prevent a shortfall. With the increased supply of energy from RPS-eligible resources, CAISO level grid operating constraints will evolve into a balance of capacity resources needed for both peak and ramping system needs in the future. SCE used the long-run value of capacity in this proceeding consistent with previous GRC proposals.[38] However, SCE is now proposing a joint allocation method for peak and flex (ramp) capacity needs, premised on the fact that a similar type of flexible CT resource will effectively meet both of these needs in the future.

To use non-confidential values in this proceeding, SCE used the installed cost of an advanced 200 MW CT from the March 2015 CEC's "Estimated Cost of New Renewable and Fossil Generation in California" Report. Using the methodology discussed above for this CT proxy and the MECs developed in Section C.1, SCE derived an annual marginal capacity cost of 147.26 $/kW-year.

b) <u>System Peak Capacity Cost Allocation</u>

(1) <u>Loss of Load Expectation (LOLE) Methodology</u>

The traditional valuation of generation capacity for purposes of establishing marginal costs is based on the likelihood that the electric system will be unable to serve customer demand in any given hour. There is always some likelihood, however small, that the system will be unable to serve demand due to insufficient availability of generation relative to the electricity demanded by customers. The risk of a generation shortage can be reduced by having more generation available than forecast peak demand (*i.e.*, a reserve margin), but this additional generation capacity imposes costs on customers. Determining the optimum supply-and-demand balance requires the study of expected system operations using a probabilistic risk-assessment approach. Analysis of a system's Loss of Load Expectation (LOLE) is one appropriate risk-assessment approach— LOLE is a measure of system reliability that predicts the ability (or inability) to deliver energy to the load. An LOLE analysis can provide insight into the planning reserve margin required for each LSE in a region.[39]

The relative LOLE provides a method for allocating annualized capacity value across hours in proportion to when the loss of load (i.e., insufficient capacity to serve demand) is

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[38] While the decision to use long-run or short-run values of capacity may significantly impact revenue allocation and rate design, it does not impact the selection of TOU periods. To illustrate this, SCE has provided in its marginal cost aggregation tool the ability to modify the capacity value.

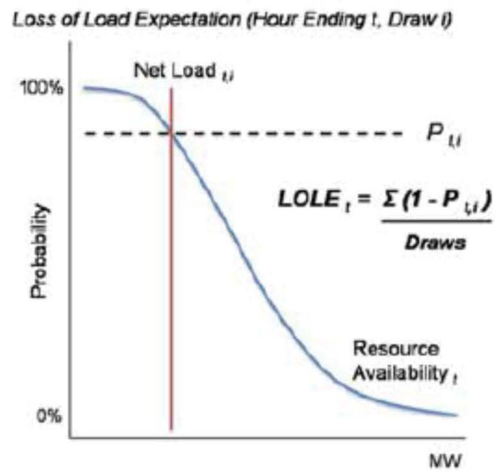
[39] In D.04-10-035, the Commission directed LSEs under its jurisdiction to plan based upon meeting a 15 to 17 percent RA requirement. This implicitly reflects a balancing of customer risks and costs.

likely to occur.[40] If the relative LOLE is greatest in the summer period primarily due to load conditions, particularly during the on-peak period, then most of the value that SCE attributes to generation capacity marginal costs will be assigned to that period. Similarly, if the relative LOLE is nearly zero during the winter off-peak period, SCE will assign very little capacity value to that period.

To develop the hourly MGCC allocation, SCE uses 30 historic weather years and a forecast of expected load in 2024 to create 30 possible 2024 annual peak demand and hourly consumption scenarios. Daily wind and solar generation forecasts are then randomized against load, by month, to generate approximately 3,600 possible net-load forecasts for each day in the model year 2024. These daily net-load forecasts are then sampled and compared to a distribution of non-intermittent-resource availability, adjusted for expected maintenance and forced outages, to determine the LOLE in each hour. This approach provides a reasonable estimate of the relative risk of being unable to serve some portion of system net load in any given period. Figure III-5 below illustrates this process. As the resources required to serve load increases (MW X-axis), the probability of being able to serve that net load decreases (Probability Y-axis). The hourly LOLE is then normalized over all hours of the year such that the sum of the normalized or relative LOLE equals 1. This creates a relative relationship of the hourly LOLE across time.

[40] The purpose of SCE's LOLE analysis is not to forecast the precise timing of future low-reserve margin events, nor is it to forecast the absolute magnitude of any single loss-of-load event. Rather, it is intended to be a relative distribution of risk used to allocate capacity value across hours.

Figure III-5
Illustration of Hourly LOLE Calculation



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(2) <u>Results</u>

SCE's loss-of-load analysis shows a high concentration of relative LOLE in September, which historically matches SCE's system peaks. Based on the relative LOLE results by hour, for the year 2024, SCE's existing summer season contains nearly all (99.7%) of the relative LOLE, with the months of August and September accounting for approximately 94%, as can be seen in Figure III-6. Additionally, SCE's analysis estimates that 97% of the relative LOLE will occur between 5:00 p.m. and 9:00 p.m.[41] (*i.e.,* HE 17 – HE 21), with 80% occurring between 6:00 p.m. and 8:00 p.m. (HE 19 – HE 20), when the sun sets, as can be seen in Figure III-7. Weekdays accounted for 97.4% of relative LOLE, while weekends accounted for only 2.6% of relative LOLE.

[41] Results are in Pacific Prevailing, or Clock, Time.

Figure III-6
Relative LOLE by Month

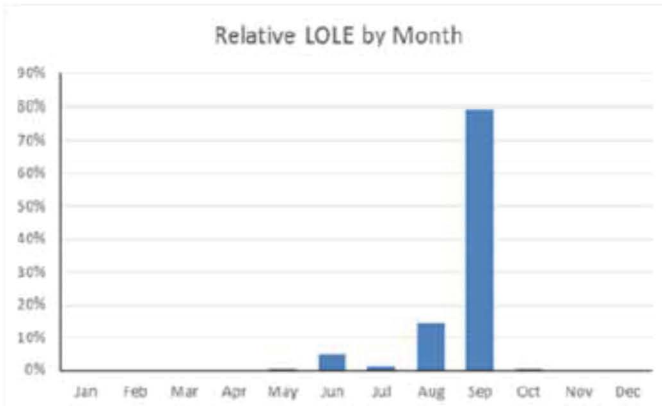
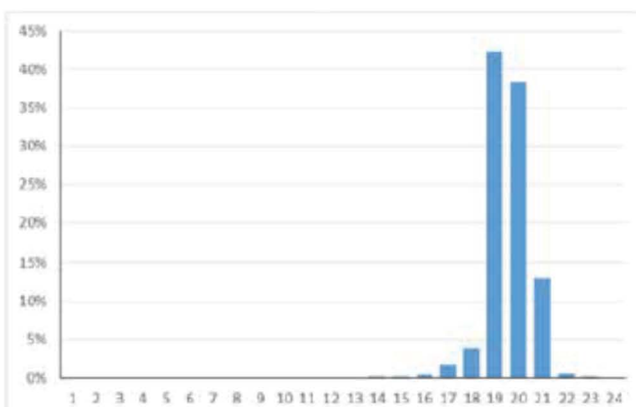


Figure III-7
Relative LOLE by Hour



SCE multiplies the relative LOLE in each hour by the annual capacity value ($147.26 per kW-year) to determine the hourly marginal generation capacity costs. The results of this analysis are shown below in Figure III-8.

Figure III-8
SCE 2024 Forecast Average Hourly Marginal Generation Capacity Costs (System Peak Only) (\$/kWh)

Weekdays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.004	0.007	0.010	0.165	0.164	0.009	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.011	0.031	0.002	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.003	0.008	0.007	0.054	0.621	0.214	0.004	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.003	0.023	0.107	0.249	2.665	1.789	0.441	0.019	0.000	-
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.004	0.011	0.002	0.000	0.000	0.000	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

Weekends and Holidays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.015	0.035	0.002	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.008	0.081	0.035	0.001	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.002	0.003	0.017	0.739	0.256	0.084	0.005	0.000	-
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-

c) Flexible Capacity Cost Allocation – Ben Baker

(1) Background

In addition to the traditional LOLE method used to allocate peak capacity costs, SCE is proposing to value capacity pursuant to its ability to provide ramping/flexibility services. In this context, "flexible capacity" is the ability of certain generation resources to sustain or increase output during the greatest upward three-hour net-load ramp in each month.[42] In recognition of the year-round need for ramping capacity on the grid, the CAISO developed an interim solution to ensure the availability of enough flexible generation in the markets. The mechanism, known as FRAC-MOO, established the interim definition of flexibility that has been developed into a market product. Although

[42] The CAISO FRAC-MOO website is *available at* https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx

the FRAC-MOO proposal has yet to be accepted as the final solution for California's flexibility issues,[43] SCE used its definitions and rules to define and characterize flexible resources for valuation purposes here.

There are two parts (supply and demand) to the flexible shortfall calculation in FRAC-MOO: (1) calculation of the effective flexible capacity ("EFC") (supply), and (2) definition of the flexible capacity need (demand). Generation resources' ability to qualify as "flexible capacity" is defined by its EFC. EFC is similar to the concept of Net Qualifying Capacity ("NQC") in the RA program, in that both programs define how much of a generator's capacity can be counted up for reliability purposes. While NQC is a peak capacity program that defines the amount of a generator's capacity that can be used to meet system peak requirements, EFC defines the amount of a generator's capacity that can be used to meet a three-hour upward net-load ramp on the system. Additional detail on determining EFC can be found on the CAISO FRAC-MOO website.[44]

Flexible capacity needs are defined as the quantity of resources needed by the CAISO to manage grid reliability during the greatest three-hour continuous ramp in each month. Once the overall monthly flexible need is determined, it is further refined into three categories, as defined by the CAISO FRAC-MOO proposal: Base Ramp—the largest morning upward ramp; Peak Ramp—the overall flexible need less the Base Ramp; and the Super-Peak Ramp—can be up to 5 percent of the maximum upward three-hour net-load ramp of the month.[45] These categories can then be evaluated to determine if and when there is a system shortfall of EFC. While the identification of

[43] The CPUC is looking to establish a durable flexible product in Track 2 of the RA Proceeding. *See* R.14-10-010, *Assigned Commissioner and Administrative Law Judge's Phase 2 Scoping Memo and Ruling*, December 23, 2015, pp. 3-5.

[44] The CAISO FRAC-MOO website is *available at* https://www.caiso.com/informed/Pages/StakeholderProcesses/FlexibleResourceAdequacyCriteria-MustOfferObligations.aspx [as of August 30, 2016].

[45] CAISO definitions of generator characteristics necessary to meet each of these ramping categories can be found on its FRAC-MOO website, *supra*. Additionally, the latest list of CAISO generator categories and EFC values can be found on the CAISO's website, *available at* https://www.caiso.com/Pages/documentsbygroup.aspx?GroupID=9A94E71F-5542-49E8-BFBF-B9E00A2EC11B [as of August 30, 2016].

system need for EFC is not within the scope of this proceeding, a methodology, similar to the LOLE, of identifying the most likely hours of flexible capacity need is the proper approach to ultimately calculate and allocate the marginal costs associated with flexible capacity.

(2) **Allocation Methodology**

SCE utilized the CAISO FRAC MOO guidance document in developing the deterministic approach to allocating flexible capacity costs to each hour in a year:

1. Each CAISO daily maximum three-hour upward ramp is grouped according to the hour in which the ramp ends, resulting in a model in which the maximum three-hour upward ramp is represented by a value, based on the amplitude of the ramp, in a single hour.[46]
2. Each value is then normalized by the sum of all of the daily maximum three-hour upward ramps.
3. The costs are then allocated to the 2nd and 3rd hour of the ramp using a 30/70 percent split.

This deterministic approach essentially identifies all hours in which a three-hour ramp need may occur, and assigns weights based on the heights of the ramp (*i.e.*, a three-hour ramp of 4,500 MW will be assigned three times the weight of a three-hour ramp of 1,500 MW)..[47] This method utilizes only one year of data and does not directly account for the likelihood of the CAISO's fleet of EFC resources being able to serve load. Instead, each day's largest three-hour upward ramp is compared against the sum of all the other daily max ramps in the year and assigned a relative weight. This weighted approach properly identifies the occurrences of greatest ramp need, and allocates the flex capacity cost accordingly.

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[46] The end of the ramp is the targeted hour in which flex need is allocated, as it informs the period during which load should be reduced to lessen the three-hour ramp.

[47] As this process is refined, a more probabilistic approach, similar to LOLE, which utilizes multiple years of data and measures the ability of the fleet's available EFC to serve the ramp may be developed for flexible capacity revenue allocation purposes.

SCE allocates the flexible capacity cost to the second and third hours of the ramp because the goal is to send a price signal that will lessen the effect of large ramps that may cause system reliability issues. Applying higher costs at the end of the ramp will incentivize customers to reduce their load closer to the peak, which in turn lowers the ramp need. If costs are spread to the beginning of the ramp, thereby incentivizing a reduction in usage during the "duck belly," the ramp may simply be "stretched," or delayed (in the case of an equal allocation to each hour of the three-hour ramp), or exacerbated (in the case of the majority of costs allocated to the first hour).[48] Spreading costs between the second and third hours, with more weight assigned to the third hour, will incentivize customers to begin reducing usage as demand approaches its peak, thus reducing the overall ramp need. This is included in SCE's proposal through a 30/70 percent split of ramp cost to the 2nd and 3rd hour of the ramp respectively, as seen in Figure III-9, below.

Figure III-9
Allocation of "Ramp Cost"

48 Lower cost incentives due to oversupply can be given to customers at the base of the ramp to help increase load during the "duck belly" and flatten the demand curve.

(3) Results

SCE's flexible resource cost allocation study demonstrated that most of the flexibility "shortfall" occurs in hours ending 17 and 18. The cost of ramps were spread to each month based on its average ramp height. These results are seen in the following Figure III-10.

Figure III-10
SCE 2024 Forecast Average Hourly Marginal Generation Capacity Costs (Flex Capacity Only)
($/kWh)

Weekdays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	0.000	0.000	-	-	-	-	-	-	-	0.000	0.001	0.001	0.000	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	0.001	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	0.000	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.002	0.000	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.002	0.000	-	-	-	-
June	-	-	-	-	-	-	-	-	-	0.000	0.000	-	-	-	-	-	-	0.001	0.001	0.001	-	-	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.002	-	-	-	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	-	-	-	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.002	-	-	-	-	-
October	-	-	-	-	-	-	0.000	0.000	-	-	-	-	-	-	-	-	0.000	0.001	0.001	-	-	-	-	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.002	0.000	-	-	-	-	-

Weekends and Holidays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	0.000	0.000	-	-	-	-	-	-	-	-	0.001	0.001	0.000	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.001	0.001	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	0.000	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.001	0.002	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	0.000	-	-	-	-
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	0.000	-	-	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.002	-	-	-	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	0.001	-	-	-	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.002	-	-	-	-	-
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.001	-	-	-	-	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.001	0.001	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.002	-	-	-	-	-	-

d) Allocation of CT Proxy between System and Flex Needs and Final Results–Ben

Typically, the MGCC is determined by allocating the annual capacity value solely to the hours of likely shortfall identified by the LOLE model. However, by including flexibility in the allocation model, the annual capacity value ($147.26 per kW-year) should now be allocated to hours of likely "peak" shortfall, as identified by the LOLE model, as well as to hours of likely "flexibility" shortfall.[49] To determine the appropriate allocation between the two functions, SCE modeled the statewide 2021 and 2024 net loads[50] to forecast future NQC and EFC needs, and determined the annual maximum peak load requirement and the annual maximum ramp requirement for each year. The ratio of the maximum ramp requirement relative to the maximum peak load requirement determines the percentage of capacity value allocated to the flexibility function, and the remaining percentage of MGCC is allocated to the peak load function[51].

$$FLEXCost = \left(\frac{MaxThreeHourNetLoadRamp_{CAISO}}{MaxPeak_{CAISO}}\right) * MCC$$
$$LOLECost = \left(1 - \left(\frac{MaxThreeHourNetLoadRamp_{CAISO}}{MaxPeak_{CAISO}}\right)\right) * MCC$$

Based on this calculation, SCE estimates that 40% (or $58.90 per kW-year) of the annual marginal capacity costs should be allocated to the flexible capacity function, and 60% (or $88.36 per kW-year) of the annual marginal capacity costs should be allocated to the system peak capacity function.

Functional MGCCs are then allocated to each hour based on its respective allocation methodology (LOLE and the flexibility methodology described above in Section III.2.b) to determine the final marginal cost allocation of the MGCC.

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[49] Although SCE has developed a proxy methodology for allocating the marginal costs between peak capacity and flexible capacity here, SCE continues to support bundling flexible capacity with generic capacity for procurement transactions.

[50] Net loads were modeled using IEPR targets applied to Transmission Expansion Planning Policy Committee ("TEPCC") shapes from the 2024 common case.

[51] SCE is proposing a functional apportionment of the proxy's annual capacity value between Flex and Peak. As the state progresses to a 50% RPS target, flexible resources that have historically been used to meet system peak demand will also be increasingly used to meet steep ramp needs.

Figure III-11
SCE 2024 Forecast Average Hourly Generation Capacity Marginal Costs (System Peak + Flex) ($/kWh)

Weekdays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	0.004	0.009	-	-	-	-	-	-	-	0.006	0.037	0.064	0.020	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.030	0.081	0.042	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.017	0.073	0.083	0.015	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.047	0.112	0.008	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.041	0.096	0.010	0.000	-	-	-
June	-	-	-	-	-	-	-	-	-	0.001	0.002	-	-	-	0.000	0.001	0.002	0.034	0.088	0.129	0.098	0.005	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.042	0.099	0.007	0.019	0.001	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.016	0.067	0.120	0.373	0.128	0.002	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.014	0.069	0.207	1.710	1.073	0.265	0.012	0.000	-
October	-	-	-	-	-	-	0.001	0.002	-	-	-	-	-	-	0.000	0.000	0.020	0.079	0.076	0.001	0.000	0.000	0.000	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.025	0.087	0.066	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.055	0.131	0.005	-	-	-	-	-

Weekends and Holidays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	-	-	-	-	-	-	0.003	0.008	-	-	-	-	-	-	-	-	0.035	0.088	0.016	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.003	0.015	0.051	0.075	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.020	0.072	0.067	0.014	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.005	0.011	0.041	0.095	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.004	0.042	0.082	0.010	0.000	-	-	-
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.004	0.039	0.077	0.018	0.001	0.000	-	-
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.044	0.102	0.009	0.021	0.001	-	-
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.018	0.051	0.039	0.041	0.048	0.021	0.000	-	-
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.001	0.002	0.063	0.567	0.153	0.050	0.003	0.000	-
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.029	0.089	0.050	0.000	0.000	0.000	0.000	-
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.020	0.083	0.082	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.055	0.129	-	-	-	-	-	-

D. Marginal Distribution Costs

Distribution marginal costs have typically been categorized into design demand and customer-related components. Customer-related costs[52] are designed to collect some "fixed" portion of the utility's distribution costs—that is, the costs[53] of connecting a new customer to the grid that are not considered to be dependent on the level of demand or usage of the system, plus any marginal costs of providing service to customers. The remaining portion of distribution marginal costs are associated with design demand, or distribution capacity, and are typically considered "peak load driven" costs. To maintain service reliability and to meet the demand needs of our customers, SCE expands, upgrades, and reinforces all levels of its electric system, including transmission, sub-transmission, and distribution

[52] Customer charges are collected as fixed charges on a per-customer-per-month basis for non-residential customers. While SCE does have fixed customer charges for its residential customers, those are currently established at less than $1 per month.

