Application No.: A.19-08-013
Exhibit No.: SCE-17 Vol. 03
Witnesses: M. Bennett
J. Trapp

SOUTHERN CALIFORNIA EDISON®

(U 338-E)

2021 General Rate Case
Rebuttal Testimony

Employee Benefits, Training & Support

Before the

Public Utilities Commission of the State of California

Rosemead, California
June 12, 2020

SCE-17, Vol. 03: Employee Benefits, Training & Support

Table Of Contents

Table Of Contents (Continued)

SCE-17, Vol. 03: Employee Benefits, Training & Support

Table Of Contents (Continued)

Table Of Contents (Continued)

Section	Page	Witness

I.

INTRODUCTION

In this volume, Southern California Edison provides additional support for its Test Year 2021 forecast of operations and maintenance (O&M) expenses for Employee Benefits, Training and Support activities. If approved, this funding request will allow SCE to attract, develop, motivate, and retain a high-performing and diverse workforce. Such a workforce is foundational to achieving: (1) SCE's goals regarding Safety and Diversity, People, and Culture, (2) SCE's mission to safely deliver reliable, affordable, and clean energy to its customers, and (3) SCE's long-term objective to help transform the electric power industry by providing clean energy, efficient electrification, grid modernization, and customer choice. The following Business Planning Elements will be discussed within this volume:

Chapter II – Employee Support

Chapter III – Employee Benefits and Programs

This testimony will address the various proposals by Cal Advocates and TURN related to SCE's O&M forecasts for *Employee Benefits, Training and Support*.

Cal Advocates' principal recommendations regarding SCE's *Employee Benefits, Training and Support* forecast for test year 2021 are:

- Adopts SCE's test year forecast for activities within Employee Support.
- Adopts SCE's test year forecast for activities within Employee Benefits and Programs, with the following exceptions:
    - Ratepayers should not fund any portion of Short-Term Incentive Program (STIP) awards that are subject to financial goals; the remaining amount of the costs should be shared equally between ratepayers and shareholders.
    - The expenses for Executive Benefits should be shared equally between ratepayers and shareholders.
    - Shareholders should fund all Long-Term Incentive (LTI) Program costs.
    - The expense for Recognition awards should be shared equally between ratepayers and shareholders.
- Adopts SCE's test year forecast for activities within Employee Training.

TURN's recommendations regarding SCE's *Employee Benefits, Training and Support* O&M forecast are:

- Recommends reductions to Operating Unit (OU) Support Services, due to a purportedly inappropriate escalation factor for labor, and speculative claims that forecast non-labor costs would be reallocated.
- Recommends that STIP and Officer Executive Incentive Compensation payouts that are subject to financial and lobbying goals should be disallowed.
- Recommends disallowing most of the salaries and incentive plan costs for executives, including Shared and EIX officers, due to the requirements of Senate Bill (SB) 901.
- Recommends disallowing all Executive Benefits due to the requirements of SB 901.
- Recommends disallowing all Long-Term Incentive costs based on past Commission decisions.

A. <u>Summary Of Rebuttal Position</u>

Before rebutting Cal Advocates' and TURN's proposals in detail, SCE respectfully submits that it would be helpful to level-set on certain critical, commonsense aspects of incentive compensation. The extensive Total Compensation Study presented in our GRC, using the same assumptions that Cal Advocates approved when they last co-sponsored that Study, confirms that we are paying at market. Therefore, as past Commissions have opined in prior rate cases, it is reasonable that customers should fund those costs. We have to operate in the labor market as it exists, not as we (or the GRC parties, or the Commission) might wish it existed. If we do not pay according to market, and in a format that is familiar to the marketplace, then talented employees or prospective employees with other options will simply take their talents elsewhere. It is worth noting that incentive compensation of the type we offer our workforce is standard at nearly every large company.

In Assembly Bill (AB) 1054, the Legislature recognized that utilities require a skilled and adequately compensated workforce to provide customers with safe and reliable service. The Legislature found that it "must take action to stabilize the utility workforce so as to preserve the ability of utilities to provide safe and reliable electric and gas service. This requires that the size of the workforce be preserved or increased, and workers not be lost to other utilities offering more stable employment or better compensation."[1]

We understand that incentive compensation is not favored by Cal Advocates or TURN. But it is in customers' interests to have portions of our workforce's compensation dependent on meeting clear and important goals. It motivates employees to meet those goals, rewards employees' strong performance towards those goals, and reduces compensation if those goals are not achieved.

Our goals address important fundamental measures of excellence such as safety, reliability, and customer satisfaction. In addition, meeting our goals concerning the financial condition of the utility also benefits customers. A financially healthy utility has better and cheaper access to financing. That means we can finance the projects we undertake for our customers at a lesser cost to those customers.

Also, our rate case testimony quantifies savings that are achieved by using incentive compensation rather than base pay. In other words, customers pay less for a dollar of incentive compensation versus a dollar of base salary compensation. That is because a dollar of base pay also ratchets up pension and 401(k) contribution costs associated with base pay, while a dollar of incentive compensation does not.

The important consideration for both the Commission and the GRC parties is whether the utility is compensating at market on an overall basis. If it is, then customers should be indifferent to the specific mix of compensation elements that add up to that market level of compensation, and management discretion should be permitted to determine the specific mix. Here, as we have mentioned and will discuss in detail below, customers actually *benefit* from SCE choosing to utilize incentive compensation as one of those compensation elements.

The forecast for *Employee Benefits, Training and Support* O&M expenses made by SCE, Cal Advocates, and TURN are shown in the table below. Table I-1 provides a summary of the 2021

[1] *See* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB1054. (AB1054, Section 12, (as of June 1, 2020)); Pub. Util. Code §854.2(a)(8).

O&M expense forecasts for SCE, Cal Advocates, and TURN, along with the variances from SCE's forecast.

Table I-1
Employee Benefits, Training and Support
2021 O&M Forecast[2]
Summary of SCE, Cal Advocates, and TURN's Positions[3]
(2018 Constant $000)

Line No.	Business Planning Elements	2021 Forecast			Variance from SCE		SCE Rebuttal Position
		SCE	Cal Advocates	TURN	Cal Advocates	TURN	
1	Employee Support	43,951	43,951	40,458	-	(3,493)	40,458
2	Employee Benefits &	572,372	435,372	402,751	(137,000)	(169,621)	572,372
3	Employee Training	63,795	63,795	N/C	-		63,795
4					-	-	-
5					-	-	-
6	**Total**	680,118	543,118		(137,000)		676,625

1. <u>O&M Forecast Summary</u>

Table I-2 provides the recorded amounts for 2014-2018 and the forecast for 2021 for SCE, Cal Advocates and TURN. For the *Employee Benefits, Training and Support* O&M forecast, Cal Advocates proposes changes to the Employee Benefits and Programs and specific GRC Activities. TURN proposed changes to Employee Support/OU Support Services and Employee Benefits and Programs and specific GRC Activities. In the following chapters, SCE will address in detail the issues raised by Cal Advocates and TURN, and rebut their recommendations.

---

[2] In this volume of rebuttal testimony, SCE forecasts displayed in tables and included in text mirror SCE's direct testimony, unless otherwise stated.

[3] SCE can display a total for Cal Advocates, because Cal Advocates stated in testimony that approval is recommended for any areas where Cal Advocates did not have a specific proposal for reduced funding. TURN did not make a similar representation, so SCE has not tried to provide a total for TURN here, and has grayed-out that portion of the table.

Table I-2
Employee Benefits, Training and Support
2014-2018 Recorded/2021 Forecast
Summary of SCE's Position
(2018 Constant $000)

Line No.	Business Planning Elemen	SCE Recorded					SCE Rebuttal Position
		2014	2015	2016	2017	2018	
1	Employee Support	48,009	43,378	40,693	38,297	42,035	40,458
2	Employee Benefits & Progra	611,093	521,304	458,069	416,414	431,936	572,372
3	Employee Training	70,003	60,408	55,946	56,143	61,389	63,795
4							-
5							-
6	**Total**	729,105	625,090	554,708	510,854	535,359	676,625

II.

EMPLOYEE SUPPORT

This Chapter presents the Test Year 2021 forecast for SCE's Employee Support. For Test Year 2021, SCE forecasts $43.951 million of expenses.[4] This Business Plan Element (BPE) is composed of the employment-related activities which support the entire enterprise. These activities help the Company's employees maintain a healthy and productive environment, and affirm the Company's stated goals regarding Diversity, People, and Culture. This section contains Operating Unit (OU) Support Services and Talent Solutions work activities. Table II-3 below summarizes the 2021 O&M expense forecast for SCE, Cal Advocates, and TURN, along with the variances from SCE's forecast.

Table II-3
Employee Support
2014-2018 Recorded/2021 Forecast
Summary of SCE, Cal Advocates, and TURN's Positions
(2018 Constant $000)

Line No.	Employee Support	2021 Forecast			Variance from SCE	
		SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates	TURN
1	OU Support	29,323	32,816	29,323	3,493	-
2	Talent Solutions	11,135	11,135	11,135	-	-
	Total	40,458	43,951	40,458	3,493	-

A. Operating Unit (OU) Support Services

1. SCE's Application

OU Support Services span the Company, and are not specific to an OU. The responsibilities here include supporting the Operating Units as a whole, such as providing Business Partner Support and Organizational Development/Organizational Effectiveness Support. Other beneficial activities include employee-specific activities, such as Employee Relations, Labor Relations, Internal Communications, and Administrative Support.

---

[4] Refer to WP SCE-06, Vol. 03, Part 1, Book A, pp. 1-14; Employee Support.

Table II-4
OU Support Services
2014-2018 Recorded/2021 Forecast
Summary of SCE, Cal Advocates,[5] and TURN's Positions
(2018 Constant $000)

Line #	OU Support Sevices	SCE Recorded					2021 Forecast			Variance from SCE	
		2014	2015	2016	2017	2018	SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates[5]	TURN
1	Labor	26,671	24,536	21,474	19,059	21,898	21,591	22,880	21,591	1,289	-
2	Non-Labor	9,482	9,219	10,888	8,569	7,732	7,732	9,936	7,732	2,204	-
3	Other	240	(1)	(5)					-	-	-
	Total	36,392	33,753	32,357	27,628	29,630	29,323	32,816	29,323	3,493	-

2. TURN

a) TURN's Position

TURN proposes two reductions to the OU Support Services GRC Activity. The first reduction involves the labor component. SCE selected a last recorded year forecast method, with adjustments which decrease the overall forecast; SCE then applied a 2.9 percent labor escalation rate.[6] TURN states it is not appropriate to apply any labor escalation to the 2018 base year, as the Results of Operations Model (RO Model) will apply all escalation.[7] TURN recommends a disallowance of $1.289 million to the Test Year forecast.

Next, TURN recommends a $2.204 disallowance to OU Support Services non-labor forecast on two grounds: (a) costs anticipated for union-negotiated benefit changes did not materialize; and (2) SCE's data request response, which explained that this money would be used for additional groups attempting to organize within the Company, was vague and speculative.[8]

---

[5] Cal Advocate's positive variance is due to SCE adopting and conceding to TURN's position.

[6] *See* Exhibit SCE-06, Vol. 03, Part 1, p. 15.

[7] Exhibit TURN-04, p. 26.

[8] *Ibid.*

3. **SCE's Rebuttal To TURN's Position**

a) Reduction In OU Support Services Forecast

TURN opposes SCE's application of a 2.9 percent labor escalation and thus recommends reducing the 2021 labor forecast for OU Support Services by $1.289 million. SCE does not contest this reduction.

TURN recommends reducing OU Support Services' non-labor forecast by $2.204 million. On February 25, 2020, SCE received a notice of petition for election from the National Labor Relations Board (NLRB) on behalf of Engineers and Scientists of California (ESC) Local 20. The initial petition of notice for election was received, and the process moved forward. The ultimate vote count occurred on May 5, 2020 and the formal certification of results was received on May 14, 2020. The results confirmed that the Company prevailed, and the employees remain non-represented. Because of these recent events, SCE does not contest the removal of $2.204 million from OU Support Services' non-labor forecast.

4. **Conclusion**

SCE does not contest TURN's recommendation to reduce the Test Year forecast for OU Support Services by $1.289 million for labor and $2.204 million for non-labor, for a total reduction of $3.493 million.

III.

EMPLOYEE BENEFITS AND PROGRAMS

This Chapter presents the Test Year 2021 forecast of SCE's Employee Benefits and Programs. For Test Year 2021, SCE reaffirms in this rebuttal testimony its forecast of $572.372 million for Employee Benefits and Programs. Table III-5 below provides a summary of the 2021 O&M expense forecast for SCE, Cal Advocates, and TURN, along with the variances from SCE's forecast.

Table III-5
Employee Benefits and Programs
2014-2018 Recorded/2021 Forecast
Summary of SCE, Cal Advocates, and TURN's Positions[9]
(2018 Constant $000)

Line No.	Employee Benefits & Program	2021 Forecast SCE Rebuttal Position	2021 Forecast Cal Advocates	2021 Forecast TURN	Variance from SCE Cal Advocates	Variance from SCE TURN
1	401K Savings Plan	95,229	95,229	N/C	-	
2	Dental Plans	13,270	13,270	N/C	-	
3	Disability Management - Administration	533	533	N/C	-	
4	Disability Management - Programs	17,978	17,978	N/C	-	
5	Executive Benefits	15,542	7,771	-	(7,771)	(15,542)
6	Executive Compensation	18,132	18,132	4,803	-	(13,329)
7	Group Life Insurance	1,366	1,366	N/C	-	
8	Long-term Incentives	11,602	-	-	(11,602)	(11,602)
9	Medical Programs	100,217	100,217	N/C	-	
10	Miscellaneous Benefit Programs	6,302	6,302	N/C	-	
11	PBOP Costs (Non-Service)	(9,834)	(9,834)	N/C	-	
12	PBOP Costs (Service)	31,059	31,059	N/C	-	
13	Pension Costs (Non-Service)	(18,821)	(18,821)	N/C	-	
14	Pension Costs (Service)	103,170	103,170	N/C	-	
15	Recognition	74	37	N/C	(37)	
16	Severance	2,844	2,844	N/C	-	
17	Short-Term Incentive Program	180,906	63,317	51,759	(117,590)	(129,147)
18	Vision Service Plan	2,802	2,802	N/C	-	
19	Total	572,372	435,372		(137,000)	

A. <u>Incentive Compensation Programs</u>

SCE provides two short-term incentive pay plans: one for non-officer employees referred to as the Short-Term Incentive Program (STIP) and the other for executive officers called the Executive Incentive Compensation Plan (EIC). TURN's recommendation for the STIP and the EIC are based on the same premise. For ease of understanding, we are addressing TURN's recommendations for both plans here. Cal Advocates only contested SCE's STIP forecast, and has not opposed SCE's forecast for EIC.

---

[9] SCE can display a total for Cal Advocates, because Cal Advocates stated in testimony that approval is recommended for any areas where Cal Advocates did not have a specific proposal for reduced funding. TURN did not make a similar representation, so SCE has not tried to provide a total for TURN here, and has greyed-out that portion of the table.

1. SCE's Application For Short-Term Incentive Program (STIP)

SCE's application requests ratepayer recovery for its STIP forecast of $180.906 million in the Test Year. Variable "at risk" pay helps employees align their motivations and job performance with important Company goals that benefit our customers. When goals are met, the employees can earn a cash award, reflecting the Company's pay-for-performance compensation philosophy. *As shown in the Total Compensation Study, this cash award is part of the employee's at-market compensation package. It is not "extra" compensation provided on top of an at-market compensation package. Further, this bonus payment is at risk if performance is not achieved.*

Incentive compensation accounts for approximately 9.1 percent of SCE's total compensation in the Total Compensation Study. If STIP and EIC were completely removed from the Study, SCE's total compensation and benefits compared to market decreases from -3.0 percent (which is within the margin of error for determining whether SCE's total compensation is at market) to -12.1 percent (which is significantly under market).[10] Rejecting ratepayer funding of all or a portion of funding for the STIP means that a funding shortfall occurs, and ratepayers will be served by an SCE workforce employed at a below-market level of compensation. This is neither fair to SCE employees nor likely to provide the stable and talented workforce that ratepayers expect. Moreover, because variable pay is an "at-risk" component of total compensation, ratepayers do not have to fund the increased benefit costs, such as 401(k) matching, that are associated with base pay.

The STIP GRC Activity includes: (i) STIP for non-executive employees; (ii) the Key Contributor Incentive Plan (KCIP) for a limited group of non-executive employees; and (iii) the Executive Incentive Compensation (EIC) plan for non-officer executives. The STIP GRC Activity forecast also includes certain incremental costs related to the Compensation Design Project (CDP)[11] and KCIP that were not included in the base year. STIP expenses and forecasts are presented in Table III-6

---

[10] Appendix A-2, Exclusion of STIP and EIC Plans.

[11] In 2016, the Company began the CDP to redefine its compensation structure as part of a larger review of SCE's compensation and benefits plans. This effort supports the Company's objective of balancing the mix of benefits and compensation to align with the market.

below. The table provides the recorded amounts for 2014-2018 and the forecasts from SCE, Cal Advocates and TURN for Test Year 2021.