[53] Such customer connection costs have typically included the cost of the final line transformer, service drop and the meter.

assets. SCE uses peak load data and load growth forecasts to evaluate whether existing distribution facilities will exceed their loading thresholds (also known as a planning load limit) under normal and abnormal[54] conditions, and plans infrastructure projects to mitigate existing and expected constraints.[55]

Pursuant to a term in the Marginal Cost and Revenue Allocation Settlement agreement adopted in D.16-03-030, SCE agreed to review the time-differentiation of distribution costs in this proceeding.[56] The state policy of promoting customer choice in the adoption of customer-sited renewable energy systems (DERs) will significantly change the landscape of the electrical system of the future and affect the drivers of distribution marginal costs. The distribution grid will increasingly serve two different functions: (1) a peak capacity function to meet peak customer demand, which is time-dependent (and should be used to inform the hourly allocation of distribution costs); and (2) a grid or network function that enables the bi-directional transfer of energy to and from customers, which is not time- or peak-dependent. SCE developed a methodology to split design demand distribution marginal costs into these two components, which should be used on an interim basis in this proceeding, with the expectation that SCE will include a more comprehensive evaluation of distribution costs in SCE's 2018 GRC Phase 2 proceeding.

SCE has traditionally used an "Effective Demand Factor" (EDF) analysis, which estimates each rate group's (coincident) contribution to typical distribution circuit peaks to allocate design demand marginal cost revenue across rate groups.[57] While such a method accounts for some time-dependency of distribution marginal costs (*i.e.,* through the *revenue allocation* stage), SCE currently uses non-time-

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[54] Abnormal conditions include, for example, planned facility outages for maintenance, unplanned facility outages due to equipment failures, and facilities removed from service because of a fault on the system.

[55] This planning process is described in detail in SCE's 2018(Transmission and Distribution Volume 3 – System Planning Projects) GRC Phase 1 application.

[56] *See* Paragraph 4.C.1. of the Marginal Cost and Revenue Allocation Settlement Agreement, which provided, in part, that "As part of its 2016 RDW filing, SCE will include a new study of the time-dependence, and, at its option, the temperature-dependence, of its marginal subtransmission and distribution costs." SCE found that hours of high temperatures did not always coincide with hours of high marginal distribution costs. *See* SCE's July 19 Reply Comments in R.15-12-012.

[57] *See* A.14-06-014, Exhibit SCE-02, Appendix B.

differentiated charges to recover such costs from customers. With deployment of smart meters now complete, mandatory TOU rates implemented for non-residential customers, and default TOU for residential customers expected to begin in 2019, time-differentiated distribution costs can now be more precisely recovered from specific customers who demand power during distribution circuit peak periods (*i.e.*, through the *rate design* process).

In this section, SCE presents an asset accounting-based methodology to distinguish between peak- and grid-related distribution marginal costs, and a methodology to determine the hourly allocation of the peak-related distribution marginal costs.

1. <u>Differentiation between Fixed and Peak Capacity-Driven Distribution Design Demand Costs</u>

SCE expects to expand the definition of design demand distribution marginal costs in its 2018 GRC Phase 2 application. Here, SCE is only proposing a methodology to split design demand costs into peak- and grid-related sub-components. The peak sub-component is time-differentiated and its hourly allocation is included in the TOU period marginal cost analysis. The grid sub-component is not time-differentiated and is therefore excluded from the TOU period marginal cost analysis.

The NERA/FERC method categorizes peak- and grid-related design demand costs based on recorded investments in SCE's FERC Form 1 filing.[58] The analysis uses the existing FERC asset class-differentiated accounting to differentiate between expenditures that are typically driven by peak load needs and those that are not. This approach is complementary to SCE's existing process of GRC Phase 2 distribution marginal cost valuation, wherein SCE uses the GRC Phase 1 forecast of capital expenditures in those accounts as an input to its Design Demand regression model.

Sub-transmission (66kV and 115kV) capital expenditures are recorded to FERC accounts 350 through 359. 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

[58] SCE's FERC Form1 filing captures invested capital, by asset class and by FERC accounts.

demand marginal costs. Distribution capital expenditures are recorded to FERC accounts 360 through 370, as shown in Figure III-12, below.

Figure III-12
Distribution Plant Account FERC Form 1 Classifications

		Distribution Plant		
Asset Class	Costs	Acct#	Description	
Land	Design Demand	360	Land and land Rights	
Substations	Design Demand	361	Structures and Improvements	
Substations	Design Demand	362	Station Equipment	
Lines	Design Demand	364	Poles, Towers, and Fixtures	
Lines	Design Demand	365	Overhead Conductors and Devices	
Lines	Design Demand	366	Underground Conduit	
Lines	Design Demand	367	Underground Conductors and Devices	
Lines	Customer	368	Line Transformers	Customer Marginal Costs accounts
Lines	Customer	369	Services	
Meters	Customer	370	Meters	

The basis of SCE's proposed FERC-account based bifurcation of design demand marginal costs is the following:[59]

- The cost of land for distribution substations and lines is driven by the physical connectivity of customers to the grid; therefore, all such costs as recorded in FERC account 360 are categorized as part of the grid component of design demand marginal costs.
- Distribution substation assets are generally designed and planned to consider coincident peak load needs; therefore, all such costs, as recorded in FERC accounts 361 (Substation Structures and Improvements) and 362 (Substation Equipment), are categorized as part of the peak capacity component of design demand marginal costs.

[59] Assets recorded in accounts 368 (Line Transformers), 369 (Service Drops) and 370 (Meters) are typically classified as customer-related marginal costs. Because SCE is only analyzing design-demand costs for the split between peak capacity and grid-related costs, customer- related costs and accounts have been excluded from the TOU period analysis.

- Distribution Lines for circuitry are installed to meet both peak-load-driven needs and to provide access or connectivity to the grid. Consistent with the FERC method of using transmission circuit miles as a means of allocating costs between ISO and Non-ISO jurisdictional assets, SCE proposes to use distribution circuit miles, as the basis of allocating design demand marginal costs between those that are peak-load-driven and the those that are grid related. A more detailed calculation of the main and radial split is included below.
  - Main Line - Primary Voltage (12kV to 33kV) circuit miles form the basis of apportioning distribution line costs to the peak capacity component of design demand marginal costs.
  - Radial Line - Primary Voltage circuit miles, inclusive of Secondary Voltage (600V and below) circuit miles form the basis of apportioning distribution line costs to the grid-related component of design demand marginal costs.
  - An analysis of SCE's 2015 distribution system circuit miles demonstrated that approximately 26 percent of the circuit miles were main circuit miles and 74 percent of the circuit miles were radial and secondary voltage circuit miles.

The capital expenditures recorded in each of these FERC accounts and the peak- and non-peak-related percentages are detailed in Figure III-13.

Figure III-13
NERA - FERC Method ($000)

Category of Costs	FERC Accounts	Total 2006-15 Capital Expenditures	Peak-Related	Non-Peak-Related
Sub-Transmission	CPUC-Jurisdictional 350-359	$2,910,201	100%	0%
Distribution Land	360	$27,485	0%	100%
Distribution Substations	361, 362	$1,107,324	100%	0%
Distribution Lines	364, 365, 366, 367	$4,609,439	26%	74%

The NERA – FERC based peak- and non-peak-related percentages, by category, are then multiplied by the capital expenditures to calculate the total design demand peak- and non-peak-related allocation, as detailed in Figure III-14.

Figure III-14
Final Design Demand Peak- and Non-Peak-Related Allocation ($000)

Category of Costs	Peak-Related	Non-Peak-Related
Sub-Transmission	$2,910,201	$0
Distribution Land	$0	$27,485
Distribution Substations	$1,107,324	$0
Distribution Land/Lines	$1,198,454	$3,410,985
Total Expenditures	**$5,215,979**	**$3,438,470**
Total Design Demand Allocation	**60%**	**40%**

The results indicate that approximately 60 percent of the design demand marginal costs should be allocated to peak-capacity-related marginal costs. This allocation was used in factoring the appropriate level of distribution system costs when determining the proposed TOU periods.

2. Peak Load Risk Factor (PLRF)

Once design demand distribution marginal costs have been split between those that are peak-driven and those that are grid-related, the following PLRF methodology is an appropriate way to determine its hourly allocation. The methodology 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. This is consistent with the methodology described in SCE's April 29 Comments in the TOU OIR.

When reviewing capacity needs for distribution circuits and substations, system planners utilize "planning thresholds" as the primary trigger for a more comprehensive review of capacity needs. One such trigger occurs when the peak circuit load is expected to reach 73 percent of the average Planned Loading Limit (PLL) of the all circuits connected to a single substation. This analysis identifies the potential for a capacity assessment on distribution circuits.[60]

The Peak Load Risk Factor (PLRF) method uses a two-step approach and leverages such a planning trigger when identifying the hours in which a distribution circuit may exceed the trigger. First, hours in which circuit load falls below the 73% planning threshold value are assigned a value of zero, and hours in which circuit load exceeds its threshold are considered "peak loads," are assigned a value of one, and included in the next step of the analysis.

$$Peak\ Load_{i,j} = \begin{cases} 0 & if\ \ Load_{i,j} < Threshold_j \\ Load_{i,j} & if\ \ Load_{i,j} \geq Threshold_j \end{cases} \quad (1)$$

where i= 1 to 8760[th] hour, j=1 to nth circuit.

Second, the number of peak load occurrences are then summed for all circuits in each hour[61] (equation 2, below) and a relative ratio[62] is determined for these hourly load values (equation 3). This relative ratio is called the PLRF.

$$Peak\ Load_i = \sum_{j=1}^{n} Peak\ Load_{i,j} \quad (2)$$

[60] The physical scheduling of new circuit capacity is initiated only when the criteria projected load reaches 100 percent of the PLL. Distribution Planning criteria states that the maximum projected load on a distribution circuit should not exceed a rated value of 550 amps, implying that on average normal projected load should not exceed 400 amps (400/550 = 73 percent).

[61] Because a small percentage of SCE's distribution circuits are customer-owned, or they have a single customer contributing to more than 50% of circuit load, these circuits are not representative of the entire population nor represent SCE's typical costs, and are therefore excluded from the analysis.

[62] This relative ratio defines the percentage load in an hour to the sum of the total peak load for each hour in the year, given the 73 percent threshold.

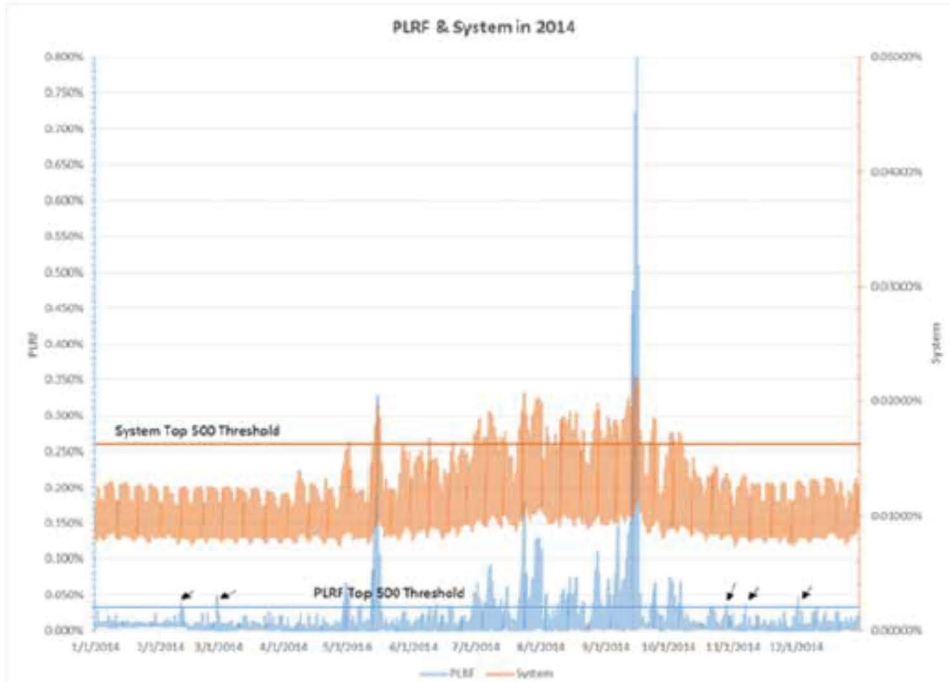
$$PLRF_i = \frac{Peak\ Load_i}{\sum_{i=1}^{8760} Peak\ Load_i} \quad (3)$$

Load Diversity: SCE's distribution system has evolved over time as load has grown across SCE's service territory. This growth has resulted in a variety of circuit load profiles and configurations across SCE's distribution system. In order to capture the effect of this load diversity across circuits, the PLRF load by hour is first identified for each circuit (equation 1) and then aggregated across all circuits on the system (equations 2 and 3).

Figure III-15 illustrates how the PLRF method captures the effect of circuit diversity. The graph, based on 2014 hourly load data, compares SCE's hourly system load (expressed as a percentage of the sum of all the hourly system loads in the year) to the PLRF percentage values described above.[63] While the graph demonstrates that peak load patterns on individual distribution circuits are largely consistent with peak load patterns on the system as a whole, the arrows highlight the hours where the circuits "peak," but the system does not. This helps illustrate that the sequential step of first identifying the PLRF load by hour on each circuit and then aggregating such load across all circuits captures the effect of load diversity across the circuits.

[63] The graph has dual y-axes, with the PLRF percentages represented on the left axis and the system load percentages represented on the right axis. The x-axis represents a chronological layout of 8,760 hours of the year. A peak threshold line for the top 500 hours for the system and the top 500 hours for the PLRF values was drawn.

Figure III-15
Circuit PLRF and System Load in 2014[64]



Analysis based on future test year - 2024: As discussed above in Section A.3 of this chapter, an analysis of forecast conditions in 2024 should be used because it is important to capture the effect of the forecast increased penetration of DERs, specifically DG, on distribution circuit peak loads. SCE expects that with increased penetration of DG, the timing of circuit peak demands will shift to later in the day, similar to the CAISO system-level duck curve, except that it will also be observed on the distribution circuits and substations (*i.e.*, "ducklings"). SCE forecasted 2024 hourly circuit load using a two-step process:

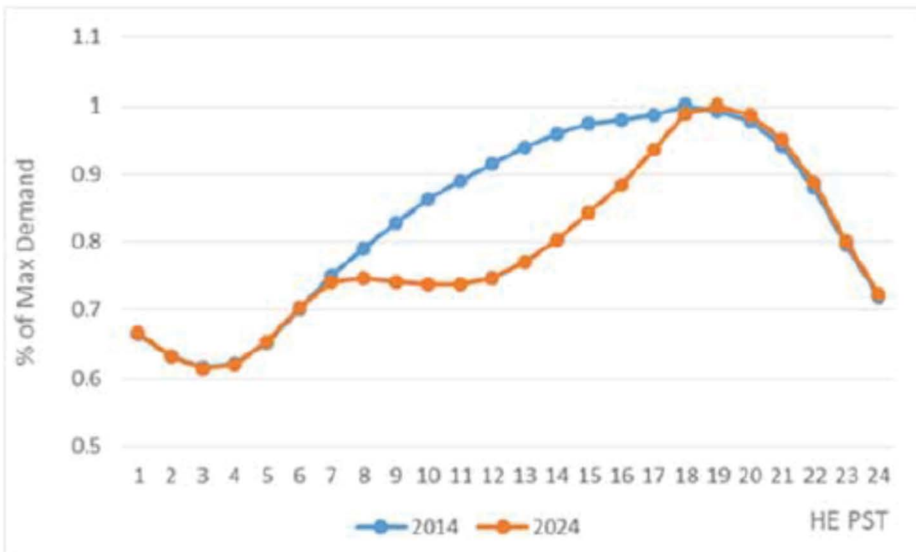
1. SCE forecast the penetration of DG on each circuit by applying a system-level growth rate of DG installations to the current penetration of DG on each circuit.

[64] Recorded data for 2014 is used in this figure to demonstrate the efficacy of the PLRF method in capturing circuit diversity. All other analysis in this chapter uses forecast 2024 data.

2. SCE netted this forecast 2024 hourly DG shape against 2014 hourly circuit load.[65] This method accounts for the impact of increased DG penetration on hourly circuit load while isolating the effects of load growth on circuits.

Figure III-16, below, compares the average hourly weekday profile for the years 2014 and 2024 after including expected DG penetration in the year 2024.[66]

***Figure* III-16**
2014 vs. 2024 Average Weekday Circuit Load - Normalized



PLRF values were then calculated based on this netted load shape. To adjust for season and day type for the year 2024, the forecast 2024 gross load and recorded 2014 gross load were both sorted and paired by season, day type, and load.

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[65] By netting against 2014 hourly load, by circuit, SCE held constant the possible effects of load growth on the *shape* of the hourly circuit load. By using a solar shape based on an estimate of the levels of DG penetration expected in the year 2024, SCE isolated the effect of increased DG penetration on the hourly *shape* of circuit load. This analysis was done for each circuit to capture the varying levels of penetration that can be expected on each circuit.

[66] Average weekday hourly load for both years was normalized to the maximum value of average hourly load in 2014.

3. Results

The PLRF percentages were then multiplied by the peak-capacity-driven portion of marginal distribution costs to determine the hourly allocation of marginal distribution costs.

Figure III-17
SCE 2024 Forecast Average Hourly Peak Component of Distribution Design Demand Marginal Costs($/kWh)

Weekdays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.002	0.001	0.001	0.001	0.001	0.003	0.007	0.006	0.006	0.005	0.003	0.002	0.003	0.003	0.004	0.006	0.006	0.024	0.018	0.015	0.010	0.007	0.008	0.005
February	0.002	0.001	0.001	0.001	0.001	0.002	0.006	0.007	0.006	0.005	0.004	0.004	0.004	0.005	0.004	0.005	0.006	0.014	0.015	0.013	0.008	0.007	0.007	0.005
March	0.002	0.000	0.001	0.001	0.000	0.002	0.005	0.005	0.004	0.002	0.003	0.002	0.002	0.002	0.003	0.004	0.006	0.008	0.010	0.010	0.010	0.008	0.006	0.004
April	0.002	0.001	0.001	0.001	0.001	0.001	0.004	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.006	0.011	0.008	0.010	0.009	0.009	0.007	0.005
May	0.004	0.001	0.001	0.001	0.001	0.001	0.003	0.003	0.003	0.002	0.002	0.003	0.003	0.003	0.004	0.006	0.009	0.020	0.013	0.015	0.016	0.012	0.008	0.006
June	0.005	0.002	0.001	0.001	0.002	0.001	0.002	0.003	0.003	0.005	0.004	0.006	0.004	0.008	0.010	0.016	0.020	0.028	0.020	0.021	0.022	0.021	0.017	0.010
July	0.009	0.005	0.003	0.002	0.003	0.004	0.007	0.007	0.009	0.009	0.012	0.013	0.012	0.019	0.025	0.029	0.043	0.088	0.060	0.043	0.036	0.032	0.024	0.015
August	0.011	0.005	0.003	0.003	0.003	0.006	0.009	0.008	0.009	0.011	0.013	0.014	0.016	0.024	0.031	0.049	0.071	0.095	0.065	0.047	0.040	0.032	0.025	0.017
September	0.007	0.003	0.002	0.002	0.002	0.004	0.010	0.008	0.008	0.009	0.010	0.011	0.015	0.019	0.026	0.040	0.059	0.101	0.044	0.046	0.036	0.025	0.021	0.015
October	0.003	0.001	0.000	0.001	0.001	0.003	0.005	0.005	0.005	0.004	0.004	0.004	0.003	0.006	0.008	0.015	0.022	0.039	0.024	0.030	0.017	0.011	0.008	0.006
November	0.002	0.001	0.001	0.001	0.001	0.002	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.006	0.006	0.009	0.045	0.024	0.014	0.009	0.007	0.007	0.005
December	0.003	0.001	0.001	0.001	0.001	0.003	0.006	0.006	0.006	0.005	0.004	0.004	0.003	0.004	0.005	0.006	0.007	0.041	0.025	0.019	0.013	0.009	0.008	0.006

Weekends and Holidays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.005	0.005	0.005	0.004	0.003	0.002	0.001
February	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.004	0.006	0.005	0.004	0.002	0.002	0.001
March	0.002	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.004	0.003	0.002	0.002	0.002
April	0.002	0.001	0.001	0.000	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.002	0.002	0.002	0.003	0.003	0.002	0.002
May	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.003	0.002	0.003	0.005	0.004	0.003	0.001
June	0.004	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.002	0.003	0.003	0.010	0.011	0.009	0.009	0.010	0.008	0.004
July	0.005	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.003	0.005	0.008	0.019	0.018	0.015	0.016	0.013	0.012	0.005
August	0.008	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.002	0.002	0.003	0.003	0.006	0.011	0.017	0.051	0.054	0.024	0.025	0.020	0.012	0.007
September	0.006	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.003	0.004	0.007	0.021	0.030	0.076	0.050	0.049	0.027	0.020	0.010	0.006
October	0.004	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.002	0.001	0.001	0.001	0.001	0.002	0.004	0.011	0.008	0.012	0.006	0.004	0.003	0.001
November	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.003	0.010	0.006	0.005	0.002	0.003	0.002	0.001
December	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.002	0.014	0.006	0.006	0.004	0.003	0.003	0.002

E. Marginal Transmission Costs

Time differentiation of transmission costs have not been included in SCE's TOU proposals for the following three reasons.

First, consistent with the cost allocation mandates and guidance from FERC, SCE allocates transmission cost and revenue responsibility to rate groups based on each rate group's average 12-month coincident peak contribution. This load-based allocation used for transmission costs is different from the load- and marginal cost-based allocation used for CPUC-jurisdictional costs.

Second, the Commission should recognize that the majority of the capacity planned for on the transmission system is governed by the ability of the transmission *network* to accommodate: (i) directional power flows in reliability-driven scenarios; (ii) movement of power from generation sources to the different load centers; and (iii) frequency modulation and congestion management on the network.[67] The premise of defining transmission-related marginal costs on pure load-growth-driven capacity planning is contrary to the actual functionality of the transmission system as an integrated *network* that promotes the dynamic power flows experienced when trying to balance generation supply sources with demand.

Third, the reliable integration of an increasing amount of utility-scale renewable resources will increasingly affect the operating constraints on the transmission system. The transmission system will need to be sufficiently robust to accommodate both the timing of the renewable generation supply and the demand for energy from customers. Again, the ability of the transmission system to function as a network and move energy is significantly more important than the singular context of a system providing pure load growth related capacity.[68]

F. Final Total Marginal Costs by Hour

Aggregated below in Figure III-18 are SCE's total marginal costs by hour. This heat map sums together the hourly marginal energy costs, hourly marginal generation capacity costs (both peak and flexible capacity), and hourly marginal distribution costs.

[67] CAISO Board Approved Transmission Plan. Projects listed under SCE's transmission network are being proposed based on reliability-driven N-1 or N-2 contingency planning at substations and/or on transmission lines.

[68] The historical context of distribution system marginal costs, typically defined as the incremental cost of adding new capacity driven by base-case load growth, should not be transposed on the transmission system. The two systems function with very different operating constraints. The primary driver of transmission system costs is contingency driven reliability planning. Such an emphasis on contingency planning allows for a sufficiently-integrated network that has the robust capability of moving bulk power from generation to load centers, or between load centers, especially in the event of a contingency.

Figure III-18
SCE 2024 Forecast Average Hourly Total Marginal Costs ($/kWh)

Weekdays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.051	0.049	0.048	0.048	0.049	0.053	0.069	0.078	0.055	0.050	0.048	0.046	0.044	0.045	0.047	0.057	0.099	0.169	0.115	0.086	0.074	0.067	0.063	0.056
February	0.050	0.048	0.047	0.048	0.049	0.052	0.064	0.060	0.053	0.049	0.047	0.047	0.046	0.047	0.047	0.051	0.084	0.162	0.133	0.086	0.072	0.067	0.061	0.055
March	0.049	0.046	0.046	0.046	0.046	0.049	0.057	0.054	0.049	0.042	0.039	0.034	0.029	0.033	0.041	0.044	0.065	0.131	0.155	0.103	0.078	0.070	0.062	0.053
April	0.048	0.045	0.045	0.045	0.046	0.048	0.055	0.047	0.042	0.036	0.033	0.032	0.030	0.031	0.039	0.041	0.046	0.102	0.170	0.087	0.080	0.067	0.059	0.052
May	0.050	0.046	0.045	0.045	0.046	0.049	0.050	0.046	0.042	0.039	0.039	0.039	0.039	0.040	0.043	0.045	0.050	0.106	0.156	0.088	0.087	0.073	0.062	0.054
June	0.052	0.047	0.046	0.046	0.047	0.049	0.048	0.046	0.043	0.044	0.044	0.045	0.043	0.047	0.051	0.059	0.066	0.112	0.157	0.215	0.194	0.097	0.074	0.059
July	0.058	0.051	0.048	0.047	0.048	0.050	0.053	0.050	0.049	0.050	0.054	0.057	0.058	0.068	0.077	0.086	0.102	0.203	0.218	0.145	0.134	0.103	0.084	0.068
August	0.060	0.052	0.049	0.049	0.049	0.054	0.058	0.053	0.052	0.053	0.055	0.057	0.059	0.070	0.080	0.104	0.146	0.235	0.249	0.511	0.248	0.101	0.084	0.070
September	0.056	0.050	0.048	0.048	0.048	0.052	0.065	0.057	0.052	0.051	0.052	0.054	0.058	0.064	0.076	0.104	0.185	0.381	1.844	1.225	0.374	0.099	0.079	0.066
October	0.051	0.048	0.047	0.047	0.047	0.051	0.060	0.062	0.050	0.045	0.045	0.045	0.046	0.049	0.052	0.061	0.089	0.180	0.173	0.111	0.084	0.071	0.064	0.056
November	0.050	0.048	0.048	0.048	0.048	0.051	0.060	0.055	0.050	0.048	0.048	0.047	0.047	0.048	0.051	0.079	0.157	0.200	0.099	0.082	0.072	0.065	0.061	0.056
December	0.053	0.049	0.048	0.049	0.049	0.054	0.063	0.063	0.055	0.051	0.050	0.050	0.049	0.049	0.051	0.054	0.122	0.255	0.107	0.092	0.080	0.072	0.067	0.058

Weekends and Holidays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January	0.050	0.049	0.048	0.048	0.048	0.049	0.054	0.058	0.045	0.039	0.040	0.037	0.035	0.032	0.033	0.043	0.086	0.161	0.088	0.073	0.064	0.059	0.056	0.051
February	0.050	0.048	0.048	0.049	0.048	0.049	0.051	0.048	0.044	0.037	0.041	0.038	0.033	0.036	0.041	0.046	0.063	0.111	0.146	0.073	0.064	0.058	0.058	0.052
March	0.049	0.046	0.047	0.047	0.047	0.047	0.048	0.046	0.038	0.021	0.014	0.007	0.008	0.007	0.012	0.030	0.058	0.120	0.125	0.086	0.066	0.060	0.059	0.051
April	0.048	0.046	0.046	0.046	0.046	0.047	0.046	0.041	0.029	0.019	0.016	0.015	0.009	0.009	0.014	0.023	0.038	0.084	0.143	0.060	0.066	0.061	0.057	0.050
May	0.048	0.045	0.045	0.045	0.046	0.047	0.045	0.035	0.019	0.022	0.018	0.020	0.018	0.012	0.015	0.028	0.041	0.086	0.127	0.069	0.068	0.062	0.055	0.049
June	0.051	0.047	0.047	0.047	0.046	0.047	0.045	0.034	0.019	0.021	0.027	0.027	0.024	0.032	0.039	0.042	0.048	0.094	0.135	0.084	0.074	0.075	0.065	0.054
July	0.054	0.049	0.048	0.047	0.047	0.047	0.045	0.037	0.028	0.035	0.037	0.039	0.041	0.044	0.047	0.050	0.054	0.112	0.172	0.092	0.105	0.079	0.070	0.055
August	0.057	0.050	0.049	0.049	0.048	0.049	0.049	0.043	0.037	0.036	0.036	0.040	0.042	0.044	0.048	0.073	0.114	0.141	0.150	0.143	0.118	0.086	0.073	0.059
September	0.054	0.049	0.049	0.048	0.047	0.048	0.048	0.045	0.033	0.021	0.028	0.034	0.037	0.044	0.049	0.066	0.078	0.195	0.683	0.286	0.147	0.083	0.067	0.056
October	0.052	0.048	0.048	0.048	0.048	0.049	0.050	0.047	0.040	0.036	0.030	0.036	0.040	0.042	0.042	0.046	0.079	0.159	0.129	0.093	0.070	0.062	0.058	0.051
November	0.050	0.049	0.048	0.048	0.048	0.049	0.051	0.048	0.044	0.040	0.037	0.035	0.032	0.036	0.041	0.067	0.139	0.173	0.077	0.072	0.063	0.061	0.056	0.051
December	0.051	0.050	0.048	0.049	0.049	0.049	0.051	0.049	0.045	0.040	0.042	0.042	0.041	0.042	0.043	0.046	0.111	0.219	0.075	0.076	0.067	0.064	0.061	0.053

IV.

PROPOSED TOU PERIODS AND SEASONS

A. Introduction

This chapter describes the process, methods, and considerations SCE examined in defining its proposed standard TOU periods and seasons that would apply to SCE's non-residential customers beginning in October 2018.[69] In summary, SCE proposes the following TOU periods and seasons:

- Retain SCE's current definitions of two seasons: summer (June through September) and winter (October through May), with a maximum of three TOU daily periods in each season.
- An on-peak period of 4:00 p.m. to 9:00 p.m. for summer weekdays.
- A mid-peak period of 4:00 p.m. to 9:00 p.m. for summer weekends and for winter weekdays and weekends.
- A super off-peak period from 8:00 a.m. to 4:00 p.m. for winter weekdays and weekends.
- An off-peak period in the summer and winter for all other hours, *i.e.*, all hours other than those hours in the on-peak period (summer), mid-peak summer weekend period, or super off-peak period (winter).

Table IV-2, below, shows this same information by season and by TOU periods.

[69] With respect to residential customers, the consolidated 2018 RDW applications for the IOUs, ordered in D.15-07-001, will address proposed rate designs for each IOU's default residential TOU rates, which are scheduled to be implemented in 2019. The standard TOU periods adopted in this proceeding will inform that process. *See* D.15-07-001, page 144, "Default TOU periods and rate structures [for residential customers] should take into account the most accurate peak and off-peak periods as determined through the GRC or RDW process on a five-year forward-looking basis."

Table IV-2
SCE Current And Proposed Seasons and TOU Periods

	Season	Existing	Proposed
On-Peak	Summer	Weekdays: 12:00 p.m. - 6:00 p.m.	Weekdays: 4:00 p.m. - 9:00 p.m.
Mid-Peak	Summer	Weekdays: 8:00 a.m. - 12:00 p.m.; 6:00 p.m. - 11:00 p.m.	Weekends: 4:00 p.m. - 9:00 p.m.
	Winter	Weekdays: 8:00 a.m. – 9:00 p.m.	Weekdays and Weekends: 4:00 p.m. - 9:00 p.m.
Off-Peak	Summer	Weekdays: 11:00 p.m. – 8:00 a.m. Weekends: All hours	Weekdays and Weekends: All hours except 4:00 p.m. – 9:00 p.m.
	Winter	Weekdays: 9:00 p.m. - 8:00 a.m. Weekends: All hours	Weekdays and Weekends: 9:00 p.m. - 8:00 a.m.
Super Off-Peak	Winter	N/A	Weekdays and Weekends: 8:00 a.m. – 4:00 p.m.

Appropriate TOU periods and rates allow customers to actively participate in reducing system operating constraints by incentivizing system-helpful modifications to their energy-use behavior. SCE's proposed TOU periods and seasons more closely align TOU periods with a cost structure that reflects the net-load curve and SCE's marginal costs. As the CAISO has stated,

> It [is] important to examine current time-of-use structures and re-align the pricing to be consistent with the expectations of available electric supply. Once customers understand the [hours in which] the cost of electricity is at its lowest and cleanest, it is anticipated they will change their behavior to realize this benefit. … In addition to direct customer benefits, by using supply when it is ample and reducing use when electricity is limited, less investment will be needed, reducing costs for all consumers.[70]

Figure IV-19, below, shows SCE's actual net-load curves from 2010 through 2015 and its projected net-load curves for 2021 and 2024, using March data for each year.

[70] CAISO, "Matching Time-of-use Rate Periods with Grid Conditions Maximizes Use of Renewable Resources," June, 2015, *available at* https://www.caiso.com/Documents/MatchingTimeOfUsePeriodsWithGridConditions-FastFacts.pdf

Figure IV-19
SCE Average Hourly Net Load for 2010 – 2024 (March)

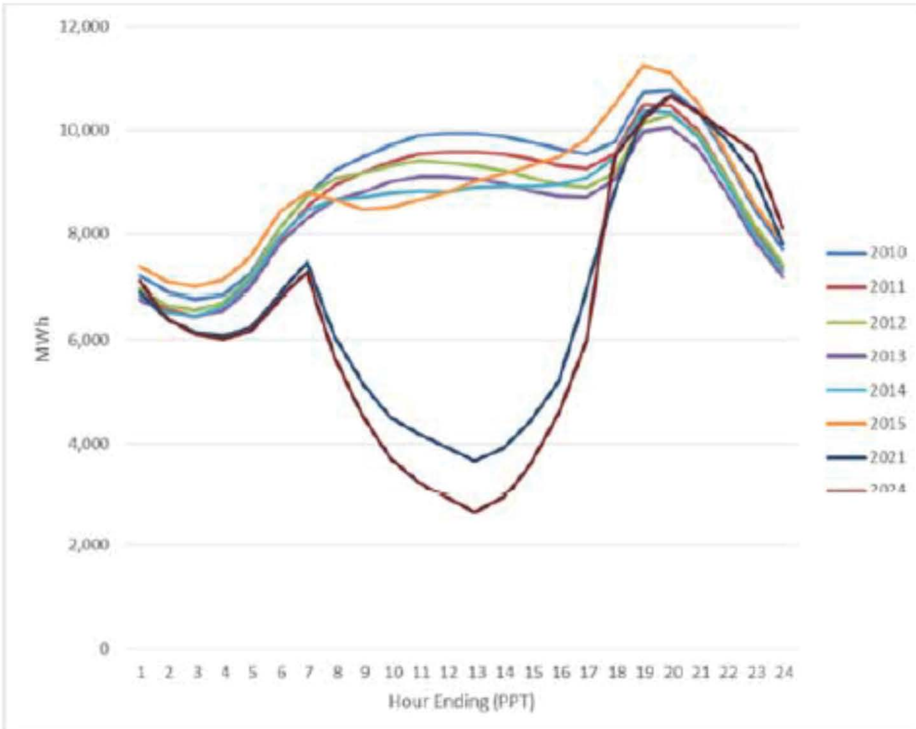
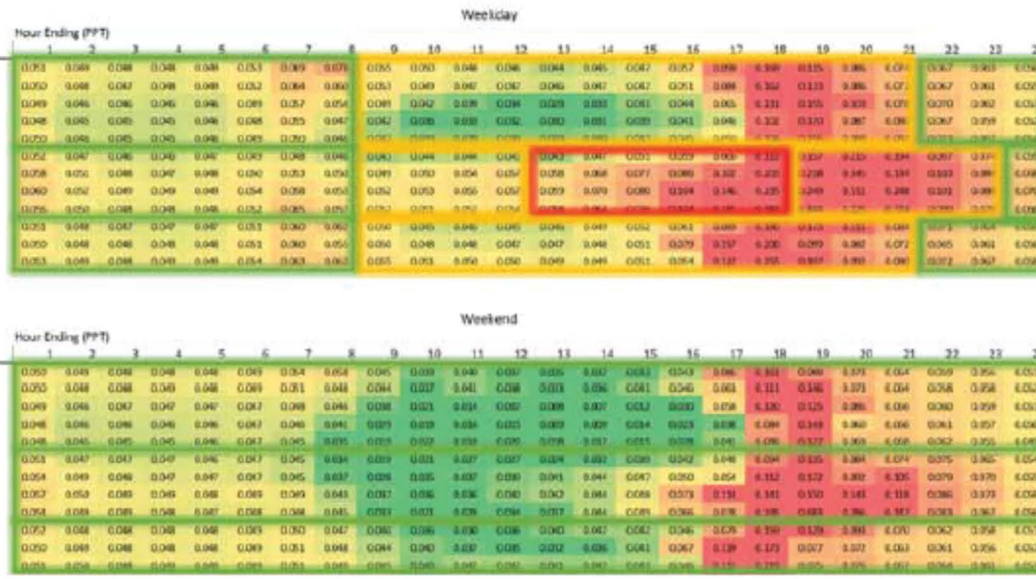


Figure IV-20 and Figure IV-21 below, present heat maps of SCE's 2010 and forecast 2024 average net load for all hours of the day and all 12 months of the year. A comparison of the two years shows the significant shift of highest net-load hours to later in the day from June through September and the addition of more lower net-load hours earlier in the day, particularly from March through June, as well as from October through December.