Table III-6
Short-Term Incentive Program
2014-2018 Recorded/2021 Forecast
Summary of SCE, Cal Advocates and TURN's Positions
(2018 Constant $000)

Line #	Short-Term Incentive Program	SCE Recorded					2021 Forecast			Variance from SCE	
		2014	2015	2016	2017	2018	SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates	TURN
1	Labor	181,924	132,571	104,350	133,063	137,027	180,906	63,317	51,759	(117,590)	(129,147)
2	Non-Labor									-	-
3	Other									-	-
	Total	181,924	132,571	104,350	133,063	137,027	180,906	63,317	51,759	(117,590)	(129,147)

2. <u>SCE's Application For Executive Incentive Compensation (EIC) For Executive Officers</u>

The executive short-term incentive pay program – the Executive Incentive Compensation Plan (EIC) – is part of the market-competitive total compensation package for SCE's executive workforce. Executive Officer EIC payments are included in the labor costs for the Executive Compensation GRC Activity. Non-officer EIC costs are included in SCE's STIP. EIC expenses and forecasts are presented in Table III-7 below. The table provides the recorded amounts for 2014-2018 and the proposed forecasts from SCE and TURN for Test Year 2021. Cal Advocates adopts SCE's 2021 Test Year forecast for the EIC.

Table III-7
Executive Incentive Compensation
2014-2018 Recorded/2021 Forecast
Summary of SCE, Cal Advocates, and TURN's Positions
(2018 Constant $000)

Line #	Employee Incentive Compensation	SCE Recorded					2021 Forecast			Variance from SCE	
		2014	2015	2016	2017	2018	SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates	TURN
1	Labor										
2	Non-Labor										
3		8,506	582	4,039	2,410	3,004	2,265	2,265	1,133	-	(1,132)
	Total	8,506	582	4,039	2,410	3,004	2,265	2,265	1,133	-	(1,132)

3. <u>Cal Advocates</u>

a) <u>Cal Advocates' Position</u>

Cal Advocates proposes a forecast of $63.317 million, which is a 67 percent reduction to SCE's 2021 STIP forecast. Cal Advocates calculates its STIP forecast by removing 30 percent of SCE's forecast attributed to the financial goal, because it purportedly only benefits shareholders.[12] Cal Advocates additionally claims that SCE is "[t]weaking the metrics to reduce the weighting of one goal . . . to increase ratepayer funding for the program."[13] It contends that the Commission should think about the program in a "new way" and ratepayers should fund half of the cost of the STIP after the cost attributed to the financial metric is entirely removed.[14]

Cal Advocates also argues that the fact that 88 percent of comparator companies within SCE's Total Compensation Study (TCS) provide this same incentive compensation element to their employees is "unpersuasive," because half the companies included in the study are not investor-owned utilities and are presumably not restricted to what is just and reasonable. Cal Advocates suggests that, in its view, the STIP represents a bonus that results in a 21 percent increase in pay for every employee, which is not reasonable.[15]

---

12 Exhibit PAO-11, p. 13.

13 *Id.* at p. 14.

14 *Id.*

15 *Id.* at p. 15.

4. **TURN**

a) TURN's Position

TURN offers proposals for both STIP and the Executive Incentive Compensation for Executive Officers. TURN first recommends disallowing all the Executive Compensation labor and non-labor costs except for the Executive Support Labor ($269 thousand).[16] (*See* Section B.2 below.) In the event the Commission disagrees with its primary recommendation, TURN recommends the following alternative recommendations regarding the incentive plans: remove goals not benefitting ratepayers, maintain incentive awards at prior approved ratios of STIP/labor, and remove incremental STIP costs.

TURN contends that SCE includes a number of metrics within the short-term incentive programs which benefit shareholders and not customers. These include the financial goal, as well as goals around the successful completion of Commission and state regulatory proceedings (which TURN incorrectly characterizes as "lobbying").[17] TURN also disagrees with SCE's proposal to increase incentive levels, and believes these ratios should remain the same as what was approved in prior rate case decisions.[18] To maintain these prior levels, TURN recommends disallowing costs attributed to the Compensation Design Project (CDP) and the Key Contributor Incentive Program (KCIP).[19]

b) SCE's Rebuttal To Cal Advocates And TURN's Positions

(1) Financial Goals Benefit Customers

Cal Advocates and TURN are simply incorrect when they suggest that a financially-based metric only benefits shareholders. There are additional costs that ratepayers bear when a company is not financially healthy.[20] SCE's access to equity capital markets helps reduce the cost of debt financing for SCE's operations and capital projects, and is more readily obtainable and less costly

---

[16] Exhibit TURN-04, pp. 27-28.

[17] Exhibit TURN-05, p. 4.

[18] *Ibid.*

[19] *Ibid.*

[20] A recent example is Pacific Gas & Electric Company's bankruptcy proceedings.

when the utility is in a financially healthy condition. This benefits customers. Table III-8 below shows the higher costs SCE's customers pay due to SCE having elevated risks which affect its financial condition.

Table III-8
Debit and Equity Impacts Affecting Customers
(Nominal $ in Millions)

$ in Millions

	2021	2022	2023	2024	Total
Rate Base[1]	35,877	38,224	40,978	47,659	
Authorized Debt Capitalization	43%	43%	43%	43%	
Spread over Peer Group[2]	0.75%	0.75%	0.75%	0.75%	
Debt Impact	116	123	132	154	525
Rate Base[1]	35,877	38,224	40,978	47,659	
Authorized Common Equity Capitalization	52%	52%	52%	52%	
ROE Spread (Wildfire Risk)[3]	0.85%	0.85%	0.85%	0.85%	
Tax Gross Up	1.39	1.39	1.39	1.39	
Equity Impact	220	235	251	293	999
Total Impact	336	358	384	446	1,524

[1]Rate base forecast includes 2021-2023 request, and latest Non-GRC and FERC estimates
[2]Based on non-California peer utilities as of December 2019
[3]Estimated based on Cost of Capital application filed March 2019

The Company's estimated Rate Base in Test Year 2021 is $35.9 billion and the authorized debt capitalization ratio is 43 percent. SCE's customers are paying 75 basis points higher in financing costs due to elevated risk compared to other non-California utilities. This amounts to $116 million in the Test Year alone that SCE customers are paying over other non-California peer utilities.

In reviewing SCE's authorized common equity capitalization, which is 52 percent of rate base, the Company estimates an additional charge of 85 basis points due to increased financial risks as a result of wildfires. This, along with a 39 percent tax gross-up, leads to $220 million of additional costs to customers in the Test Year. The total impact over this rate case cycle, including the 2024 attrition year, amounts to $1.5 billion in additional costs to customers based on the financial performance of the Company. To say that customers do not benefit from a financially healthy company is simply inaccurate, from a strictly quantitative standpoint.

As far back as 2003, the Commission recognized that these additional costs to customers exist. In the Commission's decision approving the settlement agreement which allowed PG&E to exit bankruptcy following the California Energy Crisis, the Commission stated:

> In setting just and reasonable rates, in addition to protecting the consumers, we also must consider the financial health of the public utility. Indeed, we view this commitment to act to facilitate and maintain investment grade credit ratings as essentially doing what we have always done under cost-of-service regulation: provide just and reasonable rates and authorize a reasonable capital structure that maintains the fiscal integrity of the utility.[21]

Also, during his tenure as Commission President, Michael Picker stated that "[t]he challenge is that as the cost of borrowing goes up so does peoples' rates, and that is what we need to avoid."[22] This was recently reaffirmed when the California State Legislature, through AB 1054, declared that "(e)lectrical corporations need capital to fund ongoing operations and make new investments to promote safety, reliability, and California's clean energy mandates and ratepayers benefit from low utility capital costs in the form of reduced rates."[23] That same legislation states that: "(t)he establishment of wildfire fund supports the credit worthiness of electrical corporations, and provides a mechanism to attract capital for investment in safe, clean, and reliable power for California at a reasonable cost to ratepayers."[24] A financially healthy company -- even one facing wildfire risk -- can

---

[21] D.03-12-035, pp. 32-33 (internal citation omitted).

[22] *See Sacramento Bee* at https://www.sacbee.com/news/california/fires/article221740610.html (as of June 1, 2020).

[23] *See* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB1054. (AB1054, Section 1(a)(4)) (as of June 1, 2020).

[24] *Ibid.* at Section 1.(a)(5).

obtain favorable interest rates when borrowing, which in turn will provide more favorable rates for customers.

(2) Core Earnings Do Not Solely Benefit Shareholders

In testimony, TURN suggests that SCE's goal to "Achieve Core Earnings" is a goal that primarily benefits shareholders.[25] TURN's discussion is based on three points:

1) Core Earnings are self-defined, do not adhere to Generally Accepted Accounting Principles (GAAP) and, therefore, are not comparable to other companies.
2) The use of Core Earnings insulates STIP recipients from the impact of safety-related liability costs.
3) There is no evidence that "investors follow and use 'Core Earnings' as the basis of investment decisions and [Core Earnings] reflect Edison's financial health." To support this statement, TURN states that a UBS Warburg research report provided by SCE does not reference Core Earnings and shows only GAAP measures.

TURN and SCE are aligned on the point that Core Earnings are a non-GAAP measure. Core Earnings are defined in each quarterly filing with the Securities and Exchange Commission as earnings attributable to Edison International shareholders less non-core items. Non-core items include income or loss from discontinued operations. These items also encompass income or loss from significant discrete items that management does not consider representative of ongoing earnings. Examples include write-downs, asset impairments, and other income and expense related to changes in law, outcomes in tax, regulatory or legal proceedings, and exit activities, including sale of certain assets and other activities that are no longer continuing. Therefore, Core Earnings go both ways, so to speak. Core Earnings are not only modified for costs, but also reduced for gains that are also not considered

[25] *See* Exhibit TURN-05, p. 12. TURN also states that maintenance of core earnings does not benefit ratepayers *Id*. at p. 13.

indicative of ongoing operations. SCE also reconciles Core Earnings to Net Income in each quarterly filing. Thus, while Core Earnings and Net Income may be divergent as presented in TURN's graph,[26] such a divergence is identified, explained, and reconciled in each period to ensure Core Earnings comply with U.S. Securities and Exchange Commission rules.

SCE believes that TURN mistakenly read the UBS Warburg research report. SCE respectfully submits that the report indicates that UBS Warburg utilizes Core Earnings in evaluating investment decisions. The first sentence of the UBS Warburg research report[27] is "Edison International reported Q3 core EPS of $1.56 versus the $1.29 consensus." Core EPS is simply Core Earnings, divided by shares outstanding. The "1.29 consensus" refers to the UBS forecast/expectation of Core EPS for the earnings period. TURN is correct in stating that a great deal of financial information is provided in the report. SCE uses Core Earnings internally, and to communicate with investors, as it is a measure of the performance of the operations of the company. Core Earnings is by no means the only piece of financial information available to investors, but there is concrete evidence that the measure is used.

(3) SCE's Regulatory Goals Are Based On Advocating For Our Customers

TURN contends that SCE's goals related to the GRC and the Cost of Capital proceedings and Transportation Electrification, Community Choice Aggregation, Distributed Generation, and Wildfire Resiliency policy development are related to lobbying. This is untrue. *All employees who perform work to influence legislative votes, or lobbying, record their costs to non-GRC accounts which are charged to shareholders. This is a longstanding practice at SCE.* The regulatory proceedings which TURN cites as "lobbying" concern SCE's efforts in helping develop public policy and obtain what SCE needs to serve its customers. As one of the largest electric utilities in California, SCE has a responsibility to participate in the development of energy-related public policies, in order to

---

[26] Exhibit TURN-05, p. 15.

[27] Appendix A-3, TURN-SCE-026 Q.01.a-b, and Appendix A-5, 10-30-18 (UBS) EIX - Uncertainty Slowly Declining.

assist in the formation and refinement of such policies to help ensure they foster, and do not detract from, safe, reliable, and affordable energy for our customers.

(a) Achieving Final Results On The General Rate Case And The Cost Of Capital Proceedings Benefits Ratepayers

The GRC is a public proceeding where the Commission establishes a revenue requirement for investor-owned utilities to recover the reasonable costs of providing and maintaining safe and reliable service to customers. The Rate Case Plan (RCP) requires California's biggest investor-owned utilities to follow the schedule of the RCP and file a GRC every four years.[28] The GRC requires the utility to estimate its operational plan and service needs for the next several years.

In the Cost of Capital (CoC) proceeding, the Commission establishes a reasonable rate of return for the utilities' investors. These investments allow the utility to build and maintain an electric infrastructure so that customers receive safe and reliable electricity. SCE is required to participate in the CoC based on the rate case plan which defines the schedule.[29]

These proceedings are an established part of forecast-based ratemaking, and SCE's costs here are not for lobbying in the proceeding, but instead for securing adequate funding to achieve what SCE needs to do on behalf of its customers, and to comply with established state goals.

(b) SCE's Participation In Transportation Electrification Benefits Ratepayers

TURN argues that the Transportation Electrification corporate goal does not benefit ratepayers. This is inaccurate. As far back as 2002, California established policies to reduce Green House Gas (GHG) emissions. Senate Bill 32 (2016) created the State's GHG goal for a 40

---

[28] D.20-01-002, p. 1, fn. 1.

[29] D.89-01-040, Appendix C, p. 36; D.08-05-035, pp. 6-7.

percent reduction in GHG emissions from 1990 levels by 2030 and an 80 percent reduction by 2050.[30] The electric sector accounts for only 19 percent of the State's GHG emissions. The transportation sector and fossil fuels account for almost three times as many GHG emissions as the electric sector and more than 80 percent of the air pollution in California.[31] SCE's Clean Power and Electrification Pathway integrates existing state programs and policies to achieve California's climate and air quality goals, while making sure that the change is efficient and affordable. In order for the State to meet the decarbonization goals, three-quarters of light-duty vehicles, two-thirds of medium-duty vehicles, and one-third of heavy-duty vehicles will need to be powered by electricity by 2045.[32]

Transportation Electrification strives for vehicle affordability, product diversity, and charging infrastructure availability. All are needed to accelerate adoption of electric vehicles (EVs) to meet 2030 targets and prepare for 2045.[33] SCE is advancing the progress of adoption of electric transportation through the execution of approved pilots and programs. *The corporate goal within the STIP metrics is specific to SCE's Charge Ready programs. These programs are approved by the Commission prior to implementation within communities.* Without the assistance of SCE installing the infrastructure, many businesses and residential customers would not be able to afford EVs or charging stations.

SCE works in conjunction with the State of California, the Commission, and other stakeholders to assist in developing policies to support consumer education, continued incentives for electric vehicle (EV) purchases, adequate charging infrastructure, pricing that

---

[30] *See* https://www.sce.com/about-us/reliability/meeting-demand/pathwayto2030?from=/pathwayto2030, p. 2 (as of June 1, 2020).

[31] *Ibid.*, at p. 1.

[32] *Ibid.,* at p. 5.

[33] *See* https://www.edison.com/home/our-perspective/pathway-2045.html, p. 2 (as of June 1, 2020).

keeps electric fueling costs competitive with gasoline or diesel, and affordability to access EVs for mid- and low-income customers.[34]

(c) SCE's Advocacy In Community Choice Aggregation (CCA) Benefits Ratepayers

TURN argues that the regulatory work SCE performs with respect to CCA is lobbying and does not benefit the ratepayer. This is flatly incorrect. The CCA program allows cities, counties, and Joint Power Authorities (JPAs) to procure electricity for individual customers within a defined jurisdiction. The CCA Code of Conduct specifically prohibits SCE from lobbying.[35] The corporate goal regarding Community Choice Aggregation is specific to the proceeding for Power Charge Indifference Adjustment (PCIA). PCIA is the cost-recovery mechanism used to ensure that customers who remain with the utility (*i.e.,* bundled service customers) do not become responsible for the long-term financial obligations that the utility incurred on behalf of customers who have since departed bundled service (*i.e.,* departing load customers).

In 2017, the Commission opened a rulemaking (R.17-06-026) to address concerns that the existing PCIA methodology was no longer preventing cost-shifts between customers. As warranted and appropriate, the rulemaking sought to revise the PCIA methodology to make sure that bundled service customers would not experience any cost increase as a result of either: (1) retail customers of an electrical corporation electing to receive service from other providers, or (2) the implementation of a community choice aggregation program.

In 2018, the Commission issued D.18-10-019 in Phase 1 of the PCIA rulemaking. There, the Commission adopted the following changes to the PCIA methodology:

1. Revisions to the market price benchmarks (MPBs) that are used to calculate the PCIA;

---

[34] *See* https://www.sce.com/about-us/reliability/meeting-demand/pathwayto2030?from=/pathwayto2030, p. 10 (as of June 1, 2020).

[35] *See* https://www.cpuc.ca.gov/general.aspx?id=2567 for a link to the CCA Code of Conduct (as of June 1, 2020).