The SCE net-load "duck curves," shown above in Figure IV-19, and the 2024 heat map, shown above in Figure III-2, illustrate the changing net-load characteristics that concern the CAISO. These concerns include (1) a deepening net-load trough in the middle of the day due to abundant solar production combined with lower demand in the cooler months; (2) the shift of peak load hours to later hours of the day; and (3) a steep ramp from the lowest net-load hours, *i.e.*, the trough, to the highest net-load hours, *i.e.,* the peak.

The current TOU periods are no longer appropriate given the forecast marginal costs modeled in Chapter III. Figure IV-20, below, illustrates the need for revised TOU periods by overlaying the current TOU periods on the 2024 weekday and weekend hourly cost heat maps, also shown in Figure III-17.

Figure IV-20
Overlay of Current TOU Periods on 2024 Average Hourly Costs (\$/kWh)(weekdays and weekends)



1. The yellow rectangular boundary represents SCE's current mid-peak period.
2. The red rectangular boundary represents the current on-peak period.
3. All areas bordered by green represent the current off-peak period, with weekends currently being entirely off peak.

SCE's current TOU periods are misaligned with 2024 forecast average hourly marginal costs. For example, the current summer on-peak period from 12:00 p.m. to 6:00 p.m. "misses" a significant portion of the highest-cost hours, as indicated by the *red* cells not contained within the current peak-period red box (*i.e.*, the 90th percentile of the 288 values shown for weekdays and weekends). However, it also captures several medium-cost hours, as indicated by the *yellow* cells contained within the current peak-period red box. Additionally, the lowest-cost hours in the middle of the day, as indicated by the *green* cells (*i.e.*, the 10th percentile of the 288 values), are included together with higher-cost evening hours in the current winter mid-peak periods. TOU periods should be aligned with forecast costs to send appropriate price signals and properly-timed consumption and conservation incentives to customers.

1. Guiding Principles

Chapter II.B laid out the principles for setting TOU periods developed from the TOU OIR,[71] and discussed the following principles that underlie SCE's methodology and its proposal.

1. Utility-specific marginal costs, as defined in Chapter III, should be the principal basis for the proposed TOU periods.
2. While the primary goal of correctly-defined TOU periods is to send accurate price signals that address the challenging system conditions identified by the CAISO in its TOU Analysis,[72] the final determination of TOU periods should also consider the principles of customer understanding, acceptance, and ability to respond to the price signals incorporated in the new TOU periods. Such considerations include limiting the number of TOU periods, helping to ensure that TOU periods are not too short, and aligning the starting and ending times for TOU periods across seasons.
3. Stability—TOU periods and associated pricing should be predictable and stable over time to minimize unexpected changes to customers' investments and behaviors.

2. Overview of Analysis and Methodology

In Chapter III, SCE calculated forecast total marginal costs by hour for the year 2024. Starting with these 2024 hourly total marginal costs,[73] the subsections of Section B below describe how TOU periods and seasons are determined, starting with total marginal costs for each hour and then grouping them on an interim basis to establish the core months and hours that should form the basis of

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[71] R.15-12-012

[72] CAISO TOU Report and Analysis (CAISO TOU Analysis), dated and filed in R.15-12-012 on January 22, 2016, Appendix D.

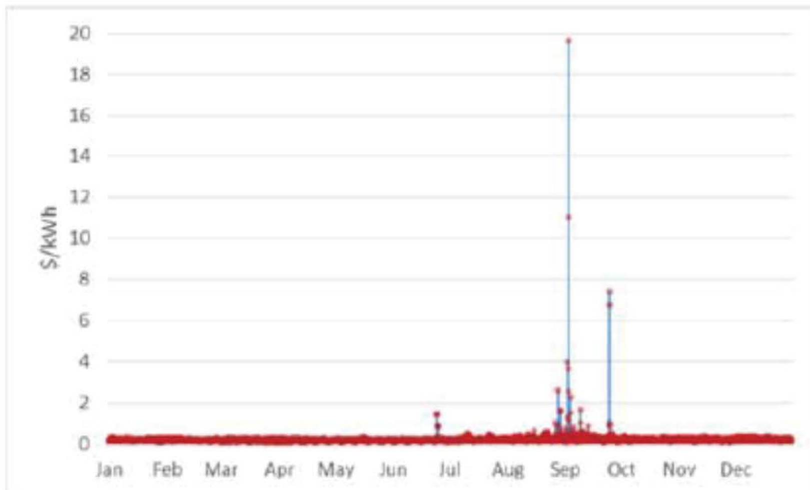
[73] Chapter III.A.3 explains why data for the year 2024 are used. The year 2024 is a leap year and therefore includes 8,784 hours. For simplicity and comparability purposes, as well as for ease of merging data obtained from the analyses of other non-leap years, SCE omitted the extra 24 hours of February 29. Those hours have very low costs assigned to them and they do not meaningfully impact the analysis.

the proposed seasons and TOU periods. Sections B.1 through B.5 detail the considerations that guide the logic to a final design of the TOU periods and seasons. Because many of these considerations are not easily quantifiable, the weight assigned to them reflects a degree of informed judgment and common sense. Section B.6 presents SCE's final assessments of proposed TOU periods and seasons. Section C validates and confirms the reasonableness of the proposals, including an evaluation of how SCE's proposal compares to alternatives using a regression analysis and a test that measures the effectiveness of the proposed TOU periods in capturing the highest-cost hours of the day.

B. Determination of TOU Seasons and Periods

An overarching goal for defining seasons and TOU periods is to group together hours with similar costs and, at the same time, obtain reasonable separation in costs between TOU periods. As described in Chapter III, the total marginal cost in each hour of year 2024 is the sum of generation (energy and capacity including flex capacity) and peak-capacity driven distribution system costs. SCE's analysis of TOU periods and seasons starts by identifying the costs in all hours of the year. Figure IV-21, below, presents chronologically the forecast costs in $/kWh for all 8,760 hours in 2024. It clearly shows that a very limited number of hours, primarily certain hours in August and September, have costs that far exceed the costs for all other hours.

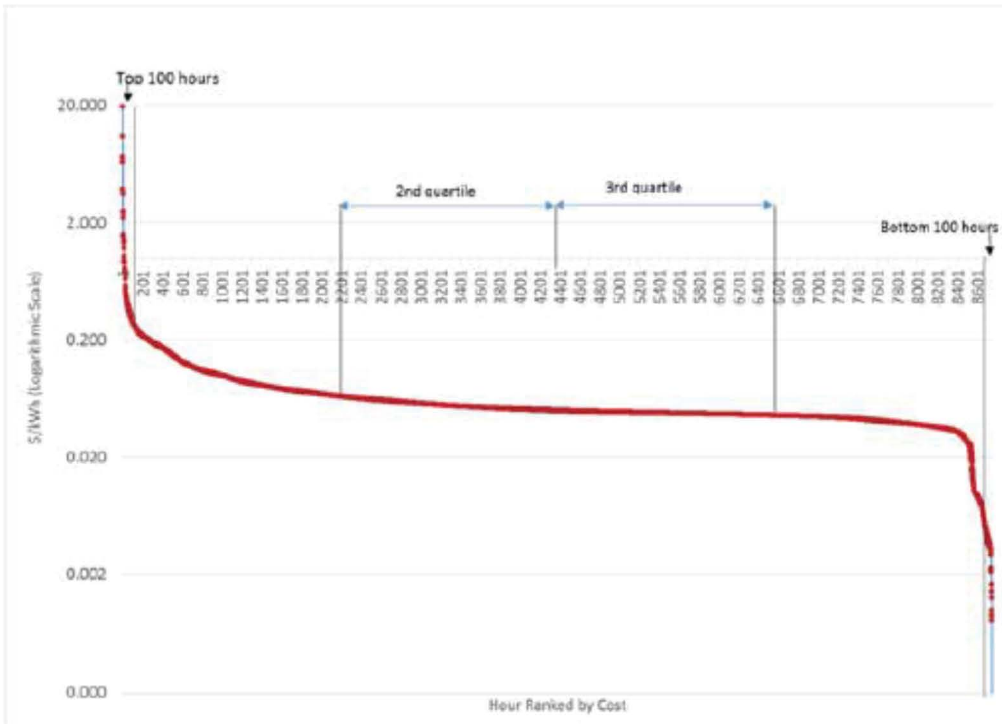
Figure IV-21
2024 Chronological Forecast Overall Hourly Marginal Costs



A cost duration curve, which ranks costs in descending order, helps to identify and group together hours with similar costs into interim TOU periods.[74] Figure IV-22, below, illustrates hours starting with the very highest-cost hour (approximately $20/kWh) to the very lowest-cost hour (-$.001/kWh) for all 8,760 hours in 2024. The relatively limited number of hours with the highest costs are very distinct from the vast majority of hours with mid-range costs and from the relatively limited number of hours with the very lowest costs. TOU periods and seasons should be established that accurately and separately capture the core hours containing the highest- and lowest-cost hours, as well as the majority of hours in the mid-range cost group.

[74] Inflection points, which are points on the curve that indicate when the curve changes its pattern, can be identified by locating all points in which the second derivative is equal to zero.

Figure IV-22[75]
2024 Cost Duration Curve



SCE captured these core hours by conducting separate frequency analyses and average cost analyses to identify and separately flag the core hours and seasons that reflect the highest-costs, lowest-costs, and mid-range costs. Then, patterns and trends in the highest- and lowest-cost hours were used to identify other hours and months that predominantly display similar cost characteristics. Finally, the remaining hours that were not clearly associated with other groupings were then classified based on cost characteristics and other considerations, such as overall desire to reasonably simplify or limit the number of seasons and TOU periods in line with SCE's preference of two seasons and no more than

[75] The y-axis uses a logarithmic scale to take into account the highly skewed distribution of hourly costs in $/kWh.

three TOU periods in either season. The results of this mul,ti-step exercise are aggregated and tracked in a heat map, which differentiates groups of hours by cost, time and by month.

1. Assessment and Classification of Highest Cost Hours

Table IV-3 and Table IV-4, below, detail the frequency distribution, by percentages, of the 20 and 100 highest-cost hours (top 20 and top 100, respectively) and the months in which they occur.

Table IV-3
Frequency Distribution of the Highest-Cost 20 Hours by Month (Forecast 2024)

	Hour Ending (PPT)					
Month	17	18	19	20	21	Total
June	0%	0%	0%	5%	5%	10%
August	0%	0%	0%	20%	0%	20%
September	5%	5%	25%	25%	10%	70%
Total	5%	5%	25%	50%	15%	100%

Table IV-3 demonstrates that 100% of the 20 highest-cost hours occur in June, August and December, and a full 50% of those highest-cost hours occur in one single hour (HE 20) in those three months. Accordingly, this frequency data for the 20 highest-cost hours out of the 8,760 hour annual period overwhelmingly support the designation of June, August and September, and the period from 4:00 p.m. until 9:00 pm, (HE 17 to HE 21), as the core highest-cost months and hours, respectively, because those hours capture 100% of the 20 highest-cost hours.

The frequency data for the 100 highest-cost hours, as shown in Table IV-4, below, leads to almost identical results. Specifically, it demonstrates that 98% of the 100 highest-cost hours occur between 4:00 p.m. and 9:00 p.m. (HE 17 to HE 21), and 95% of the 100 highest-cost hours occur between June and September.

Table IV-4
Frequency Distribution of Highest-Cost 100 Hours by Month (Forecast 2024)

	Hour Ending (PPT)						
Month	16	17	18	19	20	21	Total
June	0%	0%	0%	0%	2%	2%	0%
July	0%	0%	3%	1%	2%	1%	7%
August	1%	2%	7%	7%	11%	5%	33%
September	1%	3%	10%	17%	14%	4%	49%
October	0%	0%	0%	2%	0%	0%	2%
November	0%	0%	1%	0%	0%	0%	1%
December	0%	0%	4%	0%	0%	0%	4%
Total	2%	5%	25%	27%	29%	12%	100%

Because a frequency analysis assigns equal "weight" to each occurrence (*i.e.*, there is no differentiation between the costs in the 1st highest-cost hour, which has a marginal cost of \$19.61/kWh, and the costs in the 99th highest-cost hour, which has a marginal cost of \$0.29/kWh, those results should be validated based on an average marginal cost analysis. Table IV-5, below, presents the average marginal costs, by hour and month, for the top 20 and top 100 highest-cost hours.

Table IV-5
Distribution of Average Hourly Marginal Costs for Top 20 and Top 100 Forecast 2024 Hours ($/kWh)

	Hour Ending (PPT)					
Month	**16**	**17**	**18**	**19**	**20**	**21**
Top 20						
June					$ 1.37	$ 1.37
August					$ 1.63	
September		$ 1.06	$ 2.49	$ 6.91	$ 4.26	$ 2.26
Top 100						
June					$ 1.08	$ 1.08
July			$ 0.38	$ 0.46	$ 0.39	$ 0.33
August	$ 0.41	$ 0.43	$ 0.38	$ 0.38	$ 0.86	$ 0.47
September	$ 0.32	$ 0.59	$ 0.60	$ 2.38	$ 1.76	$ 1.34
October				$ 0.30		
November			$ 0.32			
December			$ 0.30			

This analysis confirms that the hours from 4:00 p.m. to 9:00 p.m. (HE 17 to HE 21) in June through September are the highest-cost hours, from both an average-cost and frequency perspective, and thus belong in the highest-cost period. The data in Table IV-4, above, also show that 7% of the 100 highest-cost hours occur in October, November, and December, specifically between 5:00 p.m. and 7:00 p.m. (HE 18 and HE 19). However, because the frequency and average marginal cost for these hours are lower than they are for the core hours and months, these hours are grouped with other hours shown by the light red color in the heat map Figure IV-25, below.

Finally, the data indicate that all hours identified in the 20 and 100 highest-cost hours occur in the late afternoon and evening hours. Moreover, the average daily cost profiles for other months, as shown in Figure IV-23 and Figure IV-24 below, reveal that the same pattern occurs year-round. In other words, the period from 4:00 p.m. to 9:00 p.m. in all months of the year (*i.e.*, for the months of January-May and October-December, as well as in the "extremes" of the cost duration curve for the months of June-September) are the highest-cost hours. Figure IV-23 and Figure IV-24 below, illustrate this average higher-cost profile for summer and non-summer months, respectively.

***Figure* IV-23**
Average Hourly Cost (summer season):

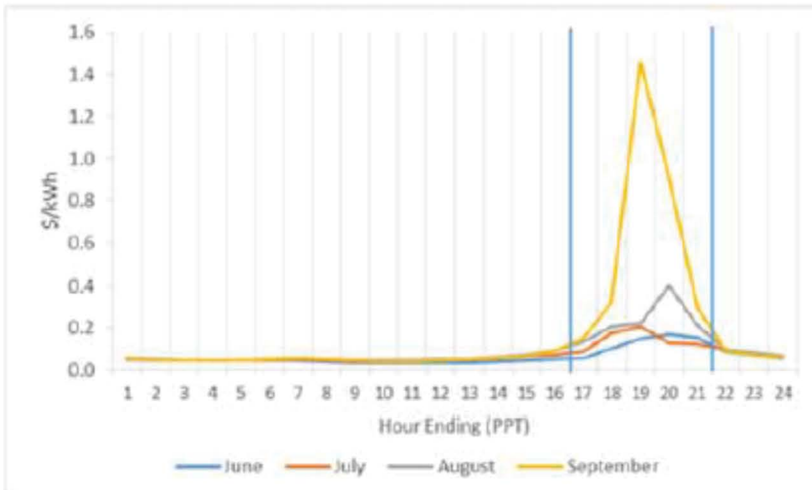
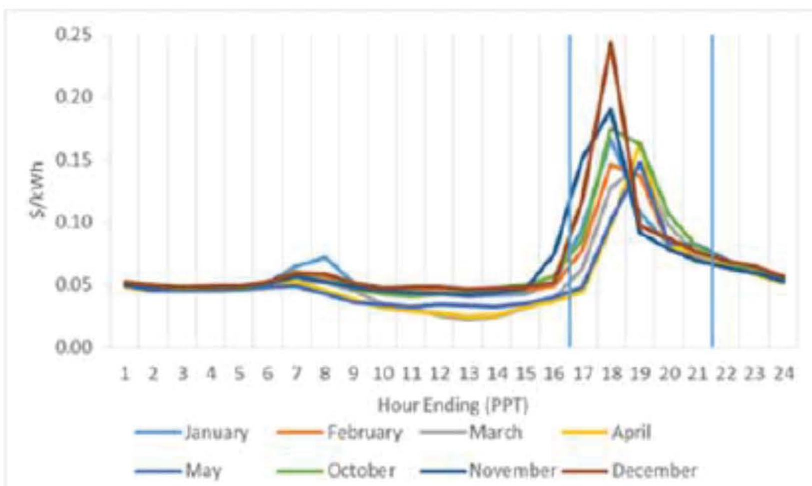


Figure IV-24
Average Hourly Cost (non-summer months)



The hours of 4:00 p.m. to 9:00 p.m. (HE 17 – HE 21) for the period from June through September are identified by the dark red color in Figure IV-25, below, where the dark red color identifies the highest-cost core hours, and the lighter red color identifies other high-cost hours that display similar characteristics as the highest-cost hours. Average costs for these two TOU periods are shown in $/kWh inside each of the two highest-cost periods, *i.e.*, $0.282/kWh from June through September and $0.11/kWh from October through May.

Figure IV-25
Interim Selection of Highest-Cost Hours and Months

2. <u>Assessment and Classification of Lowest-Cost Hours</u>

Table IV-6 and Table IV-7 detail the frequency distribution, by percentages, of the 20 and 100 lowest-cost hours (bottom 20 and bottom 100, respectively) and the months in which they occur.