2. Adoption of an annual true-up to ensure that bundled and departing load customers pay equally for the above-market costs of PCIA-eligible resources;

3. A zero or *de minimis* price for capacity and Renewable Energy Credits (RECs) that were expected to remain unsold; and,

4. Instructions to open Phase 2 of the proceeding to, among other things, develop a detailed framework for calculating and trueing up the Resource Adequacy and Renewables Portfolio Standard (RPS) MPBs.

In 2019, the Commission issued D.19-10-001 in Phase 2, Track 1 of the proceeding to further refine the PCIA methodology related to the calculation of the RA and RPS MPBs and the true-up of all components of the PCIA.

The 2018 and 2019 PCIA decisions described above significantly helped in establishing a fairer recovery of costs between bundled service and departing load customers. Now, actual costs are tracked by vintage in the Portfolio Allocation Balancing Account (PABA) to facilitate a true-up of the above-market value and costs that are applicable to all customers. Prior to the establishment of the PABA and true-up process, any difference in actual above-market costs compared to the forecast above-market costs of the PCIA-eligible resources was borne solely by bundled service customers. As a result, in the first year of implementing the PABA, approximately $135 million in costs appropriately remained the responsibility of the departing load customers for whom those costs were incurred instead of being shifted to bundled service customers.[36]

Here, SCE's customers benefit in that they have more options. The customer can choose to participate in the CCA, or opt out and continue to have SCE deliver electricity. The PCIA decisions result in a fairer and more accurate cost allocation between bundled service and departing load customers. A balancing account is established to monitor and maintain the under- and over- collection of each of the resource vintages. At the end of the year, any under- or over- collection

[36] Appendix A-13, Advice Letter, 4168-E.

goes back to the customers who are responsible for that vintage; this helps achieve customer parity. In other words, this is customer-focused activity, not lobbying.

(d) Distributed Generation (DG) Policies Benefit Ratepayers

TURN inaccurately suggests that the corporate goal concerning DG is lobbying. The goal for DG is specific to the Commission's forthcoming DG Successor Tariff, which will consider developing and adopting successor tariffs to the Net Energy Metering (NEM) Successor Tariff. NEM allows customers with solar, wind, biogas, and fuel cell generation to generate their own energy and receive a financial credit on their electric bill for any surplus energy that goes back to the utility.[37] California enacted NEM in 1996 to promote the adoption of rooftop solar. While grid conditions and rooftop solar have changed over the years, the basic policy of NEM has remained unchanged.[38]

One of the goals of the rate reform is to have rate structures in place to help California achieve its overall decarbonization pathway, by (1) keeping rates affordable, and (2) looking for cost-effective ways to achieve GHG reduction through broad adoption of electrification and Distributed Energy Resource technologies in addition to rooftop solar.

DG benefits our customers in that it gives them additional options. They can choose to generate their own electricity and receive a financial benefit if they generate more than they use. DG efforts also support California GHG emission reduction goals. But, for customers who are unable or do not want to participate in rooftop solar, NEM has led to increasing utility bills that continue to grow.[39] The development of a DG Successor Tariff is essential in helping ensure sustainable growth of the distributed generation industry, while simultaneously promoting fair and equitable rate structures to keep rates affordable for DG and non-DG customers. Again, this is a customer-focused area.

---

[37] *See* https://www.cpuc.ca.gov/NEM/ (as of June 1, 2020).

[38] Appendix A-37, Evolution of Net Energy Metering (NEM) Impact, June 2019, p. 3.

[39] *Ibid.,* at p. 4.

(e) Wildfire Resiliency Goals Benefit Ratepayers

Wildfire policies are unique to California. In an attempt to minimize the risk of wildfires and provide better coordination and communication across the State's agencies, California established wildfire activity sessions. The utilities participate in these sessions because they have a unique expertise in this area and it is critically important to the State. We are advocating *for our customers* to improve safety within the communities we serve, and to maintain reliable service.

(4) SCE Cannot Maintain The Same Level Of STIP To O&M Labor As In Past GRC Decisions

(a) Cal Advocates' Recommendation For Maintaining Past GRC Decision Ratios

Cal Advocates contends that SCE is awarding a bonus of over 21 percent to each employee.[40] Within the RO Model, the calculation of O&M labor forecast to STIP is a composite figure. In Cal Advocates' example, it provides a WorldatWork median average target for STIP, expressed as a percentage of base pay for nonexempt (5 percent) and salaried (15 percent) employees.[41] However, Cal Advocates chooses to omit the median target for STIP of 49 percent for officers and executives.[42] This is inaccurate analysis. SCE's STIP plan includes non-officer executives. These executives have significantly more of their compensation placed at risk based on pay-for-performance. Cal Advocates' omission of officers and executives in its analysis distorts the results. An analysis that uses all employees shows that SCE is not awarding a bonus of over 21 percent to each employee. SCE is simply compensating at market levels.

Cal Advocates claims the Commission adopted $57.592 million in funding for STIP in SCE's Test Year 2018 GRC,[43] but this figure is an illustrative amount. The amount

---

[40] *See* Exhibit PAO-11, p. 15.

[41] *Ibid.* at p. 16.

[42] WPSCE-06, Vol. 03, Part 1, Book A, p. 82.

[43] *See* Exhibit PAO-11, p. 15.

was calculated based on TURN's methodology for calculating STIP, labor expense, and the associated headcount derivation. It does not match the final amount actually approved. That final amount used TURN's method for calculating STIP, but did not include its method for calculating labor expense. Because the STIP expense is dependent on total labor expense, the total STIP amount was adjusted in the GRC final decision within the RO Model to $70.180 million.[44] Cal Advocates applies a 3 percent inflation rate adjustment to an incorrect and greatly reduced 2018 STIP amount, and suggests the result is comparable to the amount Cal Advocates is recommending for Test Year 2021 ($63.317 million).[45]

Table III-9 below is a more accurate representation of the reductions Cal Advocates is proposing in this GRC.

Table III-9
Cal Advocates Proposed STIP/Labor[46]
(Constant 2018 $000)

Line No	LABOR			
1	2018-2020 Authorized Labor	823,945	820,415	820,415
2	2021-2023 CalPA Proposed Labor	796,102	796,102	796,102
3	CalPA Labor $ Decrease	(27,843)	(24,313)	(24,313)
4	CalPA Labor % Decrease	-3.4%	-3.0%	-3.0%
	STIP			
5	2018-2020 Authorized STIP	76,500	76,169	76,169
6	2021-2023 CalPA Proposed STIP	58,901	58,901	58,901
7	CalPA STIP $ Decrease	(17,599)	(17,268)	(17,268)
8	CalPA STIP % Decrease	-23.0%	-22.7%	-22.7%

Lines 2 and 6 represent SCE's modeling of CalPA testimony and updated CalPA RO model.

Lines 1 and 5 show the labor and STIP approved in the 2018 GRC for the years 2018-2020. Lines 2 and 6 represent the amounts SCE modeled based on Cal Advocates'

[44] D.19-05-020, p. 186, fn. 443.

[45] *Ibid*.

[46] Calculations are based on SCE's preliminary modeling of Cal Advocates' recommendations.

recommendations for Test Year 2021 and attrition years 2022-2023, in constant 2018 thousands of dollars. Cal Advocates is recommending a labor decrease of approximately 3 percent below the amount approved for 2018-2020. And Cal Advocates is proposing a STIP decrease of approximately 23 percent below the amount approved for 2018-2020. These proposed reductions are not in line with the Commission's past practice as Cal Advocates suggests.

Cal Advocates' calculations and conclusions appear to contradict the principle that SCE should be able to select the right mix of base pay, incentives and benefits for its workforce, so long as total compensation is at market. Moreover, Cal Advocates' calculations and recommendations are not consistent with the TCS, which demonstrated that SCE is compensating at market on an aggregate basis. Instead, Cal Advocates' recommendations would lead to SCE employees being compensated at below market.

(b) <u>TURN Incorrectly Criticizes The Incremental Costs To SCE's STIP Associated With The Compensation Design Program (CDP) And Key Contributor Incentive Plan (KCIP)</u>

TURN states that short-term incentives should increase at approximately the same rate as base pay. TURN contends that by augmenting STIP above base pay increases, SCE is causing ratepayers to fund increases above what is included in SCE's forecast.[47] All the incentive compensation costs for non-officer employees, including KCIP and Incremental STIP, are included in SCE's Test Year forecast for STIP.[48] Through the results of the TCS, SCE has provided objective evidence that with these increases, SCE's total compensation is at market. Whether SCE pays 100 percent base pay, or 100 percent incentive pay, or decides to reallocate these amounts up or down as it sees fit to properly compensate employees, should make no difference since the results of the TCS demonstrate that, in the aggregate, SCE pays its employees at market. Ratepayers will only be funding at-market levels of compensation if SCE's GRC request is granted.

---

47 Exhibit TURN-05, p. 8.

48 *See* WPSCE-06, Vol. 03, Part 1, Book A, pp. 34-42.

SCE has gone to great lengths to make sure that it controls costs for its customers by changing the allocation of its total rewards strategy. The KCIP replaces the prior Augment Plan SCE had provided to certain of its higher-level managers from 2012-2017. KCIP's first plan year, 2018, was not paid until 2019. The TCS was performed using 2018 recorded costs. While the recorded costs for the KCIP plan were not included in the TCS, the Augment Plan, which had similar costs, was included.[49] Our customers and our Company benefit from the KCIP plan because it motivates key performers in a manner similar to the Augment Plan, and it helps SCE retain these key performers by making the full payment over two years (versus one year for the Augment Plan). If the employee leaves prior to the two years, the unpaid portion of the award is forfeited by the employee.

Likewise, with the Compensation Design Project (CDP) and the proactive changes that SCE made to its benefits (primarily pension and post-retirement (retiree) healthcare benefits), SCE recognized it needed to rebalance its total rewards strategy in relation to market benchmarks. Current and prospective employees were placing more value on their total cash compensation (including incentive plans) and less value on more costly benefit programs. To continue to maintain its total compensation in line with market benchmarks, SCE reevaluated its allocation of total cash compensation to benefits by decreasing the cost of certain benefit programs and increasing the cost of certain elements of its compensation programs. Based on SCE's analysis, certain employee classifications required an increase in incentive compensation to keep their total compensation in line with the market and counterbalance the loss of certain benefits. SCE believes that any increase in STIP costs will be mitigated by the expected decreases in the costs of pensions and post-retirement benefits in coming years.

Employees hired after December 31, 2017 are no longer eligible for SCE's cash balance plan or retiree healthcare benefits. Instead of those benefits, these employees will receive an additional contribution to their 401(k) plans and a health care reimbursement account,

[49] The 2017 Augment plan, payable in 2018 was approximately $4.689 million versus the 2018 KCIP plan payable in 2019 and 2020 of $2.528 million and $2.506 million respectively (or total $5.034 million). Please refer to SCE's response to TURN-SCE-026, question 09.a supplemental. A copy of this data request response is attached as Appendix A-84 and the attachment at Appendix A-85.

respectively, both of which are lower cost than the programs they replaced. In the near term, incremental STIP costs will exceed the cost savings from the benefit program changes. However, as more employees are hired under the new benefit programs, the savings will surpass the increased cost of incremental STIP. Based on calculations by SCE's actuaries, the long-term savings amount appears to increase from approximately $295 million in ten years to approximately $1,120 million in 20 years.[50] Table III-10 compares the cost savings of the benefit reductions over a 20-year period with the Incremental STIP cost increases. Within a 10-year period, SCE will have a Net Present Value of $16.63 million in cost savings, and $116.20 million in cost savings after 20 years. Thus, the modifications that SCE made that result in an increase in STIP costs should more than pay for themselves in the long run with the cost savings that ratepayers receive from the benefit reductions.

[50] Appendix A-86, Impact of Benefit Plan Changes; Pension, 401(k), PBOP.

Table III-10
Estimated Impact of Benefit Plan Reductions to Incremental STIP Increase[51]
(Nominal $ in Millions)

Year	2021	2021-2030	2021-2035	2021-2040
Pension	(16.90)	(339.80)	(677.20)	(1,155.90)
401(k)	11.30	224.40	449.70	768.90
Retiree Medical	(6.60)	(179.10)	(396.30)	(733.30)
Total	**(12.20)**	**(294.50)**	**(623.80)**	**(1,120.30)**
Incremental STIP	21.19	243.08	394.09	568.79
Gross Difference	**8.99**	**(51.43)**	**(229.71)**	**(551.51)**
Net Difference	**8.99**	**(60.41)**	**(178.29)**	**(321.80)**

Discount Rate	10%			
Year	**2021**	**2030**	**2035**	**2040**
PV	8.99	(25.62)	(46.95)	(52.62)
NPV[1]	**8.99**	**(16.63)**	**(63.58)**	**(116.20)**

[1]To be conservative, discounting at end of ranges, s.t. NPV savings are 2030, 2035, 2040 respectively

TURN claims that SCE's TCS results show that the company's compensation is already at market and any additional increases would put the compensation above market. This is incorrect. The CDP implementation had already begun at the time the TCS was compiled. The incremental STIP amount (which also includes KCIP) continues to keep SCE "at market"

[51] The amount of incremental STIP is based on the RO Model as of June 12, 2020.

with respect to the market range of +/- 5% used in the Study. In other words, inclusion of the incremental STIP brings SCE from -3 percent below market to -1.7 percent below market.[52], [53]

(c) The Ratio Of STIP To Labor Should Be Updated

SCE respectfully requests that the Commission approve SCE's Test Year forecast for STIP, and SCE does not agree with the proposals made by Cal Advocates and TURN. However, even if the if the Commission were to agree with TURN and Cal Advocates and approve a STIP to Labor ratio, at a minimum this ratio should be updated to a current six-year average. In SCE's Test Year 2015 GRC decision, D.15-11-021, the Commission approved a six-year average based on 2008-2013 recorded data.[54] Table III-11 shows the average that was previously adopted in SCE's 2015 GRC, and then adopted again (with no updating) in SCE's 2018 GRC.[55]

[52] This is based on Aon including the Incremental STIP amount of $19.331 million (based on the RO Model calculation as of May 18, 2020) to the 2021 TCS results. Aon cautions against interpreting this as representative of the market as of today, as the TCS was effective as of 12/31/2018, or 18 months ago. Therefore, SCE's actual position to market will not truly be known until all the data is updated to current market pay and practice.

[53] *See* Appendix A-92, Inclusion of Incremental STIP in TCS.

[54] D.15-11-021, p. 265.

[55] D.19-05-020, p. 186.

Table III-11
SCE's STIP /Labor Ratio
Approved in 2015 GRC
(Constant 2012 $000)

Year	STIP	Labor	% STIP to Labor
SCE Recorded			
2008	$ 114,496	$ 1,053,840	10.86%
2009	$ 137,812	$ 1,201,115	11.47%
2010	$ 141,787	$ 1,311,510	10.81%
2011	$ 141,358	$ 1,281,256	11.03%
2012	$ 174,767	$ 1,202,391	14.53%
2013*	$ 156,871	$ 1,125,627	13.94%
6 Year Average			
2008-2013 Average	$ 144,515	$ 1,195,957	12.11%

*Preliminary Unadjusted in Nominal Dollars

Given that the most recent year in these values is six years old, and that the oldest year is now a dozen years ago, the values are stale, out of date, and do not represent SCE's more current total reward strategy of moving away from costly benefits, such as pension and retiree healthcare, and instead providing a higher at-risk incentive compensation award. In contrast to the table above, Table III-12 shows the six-year average for the *most current* six years of recorded data.

Table III-12
SCE's STIP /Labor Ratio
2014-2019
(Constant 2018 $000)

Year	STIP	Labor	% STIP to Labor
SCE Recorded			
2014	$ 181,924	$ 908,424	20.03%
2015	$ 132,571	$ 873,010	15.19%
2016	$ 104,350	$ 818,900	12.74%
2017	$ 133,063	$ 787,945	16.89%
2018	$ 137,027	$ 768,709	17.83%
2019*	$ 180,537	$ 684,191	26.39%
6 Year Average			
2008-2013 Average	$ 144,912	$ 806,863	18.18%

*Preliminary Unadjusted in Nominal Dollars

Accordingly, even if the Commission disregards the market results of SCE's independent TCS analysis and instead agrees with Cal Advocates and TURN to use a STIP/Labor ratio as the Commission has done previously, the six-year average should reflect the most recent data. The most recent data places the ratio at 18.18 percent.

(1) STIP Costs Are Just And Reasonable Costs Of Service, And Should Not Be Funded To Any Degree By Shareholders

Cal Advocates and TURN assert that STIP costs should be shared between shareholders and ratepayers in connection with goals that benefit both shareholders and ratepayers.[56]

(a) SCE Is Modifying Its STIP Goals

Cal Advocates suggests that SCE is "tweaking" its STIP goals in an attempt to make ratepayers fund the entire STIP program. However, this sidesteps the main point of SCE's argument. SCE can already reorganize the components of its market compensation costs by simply transferring all of the compensation to base pay. The 2021 TCS found that SCE's total compensation is at market. As such, it is reasonable and recoverable from customers based on cost-of-

[56] *See* Exhibit TURN-05, p. 19; Exhibit PAO-11, p. 14.

service ratemaking principles. Whether it is paid as an incentive or as 100 percent base pay, the amount of compensation is reasonable.

As stated in our opening testimony, variable pay benefits ratepayers, since it is an "at-risk" component of compensation that aligns pay with performance, rather than simply guaranteeing the entire "package" of compensation regardless of how well or how poorly the employee performs. It also avoids increased costs associated with benefits, such as retirement and 401(k) contributions. If SCE were to move STIP costs to base pay, customers would still pay all of the compensation (because it is reasonable compared to the market) but customers would forfeit the benefits of it being "at-risk." Additionally, as shown in SCE's opening testimony, ratepayers' costs would increase by $30.608 million per year in benefit costs associated with base pay.[57] This is not the best strategy for the Company or its customers.

SCE provides service to over 15 million Californians, receives over $12 billion in annual revenue, and is requesting a Revenue Requirement of approximately $7.5 billion. Simply as a matter of proportion if nothing else, Cal Advocates is illogical in suggesting that SCE would somehow manipulate its corporate goals to saddle ratepayers with $63 million in STIP costs.[58] This STIP portion of our request represents less than 1 percent of SCE's overall request.

Cal Advocates correctly notes that corporate goals will change from year to year.[59] But that change does not occur due to some purported attempt to get ratepayers to pay an unfair share of the STIP costs. The criteria and allocation of corporate goals change from year to year based on business and service priorities. They are reviewed and approved by SCE's Compensation Committee of the Board of Directors. That Compensation Committee is comprised of independent directors. From 2018 to 2019, the financial goal allocation decreased from 40 percent to 30 percent because SCE established a new goal category, Wildfire Resiliency, aimed at improving the resiliency of

---

[57] *See* SCE-06, Vol. 03, Part 1, fn. 70.

[58] The $63 million is the amount reduced by 50 percent divided by $7 billion, the amount of SCE's Revenue Requirement request.

[59] Exhibit PAO-11, p. 13.

the electric infrastructure and protecting the communities SCE serves (just as AB 1054 intends). SCE introduced the new metric, and then redistributed the existing allocations accordingly.

With the Company, the Commission, the Wildfire Safety Division, and other State agencies placing more and more emphasis on safety, SCE's annual goal allocations have continued to change. In 2020, SCE's financial goal allocation will continue to decrease as the Company continues to increase the importance of safety and grid resiliency above all else.[60] Table III-13 lists the 2020 STIP and EIC goals and allocation. Please note that in 2020 the target score for the Safety & Resiliency goal has increased to 45 percent and the Financial Performance has decreased to 25 percent.

---

60 AB 1054 states that electrical corporations should establish executive incentive compensation "structured to promote safety as a priority and to ensure public safety and utility financial stability with performance metrics . . . this may include tying 100 percent of incentive compensation to safety performance." *See* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB1054 Section.21.8389.(e)(4) (as of June 1, 2020).

Table III-13
2020 STIP and EIC Goals

Goal Category	Goals	Target Score
Overarching Goals Framework	• No Worker Fatalities (Employee and Contractor)	Deduct Only
	• No serious injuries to Public from system failures.	
	• No Significant Non-compliance Events.	
	• No Significant Disruption, Data Breach or System Failure.	
Safety & Resiliency	• Worker Safety: Make significant progress toward eliminating serious injuries and fatalities.	45
	• Public Safety: Reduce risk of public injuries related to our electric infrastructure.	
	• Wildfire Resiliency: Reduce the risk of catastrophic wildfires associated with electric infrastructure by executing our Wildfire Mitigation Plan (WMP) and programs.	
	• Cybersecurity: Maintain effective controls to prevent and mitigate significant disruptions, data breach or system failure.	
Financial Performance	• Achieve Core Earnings.	25
Operational Excellence & Strategic Advancement	• Capital Deployment: Execute grid, technology, electrification, and other improvements to deliver safe, reliable, clean, and affordable energy for customers.	30
	• Policy Outcomes: Shape California legislative and regulatory policies to align with SCE's strategy.	
	• Diversity and Inclusion: Improve diversity in our leadership and supplier base.	
	•Customer Service Re-Platform: Complete critical Customer Service Re-Platform milestones and scope while staying on schedule and budget.	
	• San Onofre Nuclear Generating Station (SONGS) Decommissioning: Safely and effectively manage SONGS decommissioning.	
	• Reliability: Improve reliability performance for repair outages.	
Total Multiplier Range		**100**

(b) Shareholders Should Not Pay For The Costs Of Service

TURN asserts that because both shareholders and ratepayers can benefit from other, non-financial incentive goals, they should share the incentive costs equally.[61] This misses the point of cost of service ratemaking and negates the results of the 2021 TCS. Ratepayers – not shareholders – are responsible for paying all reasonable costs of utility service, including market-level employee compensation. Given the findings of the TCS, shareholders cannot be expected to make up the deficit. TURN is asking the Commission to exclude known expenses and recognized costs of service from the authorized revenue requirements. That creates a Hobson's choice for SCE – either not spending authorized revenues in other areas or not paying investors their expected return. Both paths are detrimental to customers over time.

The Commission must provide SCE a reasonable opportunity to earn its authorized rate of return. Ultimately, absent a fair market return, the utility cannot invest in new equipment to serve its customers, nor can it borrow to finance capital expenditures or secure power purchase agreements at a reasonable cost. Any short-term benefits to customers from below-market authorized returns will be eroded by higher costs for borrowing or a lower-quality workforce – or both.[62]

Thus, even if the Commission agrees with Cal Advocates and TURN and believes a 50 percent cost sharing of the incentive programs is reasonable (and SCE does not believe it is), the Commission should impose such a sharing mandate based on the total forecast amount of the STIP program and not after financial and other goals have been removed. All of SCE's goals (which help determine payouts under STIP) benefit ratepayers.

---

[61] Exhibit TURN-05, p. 19.

[62] *See generally* Bluefield Waterworks & Improvement Co. v. Public Service Commission of West Virginia *et al.*, 262 U.S. 679, 43 S. Ct. 675 (1923), and Federal Power Commission *et al.* v. Hope Natural Gas Co., 320 U.S. 591, 64 S. Ct. 281 (1944).

(2) <u>The Argument That Companies Within The TCS Are Not Investor-Owned Utilities And Not Restricted By Just And Reasonable Costs, Is Illogical</u>

Cal Advocates claims that because half of the companies within the TCS are non-investor owned utilities, they are not bound by a "just and reasonable costs" restriction.[63] Because of this, Cal Advocates suggests that the fact that 88 percent of comparator companies within the TCS are compensating their employees through a form of variable pay is not persuasive.[64] We strongly disagree.

In citing to SCE's direct testimony, Cal Advocates appears to be inadvertently confusing the TCS with the separate 2017 Variable Compensation Measurement Report.[65] The Variable Compensation Measurement Report indicates that 88 percent of comparator companies within that study compensate employees through a form of variable pay.[66] SCE's TCS actually indicates that *100 percent* of all participating comparator companies provide some form of incentive pay to their employees.

The TCS methodology is the same as was developed for the Test Year 2015 SCE GRC. That methodology was originally developed in conjunction with Cal Advocates, with that agency serving as co-manager of the Study.[67] The TCS is not performed to see which utilities are providing which specific benefits. It is performed to establish whether SCE's compensation levels are competitive with the market. If SCE was only hiring employees from other energy utility companies, it might be appropriate to only include other utilities in the Study. However, SCE has to be competitive in the entire market from which it draws potential candidates. That market includes both energy utilities and general industry companies. The TCS results compare SCE's compensation and benefits to the competitive market. Thus, it is quite relevant that 100 percent of the companies within the market in

---

63 *See* Exhibit PAO-11, pp. 14-15.

64 *Ibid.* at p. 15.

65 Exhibit SCE-06, Vol. 03, Part 1, p. 36.

66 2017 Variable Compensation Measurement Report, p. 6.

67 *See* Exhibit SCE-06, Vol. 03, Part 2, p. 4.

which SCE competes to attract and retain employees, also provide incentive compensation. Moreover, even if one were to hypothetically accept Cal Advocates' position and remove the general industry from the Study, the results in the Study still indicate that 100 percent of electric utilities participating in the Study do provide some form of incentive compensation to their employees.

(3) Settlement Agreements Do Not Constitute Precedent

Cal Advocates makes reference to decisions reached in the Sempra Utilities' Test Year 2016 GRC and PG&E's Test Year 2017 GRC.[68] To the extent Cal Advocates is relying on these two specific Commission decisions, SCE notes that these two cases were resolved through settlement. Settlements are based on negotiated puts and takes; certain expenses are authorized while others are reduced or eliminated in order to arrive at a settlement agreement. Commission Rule of Practice and Procedure 12.5 specifically states that "[u]nless the Commission expressly provides otherwise," the Commission's adoption of a settlement "does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding."[69] Therefore, Cal Advocates' arguments involving these two particular rate cases should be disregarded.

c) Conclusion

The TCS reveals that SCE pays slightly below market. Eliminating the funding for incentive compensation would drop authorized funding even further below market.

The total cash compensation that SCE pays its employees (including incentive compensation) was estimated to be 4 percent below market.[70] This is within the Commission's stated acceptable market range of +/- 5% of market, and thus is reasonable. The means by which SCE

---

[68] Exhibit PAO-11, p. 14.

[69] *See*, *e.g.,* In re Pac. Gas & Elec. Co., D.06-11-048, 2006 WL 3511432 (Nov. 30, 2006) (In response to challenges interposed to PG&E's estimated owner's costs based upon "ratemaking treatment recently approved for Contra Costa 8 as part of a settlement in D.06-06-035," the Commission wrote: "We reject this justification as contrary to Rule 12.5 of our Rules of Practice and Procedure. ('Unless the Commission expressly provided otherwise, such adoption [of a settlement] does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding.')").

[70] *See* Exhibit SCE-06, Vol. 03, Part 2, p. 4.

structures its total cash compensation should be immaterial as long as the total cost is reasonable. However, AB 1054 requires that electrical corporations place "[s]trict limits on guaranteed cash compensation, with the primary portion of the executive officers' compensation based on achievement of objective performance metrics."[71] California's Legislature is moving away from the concept of base pay, and orienting toward incentive compensation. We respectfully ask that the Commission take this into account as it adjudicates SCE's STIP request.

Incentive compensation helps motivate SCE's workforce to more closely focus on affordability, safety, customer service, and cost control. It is an important component of total compensation. Nearly 90 percent of the companies that SCE competes with to attract and retain talent are providing their employees with some form of incentive compensation plan. To deny SCE the same opportunity to place a portion of its market-based total compensation in at-risk incentives would undercut the Company's ability to attract and retain the talent necessary to run the business effectively on behalf of our customers, and would be inconsistent with the guidance found in AB 1054.

B. Executive Compensation

1. SCE's Application

Table III-14 below shows recorded costs for the years 2014 through 2018, plus SCE's forecast for Test Year 2021. For recorded and forecast years 2014 through 2021, Executive Compensation that is subject to SB 901 has been removed.[72] For Test Year 2021, SCE forecasts $18.133 million of expenses for Executive Compensation (salaries and short-term incentives), non-labor expenses, and outside services. Besides SCE executive officers, certain executive officers are dual officers of both SCE and its parent company, Edison International (EIX). The salaries, expenses, and incentive costs of these "Shared Officers" are allocated between SCE and EIX. The Shared Officers include: (1) EIX Chief Ethics and Compliance Officer (CECO) and SCE Chief Compliance Officer;

---

[71] *See* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB1054: (AB 1054, Section 21, (as of June 1, 2020)); Pub. Util. Code §8389(e)(6)(A)(i)(I).

[72] Refer to WP SCE-07, Vol. 01, Results of Operations, Ratemaking Adjustments; and WP SCE-06, Vol. 03, Part 1, Book A, p. 15, SB 901 Compensation and Benefits Adjustments.

(2) Vice President, Associate General Counsel, Chief Governance Officer, and Corporate Secretary; (3) Vice President, Tax; (4) Senior Vice President, Human Resources; and (5) Vice President and Corporate Controller.

Executive Compensation expenses and forecasts are presented in Table III-14 below. The table provides the recorded amounts for 2014-2018 and the proposed forecasts from SCE and TURN for Test Year 2021. Cal Advocates does not oppose SCE's 2021 Test Year forecast for Executive Compensation.[73]

Table III-14
Executive Compensation
2014-2018 Recorded/2021 Forecast
Summary of SCE, Cal Advocates, and TURN's Positions
(2018 Constant $000)

Line #	Executive Compensation	SCE Recorded					2021 Forecast			Variance from SCE	
		2014	2015	2016	2017	2018	SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates	TURN
1	Labor	17,820	9,012	6,192	6,031	7,988	8,493	8,493	269	-	(8,224)
2	Non-Labor	7,886	9,880	9,257	7,541	8,354	9,639	9,639	4,534	(0)	(5,105)
3	Other	3	2	4	4	4				-	-
	Total	25,709	18,894	15,453	13,576	16,346	18,132	18,132	4,803	(0)	(13,329)

2. <u>TURN</u>

a) TURN's Position

TURN makes two recommendations concerning Executive Compensation. Its first recommendation is to disallow $13.329 million of the Executive Compensation consistent with Senate Bill (SB) 901.[74] If the Commission does not adopt TURN's initial proposal, TURN provides an alternative proposal specific to the Executive Incentive Compensation plan for Executive Officers. Please refer to SCE's rebuttal to this alternative proposal in Section A.4 above.

b) SCE's Rebuttal To TURN's Position

At the outset, it is important to level-set on the central issue of TURN's testimony here. TURN seeks to use this GRC to expand the scope of which individuals at SCE are subject to the

---

[73] *See* Exhibit PAO-04, p. 10.

[74] Exhibit TURN-04, pp. 27-28.

restrictions of Public Utilities Code section 706. That code section prohibits IOUs from recovering "any annual salary, bonus, benefits, or other considerations for any value, paid to an officer of an electrical corporation."[75] The dispute between TURN and SCE concerns what the term "officer" means for purposes of excluding recovery pursuant to section 706.

The purpose of the statutory prohibition, as applied by the Commission, appears to be to make sure that shareholders rather than ratepayers are responsible for the compensation of those utility personnel who in turn possess the authority to direct the policy positions of the company. In its testimony, TURN seeks to materially and unilaterally expand the definition of "officer." TURN attempts to bypass the policy-making threshold requirement and create out of whole cloth as expansive a definition as possible in order to impose as much compensation responsibility as possible on shareholders. As discussed in detail below, this approach is inconsistent with the applicable precedent, and would constitute error if applied in this GRC.

(1) The Governing Authority Supports SCE's Position, Not TURN's

On December 13, 2018, the Commission issued Resolution E-4963 (Resolution), which directed California gas and electrical corporations "to open memorandum accounts to track compensation paid to IOU officers pursuant to Public Utilities Code Section 706."[76] In the Resolution, the Commission expressly states, in Finding Number 5, that "[t]he term 'officer' means those employees of the investor owned utilities in positions with titles of Vice President or above, consistent with Rule 240.3b-7 of the Securities Exchange Act." And Finding Number 6 of the Resolution reflects that the memorandum accounts are intended to apply in "future proceedings." In turn, the full text of Rule 3b-7 of the Securities Exchange Act reads as follows:

[75] This language was added to section 706 through Senate Bill (SB) 901.

[76] Appendix A-93, CPUC Resolution E-4963, p. 1.

> The term *executive officer*, when used with reference to a registrant, means its president, any vice president of the registrant in charge of a principal business unit, division or function (such as sales, administration or finance), any other officer who performs a policy making function or any other person who performs similar policy making functions for the registrant. Executive officers of subsidiaries may be deemed executive officers of the registrant if they perform such policy making functions for the registrant.[77]

On December 21, 2018, SCE filed Advice Filing 3927-E (Advice Filing), titled Establishment of the Officer Compensation Memorandum Account (OCMA) Pursuant to Resolution E-4963. In the proposed tariff changes contained in the Advice Filing, SCE expressly stated the following:

> The term "*officer*" shall be defined as those employees of SCE in positions with titles of Vice President or above who are Rule 3b-7 officers of SCE under the Securities Exchange Act. As of the date of this filing, SCE's officers for purposes of this OCMA are its:
>
> > (1) Chief Executive Officer, (2) President, (3) Senior Vice President (SVP) & Chief Financial Officer, (4) SVP & General Counsel, (5) SVP Customer and Operational Services, (6) SVP Transmission and Distribution, and (7) SVP Regulatory Affairs.[78]

Thus, in the plainest possible terms, SCE's Advice Filing set forth a definition of "officer" and listed, one by one, each specific officer that the definition applied to. On January 29, 2019, the Advice Filing was approved.[79]

(2) Use Of SCE's Definition Of Officer In the 2018 GRC Decision

On March 6, 2019, during the timeframe when modeling was occurring with respect to the proposed decision on SCE's Test Year 2018 GRC, the Commission's Energy Division issued a data request. That data request asked SCE to provide the reductions for 2019-2020 based on the exclusion of officers pursuant to Resolution E-4963 and SB 901.[80] In responding to the data

---

77 17 CFR 240.3b-7 (italics in original). The correct nomenclature for the Rule is "Rule 3b-7" rather than "Rule 240.3b-7." In this testimony, the phrasing "Rule 240.3b-7" only appears if used in passages that are being quoted verbatim.