Table IV-6
Distribution of 20 Lowest-Cost Hours By Month and Hour (2024)

	Hour Ending (PPT)						
Month	10	11	12	13	14	15	Total
January	0%	0%	0%	5%	0%	0%	5%
March	0%	5%	15%	5%	10%	0%	35%
April	0%	5%	5%	5%	5%	10%	30%
May	5%	5%	5%	5%	5%	5%	30%
Total	5%	15%	25%	20%	20%	15%	100%

This chart demonstrates that 100% of the 20 lowest-cost hours occur in the four-month period of January-May, and 95% of those hours occur in the six-hour period of 9:00 a.m. to 3:00 p.m. in just three months (March, April, and May). Accordingly, the frequency analysis for the bottom 20 hours indicates that the lowest-cost TOU period should include, at a minimum, the hours from 9:00 a.m. to 3:00 p.m. (HE10 – HE15) in March, April and May. These hours are identified by the dark green color in Figure IV-27, below.

Table IV-7
Distribution of 100 Lowest-Cost Hours By Month and Hour (2024)

	Hour Ending (PPT)										
Month	8	9	10	11	12	13	14	15	16	17	Total
January	0%	0%	0%	0%	1%	1%	1%	1%	0%	0%	4%
February	0%	0%	1%	0%	0%	0%	0%	0%	0%	0%	1%
March	0%	0%	3%	5%	7%	6%	7%	2%	1%	0%	31%
April	0%	1%	3%	4%	4%	4%	4%	2%	2%	1%	25%
May	0%	1%	2%	4%	3%	2%	3%	3%	1%	0%	19%
June	1%	3%	3%	1%	1%	1%	1%	0%	0%	0%	11%
July	0%	1%	0%	0%	0%	0%	0%	0%	0%	0%	1%
September	0%	0%	1%	2%	1%	1%	0%	0%	0%	0%	5%
October	0%	0%	0%	2%	0%	0%	0%	0%	0%	0%	2%
November	0%	0%	0%	0%	0%	1%	0%	0%	0%	0%	1%
Total	1%	6%	13%	18%	17%	16%	16%	8%	4%	1%	100%

An analysis of the 100 lowest-cost hours produces very similar results. Table IV-7 shows that March, April, and May include 75% of the 100 lowest-cost hours, with June being ranked next in frequency, but with June having less frequency of lowest-cost hours than March, April, or May. It also shows that 68% of the 100 lowest-cost hours occur from March through May in the period from HE 10 through HE 15. Thus, the frequency analyses for the 20 and 100 lowest-cost hours indicate that the lowest-cost TOU period should include, at a minimum, 9:00 a.m. to 3:00 p.m. (HE 10 – HE 15) in March, April and May. These results are confirmed by the distribution of average costs for the 20 and 100 lowest-cost hours, as detailed in Table IV-8, below.

Table IV-8
Distribution of Average Hourly Costs for Lowest-Cost 20 and 100 hours (2024){($/kWh)}

	Hour Ending (PPT)									
Month	**8**	**9**	**10**	**11**	**12**	**13**	**14**	**15**	**16**	**17**
Bottom 100										
January					$0.0036	$0.0022	$0.0037	$0.0048		
February			$0.0052							
March			$0.0048	$0.0043	$0.0042	$0.0035	$0.0034	$0.0055	$0.0064	
April		$0.0040	$0.0045	$0.0034	$0.0030	$0.0033	$0.0027	$0.0013	$0.0051	$0.0044
May		$0.0048	$0.0031	$0.0031	$0.0030	$0.0012	$0.0033	$0.0039	$0.0034	
June	$0.0050	$0.0040	$0.0042	$0.0050	$0.0050	$0.0034	$0.0034			
July		$0.0062								
September			$0.0044	$0.0044	$0.0037	$0.0037				
October				$0.0051						
November						$0.0065				
Bottom 20										
January						$0.0022				
March				$0.0015	$0.0017	$0.0010	$0.0011			
April				$0.0002	$0.0008	$0.0000	-$0.0010	$0.0013		
May			$0.0017	-$0.0003	-$0.0010	-$0.0013	-$0.0006	$0.0013		

The analysis of the 100 lowest-cost hours shows that a smaller percentage of the lowest-cost hours also occurs in months other than March, April, and May. Analysis of the average daily cost profiles in the other months, as shown in Figure IV-26, below, reveals that the "mid-day trough" in lowest-cost hours from March through May also occurs from October through February, albeit with a mid-day trough of lesser magnitude.

Figure IV-26
Average Hourly Cost Profiles for Non-Summer Months (2024)

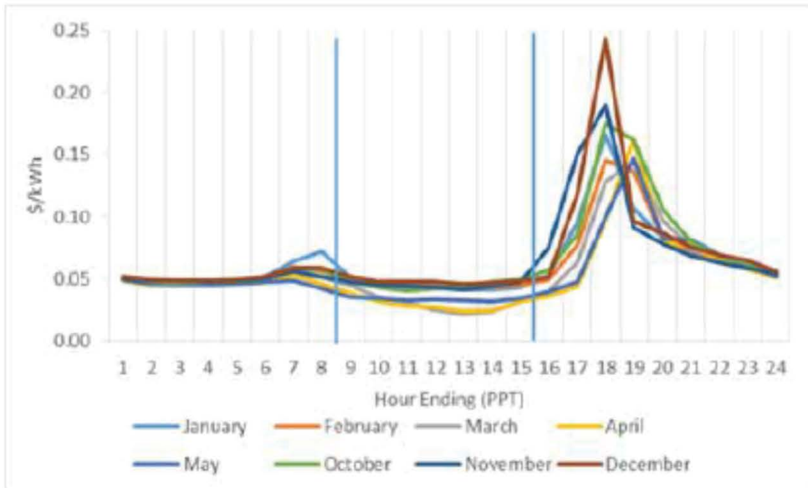


Figure IV-27, below, categorizes by two shades of green the lowest-cost hours and months and adds those results to the two shades of red that were used in Figure IV-25 to categorize the selection of the highest-cost hours and months. The dark green color identifies the lowest-cost "core" hours from March through May, and the lighter green color identifies the lower-cost hours occurring from October through February but displays similar cost characteristics to the months from March through May. The average cost for these two lowest-cost TOU periods is shown in $/kWh inside each of the two low-cost periods, *i.e.*, $0.046/kWh for October through February and $0.031/kWh for March through May.

Figure IV-27
Interim Selection of TOU Periods and Months for Lowest and Highest-Cost Hours

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24
January, February										$0.046/kWh							$0.114/kWh							
March, April, May										$0.031/kWh							$0.095/kWh							
June, July, August, September																	$0.282/kWh							
October, November, December										$0.046/kWh							$0.114/kWh							

3. Assessment and Classification of Second and Third Quartile Cost Hours

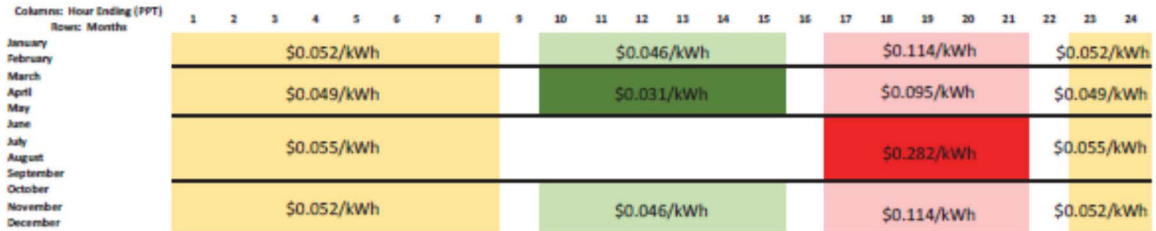
In addition to examining the distribution frequency and average cost of the highest- and lowest-cost hours, mid-range cost hours in the second and third quartiles must be assessed to identify a third grouping of similar-cost hours. Table IV-9, below, illustrates the distribution frequency of the hours in the second quartile and the third quartile of the cost-duration curve.

Table IV-9
Distribution of Middle 50% Cost Hours By Month and Hour (Forecast 2024)

	Hour Ending (PPT)																								
Month	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Total
January	31	31	29	27	30	31	20	18	22	18	16	11	8	10	13	18	12	0	3	2	11	18	28	30	437
February	28	28	25	24	28	28	21	24	22	16	13	13	10	13	15	15	14	1	1	1	11	18	25	28	422
March	31	17	21	21	20	26	28	26	13	5	5	2	2	2	3	6	10	4	2	3	8	17	26	31	329
April	26	7	3	4	8	25	25	15	3	1	1	1	2	1	2	5	12	2	1	8	7	17	29	30	235
May	29	10	6	3	13	24	22	10	4	2	0	2	1	1	5	10	15	2	1	10	5	13	27	31	246
June	30	22	19	19	20	22	17	8	4	7	5	6	5	7	10	13	18	4	2	4	3	1	9	29	284
July	30	30	26	27	25	28	22	17	14	17	16	17	15	13	10	10	10	0	0	1	2	1	3	19	353
August	27	31	30	31	31	31	31	23	20	20	20	18	17	15	14	8	2	0	0	0	0	0	1	16	386
September	30	29	29	29	28	29	22	23	14	14	12	16	15	15	15	10	4	0	0	0	0	2	6	23	365
October	31	31	26	28	29	31	29	26	21	9	9	5	10	17	20	21	11	0	0	0	4	10	24	31	423
November	30	28	29	28	28	29	29	27	18	14	11	10	11	12	17	12	0	0	1	3	12	20	29	30	428
December	31	29	31	31	28	30	24	26	25	23	21	20	17	17	20	26	1	0	1	2	7	12	19	31	472
Total	354	293	274	272	288	334	290	243	180	146	129	121	113	123	144	154	109	13	12	34	70	129	226	329	4380

The frequencies of occurrence support grouping the period from 10:00 p.m. to 12:00 a.m. (HE 23 – 24) with the period from 12:00 a.m. to 8:00 a.m. (HE 1 – HE 8). While there is some monthly variation in frequencies, an analysis of the average costs of the second and third quartile hours indicates that these hourly costs remain relatively constant over all 12 months. For example, the costs in a cold month, January, and a hot month, September, for the hours 12:00 a.m. until 6:00 a.m. (HE 1 to HE 6) are very similar, and there is little cost variation across this broad range of hours. The hours between 10:00 p.m. and 8:00 p.m. (HE 23 - HE 24 and HE 1- HE 8) are flagged as yellow, below, and have been added to the highest- and lowest-cost colored hours and months in Figure IV-28, below. The average cost for these two mid-range cost TOU periods is shown in $/kWh inside each of the two low-cost periods, *i.e.*, $0.052/kWh from October through February and $0.049/kWh from March through May.

Figure IV-28
Interim Selection of High-Cost (Red), Low-Cost (Green), and Mid-Range (Yellow) Cost Periods



4. <u>Assessment and Classification of Other Hours</u>

An initial assessment of the data discussed above and Figure IV-28, above, supports the following interim classifications of TOU periods and seasons:

- The highest-cost hours from 4:00 p.m. to 9:00 p.m. (HE 17 - HE 21), which occur in the 100 highest cost hours in June through September, should be included in an on-peak summer season from June through September.
- The highest-cost hours in the non-summer months, while of lower magnitude than the highest-cost hours in the summer, also occur during the same period from 4:00 p.m. until 9:00 p.m. (HE 17 – HE 21), as the highest cost hours in the summer. As such, those same hours should be included in the highest-cost period in the non-summer season, *i.e.*, winter season.
- Costs from 9:00 a.m. to 3:00 p.m. (HE 10 – HE 15) in the winter months are significantly lower than the costs in the other hours. As such, those hours should be included in the lowest-cost period in the winter season.

The remaining hours not yet categorized are shown without any colors in Figure IV-28, above. These hours are as follows: From June through September, 10:00 a.m. to 3:00 p.m. (HE 11 – HE 15); and in all months, 8:00 a.m. to 9:00 a.m. (HE 9), 3:00 p.m. to 4:00 p.m. (HE 16), and 9:00 p.m. to 10:00 p.m. (HE 22).

The costs for the hours from 10:00 a.m. to 3:00 p.m. from June through September appear frequently in the second and third quartiles. Additionally, the average cost in those hours ($0.051/kWh) is comparable to the average cost in the yellow-colored summer hours. As such, it is reasonable to group these summer hours with the other yellow-colored summer hours.

HE 9, HE 16, and HE 22 are three "border" hours shown in Figure IV-28, above, that are somewhat distinct in cost but, for practical considerations, should be grouped with either the preceding or subsequent group of TOU hours so that TOU period start and end times are consistent across seasons. Because these hours do not consistently fall in a single TOU period, some judgment is necessary and consideration should be given to external factors, such as what price signals would best encourage "system-helpful" behavior.

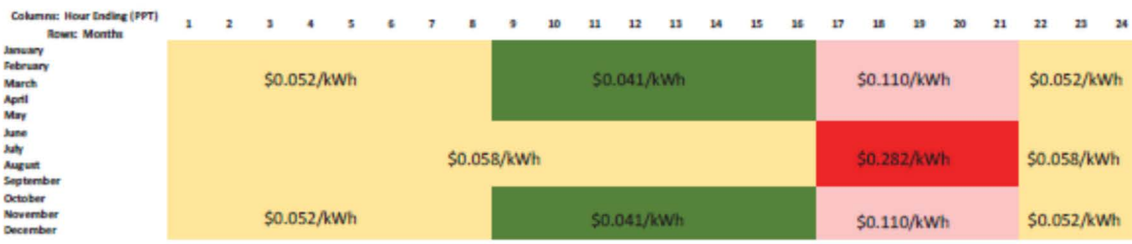
HE 9, or 8:00 a.m. to 9:00 a.m., while not as low-cost as the group of lowest-cost hours from 10:00 a.m. to 3:00 p.m., is significantly lower in cost than the preceding hours. As such, it is reasonable to include it with the 9:00 a.m. to 3:00 p.m. group.

HE 16, or 3:00 p.m. to 4:00 p.m., has costs that are higher in the summer (*i.e.*, could be grouped with the summer on-peak) and lower in the non-summer months (*i.e.*, could be grouped with the lowest-cost winter period). Because this hour typically represents the beginning of the ramp described in Chapter III.B. and as shown in Figure III-9, including this hour in the period from 9:00 a.m. to 3:00 p.m. should give a price-signal that incentivizes usage, thereby increasing load and flattening the demand curve during the "duck belly" portion of the net-load curve. As such, it is reasonable to include this hour with the 9:00 a.m. to 3:00 p.m. group.

HE 22, or 9:00 p.m. to 10:00 p.m., could be grouped with the summer on-peak period, but could also be grouped with the lower-cost hours of 10:00 p.m. to 8:00 a.m. for the non-summer months. While it is still a relatively high-cost hour, it also occurs well after the peak net load as demand is decreasing. Because there is less of a need from a grid perspective to incentivize a reduction in usage in this hour, it is reasonable to group the hour from 9:00 p.m. to 10:00 p.m. with the 10:00 p.m. to 8:00 a.m. TOU period.

Based on these determinations, the remaining hours are categorized in Figure IV-29 by colors as shown below.

Figure IV-29
Interim Selection of High-Cost (Red), Low-Cost (Green), and Mid-Range (Yellow) Cost Periods



5. <u>Separation of TOU Periods by Weekdays and Weekends</u>

SCE's current TOU periods distinguish between weekends and weekdays. For 2024, Figure IV-30 and Figure *IV-31*, below, depict summer and winter average weekday and weekend hourly marginal costs.

Figure IV-30
SCE 2024 Forecast Average Hourly Costs for Summer Weekdays and Weekends

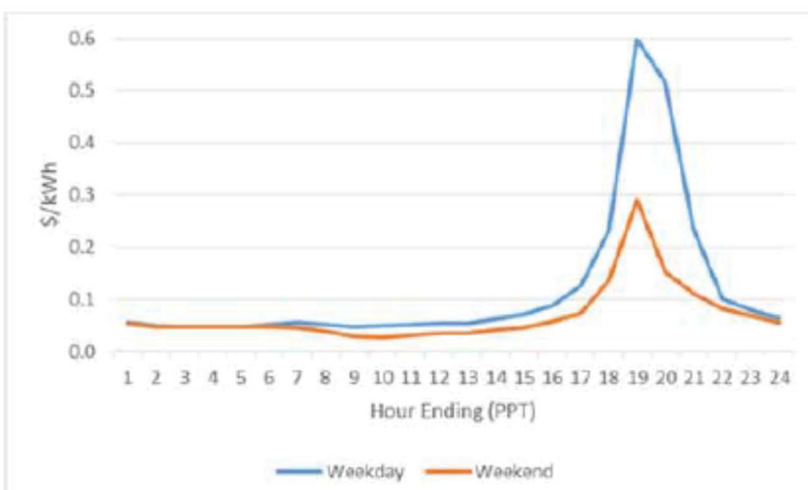


Figure IV-31
SCE 2024 Forecast Average Hourly Costs for Winter Weekdays and Weekends

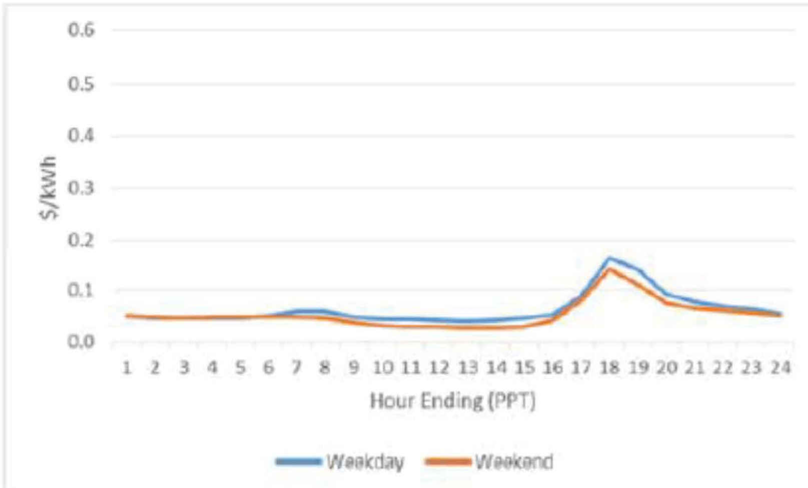


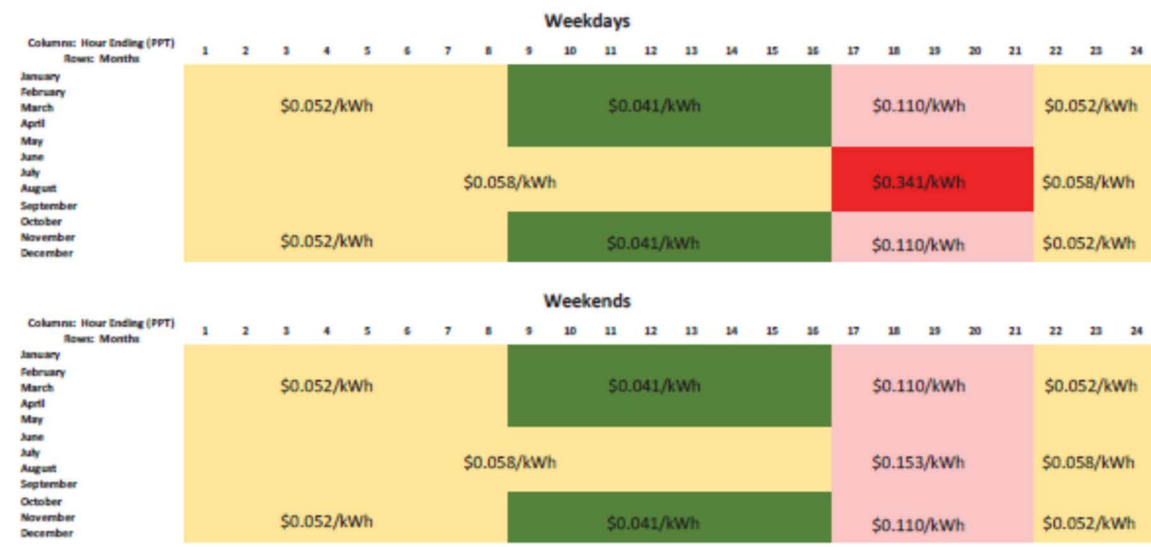
Figure IV-30 and Figure IV-31 show that, while summer and winter weekends and weekdays have similar daily cost patterns, average marginal costs are lower on weekends than they are on weekdays. The difference in average marginal costs is especially pronounced in the summer on-peak period from 4:00 p.m. to 9:00 p.m., because 90%[76] of the 100 highest-cost hours fall on weekdays. Accordingly, it is reasonable to define a separate TOU period that will apply to summer weekends from 4:00 p.m. to 9:00 p.m.