78 Appendix A-102, CPUC Advice Filing, 3927-E, p.11.

79 Appendix A-102 to this testimony contains a copy of the Advice Filing, and the approval of it.

80 The Energy Division also used the following phrasing to define the scope of the data request: "employees of SCE in positions of Vice President or above who are Rule 3b-7 officers of SCE under the Securities Exchange Act."

request, SCE stated that the exclusion of officers was determined pursuant to Resolution E-4963 and SB 901.[81]

The Energy Division's workpapers that supported the modeling for the 2018 GRC proposed decision stated that: "The labor on this worksheet represent labor for employees of SCE in positions of Vice President or above who are Rule 3b-7 officers of SCE under the Securities Exchange Act. The amount includes base salary, overhead paid absence and severance pay. Overhead paid absence and severance pay are allocated based on total SCE labor."[82]

Thus, the Energy Division specifically used the definition that the Commission had authorized via the Advice Filing; this definition is reflected in the Commission's final decision on SCE's 2018 GRC.[83]

In sum, SCE has followed Commission precedent. TURN seeks to contradict Commission precedent.

(3) Additional Rebuttal To Each Of TURN's Individual Arguments

Although the items set forth above are dispositive in showing that TURN's recommendations are not valid, SCE will also rebut each individual argument on a specific basis as well.

First, TURN seeks an illogical reading of the Commission's words. TURN says the Commission may have intended the application of the Rule 3b-7 definition of "officer" to strictly apply to the specific memorandum accounts and not necessarily apply on an ongoing basis.[84] TURN is incorrect. As discussed above, in Commission Resolution E-4963, the Commission expressly states, in Finding Number 5, that "[t]he term 'officer' means those employees of the investor-owned utilities in positions with titles of Vice President or above, consistent with Rule 240.3b-7 of the

---

[81] A.16-09-001, Data Request ED-SCE-Verbal-033. A copy of the data request and response is included in Appendix A-115.

[82] A copy of this Energy Division workpaper is attached as Appendix A-109.

[83] *See* D.19-05-020, pp. 173-174.

[84] Exhibit TURN-04, p. 29, lines 11-17.

Securities Exchange Act." And Finding Number 6 of Resolution E-4963 reflects that the memorandum accounts are intended to apply in "future proceedings." The language of the Resolution defeats TURN's argument.

Next, TURN appears to incorrectly interpret how the rule is applied. TURN suggests that the definition of "officer" in Resolution E-4963 could mean all individuals who have a title of Vice-President or above, without any limitation within that pool of individuals.[85] TURN asks the Commission to consider TURN's interpretation of the words "consistent with Rule 240.3b-7." TURN argues that Resolution E-4963 can be interpreted in such a manner that the inclusion of all vice presidents in the definition of "officer" would somehow be consistent with Rule 3b-7.[86] This is simply wrong. Rule 3b-7 specifies that the only Vice Presidents to whom the rule applies are those (i) "in charge of a principal business unit, division or function (such as sales, administration or finance)" or (ii) "who perform[] a policy making function." Treating any other Vice Presidents as officers would be inconsistent with the plain language of Rule 3b-7.

Then, TURN attempts to suggest a clear distinction exists between the terms "officer" and "executive officer." TURN argues that Rule 3b-7 is only a definition for "executive officer," not "officer." Again, the language of the Commission's Resolution appears to contradict TURN. As Resolution E-4963 reflects, the terminology "executive" and "officer" are "frequently used interchangeably in GRC testimony and decisions."[87]

As an illustration of the interchangeability of the terms "executive" and "officer," SCE notes that the U.S. Securities and Exchange Commission uses essentially the same definition for "officer" and "executive officer." Rule 16a-1(f) of the Securities Exchange Act[88] states:

---

[85] Exhibit TURN-04, p. 30, lines 7-8.

[86] Exhibit TURN-04, p. 30, lines 7-17.

[87] Appendix A-87, CPUC Resolution E-4963, fn. 4.

[88] 17 CFR 240.16a-1(f).

> The term "officer" shall mean an issuer's president, principal financial officer, principal accounting officer (or, if there is no such accounting officer, the controller), any vice-president of the issuer in charge of a principal business unit, division or function (such as sales, administration or finance), any other officer who performs a policy-making function, or any other person who performs similar policy-making functions for the issuer.

For SCE, the only practical difference between the definition of "officer" and "executive officer" for U.S. Securities and Exchange Commission purposes is that the principal accounting officer (*i.e.,* SCE's Controller) is an "officer" but not an "executive officer." Each year, SCE's Board of Directors designates officers for purposes of Rule 16a-1(f) and executive officers for purposes of Rule 3b-7 in the same resolution. The Board of Directors designates the same individuals for both purposes, with the exception of SCE's Controller (who must be designated for purposes of Rule 16a-1(f) but doesn't fall under the definition for Rule 3b-7).

The U.S. Securities and Exchange Commission defers to the company's Board of Directors in designating officers and executive officers. The Code of Federal Regulations includes a note that specifies that if the Board identifies an individual as an "executive officer" for purposes of Item 401(b) (which uses the Rule 3b-7 definition), then that individual is also presumed to be an "officer" for purposes of Rule 16a-1(f):

> If pursuant to Item 401(b) of Regulation S–K (§ 229.401(b)) the issuer identifies a person as an "executive officer," it is presumed that the Board of Directors has made that judgment and that the persons so identified are the officers for purposes of Section 16 of the Act, as are such other persons enumerated in this paragraph (f) but not in Item 401(b).[89]

TURN then argues that the Rule 3b-7 definition "only applies to registrants of the Securities and Exchange Commission, among which EIX is counted and SCE is not."[90] TURN is factually incorrect. SCE is a registrant because of its registered preferred stock. The cover page of each of SCE's Form 10-K and Form 10-Q filings states which SCE securities are registered pursuant

[89] 17 CFR 240.16a-1(f).

[90] Exhibit TURN-04, p. 31, lines 4-7, and fn. 75.

to Section 12(b) of the Act. The most recent SCE 10-Q[91] specified the following registered securities for SCE:

Table III-15
SCE Registered Securities

Title of each class	Trading Symbol(s)	Name of each exchange on which registered
Cumulative Preferred Stock, 4.08% Series	SCEpB	NYSE American LLC
Cumulative Preferred Stock, 4.24% Series	SCEpC	NYSE American LLC
Cumulative Preferred Stock, 4.32% Series	SCEpD	NYSE American LLC
Cumulative Preferred Stock, 4.78% Series	SCEpE	NYSE American LLC

TURN then attempts to argue that the definition of "officer" can be expanded to include any Vice President, because in TURN's view the fact that Vice Presidents report to Senior or Executive Vice Presidents or the President/CEO makes no difference.[92] Again, TURN is mistaken.

First, as indicated above, the U.S. Securities and Exchange Commission defers to the judgment of SCE's Board of Directors regarding who is an officer and who is an executive officer of SCE.[93] In its business judgment, SCE's Board of Directors does not view any Vice Presidents as being *in charge* of a principal business unit, division, or function or performing a policy-*making* function. All Vice Presidents report up to a Senior Vice President, Executive Vice President, or President/CEO. These higher-ranked individuals make the policy decisions for the company. Even some Senior Vice-Presidents are not treated as being *in charge* of a principal business unit, division or

[91] *See* SCE's most recent Form 10-Q, https://edison.gcs-web.com/static-files/decc205b-3828-436e-86a6-eb924f8a191b (as of June 1, 2020).

[92] Exhibit TURN-04, pp. 31-32.

[93] Please refer to the above-cited note that was included in 17 CFR 240.16a-1(f).

function, or performing a policy-*making* function, because they advise the President/CEO or Executive Vice President rather than make final policy decisions themselves on major issues.

Perhaps recognizing the lack of strength in its arguments concerning Rule 3b-7, TURN attempts to suggest that the Commission should pivot and use Rule 3b-2 instead.[94] This different provision is irrelevant. The definition found in Rule 3b-2 is an old definition. It was adopted in 1948 with revisions in 1982.[95] It has essentially been superseded in relevance for U.S. Securities and Exchange Commission purposes because it focuses on titles instead of roles and responsibilities. The definition of officer in Rule 16a-1(f) and the definition of executive officer in Rule 3b-7 are more recent and relevant, and both of these provisions focus on an individual's actual roles and responsibilities.

Moreover, TURN's request that the Commission change the terms of Resolution E-4963 raises serious due process issues as well. By its terms, Resolution E-4963 specifically applies to ten separate utilities. A majority of these ten utilities filed comments on the draft version of the resolution.[96] The resolution cannot be changed without giving all of these utilities notice and an opportunity to be heard. SCE will address the due process issue in greater detail in legal briefs.

TURN also attempts to suggest that certain predecessor legislation, Assembly Bill (AB) 1266, has some applicability here.[97] TURN's reliance on AB 1266 is misplaced. SB 901 superseded AB 1266. AB 1266 has no applicability to SCE's current GRC request.[98] In fact, in Resolution E-4963, the Commission clarified that utilities were not even required to open any officer compensation memorandum accounts in conformance with the now-superseded AB 1266.[99]

---

[94] Exhibit TURN-04, p. 32, lines 12-13.

[95] *See* 47 FR 11819 (Mar. 19, 1982).

[96] Appendix A-87, CPUC Resolution E-4963, p. 5.

[97] *See* Exhibit TURN-04, pp. 32-33.

[98] *See,* Appendix A-87, *e.g.*, CPUC Resolution E-4963, pp. 2-3 ("AB 1266 added Public Utilities Code Section 706…. On August 31, 2018, the California Legislature passed SB 901, and Governor Edmund Brown Jr. signed it into law on September 21, 2018. SB 901 repeals the language in Public Utilities Code Section 706 …").

[99] *See* Appendix A-87, CPUC Resolution E-4963, p. 8, Finding Number 6 ("*Pursuant to SB 901*, the Commission should require the IOUs to establish memorandum accounts to track officer compensation, as

Next, TURN notes that SCE treats Vice Presidents as officers for purposes of SCE's bylaws.[100] However, TURN fails to mention that other, lower job classifications are also treated as officers for purposes of SCE's bylaws.[101] For example, Assistant Secretaries are officers according to SCE's bylaws. A senior specialist is currently an elected Assistant Secretary. So is a senior staff attorney. A corporate title as an officer under the bylaws does not mean that the individual has an "in charge" role at SCE or any policy-making authority.

TURN also argues that officers are elected every year by the Board and should be treated differently on that basis. TURN contends that holding a job that is subject to an annual hiring and firing voting decision is different than the jobs held by lower-level employees, whose status is dictated by employment law and other factors.[102] However, the Board does not evaluate the performance of those Vice Presidents who are not officers as defined in Rule 16a-1(f).[103] Accordingly, the annual election does not impact hiring and firing decisions for Vice Presidents and other officers under the bylaws who are not officers as defined in Rule 16a-1(f).

Finally, TURN attempts to draw support for its position by referring to D.19-09-051, the Sempra 2019 GRC decision.[104] TURN seems to be basing its argument on the fact that D.19-09-051 happened to use the language found in Public Utilities Code section 706 regarding

---

defined by Public Utilities Code Section 706, so that such amounts may be refunded to ratepayers through future proceedings.") (emphasis added).

[100] Exhibit TURN-04, p. 33, lines 19-21.

[101] SCE's bylaws are available online at https://www.sce.com/sites/default/files/inline-files/SCE_AmendedBylaws_0.pdf (as of June 1, 2020).

[102] Exhibit TURN-04, pp. 33-34.

[103] *See* Charter for the Compensation and Executive Personnel Committee for SCE's Board of Directors, at Article IV, section 1(b). This document is available at https://www.sce.com/sites/default/files/inline-files/SCECEPAmendedCharter_0.pdf (as of June 1, 2020).

[104] Exhibit TURN-04, p. 34, lines 9-16 and fn. 86.

officers.[105] But this does not mean that the Commission is moving away from the interpretation it expressly adopted in Resolution E-4963.[106]

(4) Shared Officers And EIX Executives (FERC 923)

Here, TURN asks that the Commission "reconsider the determination in Resolution E-4963 to exclude EIX Executives from the classification of executives whose compensation is subject to removal from rates pursuant to PUC 706."[107] TURN's argument is based on its incorrect characterization of the statutory intent of SB 901. It is clear from the actual language of SB 901 that EIX officers who are not SCE officers are excluded under the statute. SB 901 by its own terms only applies to "*an officer of an electric corporation*." Edison International may own an electric corporation, but Edison International itself is not an electric corporation.

3. Conclusion

The approach that TURN proposes is contrary to Commission precedent, and factually unsupported. SCE respectfully requests that the Commission reject TURN's proposal.

C. Executive Benefits

1. SCE's Application

SCE forecasts Executive Benefit costs of $15.542 million for Test Year 2021. The Executive Benefits Program is part of the competitive compensation package used to attract and retain well-qualified executives and is reflected in the TCS. The program provides benefits which executives cannot receive through the qualified SCE pension plan, due to Internal Revenue Code (IRC) limits on covered compensation and benefits payable from qualified plans. This Executive Retirement Plan

[105] TURN cites the following language from the Sempra 2019 GRC decision: "Pursuant to Senate Bill (SB) 901, Public Utilities Code section 706 has been amended prohibiting certain investor owned utilities (IOUs) including SDG&E and SoCalGas, from recovering from ratepayers any annual salary, bonus, benefits, or other consideration of any value (compensation and benefits), paid to an officer and requires that compensation instead be funded solely by shareholders." Exhibit TURN-04, p. 34, fn. 86.

[106] TURN appears to have inaccurately interpreted the Sempra 2019 GRC decision. SCE plans to address this issue in greater detail in the briefs.

[107] Exhibit TURN-04, p. 36, lines 10-14.

supplements the SCE Retirement Plan. The primary purpose of the Executive Retirement Plan is to restore benefits that executives cannot receive in the qualified SCE Retirement Plan.

Executive Benefits expenses and forecasts are presented in Table III-16 below. The table provides the recorded amounts for 2014-2018 and the proposed forecasts from SCE, Cal Advocates and TURN for Test Year 2021.

Table III-16
Executive Benefits
2014-2018 Recorded/ 2021 Forecast
Summary of SCE, Cal Advocates, and TURN's Positions
(2018 Constant $000)

Line #	Executive Benefits	SCE Recorded					2021 Forecast			Variance from SCE	
		2014	2015	2016	2017	2018	SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates	TURN
1	Labor									-	-
2	Non-Labor									-	-
3	Other	11,861	19,344	13,769	14,354	14,545	15,542	7,771	-	(7,771)	(15,542)
	Total	11,861	19,344	13,769	14,354	14,545	15,542	7,771	-	(7,771)	(15,542)

2. Cal Advocates

a) Cal Advocates' Position

Cal Advocates recommends ratepayer funding of no more than 50 percent of the forecast Executive Benefits expense, which would amount to ratepayer funding of $7.771 million.[108] Cal Advocates claims that ratepayers should not fund benefits that are in excess of federal limits and enhance the benefits of already highly-compensated executives. Cal Advocates concedes that SCE has made significant changes to reduce the cost structure of the Executive Retirement Plan, where executives hired or promoted in or after 2018 will, instead, receive a company contribution into an Executive Retirement Account of 12 percent of their base pay and bonus, offset by certain other company contributions, such as the 401(k) company matching contributions.[109] (Please note that these

[108] *See* Exhibit PAO-11, p. 21.

[109] *Ibid.*

executives will not be eligible to participate in the Executive Retirement Plan.) Based on past practice, Cal Advocates recommends ratepayers and shareholders should equally share this expense.

3. **SCE's Rebuttal To Cal Advocates' Position**

a) Cal Advocates

SCE competes with other major utilities to attract and retain well-qualified executives. The features and qualification requirements of the Executive Benefits (as discussed in our direct testimony) were preserved in the Executive Retirement Plan because of their value in (a) retaining critical executives to older ages, and (b) avoiding an excessive amount of turnover.[110] According to the Willis Towers Watson's survey, the projected average turnover rate in 2018 within the Energy sector was 8.9 percent.[111]

In light of such a percentage, SCE has made reasonable efforts to keep the benefit package attractive at a prudent cost, and thus has experienced long tenures of service and strong continuity of performance from the executive ranks. The longevity is important not only for continuity purposes but also because executive searches tend to take significantly more time, resources, and cost compared to the average hire. According to Global HR Researching firm, it takes approximately 76 days to hire an executive compared to 43 days for a non-executive.[112] The cost savings resulting from the long tenures and the lower recruiting costs are then translated to the customer.