6. <u>Final Determination of TOU Seasons and Periods</u>

Based on the discussion in Sections B.1 through B.5, SCE's final proposed TOU periods and seasons are summarized in Figure IV-32.

[76] Weekdays account for 71% of the week (5 out of 7 days).

Figure IV-32
Final Determination of TOU Periods and Seasons
High-Cost (Red), Low-Cost (Green), and Mid-Range (Yellow) Cost Periods



7. <u>SCE's Proposed TOU Seasons and Periods are Aligned with Customer Preferences</u>

In establishing reasonable TOU periods, it is important to "balance considerations of simplicity and practicality with considerations of accuracy."[77] SCE's proposal reflects an appropriate balance of accuracy, simplicity, and customer preference. For example, SCE proposes the same starting and ending hours for the summer on-peak period and for the winter mid-peak period. Accordingly, throughout the year, customers will receive an appropriate load-shifting price signal for the exact same hours (i.e., starting at 5:00 p.m. and lasting until 9:00 p.m, electricity is more expensive). Similarly, throughout the year, from 10:00 p.m. to 8:00 a.m., customers will receive an appropriate price signal that neither load-shifting nor increased consumption is warranted. This consistent start and end time of similarly-categorized periods throughout the year is easier for customers to understand and respond to. Many current non-residential TOU customers have become accustomed to the summer and winter

[77] R.15-12-012, Green Power Institute's June 27, 2016 Comments to the TOU-OIR Scoping Memo at p.4.

seasons in their operations. Accordingly, retaining only two seasons (the current summer and winter seasons with the same months) is likely to be preferable to customers and will make SCE's other proposed changes in TOU periods easier for customers to understand and accept. Under SCE's proposal, current TOU customers would therefore only need to focus on the changes to the TOU daily periods and prices.

The analysis of the costs discussed above in Section IV.B, could theoretically support the addition of a spring season, and it is reasonable to consider whether a third season from March through May with a super off-peak period from 8:00 a.m. to 4:00 p.m. should also be established. Adoption of three seasons would improve segregation of costs by seasons. However, customer considerations suggest that maintaining two seasons, defined by the same months as the current seasons which have applied for more than thirty years, is preferable, when compared to the incremental complexity resulting from implementation of a third seasonal period. Going forward with the RPS obligations to the year 2030 and beyond and with the continued increase in solar generation, the months of October through February are expected to see a comparable deepening of the mid-day hourly cost curve similar to the deepening trough for net load illustrated in Section A. While separating the months of March through May would result in a more refined super off-peak period, for simplicity, customer understanding, and to take into account the anticipated future evolution of the net load, here SCE proposes that all non-summer months should be combined into one winter season, with a winter super-off-peak period from 8:00 a.m. to 4:00 p.m.

Customers also prefer fewer daily TOU periods in each season. Currently, SCE customers have three TOU periods on summer weekdays. To respond to this customer preference, SCE's proposal limits TOU periods to no more than three periods in the summer or winter. In addition, to promote customer acceptance of the revised TOU periods, SCE proposes the same TOU periods for weekdays and weekends, even though some cost differences could justify differentiation of a winter super off-peak period between weekdays and weekends, as discussed in Section B.5, above.

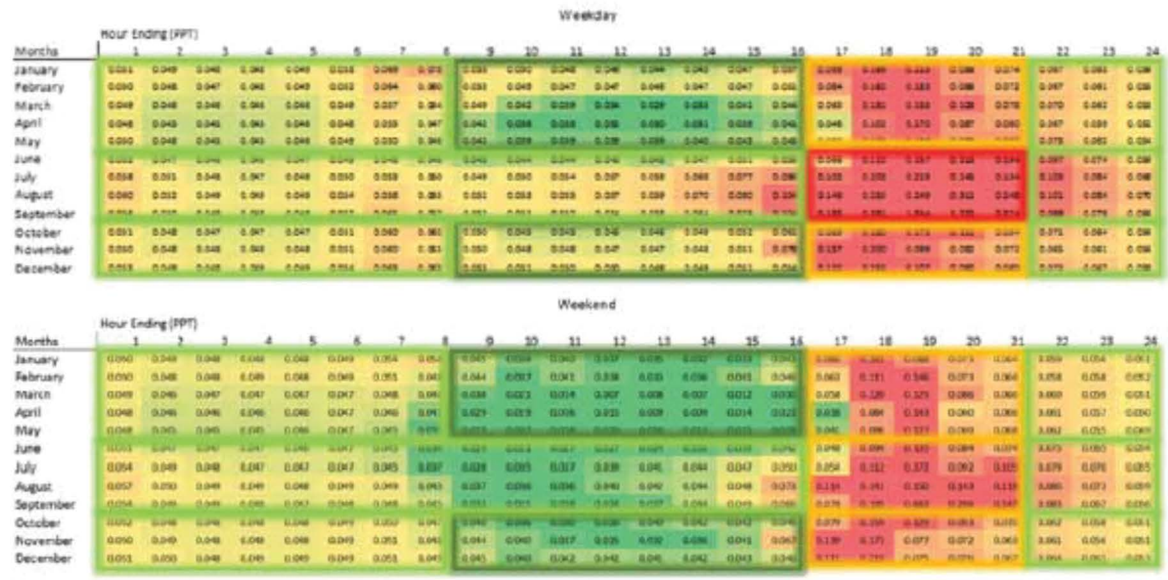
C. Validation of Proposed TOU Periods and Seasons

SCE considered four different approaches to assess its proposed TOU periods and seasons.

1. <u>Visual Test For TOU Periods</u>

Figure IV-33, below, shows SCE's proposed TOU periods overlaid on average hourly marginal costs for weekdays and weekends. These heat maps demonstrate that SCE's proposed TOU periods group similar costs (highest, lowest, and mid-range), as shown in Figure IV-34, much better than the current TOU periods (noon to 9:00 p.m. for summer on-peak period, etc.) that have been in effect for more than 30 years.

Figure IV-33
Overlay of Proposed TOU Periods on Average Hourly Marginal Cost Heat Maps



The colored boundary lines mean the following: the red boundary includes the summer on-peak period; the yellow boundary includes the summer and winter mid-peak periods; the dark green boundary includes the winter super off-peak period; and the light green boundary includes the summer and winter off-peak periods.

2. <u>Performance Measures</u>

A performance measure for TOU periods is a classification exercise in which the hours in a year are classified into periods that effectively predict the relative value of their cost. Statistics can measure how correctly or accurately any proposed classification captures the true state. Here, the classification rule is the proposed period and the true state is the relative value of the cost. If the summer on-peak period is defined as the hours of 4:00 p.m. to 9:00 p.m., as proposed by SCE, the percentage of the highest cost hours that the proposed on-peak period captures is called the true positive rate (TPR), or "hit rate."[78] Table IV-10, below, shows the TPR or hit rate for different summer weekday on-peak period definitions or classifications when the top 20 and top 100 highest-cost hours are considered.

Table IV-10
True Positive Rate For Highest-Cost Hours in Various Summer On-Peak Periods

		Weekday Peak Period							
		4 p.m. to 9 p.m.	4 p.m. to 8 p.m.	4 p.m. to 10 p.m.	5 p.m. to 9 p.m.	5 p.m. to 8 p.m.	5 p.m. to 10 p.m.	Noon to 6 p.m.	2 p.m. to 8 p.m.
Top 20 hours	Number of Hours Captured	18	15	18	17	14	17	2	15
	% Captured	0.9	0.75	0.9	0.85	0.7	0.85	0.1	0.75
Top 100 hours	Number of Hours Captured	80	69	80	75	64	75	25	71
	% Captured	0.8	0.69	0.8	0.75	0.64	0.75	0.25	0.71

Table IV-10 shows that the proposed summer on-peak period of 4:00 p.m. to 9:00 p.m. captures the highest percentage of the top 20 (90%) and 100 (81%) highest-cost hours. It also shows that the 4:00 p.m. to 9:00 p.m. period captures a significantly-higher percentage of the high-cost hours than it would if the period were shortened to 4:00 pm to 8:00 pm (i.e., 75% and 69%). Expanding the ending hour from 9:00 p.m. to 10:00 p.m. provides no incremental increase in the TPR. Thus, a peak

[78] TPR=TP/(TP+FN), where true positive (TP) = correct hit; true negative (TN) = correct rejection; false positive (FP) = false alarm or Type I error; false negative (FN) = miss or Type II error.

period of 4:00 p.m. to 9:00 p.m. is better than either extending or shortening the proposed 9:00 p.m. ending hour of SCE's proposed on-peak period.

3. Regression Test

Another approach to validating the accuracy of different TOU period scenarios is to perform regression analyses in which a series of variables defining the combination of the season and TOU period are regressed on the forecast hourly marginal costs for 2024.[79] Various options for seasonal and TOU periods are analyzed and ranked based on the regression performances and are tested against SCE's current non-residential TOU structure, with the results shown in Table IV-11, below.

Table IV-11
Summary of Regression Results

Rank	Model	Reasons for Sub-Optimality
1	Similar to Proposed with on-peak 5 p.m. -8 p.m. and mid-peak on summer weekdays 3 p.m.-5 p.m. and 8 a.m.-12 p.m.	Shoulders add 2 periods in summer with different start/end times
2	Similar to Proposed with on-peak 5 p.m.-8 p.m.	Non-optimal on-peak
3	Similar to Proposed with on-peak 5 p.m.-9 p.m.	Non-optimal on-peak
4	TOU Pilot Rate 3	3 seasons, 4 periods per season
5	Similar to Proposed with on-peak 4 p.m.-8 p.m.	Non-optimal on-peak
6	3 seasons; super off-peak in spring only; on-peak 4 p.m.-9 p.m.	3 seasons
7	**Proposed TOU periods**	
8	Similar to proposed; no super off-peak	No super off-peak
9	Similar to Proposed with on-peak 5 p.m.-10 p.m.	Non-optimal on-peak
10	Similar to Proposed with on-peak 4 p.m.-10 p.m.	Non-optimal on-peak
11	CAISO Proposal	4 seasons, September not in peak season
12	SCE current TOU-D-A/B	2 p.m. - 8 p.m. on-peak, non-optimal
13	SCE Current TOU	Misaligned with costs

As expected, scenarios with more TOU periods and more seasons fare better in this assessment because they produce a closer fit. Scenarios in which the peak period is narrower also perform well and are ranked higher than SCE's proposal because they track better with the peaky

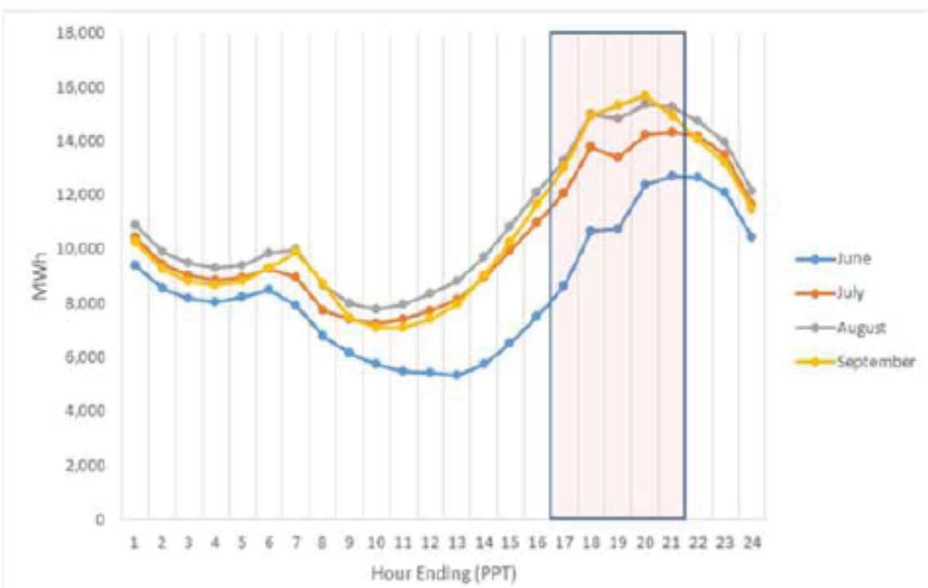
[79] This same method was used in SCE's 2015 GRC Phase 2 application to determine whether a change to the TOU periods was warranted at that time. *See* Appendix D in A.14-06-014 SCE-02, Marginal Cost and Sales Forecast Proposals.

distribution of SCE's hourly costs. However, customers' preferences relating to the number and duration of TOU periods outweigh this ranking result. Also, Section C.2 demonstrates that some of the narrower on-peak periods in better-ranked scenarios do not capture the high cost hours as well as SCE's proposed structure. SCE's proposal (line 8) performs adequately and improves upon the optional residential TOU structure (line 12) approved in SCE's 2013 RDW[80] (which has a weekday on-peak period from 2:00 p.m. until 8:00 p.m.); the CAISO's proposal (line 11) and the current non-residential TOU structure.

4. <u>Net-Load Test</u>

Figure IV-34 graphs average monthly net-load curves for weekdays for June through September. The pink shaded rectangular area is SCE's proposed on-peak period. The off-peak hours include all the other hours.

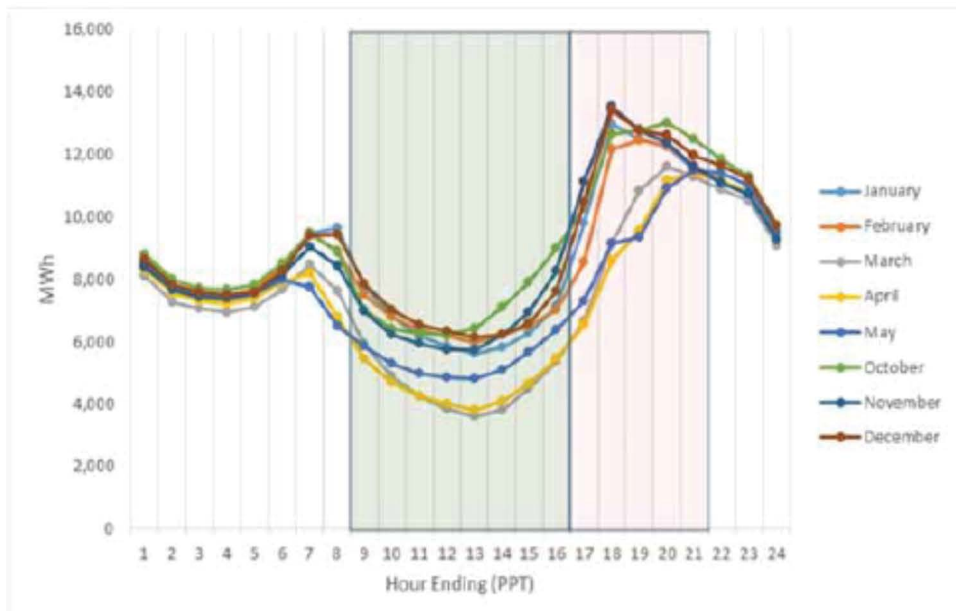
Figure IV-34
Overlay of Proposed On- and Off-Peak Periods on Summer Weekday Average Hourly Net Load



[80] *See* D.14-12-048, which approved SCE's Schedule TOU-D, with options A and B.

Figure IV-35, below, shows the average monthly net-load curves for weekdays for October through May. The area shaded in pink is SCE's proposed mid-peak period and the area shaded in green is the super off-peak period.

Figure IV-35
Proposed Mid-, Off-, and Super Off-Peak Periods Overlaid on Winter Weekday Average Hourly Net Load



These graphs show that the proposed peak periods capture the highest net-load hours as well as the steepest part of the ramping periods. A decrease in load in those periods would help flatten the overall net-load curve. Conversely, the winter super-off peak period of 8:00 a.m. to 4:00 p.m. is appropriate because it provides a lower-cost incentive to customers to increase their load during that period that would also help flatten the net-load curve.

D. <u>Conclusion</u>

SCE's proposed definitions of TOU periods and seasons are grounded in a detailed analysis of the cost data and track marginal costs much better than the current TOU periods. They also make allowance for customer preferences, as customers' buy-in is essential to the success of any proposal.

SCE's proposal retains the same summer and winter seasons that have been in place for more than thirty years, making the transition process a lot simpler for most customers. The TOU periods are identical on weekdays and weekends, reducing potential customer confusion and the need to accommodate different start and end times, and the summer on-peak period is a little shorter than the current on-peak period. A super off-peak period in the middle of the day in the winter season is followed by a higher priced mid-peak period. This will provide pricing signals that will help flatten the net-load curve and mitigate the problems associated with the "duck curve."

Appendix A

As a reference, SCE hereby attaches large-scale versions of the following "heat map" figures in Chapter III:

- Figure III-18 – SCE 2024 Forecast Average Hourly Total Marginal Costs
- Figure III-3 – SCE 2024 Forecast Average Hourly Marginal Energy Costs
- Figure III-8 – SCE 2024 Forecast Average Hourly Marginal Generation Capacity Costs (System Peak Only)
- Figure III-11 – SCE 2024 Forecast Average Hourly Marginal Generation Capacity Costs (System Peak + Flex)
- Figure III-17 – SCE 2024 Forecast Average Hourly Peak Component of Distribution Design Demand Marginal Costs

The following graphs can be recreated in the RDW Tool by using the following values, as described in Chapter III, in the User Input fields:

Input Field	**Default Value**
Year	2024
Marginal Energy Costs	On
Weighting of LOLE and Flex	60% LOLE; 40% Flex
Weighting of Flex Allocation in Hour 2/Hour 3%	30% Hour 2; 70% Hour 3
% of Variable Distribution Marginal Cost	60%
Generation Capacity Marginal Cost Value	$147.26/kW-Year
Distribution Capacity Marginal Cost Value	$126.41/kW-Year

Total Marginal Costs ($/kWh)

Weekdays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	0.051	0.049	0.048	0.048	0.049	0.053	0.069	0.078	0.055	0.050	0.048	0.046	0.044	0.045	0.047	0.057	0.099	0.169	0.115	0.086	0.074	0.067	0.063	0.056	0.065
February	0.050	0.048	0.047	0.048	0.049	0.052	0.064	0.060	0.053	0.049	0.047	0.047	0.046	0.047	0.047	0.051	0.084	0.142	0.133	0.086	0.072	0.067	0.061	0.055	0.064
March	0.049	0.046	0.046	0.046	0.046	0.049	0.057	0.054	0.049	0.042	0.039	0.034	0.029	0.033	0.041	0.044	0.065	0.131	0.155	0.103	0.078	0.070	0.062	0.053	0.059
April	0.048	0.045	0.045	0.045	0.046	0.048	0.055	0.047	0.042	0.036	0.033	0.032	0.030	0.031	0.039	0.041	0.046	0.102	0.170	0.087	0.080	0.067	0.059	0.052	0.055
May	0.050	0.046	0.045	0.045	0.046	0.049	0.050	0.046	0.042	0.039	0.039	0.039	0.039	0.040	0.043	0.045	0.050	0.106	0.136	0.088	0.087	0.073	0.062	0.054	0.058
June	0.052	0.047	0.046	0.046	0.047	0.049	0.048	0.046	0.043	0.044	0.044	0.045	0.043	0.047	0.051	0.059	0.066	0.112	0.157	0.215	0.194	0.097	0.074	0.059	0.072
July	0.058	0.051	0.048	0.047	0.048	0.050	0.053	0.050	0.049	0.050	0.054	0.057	0.058	0.068	0.077	0.086	0.102	0.203	0.218	0.145	0.134	0.103	0.084	0.068	0.082
August	0.060	0.052	0.049	0.049	0.049	0.054	0.058	0.053	0.052	0.053	0.055	0.057	0.059	0.070	0.080	0.104	0.146	0.235	0.249	0.511	0.248	0.101	0.084	0.070	0.108
September	0.056	0.050	0.048	0.048	0.048	0.052	0.065	0.057	0.052	0.051	0.052	0.054	0.058	0.064	0.076	0.104	0.185	0.381	1.844	1.225	0.374	0.099	0.079	0.066	0.216
October	0.051	0.048	0.047	0.047	0.047	0.051	0.060	0.062	0.050	0.045	0.045	0.045	0.046	0.049	0.052	0.061	0.089	0.180	0.173	0.111	0.084	0.071	0.064	0.056	0.068
November	0.050	0.048	0.048	0.048	0.048	0.051	0.060	0.055	0.050	0.048	0.048	0.047	0.047	0.048	0.051	0.079	0.157	0.200	0.099	0.082	0.072	0.065	0.061	0.056	0.067
December	0.053	0.049	0.048	0.049	0.049	0.054	0.063	0.063	0.055	0.051	0.050	0.050	0.049	0.049	0.051	0.054	0.122	0.255	0.107	0.092	0.080	0.072	0.067	0.058	0.070
Hourly Average	0.052	0.048	0.047	0.047	0.048	0.051	0.059	0.056	0.049	0.047	0.046	0.046	0.046	0.049	0.055	0.065	0.101	0.186	0.298	0.236	0.131	0.079	0.068	0.058	

Weekends and Holidays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	0.050	0.049	0.048	0.048	0.048	0.049	0.054	0.058	0.045	0.039	0.040	0.037	0.035	0.032	0.033	0.043	0.086	0.161	0.088	0.073	0.064	0.059	0.056	0.051	0.056
February	0.050	0.048	0.048	0.049	0.048	0.049	0.051	0.048	0.044	0.037	0.041	0.038	0.033	0.036	0.041	0.046	0.063	0.111	0.146	0.073	0.064	0.058	0.058	0.052	0.056
March	0.049	0.046	0.047	0.047	0.047	0.047	0.048	0.046	0.038	0.021	0.014	0.007	0.008	0.007	0.012	0.030	0.058	0.120	0.125	0.086	0.066	0.060	0.059	0.051	0.047
April	0.048	0.046	0.046	0.046	0.046	0.047	0.046	0.041	0.029	0.019	0.016	0.015	0.009	0.009	0.014	0.023	0.038	0.084	0.143	0.060	0.066	0.061	0.057	0.050	0.044
May	0.048	0.045	0.045	0.045	0.046	0.047	0.045	0.035	0.019	0.022	0.018	0.020	0.018	0.012	0.015	0.028	0.041	0.086	0.127	0.069	0.068	0.062	0.055	0.049	0.044
June	0.051	0.047	0.047	0.047	0.046	0.047	0.045	0.034	0.019	0.021	0.027	0.027	0.024	0.032	0.039	0.042	0.048	0.094	0.135	0.084	0.074	0.075	0.065	0.054	0.051
July	0.054	0.049	0.048	0.047	0.047	0.047	0.045	0.037	0.028	0.035	0.037	0.039	0.041	0.044	0.047	0.050	0.054	0.112	0.172	0.092	0.105	0.079	0.070	0.055	0.060
August	0.057	0.050	0.049	0.049	0.048	0.049	0.049	0.043	0.037	0.036	0.036	0.040	0.042	0.044	0.048	0.073	0.114	0.141	0.150	0.143	0.118	0.086	0.073	0.059	0.068
September	0.054	0.049	0.049	0.048	0.047	0.048	0.048	0.045	0.033	0.021	0.028	0.034	0.037	0.044	0.049	0.066	0.078	0.195	0.683	0.286	0.147	0.083	0.067	0.056	0.096
October	0.052	0.048	0.048	0.048	0.048	0.049	0.050	0.047	0.040	0.036	0.030	0.036	0.040	0.042	0.042	0.046	0.079	0.159	0.129	0.093	0.070	0.062	0.058	0.051	0.058
November	0.050	0.049	0.048	0.048	0.048	0.049	0.051	0.048	0.044	0.040	0.037	0.035	0.032	0.036	0.041	0.067	0.139	0.173	0.077	0.072	0.063	0.061	0.056	0.051	0.059
December	0.051	0.050	0.048	0.049	0.049	0.049	0.051	0.049	0.045	0.040	0.042	0.042	0.041	0.042	0.043	0.046	0.111	0.219	0.075	0.076	0.067	0.064	0.061	0.053	0.061
Hourly Average	0.051	0.048	0.048	0.048	0.047	0.048	0.048	0.044	0.035	0.030	0.031	0.031	0.030	0.032	0.035	0.047	0.076	0.138	0.171	0.101	0.081	0.068	0.061	0.053	

Marginal Energy Costs ($/kWh)

Weekdays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	0.049	0.048	0.047	0.047	0.048	0.050	0.058	0.062	0.049	0.046	0.045	0.044	0.041	0.042	0.043	0.046	0.057	0.081	0.077	0.071	0.063	0.060	0.055	0.051	0.053
February	0.048	0.047	0.047	0.047	0.048	0.050	0.059	0.053	0.047	0.044	0.043	0.043	0.042	0.042	0.043	0.044	0.049	0.067	0.076	0.073	0.065	0.060	0.054	0.050	0.052
March	0.047	0.046	0.046	0.046	0.046	0.047	0.052	0.049	0.045	0.040	0.037	0.032	0.027	0.030	0.038	0.040	0.042	0.050	0.062	0.079	0.069	0.061	0.056	0.049	0.047
April	0.046	0.044	0.044	0.044	0.045	0.047	0.051	0.044	0.040	0.035	0.032	0.030	0.028	0.029	0.036	0.038	0.040	0.044	0.050	0.069	0.071	0.058	0.052	0.047	0.044
May	0.046	0.045	0.044	0.044	0.045	0.047	0.047	0.043	0.039	0.037	0.037	0.037	0.036	0.037	0.038	0.040	0.041	0.045	0.047	0.063	0.071	0.062	0.054	0.048	0.046
June	0.047	0.045	0.045	0.045	0.046	0.047	0.046	0.042	0.039	0.038	0.038	0.039	0.038	0.039	0.040	0.042	0.044	0.050	0.068	0.065	0.074	0.070	0.057	0.049	0.047
July	0.049	0.046	0.045	0.045	0.045	0.047	0.046	0.043	0.040	0.041	0.042	0.044	0.046	0.049	0.053	0.056	0.060	0.073	0.069	0.096	0.079	0.070	0.060	0.053	0.054
August	0.049	0.047	0.046	0.046	0.046	0.048	0.050	0.045	0.043	0.042	0.042	0.043	0.044	0.046	0.049	0.053	0.060	0.074	0.085	0.092	0.080	0.067	0.059	0.053	0.054
September	0.049	0.047	0.046	0.046	0.046	0.049	0.055	0.049	0.044	0.042	0.042	0.042	0.043	0.045	0.048	0.050	0.057	0.073	0.090	0.106	0.074	0.062	0.057	0.051	0.055
October	0.048	0.047	0.046	0.046	0.046	0.048	0.054	0.054	0.045	0.042	0.041	0.041	0.042	0.043	0.045	0.046	0.048	0.062	0.075	0.079	0.067	0.060	0.056	0.050	0.051
November	0.049	0.047	0.047	0.047	0.047	0.049	0.055	0.050	0.046	0.044	0.044	0.043	0.043	0.044	0.045	0.048	0.061	0.089	0.076	0.068	0.063	0.059	0.054	0.050	0.053
December	0.050	0.048	0.048	0.048	0.048	0.050	0.057	0.057	0.049	0.047	0.046	0.046	0.045	0.045	0.046	0.048	0.060	0.084	0.077	0.073	0.068	0.062	0.059	0.052	0.055
Hourly Average	0.048	0.048	0.046	0.046	0.046	0.048	0.053	0.049	0.044	0.041	0.041	0.040	0.040	0.041	0.044	0.046	0.052	0.066	0.067	0.078	0.070	0.063	0.056	0.050	

Weekends and Holidays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	0.048	0.048	0.047	0.047	0.047	0.048	0.049	0.049	0.044	0.038	0.040	0.036	0.034	0.031	0.032	0.042	0.050	0.068	0.098	0.068	0.061	0.057	0.054	0.050	0.048
February	0.048	0.048	0.047	0.048	0.048	0.048	0.050	0.047	0.043	0.036	0.040	0.037	0.033	0.036	0.040	0.042	0.046	0.056	0.085	0.068	0.060	0.056	0.056	0.051	0.048
March	0.047	0.046	0.046	0.046	0.046	0.046	0.047	0.045	0.038	0.020	0.013	0.006	0.008	0.007	0.011	0.030	0.037	0.046	0.096	0.068	0.063	0.059	0.057	0.050	0.039
April	0.046	0.045	0.045	0.045	0.045	0.046	0.045	0.040	0.028	0.019	0.015	0.015	0.008	0.008	0.013	0.017	0.027	0.042	0.046	0.058	0.062	0.059	0.055	0.049	0.037
May	0.046	0.045	0.045	0.045	0.045	0.046	0.044	0.034	0.018	0.021	0.017	0.019	0.018	0.010	0.014	0.027	0.036	0.041	0.044	0.055	0.063	0.058	0.053	0.048	0.037
June	0.047	0.045	0.045	0.045	0.045	0.046	0.044	0.033	0.019	0.020	0.027	0.026	0.024	0.031	0.037	0.039	0.041	0.045	0.046	0.057	0.064	0.065	0.058	0.049	0.042
July	0.049	0.047	0.046	0.045	0.045	0.045	0.044	0.036	0.027	0.034	0.036	0.038	0.039	0.041	0.044	0.045	0.045	0.049	0.052	0.068	0.068	0.065	0.058	0.050	0.046
August	0.049	0.047	0.047	0.047	0.047	0.047	0.047	0.042	0.036	0.034	0.034	0.038	0.039	0.041	0.043	0.044	0.046	0.052	0.064	0.071	0.073	0.066	0.061	0.051	0.048
September	0.048	0.047	0.047	0.046	0.046	0.047	0.047	0.044	0.032	0.020	0.027	0.032	0.034	0.040	0.042	0.044	0.047	0.056	0.066	0.084	0.070	0.061	0.057	0.050	0.047
October	0.048	0.047	0.047	0.047	0.047	0.048	0.049	0.047	0.040	0.035	0.029	0.035	0.039	0.041	0.041	0.043	0.046	0.058	0.075	0.082	0.064	0.058	0.055	0.049	0.049
November	0.049	0.048	0.048	0.048	0.048	0.048	0.050	0.047	0.043	0.040	0.037	0.035	0.032	0.035	0.040	0.045	0.054	0.081	0.071	0.066	0.060	0.058	0.054	0.050	0.049
December	0.051	0.049	0.048	0.048	0.048	0.048	0.050	0.049	0.044	0.039	0.042	0.042	0.041	0.041	0.042	0.045	0.054	0.076	0.069	0.070	0.062	0.062	0.057	0.051	0.051
Hourly Average	0.048	0.047	0.046	0.046	0.047	0.047	0.047	0.043	0.034	0.030	0.030	0.030	0.029	0.030	0.033	0.039	0.044	0.056	0.059	0.068	0.064	0.060	0.056	0.050	

Marginal Generation Capacity Costs - LOLE Only ($/kWh)

Weekdays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-	0.000
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.004	0.007	0.010	0.165	0.164	0.009	-	-	0.015
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.011	0.031	0.002	-	-	0.002
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.003	0.008	0.007	0.064	0.621	0.214	0.004	-	-	0.038
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.003	0.023	0.107	0.249	2.668	1.789	0.441	0.019	0.000	-	0.221
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.004	0.032	0.002	0.000	0.000	0.000	-	0.001
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hourly Average	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.002	0.010	0.022	0.228	0.216	0.071	0.003	0.000	-	

Weekends and Holidays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	-	-	-	0.000
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.001	0.000	-	-	0.000
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.015	0.035	0.002	-	-	0.002
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.008	0.081	0.035	0.001	-	-	0.005
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.002	0.003	0.017	0.738	0.256	0.084	0.005	0.000	-	0.046
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	-	0.000
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
Hourly Average	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.000	0.001	0.062	0.029	0.013	0.001	0.000	-	

Total Marginal Generation Capacity Costs -- LOLE and Flex ($/kWh)

Weekdays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	-	-	-	-	-	-	0.004	0.009	-	-	-	-	-	-	-	0.006	0.037	0.064	0.020	-	-	-	-	-	0.006
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.030	0.081	0.042	-	-	-	-	-	0.006
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.017	0.073	0.080	0.015	-	-	-	-	0.008
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.047	0.112	0.008	-	-	-	-	0.007
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.001	0.041	0.098	0.010	0.000	-	-	-	0.006
June	-	-	-	-	-	-	-	-	-	0.001	0.002	-	-	-	0.000	0.001	0.002	0.034	0.088	0.129	0.098	0.005	-	-	0.015
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.042	0.099	0.007	0.019	0.001	-	-	0.007
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.016	0.067	0.120	0.373	0.128	0.002	-	-	0.030
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.002	0.014	0.069	0.307	1.710	1.073	0.265	0.012	0.000	-	0.140
October	-	-	-	-	-	-	0.001	0.002	-	-	-	-	-	-	0.000	0.000	0.020	0.079	0.076	0.001	0.000	0.000	0.000	-	0.007
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.025	0.087	0.066	-	-	-	-	-	-	0.007
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.055	0.131	0.005	-	-	-	-	-	0.008
Hourly Average	-	-	-	-	-	-	0.000	0.001	-	0.000	0.000	-	-	0.000	0.000	0.004	0.028	0.078	0.204	0.135	0.042	0.002	0.000	-	

Weekends and Holidays

Columns: Hour Ending (PPT) Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	-	-	-	-	-	-	0.003	0.008	-	-	-	-	-	-	-	-	0.035	0.088	0.016	-	-	-	-	-	0.006
February	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.003	0.015	0.051	0.075	-	-	-	-	-	0.006
March	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.020	0.072	0.067	0.014	-	-	-	-	0.007
April	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.005	0.011	0.041	0.095	-	-	-	-	-	0.006
May	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.004	0.042	0.082	0.010	0.000	-	-	-	0.006
June	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.004	0.039	0.077	0.018	0.001	0.000	-	-	0.006
July	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.000	0.044	0.102	0.009	0.021	0.001	-	-	0.007
August	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.018	0.051	0.039	0.041	0.048	0.021	0.000	-	-	0.009
September	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.001	0.002	0.063	0.147	0.153	0.050	0.003	0.000	-	0.035
October	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.000	0.000	0.029	0.089	0.090	0.000	0.000	0.000	0.000	-	0.007
November	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.020	0.083	0.082	-	-	-	-	-	-	0.008
December	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-	0.055	0.129	-	-	-	-	-	-	0.008
Hourly Average	-	-	-	-	-	-	0.000	0.001	-	-	-	-	-	0.000	0.000	0.004	0.026	0.065	0.098	0.021	0.008	0.000	0.000	-	

Total Marginal Distribution Costs ($/kWh)