Furthermore, extensive research within the TCS indicates that, compared to comparator companies, SCE's benefits dropped below the market due to the significant changes in the Executive Retirement Plan.[113] Executives hired or promoted prior to 2018 continue to participate in the Executive Retirement Plan, but after 2017, the value of new accruals in that plan was reduced by changing some components of the final average pay formula. New executives hired on or after January

[110] *See* Exhibit SCE-06, Vol. 03, Part 1, p. 135.

[111] Appendix A-116, 2018 General Industry Salary Budget Survey Report, p. 154.

[112] *See* https://www.ghrr.com/how-long-does-it-take-to-hire-an-executive/ (as of June 1, 2020).

[113] *See* Exhibit SCE-06, Vol. 03, Part 2, p. 5.

1, 2018 receive a company contribution of 12 percent of the executive's base pay and bonus. This contribution goes into an Executive Retirement Account. These newer executives do not participate in the Executive Retirement Plan.[114]

While Cal Advocates concedes that SCE has made significant changes to the Executive Retirement Plan, Cal Advocates fails to point out that according to the TCS submitted by SCE, "the value of Executive Benefits for SCE has dropped significantly versus the last study from almost double the market to approximately 10 percent below market."[115] SCE has also included a chart in our appendix which illustrates the decreased benefit values for executives in 2021 with a comparison to 2018 percentages.[116]

4. <u>TURN</u>

a) <u>TURN's Position</u>

TURN argues that based on *its* definition of officer pursuant to SB 901, the Commission should remove all of the Executive Benefit costs from SCE's forecast. This would be a reduction of $15.542 million.[117]

b) <u>SCE's Rebuttal To TURN's Position</u>

TURN's argument here is not well-taken, for the same reasons that SCE discusses at length in Section B.2.

Even if the Commission were to still decide to disallow funding for the Executive Benefits based on TURN's argument, SCE notes that not all of the costs forecast in Executive Benefits are for Vice Presidents and above. Employees in non-officer job classifications, like Directors, are considered executives and are eligible for Executive Benefits. These executives would not be included

---

114 *See* Exhibit SCE-06, Vol. 03, Part 1, p. 135 for more information on the change to final average pay accruals and the 12 percent base pay contribution.

115 *Ibid.*, at Appendix G, p. 2 of June 7, 2019 Meeting Notes.

116 *See* Appendix A-119, Total Compensation Study 2020 General Rate Case Total Compensation Review.

117 *See* Exhibit TURN-04, p. 41.

in TURN's broader definition of an officer, and should not be included in the disallowance of Executive Benefits even if TURN were to prevail here.

5. Conclusion

The Executive Benefits Program is part of the competitive compensation package used to attract and retain well-qualified executives. We have shown above how SCE has taken proactive steps to reduce the costs of these benefits for all participants as part of the overall restructuring of its total compensation approach. As shown in SCE's 2021 TCS, compensation and benefits are market-competitive across industries, and thus are a reasonable cost of service and should be authorized.

D. Long-Term Incentive (LTI) Program

1. SCE's Application

SCE's LTI represents another integral part of the total compensation package for executives. LTI is provided in various forms: non-qualified stock options, restricted stock units, and performance shares. Each year, SCE performs a detailed market assessment, position-by-position, of its executive workforce to assess each executive's market compensation package (namely, base pay, and short-term and long-term incentives). The LTI target for each executive is determined based upon the market data applicable for his or her position. While LTI is targeted at the market median, the actual grant may vary based on an annual assessment of that individual's performance, as well as retention needs. The actual value of the award is determined after the vesting period based upon company performance. The variable feature of LTI is intended to reinforce a performance culture rather than an entitlement culture.

LTI expenses and forecasts are presented in Table III-17 below. The table provides the recorded amounts for 2014-2018 and the proposed forecasts from SCE, Cal Advocates and TURN for Test Year 2021.

Table III-17
Long Term Incentive
2014-2018 Recorded/ 2021 Forecast
Summary of SCE, Cal Advocates, and TURN's Positions
(2018 Constant $000)

Line #	Long-term Incentives	SCE Recorded					2021 Forecast			Variance from SCE	
		2014	2015	2016	2017	2018	SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates	TURN
1	Labor	20,090	15,302	12,487	11,050	8,130	11,602	-	-	(11,602)	(11,602)
2	Non-Labor									-	-
3	Other									-	-
	Total	20,090	15,302	12,487	11,050	8,130	11,602	-	-	(11,602)	(11,602)

2. Cal Advocates

a) Cal Advocates' Position

Cal Advocates states that the Commission has a long history of denying funding for LTI because it is stock-based compensation tied to financial performance.[118] Cal Advocates also asserts that AB 1054 provides language regarding long-term incentive structure, but does not require that ratepayers fund the program.[119] Furthermore, Cal Advocates disputes that LTI helps in retention of higher-ranked employees, and points to the relatively higher rates of turnover in the executive population.

3. TURN

a) TURN's Position

TURN states the Commission has denied recovery of SCE's LTI costs over the past four rate cases.[120] It argues that the evidence provided by SCE in this case is the same as in the past cases; such as the calculated costs to ratepayers if transfer occurs to base pay,[121] and the claim that a

[118] *See* Exhibit PAO-11, p. 17.

[119] *Ibid.*

[120] Exhibit TURN-04, p. 41.

[121] *Ibid.* at p. 45.

majority of companies provide LTI.[122] TURN states that because there appear to be no truly new arguments, the Commission should continue to disallow LTI benefits.

4. SCE's Rebuttal To Cal Advocates And TURN's Position

a) Executives' Interests And Ratepayer Interests

Both Cal Advocates and TURN refer to the Commission's Decision in D.15-11-021. Cal Advocates quotes the referenced decision as stating that "SCE has not demonstrated that LTI furthers the provisions of safe and reliable service at just and reasonable rates,"[123] and that "LTI does not align executive' interests with ratepayer interests."[124] But Cal Advocates appears to be contradicting what it says in the preceding paragraph of its testimony, where it states that AB 1054's incentive compensation provision was designed "to hold executives accountable for improving safety and mitigating wildfire risk."[125]

Also, as previously discussed in the STIP section of this rebuttal testimony, the California State Legislature recognized that a financially healthy company can procure capital at a lower cost for purposes of investing in the electrical system. This in turn benefits ratepayers in the form of reduced rates.[126] AB 1054 amends the Public Utilities Code to limit the amount of guaranteed cash compensation, and instead move to a structure with incentives based on certain performance metrics.[127] For utilities, the California State Legislature is moving away from the concept of base pay and has recognized the importance of incentive compensation. This is exactly what SCE has been offering in the form of LTI.

---

[122] *Ibid.*

[123] *See* Exhibit PAO-11, p. 17.

[124] *Ibid.*

[125] *Ibid.*

[126] *See* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB1054. (AB1054, Section 1(a)(4)) (as of June 1, 2020).

[127] *See* https://leginfo.legislature.ca.gov/faces/billTextClient.xhtml?bill_id=201920200AB1054 (AB1054, Section 21 (as of June 1, 2020)); Pub. Util. Code §8389(e)(6)(A)(i)(I).

b) SCE Has Provided Additional Evidence That LTI Is Just And Reasonable

TURN suggests that SCE has provided no new evidence in this case as to why the Commission should reconsider authorization of the LTI forecast. However, AB 1054 itself is an entirely new framework in which to consider this issue compared to past rate cases. The regulation only became effective in July 2019. Please see the section directly above for reasons why reconsideration of the issue is merited in light of AB 1054.

TURN also contends that comparing the cost benefits of LTI and base pay is not a new argument.[128] The Commission has commented in the past that SCE's argument was rather vague.[129] By calculating a savings of $6.555 million, SCE is quantifying the benefit to ratepayers and addressing the Commission's concern. This is a 36 percent cost savings.

Finally, TURN suggests that the use of the WorldatWork "Incentive Pay Practices Survey: Publicly Traded Companies" is "verbatim" to what was provided in the 2018 GRC.[130] TURN then admits it is in fact not a resubmittal of the same survey.[131] The survey provided in connection with SCE's Test Year 2018 GRC was included in SCE's application, which filed in the Fall of 2016. That survey utilized survey data from February 2014. The survey in this 2021 GRC provides updated benchmarks. Providing a more current survey is fundamentally different from resubmitting a prior survey. TURN recognizes the survey SCE included in its 2021 GRC application as being "novel" but disregards it as unimportant.[132] In fact, these surveys are independently-generated, fact-based benchmarks that companies rely on in developing total compensation programs. Like the TCS, these surveys further demonstrate that SCE's LTI benefits are reasonable.

---

128 *See* Exhibit TURN-04, p. 45.

129 D.15-11-021, p. 266.

130 *Ibid.*

131 *Ibid.*, at fn. 117.

132 *Ibid.*, p. 45.

c) <u>The Higher Rate Of Turnover In Executive Population Is Not An Indication That LTI Is Ineffective In Retaining Executives</u>

Cal Advocates asserts that SCE's own testimony contradicts SCE's statement that LTI helps in retaining higher-ranked employees, since SCE had higher rates of turnover during the recorded period and SCE reduced the Test Year forecast compared to recorded.[133] Cal Advocates assumes that all of the turnover is triggered by voluntary separations. This is inaccurate. During part of the recorded period 2014 through 2018, SCE was implementing its Operational Excellence program. In examining executive separations as a reference point for the effectiveness of LTI, it must be noted that the overwhelming majority of executive separations occurred as a result of involuntary severances or retirements (a total of 89 percent). Only 11 percent of the executives left voluntarily without retiring.[134] Thus, the higher rate of turnover does not reflect in any way on how effective LTI is at retaining executives.

d) <u>Cost-Sharing Of Just And Reasonable Costs Between Ratepayers And Shareholders</u>

In the event that the Commission agrees with Cal Advocates and TURN's recommendations regarding cost-sharing of the STIP forecast expenses (and Cal Advocates' additional recommendation that Recognition Programs costs be shared as well) on the grounds that both shareholders and ratepayers benefit,[135] then the LTI costs should be shared as well. SCE's TCS demonstrates these costs are just and reasonable when compared to the market.[136] As discussed above, 100 percent of similarly sized companies provide employees some form of incentive compensation. Moreover, both ratepayers and shareholders benefit from an at-risk pay-for-performance compensation plan and a financially health company.

---

[133] *See* PAO-11, p. 18.

[134] Appendix A-155, Voluntary Versus Involuntary Separation.

[135] *See* Exhibit PAO-11, pp. 14, 20; Exhibit TURN-05, p. 19.

[136] *See* Exhibit SCE-06, Vol. 03, Part 2, p. 4.

5. Conclusion

Executive compensation is made up of four components, salary, annual incentives, long-term incentives, and benefits. All four of these factors are important in attracting and retaining qualified executives to lead our Company in delivering safe and reliable service to our customers. The TCS confirms that SCE has a reasonable and fair mix of compensation and benefits. By removing any one of these, the total compensation of an executive would fall well below market compensation levels, and SCE would not be able to retain qualified executives. This is a cost of service and should be authorized by the Commission.

E. Recognition

1. SCE's Application

In SCE's Application, SCE requests recovery for its nominal cash and non-cash recognition programs. They comprise the cash awards, called Spot Awards, and non-cash awards (in the form of points redeemable for merchandise, known as Encore points.[137] SCE's recognition programs are important tools for recognizing and rewarding employees for exceptional performance, safety actions, and/or outstanding achievement on the spot, closer to when that outstanding performance happens.

Table III-18 below shows the recorded cost paid to the vendor to administer these program**s** for the years 2014 through 2018, and the forecast for Test Year 2021.

---

[137] Encore was formerly known as the Awards to Celebrate Excellence, or ACE program. Encore is a non-cash *safety* recognition program that uses points to award employees for their commitment to ongoing, regular efforts to work safely and for their safety achievements. Please refer to Exhibit SCE-06, Vol. 03, Part 1, p. 69 for more information.

Table III-18
Recognition Programs
2014-2018 Recorded/ 2021 Forecast
Summary of SCE, Cal Advocates, and TURN's Positions
(2018 Constant $000)

Line #	Recognition	SCE Recorded					2021 Forecast			Variance from SCE	
		2014	2015	2016	2017	2018	SCE Rebuttal Position	Cal Advocates	TURN	Cal Advocates	TURN
1	Labor									-	-
2	Non-Labor									-	-
3	Other	109	41	55	256	856	74	37	74	(37)	-
	Total	109	41	55	256	856	74	37	74	(37)	-

The cost for the cash and non-cash awards for these programs are included in the expense forecast of each individual business unit, but are summarized in Table III-19 for transparency and ease of reference. Effective January 1, 2019, each OU has a limited budget of 0.15 percent of its individual labor budget that can be spent on employee recognition. This is a reduction of the budget of 0.20 percent in prior years. SCE is forecasting $2.096 million for the Test Year.

Table III-19
SCE's Recognition Program Costs
2021 Forecast[138]

	2021
Total Labor Budget	$ 1,397,109,000
Percent of Total Labor for Recognition Budget	0.15%
Total Recognition Budget Limit	$ 2,095,663

2. <u>Cal Advocates</u>

a) <u>Cal Advocates' Position</u>

Cal Advocates is recommending a 50 percent disallowance of the $74 thousand Test Year forecast for Recognition Programs, claiming that ratepayers and shareholders should equally share the expense. Cal Advocates states that through SCE's Recognition Program, "SCE is rewarding

138 Total Recognition budget is based on updated O&M and Capital labor dollars included in SCE's errata (SCE-06, Vol. 3, P1E).

employees for simply doing their job in the way they were hired to do it – safely."[139] Cal Advocates claims that because the Recognition Programs were not included in the TCS, jobs that are already over market (such as the Physical and Technical category of jobs) would be even further over market if Recognition Programs are funded.[140] Finally, Cal Advocates asserts that SCE has not "tightly managed" its budget, because SCE has overspent the budget in both 2018 and 2019.[141]

b) SCE's Rebuttal To Cal Advocates' Position

(1) Recognition Program Costs Are Immaterial To The TCS

Cal Advocates characterizes D.04-07-022 as follows: "the Commission stated that such program costs might be eligible for ratepayer funding if the program does not result in employees receiving above-market total compensation."[142] That is not quite what the Commission said. The Commission instead said the following in D.04-07-022:

> SCE has demonstrated that the ACE program is neither a cultural nor a social activity, but is rather a tool to enhance employee performance. Since the program encourages employee performance that is consistent with ratepayer interests, and the use of formal recognition programs such as the ACE program is an established business practice for most companies, we will allow the inclusion of this modest employee benefit expense.[143]

Cal Advocates also expresses concern that the Recognition Program was not included in the TCS, and that the Physical/Technical job category as found in the TCS is already 13.1 percent above market. The TCS reviews positions within the Company as a whole, not based on individual job categories. Any evaluation in this area would need to consider the other four categories (Clerical, Professional/Technical, Manager/Supervisor, and Executive), all of which are well under market.

---

139 *See* Exhibit PAO-11, p. 19.

140 *Ibid*.

141 *Ibid.,* at p. 20.

142 *Ibid.,* at p. 19.

143 D.04-07-022, p. 212.

As described in the Elements of Compensation-Excluded section of the TCS, several elements of compensation are excluded from the TCS.[144] Such excluded elements include shift differentials, spot awards (also commonly referred to as recognition awards), and overtime pay. These items are excluded from the TCS study because this data is not readily available in surveys on a position-by-position basis, and wide variances exist in their utilization among comparators. None of these elements of compensation were reported by other companies in total compensation amounts reported to survey databases used in the Study, or indeed in any prior TCS studies, many of which were co-managed by Cal Advocates. In other words, these compensation elements are not included in the TCS only because data is lacking on a job-to-job basis, which makes the comparisons needed for that Study impossible.

Moreover, even if Recognition were included, its overall impact would be immaterial to the TCS results. Per Aon, the independent consultant who performed the TCS, the expected range of error for the Study is -0.4 percent to +0.4 percent above or below the stated results. The market reference could move up or down by 0.4 percent due to normal error in the study results. Because of this margin of error, the inclusion of SCE's nominal forecast budget for the Recognition Programs of 0.15 percent (or even 0.20 for 2018) does not place it outside the normal range of error. Therefore, the impact of including the Recognition Programs within the TCS would be characterized as immaterial to the overall results, as confirmed by our independent consultant. The Commission stated in SCE's Test Year 2018 decision that Recognition Programs are a "modest employee benefit expense."[145]

(2) <u>SCE's Recognition Forecast Is 0.15 Percent Of Labor</u>

Cal Advocates states "SCE claims that the budget for its recognition program is 0.15% but the amount spent on the program has increased significantly in recent years."[146] SCE has forecast 0.15 percent of labor for Test Year 2021. It did not include recorded costs from 2018 in its forecast, nor is it requesting additional authorization above this amount. In its direct testimony,

---

[144] Exhibit SCE-06, Vol. 03, Part 2, p. 18.

[145] *Ibid*.

[146] Exhibit PAO-11, p. 19.

SCE explained the anomaly for the Recognition Program costs in 2018. The Spot and Encore Programs were managed separately by different vendors. In 2019, SCE moved to a new vendor to better manage both programs with controls in place to assist in limiting the recognition budget. Amounts requested over and above the budget allocated to a business unit can only be changed with senior executive approval.

Cal Advocates claims that SCE's Recognition budget for 2019 was $74,000 and SCE spent $687,000.[147] This is not accurate. The forecast amount of $74,000 found in the GRC Activity for Recognition is the administrative fee for the vendor. It is not the budget. As explained above and in SCE's opening testimony, the cost of granting the awards is recorded in each individual OU. SCE's forecast of $74,000 is not 0.15 percent of SCE's labor budget, as Cal Advocates suggests.[148] Table III-19 illustrates the anticipated 2021 budget for the Recognition Programs.

3. <u>Conclusion</u>

The Recognition Program is a modest benefit and an effective tool to motivate employees with rewards for making individual achievements and for exemplifying behaviors which promote a safe work environment. SCE has hired a new vendor to assist in managing the cost of these Recognition Programs. SCE's forecast is reasonable and should be authorized.

---

[147] *Ibid.* at pp. 19-20.

[148] *Ibid.* at p. 20.

Appendix A

Employee Benefits, Training & Support Supporting Documentation

SCE-17, Vol. 03: Rebuttal Testimony Employee Benefits, Training & Support, Appendix A
Index of Supporting Documentation

From: Alison Peterson <alison.peterson@aon.com>
Sent: Wednesday, May 27, 2020 6:17 AM
To: Pamela A Arnold <Pamela.Arnold@sce.com>
Cc: Charity Mahoney <Charity.Mahoney@sce.com>; Mark Bennett <Mark.Bennett@sce.com>; Kris G Vyas <Kris.Vyas@sce.com>; Chelsea Penaloza <chelsea.penaloza@aon.com>
Subject: (External):RE: Rebuttal Testimony Development

CAUTION EXTERNAL EMAIL

Southern California Edison

2021 GRC Study Data as of 12/31/18

2021 General Rate Case—Total Compensation Study

Competitive Summary (SCE versus Market)

June 5, 2019

2021 TCS Study

				SCE In Study +/- Market				
							SCE Demographic	
Job Category	**SCE Population**	**SCE Payroll Dollars ($000s)***	**Payroll Weighting**	**Base**	**TCC**	**LTI**	**Benefits**	**Total Comp**
Physical/Technical	3,628	$389,605.1	26.4%	15.1%	17.7%		-5.6%	13.1%
Clerical	2,574	$184,417.7	12.5%	-5.1%	-7.2%		-10.4%	-7.9%
Professional/Technical	4,421	$546,100.5	37.0%	-9.4%	-11.7%	-100.0%	-10.1%	-12.8%
Manager/Supervisor	1,816	$335,356.8	22.7%	-0.3%	1.2%	-93.4%	-5.0%	-5.1%
Executive	37	$19,089.7	1.3%	-7.9%	-16.6%	-17.8%	-19.8%	-17.4%
2021 Overall (Payroll Wtd)	**12,476**	**$1,474,569.9**	**100.0%**	**-0.2%**	**-0.4%**	**-5.1%**	**-8.0%**	**-3.0%**

Base	$1,339,882.0	**90.9%**	
STIP/Annual Incentives	$134,687.9	**9.1%**	**-9.1%**
	$1,474,569.9		**-12.1%**

Alison Peterson
Partner and Aon Rewards Solutions Co-Sourcing Leader
email: alison.peterson@aon.com
Phone: (949) 823-7463

Southern California Edison
A.19-08-013 – SCE 2021 General Rate Case

DATA REQUEST SET T U R N - S C E - 0 2 6

To: TURN
Prepared by: Evangeline K Andersen
Job Title: Director, Accounting Advisory, Reporting, and Controls
Received Date: 3/4/2020

Response Date: 3/17/2020

Question 01.a-b:
In Edison's Compensation and Benefits testimony, 06, Vol 3, Part 1, p. 48, Edison states: "Core earnings are essential to maintain SCE's financial health and to provide lower cost of capital to finance the capital projects…"

a. Does Edison contend that "core earnings", rather than "Net (loss) income attributable to Edison International Continuing operations", is the primary criterion investors use in deciding whether to invest in Edison stock shares or bonds? If the response to this question is anything other than an unqualified negative, please provide the following:

b. Identify and describe in detail all research, analysis or other evidence SCE has prepared or been provided that addresses the impact that core earnings, rather than GAAP measures of income have on the utility's access to capital markets. Please also provide a copy of all such research, analysis or other evidence.

Response to Question 01.a-b:
SCE objects to this request on the grounds that it calls for speculation with regard to how investors decide their investments. Subject to and without waiver of this objection, SCE responds as follows:

SCE uses Core Earnings internally for financial planning and for analysis of performance. Core Earnings is also used when communicating with investors and analysts regarding our financial results to facilitate comparisons of the company's performance from period to period.

Edison presents Core Earnings in our filings with the Securities and Exchange Commission (SEC) including in our Form 10-Q, Form 10-K, and earnings releases. Core Earnings is considered a financial measure that is not based on Generally Accepted Accounting Principles (GAAP), typically referred to as a non-GAAP financial measure. The presentation of non-GAAP financial measures in SEC filings is common and the SEC has issued authoritative rules governing disclosure. These rules state that a non-GAAP financial measure cannot omit material facts or mislead users of the SEC documents when considered with other information in the filing. In addition, the SEC requires that Edison explain why management believes the measure is useful to investors, how management uses the measure, and that the non-GAAP measure be reconciled to a GAAP measure and be presented with equal prominence as GAAP information.

Please see attached

1) Appendix A - SEC Regulation S-K: Standard instructions for filing forms, Item 10(a) Applicability of Regulation S-K and Item 10(e) Use of non-GAAP financial measures in commission filings

2) Appendix B: SEC Financial Reporting Manual Topic 8. Non-GAAP measures of financial performance, liquidity and net worth S8120 and S8130

3) Appendix C: Edison's most recent disclosure of Core Earnings in our Form 10-K filed February 27, 2020

4) Appendix D: Research report prepared by UBS Securities LLC, which discusses Core EPS along with other financial information in their evaluation of Edison

First Read

Edison International
Uncertainty Slowly Declining

Equities

Americas
Electric Utilities

12-month rating	**Neutral**
12m price target	**US$72.00**
Price	**US$69.53**

RIC: EIX.N **BBG:** EIX US

Trading data and key metrics

52-wk range	US$82.64-58.07
Market cap.	US$22.7bn
Shares o/s	326m (COM)
Free float	100%
Avg. daily volume ('000)	528
Avg. daily value (m)	US$36.0
Common s/h equity (12/18E)	US$12.2bn
P/BV (12/18E)	1.9x
Net debt / EBITDA (12/18E)	3.7x

EPS (UBS, diluted) (US$)

	12/18E			
	From	To	% ch	Cons.
Q1	0.80	0.80	0	0.80
Q2	0.85	0.83	-2	0.84
Q3	1.29	1.55	20	1.29
Q4E	1.21	1.22	1	1.14
12/18E	4.15	4.40	6	4.10
12/19E	4.51	4.51	0	4.51
12/20E	4.87	4.87	0	4.84

Daniel Ford, CFA
Analyst
dan.ford@ubs.com
+1-212-713-2224

Gregg Orrill
Analyst
gregg.orrill@ubs.com
+1-212-713 1064

What happened?

Edison International reported Q3 core EPS of $1.56 versus the $1.29 consensus. The company stated that they believe there were at least 2 ignition points in the Thomas fire and that their equipment was associated with one of them (the Koenigstein Road fire). They do not know causation. Management stated that the disclosures they made are consistent with those they have made historically that have led to paying the dividend. Utility Southern California Edison EPS rose to $1.62 versus $1.43 driven by $0.08/share of non-fuel operations and maintenance expense control and $0.18/share related to tax reform offset by revenue (-$0.03/share), depreciation (-$0.02/share) and net financing costs (-$0.02/share).

What are the financial implications?

We are raising our 2018 EPS estimate $0.25 to trailing 12 month EPS of $4.40. We maintain our 2019 EPS estimate of $4.51 and our 2020 estimate of $4.87. EIX maintained 2018 EPS factors except for a $0.03/share reduction for energy efficiency timing. The company has a 50% equity ratio versus the 48% required within their cost of capital mechanism. Requests not in our forecast represent $0.14/share of EPS potential and include $407M of capital for grid resiliency and $561M for the grid electrification in California.

What are the milestones ahead?

EIX expects a proposed decision in the general rate case before November 13 which could enable them to give EPS guidance. It is unclear when CAL FIRE or the California Public Utility Commission's Safety and Enforcement Division will issue an opinion on the Thomas fire. The next dividend declaration is in early December.

Valuation: Pricing in $5.0B of Wildfire Liability and 6% for Other Potential Fires

Versus our $72 target the stock reflects $5.0B of gross liability ($1.0B of insurance and $0.5B of legal fees) and a 6% discount for other wildfire potential liability.

Highlights (US$m)	12/15	12/16	12/17	12/18E	12/19E	12/20E	12/21E	12/22E
Revenues	11,524	11,869	12,320	12,524	12,855	13,202	13,507	13,798
EBIT (UBS)	2,562	2,171	2,304	2,484	2,569	2,784	2,986	3,183
Net earnings (UBS)	1,336	1,311	1,466	1,452	1,487	1,608	1,713	1,814
EPS (UBS, diluted) (US$)	4.06	3.97	4.44	4.40	4.51	4.87	5.19	5.50
DPS (US$)	1.73	1.99	2.17	2.42	2.59	2.77	2.96	3.11
Net (debt) / cash	(13,819)	(14,569)	(15,639)	(16,832)	(18,660)	(20,277)	(21,804)	(23,221)

Profitability/valuation	12/15	12/16	12/17	12/18E	12/19E	12/20E	12/21E	12/22E
EBIT margin %	22.2	18.3	18.7	19.8	20.0	21.1	22.1	23.1
ROIC (EBIT) %	12.6	10.1	6.6	5.2	5.1	5.3	5.5	5.6
EV/EBITDA (core) x	6.9	8.2	9.3	8.4	8.4	8.2	8.0	7.8
P/E (UBS, diluted) x	15.1	17.8	17.5	15.8	15.4	14.3	13.4	12.6
Equity FCF (UBS) yield %	2.1	(3.2)	(4.3)	(0.9)	(3.0)	(1.6)	(0.6)	0.3
Net dividend yield %	2.8	2.8	2.8	3.5	3.7	4.0	4.3	4.5

Source: Company accounts, Thomson Reuters, UBS estimates. Metrics marked as (UBS) have had analyst adjustments applied. Valuations: based on an average share price that year, (E): based on a share price of US$69.53 on 30 Oct 2018 18:42 EDT

Forecast returns

Forecast price appreciation	+3.6%
Forecast dividend yield	3.9%
Forecast stock return	+7.5%
Market return assumption	7.9%
Forecast excess return	-0.4%

Valuation Method and Risk Statement

Our valuation methodology for the group is price to earnings based. The adjustments applied fall into 5 categories. These are as follows: 1) Group Valuation Bias: Flowing from our valuation work comparing Baa corporate yields to group dividend yields and RU price to earnings ratios to those for the S&P 500, we incorporate a positive or negative adjustment to our group multiple representing the gap we calculate to the nearest 5%; 2) Growth Adjustment: We adjust our valuations based on the growth quartile each utility occupies. First quartile receives a 5% premium, second quartile a 2% premium, third quartile a 2% discount and fourth quartile a 5% discount; 3) Regulatory Adjustment: Our valuation adjustments for regulation are based on our proprietary Regulatory Rankings. First quartile jurisdictions receive 5%, second quartile 2%, third quartile -2% and fourth quartile -5%; 4) Multi Utility Diversified Valuation: For multi utilities (those with more than 15% diversified or foreign earnings), we perform a sum-of-parts analysis applying business/region appropriate valuations to those diversified businesses; 5) One-off Adjustments: In special situations, we value risk on an issue specific basis. Common areas where we apply such an adjustment include: ESG advantage, large project construction risk, legal risk, and announced M&A completion risk.

Our target is $72 which is a 8% discount applied to the Regulated Utility average 2020 P/E and 14% for the wildfire risk or 14.8x $4.87.

Risks factors include regulation, interest rates, operations, government regulations, California wildfires and credit.

Required Disclosures

This report has been prepared by UBS Securities LLC, an affiliate of UBS AG. UBS AG, its subsidiaries, branches and affiliates are referred to herein as UBS.

For information on the ways in which UBS manages conflicts and maintains independence of its research product; historical performance information; and certain additional disclosures concerning UBS research recommendations, please visit www.ubs.com/disclosures. The figures contained in performance charts refer to the past; past performance is not a reliable indicator of future results. Additional information will be made available upon request. UBS Securities Co. Limited is licensed to conduct securities investment consultancy businesses by the China Securities Regulatory Commission. UBS acts or may act as principal in the debt securities (or in related derivatives) that may be the subject of this report. This recommendation was finalized on: 31 October 2018 01:41 AM GMT. UBS has designated certain Research department members as Derivatives Research Analysts where those department members publish research principally on the analysis of the price or market for a derivative, and provide information reasonably sufficient upon which to base a decision to enter into a derivatives transaction. Where Derivatives Research Analysts co-author research reports with Equity Research Analysts or Economists, the Derivatives Research Analyst is responsible for the derivatives investment views, forecasts, and/or recommendations.

Analyst Certification: Each research analyst primarily responsible for the content of this research report, in whole or in part, certifies that with respect to each security or issuer that the analyst covered in this report: (1) all of the views expressed accurately reflect his or her personal views about those securities or issuers and were prepared in an independent manner, including with respect to UBS, and (2) no part of his or her compensation was, is, or will be, directly or indirectly, related to the specific recommendations or views expressed by that research analyst in the research report.

UBS Investment Research: Global Equity Rating Definitions

12-Month Rating	**Definition**	**Coverage**[1]	**IB Services**[2]
Buy	FSR is > 6% above the MRA.	48%	24%
Neutral	FSR is between -6% and 6% of the MRA.	37%	21%
Sell	FSR is > 6% below the MRA.	15%	12%
Short-Term Rating	**Definition**	**Coverage**[3]	**IB Services**[4]
Buy	Stock price expected to rise within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%
Sell	Stock price expected to fall within three months from the time the rating was assigned because of a specific catalyst or event.	<1%	<1%

Source: UBS. Rating allocations are as of 30 September 2018.
1:Percentage of companies under coverage globally within the 12-month rating category.
2:Percentage of companies within the 12-month rating category for which investment banking (IB) services were provided within the past 12 months.
3:Percentage of companies under coverage globally within the Short-Term rating category.
4:Percentage of companies within the Short-Term rating category for which investment banking (IB) services were provided within the past 12 months.

KEY DEFINITIONS:Forecast Stock Return (FSR) is defined as expected percentage price appreciation plus gross dividend yield over the next 12 months. In some cases, this yield may be based on accrued dividends. **Market Return Assumption (MRA)** is defined as the one-year local market interest rate plus 5% (a proxy for, and not a forecast of, the equity risk premium). **Under Review (UR)** Stocks may be flagged as UR by the analyst, indicating that the stock's price target and/or rating are subject to possible change in the near term, usually in response to an event that may affect the investment case or valuation. **Short-Term Ratings** reflect the expected near-term (up to three months) performance of the stock and do not reflect any change in the fundamental view or investment case. **Equity Price Targets** have an investment horizon of 12 months.

EXCEPTIONS AND SPECIAL CASES:UK and European Investment Fund ratings and definitions are: Buy: Positive on factors such as structure, management, performance record, discount; **Neutral:** Neutral on factors such as structure, management, performance record, discount; **Sell:** Negative on factors such as structure, management, performance record, discount. **Core Banding Exceptions (CBE):** Exceptions to the standard +/-6% bands may be granted by the Investment Review Committee (IRC). Factors considered by the IRC include the stock's volatility and the credit spread of the respective company's debt. As a result, stocks deemed to be very high or low risk may be subject to higher or lower bands as they relate to the rating. When such exceptions apply, they will be identified in the Company Disclosures table in the relevant research piece.

Research analysts contributing to this report who are employed by any non-US affiliate of UBS Securities LLC are not registered/qualified as research analysts with FINRA. Such analysts may not be associated persons of UBS Securities LLC and therefore are not subject to the FINRA restrictions on communications with a subject company, public appearances, and trading securities held by a research analyst account. The name of each affiliate and analyst employed by that affiliate contributing to this report, if any, follows.

UBS Securities LLC: Daniel Ford, CFA; Gregg Orrill.