Weekdays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	0.002	0.001	0.001	0.001	0.001	0.003	0.007	0.006	0.006	0.005	0.003	0.002	0.003	0.003	0.004	0.006	0.006	0.024	0.018	0.015	0.010	0.007	0.008	0.005	0.006
February	0.002	0.001	0.001	0.001	0.001	0.002	0.006	0.007	0.006	0.005	0.004	0.004	0.004	0.005	0.004	0.005	0.006	0.014	0.015	0.013	0.008	0.007	0.007	0.005	0.006
March	0.002	0.000	0.001	0.001	0.000	0.002	0.005	0.005	0.004	0.002	0.003	0.002	0.002	0.002	0.003	0.004	0.006	0.008	0.010	0.010	0.010	0.008	0.006	0.004	0.004
April	0.002	0.001	0.001	0.001	0.001	0.001	0.004	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.003	0.003	0.006	0.011	0.008	0.010	0.009	0.009	0.007	0.005	0.004
May	0.004	0.001	0.001	0.001	0.001	0.001	0.003	0.003	0.003	0.002	0.002	0.003	0.003	0.003	0.004	0.006	0.009	0.030	0.013	0.015	0.016	0.012	0.008	0.006	0.006
June	0.005	0.002	0.001	0.001	0.002	0.001	0.002	0.003	0.003	0.005	0.004	0.006	0.004	0.008	0.010	0.016	0.020	0.028	0.020	0.021	0.022	0.021	0.017	0.010	0.010
July	0.009	0.005	0.003	0.002	0.003	0.004	0.007	0.007	0.009	0.009	0.012	0.013	0.012	0.019	0.025	0.029	0.043	0.088	0.060	0.043	0.036	0.032	0.024	0.015	0.021
August	0.011	0.005	0.003	0.003	0.003	0.006	0.009	0.008	0.009	0.011	0.013	0.014	0.016	0.024	0.031	0.049	0.071	0.095	0.065	0.047	0.040	0.032	0.025	0.017	0.025
September	0.007	0.003	0.002	0.002	0.002	0.004	0.010	0.008	0.008	0.009	0.010	0.011	0.015	0.019	0.026	0.040	0.059	0.101	0.044	0.046	0.036	0.025	0.021	0.015	0.022
October	0.003	0.001	0.000	0.001	0.001	0.003	0.005	0.005	0.005	0.004	0.004	0.004	0.003	0.006	0.008	0.015	0.022	0.039	0.024	0.030	0.017	0.011	0.008	0.006	0.009
November	0.002	0.001	0.001	0.001	0.001	0.002	0.005	0.005	0.004	0.004	0.004	0.004	0.004	0.004	0.006	0.006	0.009	0.045	0.028	0.014	0.009	0.007	0.007	0.005	0.007
December	0.003	0.001	0.001	0.001	0.001	0.003	0.006	0.006	0.006	0.005	0.004	0.004	0.003	0.004	0.005	0.006	0.007	0.041	0.025	0.019	0.013	0.009	0.008	0.006	0.008
Hourly Average	0.004	0.002	0.001	0.001	0.001	0.003	0.006	0.006	0.005	0.005	0.005	0.006	0.006	0.008	0.011	0.015	0.022	0.040	0.027	0.024	0.019	0.015	0.012	0.008	

Weekends and Holidays

Columns: Hour Ending (PPT) / Rows: Months	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	Average
January	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.005	0.006	0.005	0.004	0.003	0.002	0.001	0.002
February	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.004	0.006	0.005	0.004	0.002	0.002	0.001	0.002
March	0.002	0.000	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.004	0.003	0.002	0.002	0.002	0.001
April	0.002	0.001	0.001	0.000	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.002	0.002	0.002	0.003	0.003	0.002	0.002	0.001
May	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.003	0.002	0.003	0.005	0.004	0.003	0.001	0.001
June	0.004	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.000	0.001	0.000	0.001	0.002	0.003	0.003	0.010	0.011	0.009	0.009	0.010	0.008	0.004	0.004
July	0.005	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.002	0.003	0.005	0.008	0.019	0.018	0.015	0.016	0.013	0.012	0.005	0.006
August	0.008	0.003	0.002	0.002	0.002	0.002	0.002	0.002	0.001	0.001	0.002	0.002	0.003	0.003	0.006	0.011	0.017	0.051	0.054	0.024	0.025	0.020	0.012	0.007	0.011
September	0.006	0.002	0.002	0.002	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.003	0.004	0.007	0.021	0.030	0.076	0.050	0.049	0.027	0.020	0.010	0.006	0.014
October	0.004	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.002	0.001	0.001	0.001	0.001	0.002	0.004	0.011	0.008	0.012	0.006	0.004	0.003	0.001	0.003
November	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.003	0.010	0.006	0.005	0.002	0.003	0.002	0.001	0.002
December	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.000	0.001	0.001	0.001	0.001	0.001	0.002	0.014	0.006	0.006	0.004	0.003	0.003	0.002	0.002
Hourly Average	0.003	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.001	0.002	0.004	0.006	0.017	0.014	0.012	0.009	0.007	0.005	0.003	

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF REUBEN J. BEHLHIOMJI

Q. Please state your name and business address for the record.

A. My name is Reuben J Behlihomji, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am currently the Manager of Marginal Cost and Forecasting within SCE's Regulatory Operations (RO) department. My current responsibilities include managing the Marginal Cost and Forecasting function in regulatory Operations.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Engineering degree from the University of Mumbai in 1997 and a Master of Business Administration from University of Southern California in 2003. I have been employed by SCE since 2003. From 2003 to 2006, I worked in the Transmission and Distribution Business, first in the area of Power Delivery Technology Integration and subsequently Substation Engineering. During that time, I gained an understanding of Transmission and Distribution project design and execution coupled with the process and procedures that went into transmission and distribution system planning. In 2006, I joined the Controllers organization. In my tenure from 2006 to 2014, I managed three groups, namely the Valuation Services group, the Added Facilities and Interconnection Facilities group, and the Non Energy Billing group. The Valuation group was responsible for fixed asset valuation under various Annexation and Condemnation proceedings, Department of Defense privatization and Base Realignment projects and was responsible for assessing SCE's base of insurable fixed assets. The Added Facilities and Interconnection group was responsible for cost assessment and reconciliation of special facilities projects for large retail customers and interconnection facilities projects under FERC and CPUC jurisdictional tariffs. The Non Energy Billing Group was responsible for cost assessment and reconciliation of special facilities projects for CALTRANS, Relocations and Rule 20 projects. In 2014, I joined Regulatory Operations as the Manager of the Marginal cost and forecasting group to assume my current responsibilities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of testimony identified by my name as witness in the Table of Contents of Exhibit SCE-1.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct to the best of your knowledge?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best professional judgment?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF RUSSELL D. GARWACKI

Q. Please state your name and business address for the record.

A. My name is Russell D. Garwacki, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. My current responsibilities include managing the Load Research and Rate Design functions within SCE's Regulatory Policy and Affairs (RP&A) department. These functions include the development of present rate revenue forecasts.

Q. Briefly describe your educational and professional background.

A. I received a Bachelor of Arts degree in Economics from Whittier College in 1980 and a Master of Arts degree in Economics from Claremont Graduate School in 1983. I have been employed by SCE since 1983. From 1983 to 1993, I worked in the load research area of RP&A, ultimately supervising the group. During that time, I gained an understanding of sample design, cost allocation, and other regulatory policies and procedures. In 1994, I joined the Customer Service Business Unit (CSBU) as the Credit Analysis Manager, working to reduce both write-off and credit operational costs. From 1997 to 1999, I managed the Measurement and Efficiency group, delivering process improvements for CSBU's Field Services, Credit, Payment, and Customer Communication Center functions. From 1999 to 2004, I managed various CSBU activities including Job Skills Training, Internet Delivery, Benchmarking, and various technical support functions. In 2004, I returned to Regulatory Operations to assume my current responsibilities.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of testimony identified by my name as witness in the Table of Contents of Exhibit SCE-1.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF DANIEL HOPPER

Q. Please state your name and business address for the record.

A. My name is Daniel Hopper, and my business address is 1515 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A. I am Manager of DSM Forecasting and Cost-Effectiveness in the Customer Program and Services department. My responsibilities include oversight of demand-side management resource cost-effectiveness, valuation and forecasting activities at SCE.

Q. Briefly describe your educational and professional background.

A. I earned a Bachelor of Science in Electrical Engineering from the University of Nevada, Reno and a Master in Economics from California University, Fullerton. I've been in my current role at SCE since 2013. Previously, I was a study manager under contract in SCE's DSM Program Evaluation group. Prior to working with SCE, I was a managing engineer at Raytheon Space and Airborne Systems.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of testimony identified by my name as witness in the Table of Contents of Exhibit SCE-1.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY
QUALIFICATIONS AND PREPARED TESTIMONY
OF KIPHAN KAN

Q. Please state your name and business address for the record.

A. My name is Kiphan Kan, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at the Southern California Edison Company.

A I am a Project Manager in Load Research in the Pricing Design and Research department of the Regulatory Affairs Organization. In this position, my responsibilities include development, analysis, and reporting of load research studies in support of regulatory proceedings, pricing, and forecasting.

Q. Briefly describe your educational and professional background?

A. I have a Maitrise es Sciences Economiques from the Universite d'Aix-Marseille II, France, and I received a Ph.D. in Economics from the University of Southern California. I joined SCE in 1994 as a load research analyst. In that capacity, I have been involved in all aspects of load research including sample design and selection, data management, estimation of load profiles for various rate groups and customer classes, market segmentation, statistical estimation, and econometrics modeling.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of testimony identified by my name as witness in the Table of Contents of Exhibit SCE-1.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

SOUTHERN CALIFORNIA EDISON COMPANY

QUALIFICATIONS AND PREPARED TESTIMONY

OF JOSEPH YAN

Q. Please state your name and business address for the record.

A. My name is Joseph H. Yan, and my business address is 2244 Walnut Grove Avenue, Rosemead, California 91770.

Q. Briefly describe your present responsibilities at Southern California Edison Company (“SCE”).

A. I am the principal manager of Price Forecasting and Modeling at Strategy, Integrated Planning, and Performance Organization Unit.

Q. Briefly describe your educational and professional background.

A. I hold a Ph.D. Degree in Electrical Engineering from The University of Connecticut. I have worked at SCE for more than 20 years in a variety of leadership, project management, financial analyst, engineer positions in Planning, Analysis and Forecasting, Portfolio Planning and Analysis, Energy Supply and Management, Market Strategy and Resource Planning, Market Design and Analysis, Energy Marketing, and System Operations.

Q. What is the purpose of your testimony in this proceeding?

A. The purpose of my testimony in this proceeding is to sponsor the portions of testimony identified by my name as witness in the Table of Contents of Exhibit SCE-1.

Q. Was this material prepared by you or under your supervision?

A. Yes, it was.

Q. Insofar as this material is factual in nature, do you believe it to be correct?

A. Yes, I do.

Q. Insofar as this material is in the nature of opinion or judgment, does it represent your best judgment?

A. Yes, it does.

Q. Does this conclude your qualifications and prepared testimony?

A. Yes, it does.

Appendix F

Portfolio Compliance

The Table below provides a summary of how SCE's portfolio of pilot projects and programs meet the ACR's statutory and regulatory requirements.

Table: Portfolio Compliance

ACR Action Required	Decision Reference	Compliance Action/Status
Accelerate widespread TE	Pub. Util. Code §§ 740.12(b) and 701.1(a)(1); ACR at p. 14	Section IV, B-1, p. 29; Section V, pp. 40, 42, 44, 48, 50 Section VI pp. 62-63, 67
Fulfill the legislature's findings and declarations of §740.12(a)(1)	Pub. Util. Code § 740.12(a)(2) and (b); ACR at p. 14	Section IV, B-2, pp. 29-34; Section V, pp. 40, 42, 44-45, 48-49, 50 Section VI, pp. 63-64, 67-68
Be measurable with monitoring and evaluation criteria	Pub. Util. Code § 740.12(b); ACR at pp.14	Section IV, B-3, p. 34; Section V, pp. 41, 42-43, 45-47, 49, 50-51 Section VI, pp. X, 73
Minimize costs and maximize benefits	Pub. Util. Code § 740.12(b); ACR at pp.14	Section IV, B-4, pp. 34-35; Section V, pp. 41, 42-43, 45-47, 49, 50-51 Section VI, pp. 64-67, 69-74
Be subject to a specified cost recovery mechanism	Pub. Util. Code § 740.12(b); ACR at pp.15	Section IV, B-5, p. 35; Section VII, pp. 76-82
Fairly compete with non-utility enterprises	Pub. Util. Code §§ 740.12(b) and 740.3; ACR at pp.15	Section IV, B-6, pp. 35-36; Section V, pp. 41, 42-43, 45-47, 49, 50-51 Section VI, pp. 64-67, 69-74
Be trackable with performance accountability measures	Pub. Util. Code §§ 740.12(b); ACR at pp.15	Section IV, B-7, pp. 36; Section V, pp. 41, 42-43, 45-47, 49, 50-

		51 Section VI, pp. 64-67, 69-74
Be in the interests of ratepayers	Pub. Util. Code §§ 740.12(b), 740.8, and 740.3 ACR at pp.15	Section IV, B-8, pp. 36-38; Section V pp. 41, 43, 47, 49, 51; Section VI pp. 67, 75
Demonstrate the avoidance of long-term stranded costs	Pub. Util. Code § 740.12(c); ACR at pp.15	Section IV, B-9, p. 38; Section V, pp. 41, 42-43, 45-47, 49, 50-51 Section VI, pp. 64-67, 69-74

Appendix G

SCE'S 2017 TRANSPORTATION ELECTRIFICATION APPLICATION

ACRONYMS & ABBREVIATIONS

SCE'S 2017 TRANSPORTATION ELECTRIFICATION APPLICATION

ACRONYMS & ABBREVIATIONS

A.	Application
AB	Assembly Bill
AC	Alternating Current
ACR	Assigned Commissioner's Ruling **** As used in SCE's Testimony, "ACR" means the Assigned Commissioner's Ruling Regarding the Filing of the Transportation Electrification Applications Pursuant to Senate Bill 350, issued September 14, 2016, in R.13-11-007 ****
AFDC	Alternative Fuels Data Center
AFUDC	Allowance For Funds Used During Construction
AL	Advice Letter
APCD	Air Pollution Control District
APL	Approved Package List
Application	SCE's Application for Approval of its 2017 Transportation Electrification Proposals
AQMD	Air Quality Management District
ARFVT	Alternative and Renewable Fuels and Vehicle Technology
BEV	Battery Electric Vehicle
BRRBA	Base Revenue Requirement Balancing Account
BYD	BYD Auto Co., Ltd.
CAAQS	California Ambient Air Quality Standards
CalEnviroScreen 3.0	CalEPA's Office of Environmental Health Hazard Assessment's California Communities Environmental Health's Screening Tool
CalEPA	California Environmental Protection Agency
CalETC	California Electric Transportation Coalition
CARB	California Air Resources Board
CCS	Combined Charging System
CEC	California Energy Commission
CES	CalEnviroScreen (*supra*)
CEVWG	CALSTART's Commercial Electric Vehicle Working Group
CHAdeMO	Abbreviation of "**CHA**rge **de MO**ve," (equivalent to "charge for moving"). It is the trade name of a quick charging method for battery electric vehicles delivering up to 62.5 kW of direct current via a special electrical connector. It is proposed as a global industry standard by an association of the same name.
CO2 / CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
COL	Conclusion of Law
Commission	California Public Utilities Commission

COP	Conference of Parties
CP&S	SCE's Customer Programs and Services
CPP	Critical Peak Pricing
CPUC	California Public Utilities Commission
CRPP	Charge Ready Program Pilot
CTM	Contribution to Margin
CWIP	Construction Work In Progress
D.	Decision
DC	Direct Current
DCFC	Direct Current Fast Charge
DER	Distributed Energy Resource
DOE	U.S. Department of Energy
DR	Demand Response
E3	Energy+Environmental Economics
EDR	Economic Development Rate
EPA	U.S. Environmental Protection Agency
EPIC	Electric Program Investment Charge
EPRI	Electric Power Research Institute
ERRA	Energy Resource Recovery Account
EV	Electric Vehicle
EVSE	Electric Vehicle Supply Equipment
FCEV	Fuel Cell Electric Vehicle
FERC	Federal Energy Regulatory Commission
FF&U	Franchise Fees and Uncollectible
Flex Capacity	Flexible Capacity Marginal Cost
FRD	Facilities-Related Demand
FOF	Finding of Fact
g/bhp-hr	Grams Per Brake Horsepower-Hour
g/kWh	Grams Per Kilowatt Hour
GHG	Greenhouse Gas
GO	General Order
GS	General Service
HD	Heavy Duty
HOV	High-Occupancy Vehicle
HVIP	CARB's Hybrid and Zero-Emission Truck and Bus Voucher Incentive Project
I-	Interstate
IRC	Internal Revenue Code
IRP	Integrated Resources Plan
IOU	Investor-Owned Utilities
ISO/IEC	International Orgainzation for Standardization and International Electrotechnical Commission
ITS	International Transportation Service
kV	RPM/Volt (the speed a motor need to turn so it produce 1 volt of force)
kWh	Kilowatt Hour

LCT	Low Carbon Transportation
MACRS	Modified Accelerated Cost Recovery System
MD	Medium Duty
ME&O	Marketing, Education, & Outreach
MGCC	Marginal Generation Capacity Costs
MMT	Million Metric Tons
MW	Megawatts
NAAQS	National Ambient Air Quality Standards
New EV Rate Schedules	Collectively, SCE Proposed Tariff Schedules EV-7, EV-8, and EV-9
NOx	Nitrogen Oxide / Nitrous Oxide
NRDC	Natural Resources Defense Council
O&M	Operation and Maintenance
OAT	Otherwise Applicable Tariff
OEHHA	CalEPA's Office of Environmental Health Hazard Assessment
OP	Ordering Paragraph
PD	Proposed Decision
PEV	Plug-In Electric Vehicle
PG&E	Pacific Gas and Electric Company
PHEV	Plug-In Hybrid Electric Vehicle
PM	Particulate Matter
PM2.5	Fine Inhalable Particles with diameters that are generally 2.5 micrometers and smaller
PM10	Inhalable Particles with diameters that are generally 10 micrometers and smaller
PMO	Project Management Office
POLB	Port of Long Beach
R.	Rulemaking
RDW	Rate Design Window
RFI	Request for Information
RFO	Request for Offers
RFP	Request for Proposal
RPM	Revolutions Per Minute
RPS	Renewables Portfolio Standard
RTG	Rubber Tire Gantry
RTP	Real Time Pricing
SAE	Society of Automotive Engineers; now "SAE International"
SB	Senate Bill
SCAG	Southern California Association of Government
SCAQMD	South Coast Air Quality Management District
SCE	Southern California Edison Company
SDG&E	San Diego Gas & Electric Company
SONGS	San Onofre Nuclear Generating Station
SR	State Route
T&D	Transmission and Distribution

TE	Transportation Electrification
TEA	Transportation Electrification Assessment
TEA Study	ICF International and E3's Phase I Transportation Electrification Assessment
TEPBA	Transportation Electrification Portfolio Balancing Account
TOU	Time-Of-Use
TOU-OIR Decision	Decision approved by the Commission on January 19, 2017, in R.15-12-012, *Order Instituting Rulemaking to Assess Peak Electricity Usage Patterns and Consider Appropriate Time Periods for Future Time-of-Use Rates and Energy Resource Contract Payments*
TRD	Time-Related Demand
USoA	Uniform System of Accounts
VGI	Vehicle-Grid Integration
WCEH	West Coast Electric Highway
WHO	World Health Organization
WMDVBE	Women Minority Disabled Veteran Business Enterprise
ZEV	Zero-Emission Vehicle