Company Disclosures

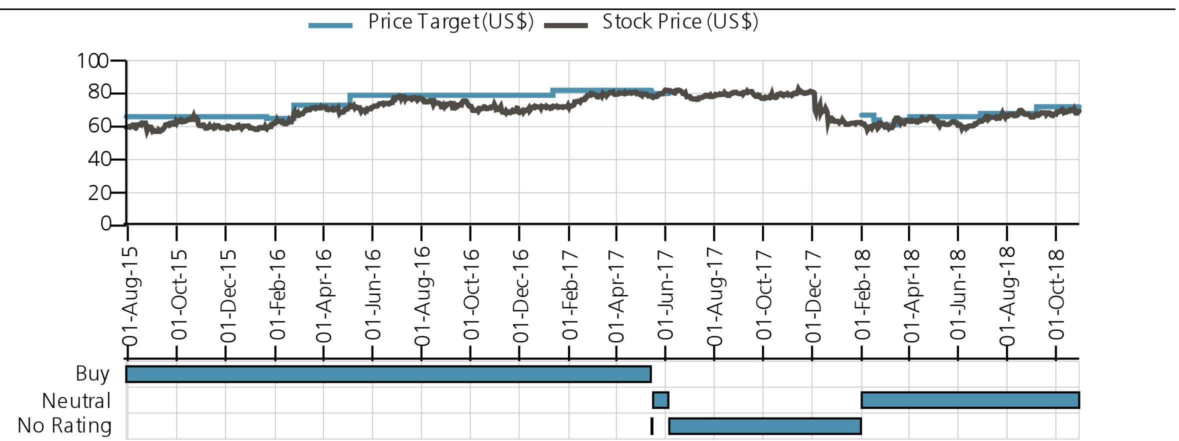
Company Name	Reuters	12-month rating	Short-term rating	Price	Price date
Edison International[7, 16]	EIX.N	Neutral	N/A	US$69.53	30 Oct 2018

Source: UBS. All prices as of local market close.
Ratings in this table are the most current published ratings prior to this report. They may be more recent than the stock pricing date

7. Within the past 12 months, UBS Securities LLC and/or its affiliates have received compensation for products and services other than investment banking services from this company/entity.
16. UBS Securities LLC makes a market in the securities and/or ADRs of this company.

Unless otherwise indicated, please refer to the Valuation and Risk sections within the body of this report. For a complete set of disclosure statements associated with the companies discussed in this report, including information on valuation and risk, please contact UBS Securities LLC, 1285 Avenue of Americas, New York, NY 10019, USA, Attention: Investment Research.

Edison International (US$)



Date	Stock Price (US$)	Price Target (US$)	Rating
2015-07-30	59.53	66.0	Buy
2016-01-21	58.72	65.0	Buy
2016-02-24	67.83	73.0	Buy
2016-05-04	72.76	79.0	Buy
2017-01-12	72.38	82.0	Buy
2017-05-15	78.72	-	No Rating
2017-05-17	77.59	80.0	Neutral
2017-06-06	81.51	-	No Rating
2018-02-01	61.74	67.0	Neutral
2018-02-16	61.05	64.0	Neutral
2018-02-23	62.17	61.0	Neutral
2018-03-16	65.15	64.0	Neutral
2018-04-02	63.1	66.0	Neutral
2018-06-29	63.27	68.0	Neutral
2018-09-07	66.66	72.0	Neutral

Source: UBS; as of 30 Oct 2018

Global Disclaimer

This document has been prepared by UBS Securities LLC, an affiliate of UBS AG. UBS AG, its subsidiaries, branches and affiliates are referred to herein as UBS.

Global Research is provided to our clients through UBS Neo, and in certain instances, UBS.com and any other system or distribution method specifically identified in one or more communications distributed through UBS Neo or UBS.com (each a system) as an approved means for distributing Global Research. It may also be made available through third party vendors and distributed by UBS and/or third parties via e-mail or alternative electronic means. The level and types of services provided by Global Research to a client may vary depending upon various factors such as a client's individual preferences as to the frequency and manner of receiving communications, a client's risk profile and investment focus and perspective (e.g., market wide, sector specific, long-term, short-term, etc.), the size and scope of the overall client relationship with UBS and legal and regulatory constraints.

All Global Research is available on UBS Neo. Please contact your UBS sales representative if you wish to discuss your access to UBS Neo.

When you receive Global Research through a System, your access and/or use of such Global Research is subject to this Global Research Disclaimer and to the terms of use governing the applicable System.

When you receive Global Research via a third party vendor, e-mail or other electronic means, you agree that use shall be subject to this Global Research Disclaimer, where applicable the UBS Investment Bank terms of business (https://www.ubs.com/global/en/investment-bank/regulatory.html) and to UBS's Terms of Use/Disclaimer (http://www.ubs.com/global/en/legalinfo2/disclaimer.html). In addition, you consent to UBS processing your personal data and using cookies in accordance with our Privacy Statement (http://www.ubs.com/global/en/legalinfo2/privacy.html) and cookie notice (http://www.ubs.com/global/en/homepage/cookies/cookie-management.html).

If you receive Global Research, whether through a System or by any other means, you agree that you shall not copy, revise, amend, create a derivative work, provide to any third party, or in any way commercially exploit any UBS research provided via Global Research or otherwise, and that you shall not extract data from any research or estimates provided to you via Global Research or otherwise, without the prior written consent of UBS.

This document is for distribution only as may be permitted by law. It is not directed to, or intended for distribution to or use by, any person or entity who is a citizen or resident of or located in any locality, state, country or other jurisdiction where such distribution, publication, availability or use would be contrary to law or regulation or would subject UBS to any registration or licensing requirement within such jurisdiction.

This document is a general communication and is educational in nature; it is not an advertisement nor is it a solicitation or an offer to buy or sell any financial instruments or to participate in any particular trading strategy. Nothing in this document constitutes a representation that any investment strategy or recommendation is suitable or appropriate to an investor's individual circumstances or otherwise constitutes a personal recommendation. By providing this document, none of UBS or its representatives has any responsibility or authority to provide or have provided investment advice in a fiduciary capacity or otherwise. Investments involve risks, and investors should exercise prudence and their own judgment in making their investment decisions. None of UBS or its representatives is suggesting that the recipient or any other person take a specific course of action or any action at all. By receiving this document, the recipient acknowledges and agrees with the intended purpose described above and further disclaims any expectation or belief that the information constitutes investment advice to the recipient or otherwise purports to meet the investment objectives of the recipient. The financial instruments described in the document may not be eligible for sale in all jurisdictions or to certain categories of investors.

Options, structured derivative products and futures (including OTC derivatives) are not suitable for all investors. Trading in these instruments is considered risky and may be appropriate only for sophisticated investors. Prior to buying or selling an option, and for the complete risks relating to options, you must receive a copy of "The Characteristics and Risks of Standardized Options." You may read the document at http://www.theocc.com/publications/risks/riskchap1.jsp or ask your salesperson for a copy. Various theoretical explanations of the risks associated with these instruments have been published. Supporting documentation for any claims, comparisons, recommendations, statistics or other technical data will be supplied upon request. Past performance is not necessarily indicative of future results. Transaction costs may be significant in option strategies calling for multiple purchases and sales of options, such as spreads and straddles. Because of the importance of tax considerations to many options transactions, the investor considering options should consult with his/her tax advisor as to how taxes affect the outcome of contemplated options transactions.

Mortgage and asset-backed securities may involve a high degree of risk and may be highly volatile in response to fluctuations in interest rates or other market conditions. Foreign currency rates of exchange may adversely affect the value, price or income of any security or related instrument referred to in the document. For investment advice, trade execution or other enquiries, clients should contact their local sales representative.

The value of any investment or income may go down as well as up, and investors may not get back the full (or any) amount invested. Past performance is not necessarily a guide to future performance. Neither UBS nor any of its directors, employees or agents accepts any liability for any loss (including investment loss) or damage arising out of the use of all or any of the Information.

Prior to making any investment or financial decisions, any recipient of this document or the information should seek individualized advice from his or her personal financial, legal, tax and other professional advisors that takes into account all the particular facts and circumstances of his or her investment objectives.

Any prices stated in this document are for information purposes only and do not represent valuations for individual securities or other financial instruments. There is no representation that any transaction can or could have been effected at those prices, and any prices do not necessarily reflect UBS's internal books and records or theoretical model-based valuations and may be based on certain assumptions. Different assumptions by UBS or any other source may yield substantially different results.

No representation or warranty, either expressed or implied, is provided in relation to the accuracy, completeness or reliability of the information contained in any materials to which this document relates (the "Information"), except with respect to Information concerning UBS. The Information is not intended to be a complete statement or summary of the securities, markets or developments referred to in the document. UBS does not undertake to update or keep current the Information. Any opinions expressed in this document may change without notice and may differ or be contrary to opinions expressed by other business areas or groups, personnel or other representative of UBS. Any statements contained in this report attributed to a third party represent UBS's interpretation of the data, information and/or opinions provided by that third party either publicly or through a subscription service, and such use and interpretation have not been reviewed by the third party. In no circumstances may this document or any of the Information (including any forecast, value, index or other calculated amount ("Values")) be used for any of the following purposes:

(i) valuation or accounting purposes;

(ii) to determine the amounts due or payable, the price or the value of any financial instrument or financial contract; or

(iii) to measure the performance of any financial instrument including, without limitation, for the purpose of tracking the return or performance of any Value or of defining the asset allocation of portfolio or of computing performance fees.

By receiving this document and the Information you will be deemed to represent and warrant to UBS that you will not use this document or any of the Information for any of the above purposes or otherwise rely upon this document or any of the Information.

UBS has policies and procedures, which include, without limitation, independence policies and permanent information barriers, that are intended, and upon which UBS relies, to manage potential conflicts of interest and control the flow of information within divisions of UBS and among its subsidiaries, branches and affiliates. For further information on the ways in which UBS manages conflicts and maintains independence of its research products, historical performance information and certain additional disclosures concerning UBS research recommendations, please visit www.ubs.com/disclosures.

Research will initiate, update and cease coverage solely at the discretion of UBS Research Management, which will also have sole discretion on the timing and frequency of any published research product. The analysis contained in this document is based on numerous assumptions. All material information in relation to published research reports, such as valuation methodology, risk statements, underlying assumptions (including sensitivity analysis of those assumptions), ratings history etc. as required by the Market Abuse Regulation, can be found on UBS Neo. Different assumptions could result in materially different results.

The analyst(s) responsible for the preparation of this document may interact with trading desk personnel, sales personnel and other parties for the purpose of gathering, applying and interpreting market information. UBS relies on information barriers to control the flow of information contained in one or more areas within UBS into other areas, units, groups or affiliates of UBS. The compensation of the analyst who prepared this document is determined exclusively by research management and senior management (not including investment banking). Analyst compensation is not based on investment banking revenues; however, compensation may relate to the revenues of UBS and/or its divisions as a whole, of which investment banking, sales and trading are a part, and UBS's subsidiaries, branches and affiliates as a whole.

For financial instruments admitted to trading on an EU regulated market: UBS AG, its affiliates or subsidiaries (excluding UBS Securities LLC) acts as a market maker or liquidity provider (in accordance with the interpretation of these terms in the UK) in the financial instruments of the issuer save that where the activity of liquidity provider is carried out in accordance with the definition given to it by the laws and regulations of any other EU jurisdictions, such information is separately disclosed in this document. For financial instruments admitted to trading on a non-EU regulated market: UBS may act as a market maker save that where this activity is carried out in the US in accordance with the definition given to it by the relevant laws and regulations, such activity will be specifically disclosed in this document. UBS may have issued a warrant the value of which is based on one or more of the financial instruments referred to in the document. UBS and its affiliates and employees may have long or short positions, trade as principal and buy and sell in instruments or derivatives identified herein; such transactions or positions may be inconsistent with the opinions expressed in this document.

Within the past 12 months UBS AG, its affiliates or subsidiaries may have received or provided investment services and activities or ancillary services as per MiFID II which may have given rise to a payment or promise of a payment in relation to these services from or to this company.

United Kingdom and the rest of Europe: Except as otherwise specified herein, this material is distributed by UBS Limited to persons who are eligible counterparties or professional clients. UBS Limited is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority. **France:** Prepared by UBS Limited and distributed by UBS Limited and UBS Securities France S.A. UBS Securities France S.A. is regulated by the ACPR (Autorité de Contrôle Prudentiel et de Résolution) and the Autorité des Marchés Financiers (AMF). Where an analyst of UBS Securities France S.A. has contributed to this document, the document is also deemed to have been prepared by UBS Securities France S.A. **Germany:** Prepared by UBS Limited and distributed by UBS Limited and UBS Europe SE. UBS Europe SE is regulated by the Bundesanstalt fur Finanzdienstleistungsaufsicht (BaFin). **Spain:** Prepared by UBS Limited and distributed by UBS Limited and UBS Securities España SV, SA. UBS Securities España SV, SA is regulated by the Comisión Nacional del Mercado de Valores (CNMV). **Turkey:** Distributed by UBS Limited. No information in this document is provided for the purpose of offering, marketing and sale by any means of any capital market instruments and services in the Republic of Turkey. Therefore, this document may not be considered as an offer made or to be made to residents of the Republic of Turkey. UBS Limited is not licensed by the Turkish Capital Market Board under the provisions of the Capital Market Law (Law No. 6362). Accordingly, neither this document nor any other offering material related to the instruments/services may be utilized in connection with providing any capital market services to persons within the Republic of Turkey without the prior approval of the Capital Market Board. However, according to article 15 (d) (ii) of the Decree No. 32, there is no restriction on the purchase or sale of the securities abroad by residents of the Republic of Turkey. **Poland:** Distributed by UBS Limited (spolka z ograniczona odpowiedzialnoscia) Oddzial w Polsce regulated by the Polish Financial Supervision Authority. Where an analyst of UBS Limited (spolka z ograniczona odpowiedzialnoscia) Oddzial w Polsce has contributed to this document, the document is also deemed to have been prepared by UBS Limited (spolka z ograniczona odpowiedzialnoscia) Oddzial w Polsce. **Russia:** Prepared and distributed by UBS Bank (OOO). **Switzerland:** Distributed by UBS AG to persons who are institutional investors only. UBS AG is regulated by the Swiss Financial Market Supervisory Authority (FINMA). **Italy:** Prepared by UBS Limited and distributed by UBS Limited and UBS Limited, Italy Branch. Where an analyst of UBS Limited, Italy Branch has contributed to this document, the document is also deemed to have been prepared by UBS Limited, Italy Branch. **South Africa:** Distributed by UBS South Africa (Pty) Limited (Registration No. 1995/011140/07), an authorised user of the JSE and an authorised Financial Services Provider (FSP 7328). **Israel:** This material is distributed by UBS Limited. UBS Limited is authorised by the Prudential Regulation Authority and regulated by the Financial Conduct Authority and the Prudential Regulation Authority. UBS Securities Israel Ltd is a licensed Investment Marketer that is supervised by the Israel Securities Authority (ISA). UBS Limited and its affiliates incorporated outside Israel are not licensed under the Israeli Advisory Law. UBS Limited is not covered by insurance as required from a licensee under the Israeli Advisory Law. UBS may engage among others in issuance of Financial Assets or in distribution of Financial Assets of other issuers for fees or other benefits. UBS Limited and its affiliates may prefer various Financial Assets to which they have or may have Affiliation (as such term is defined under the Israeli Advisory Law). Nothing in this Material should be considered as investment advice under the Israeli Advisory Law. This Material is being issued only to and/or is directed only at persons who are Eligible Clients within the meaning of the Israeli Advisory Law, and this material must not be relied on or acted upon by any other persons. **Saudi Arabia:** This document has been issued by UBS AG (and/or any of its subsidiaries, branches or affiliates), a public company limited by shares, incorporated in Switzerland with its registered offices at Aeschenvorstadt 1, CH-4051 Basel and Bahnhofstrasse 45, CH-8001 Zurich. This publication has been approved by UBS Saudi Arabia (a subsidiary of UBS AG), a Saudi closed joint stock company incorporated in the Kingdom of Saudi Arabia under commercial register number 1010257812 having its registered office at Tatweer Towers, P.O. Box 75724, Riyadh 11588, Kingdom of Saudi Arabia. UBS Saudi Arabia is authorized and regulated by the Capital Market Authority to conduct securities business under license number 08113-37. **UAE / Dubai:** The information distributed by UBS AG Dubai Branch is only intended for Professional Clients and/or Market Counterparties, as classified under the DFSA rulebook. No other person should act upon this material/communication. The information is not for further distribution within the United Arab Emirates. UBS AG Dubai Branch is regulated by the DFSA in the DIFC. UBS is not licensed to provide banking services in the UAE by the Central Bank of the UAE, nor is it licensed by the UAE Securities and Commodities Authority. **United States:** Distributed to US persons by either UBS Securities LLC or by UBS Financial Services Inc., subsidiaries of UBS AG; or by a group, subsidiary or affiliate of UBS AG that is not registered as a US broker-dealer (a **'non-US affiliate'**) to major US institutional investors only. UBS Securities LLC or UBS Financial Services Inc. accepts responsibility for the content of a document prepared by another non-US affiliate when distributed to US persons by UBS Securities LLC or UBS Financial Services Inc. All transactions by a US person in the securities mentioned in this document must be effected through UBS Securities LLC or UBS Financial Services Inc., and not through a non-US affiliate. UBS Securities LLC is not acting as a municipal advisor to any municipal entity or obligated person within the meaning of Section 15B of the Securities Exchange Act (the "Municipal Advisor Rule"), and the opinions or views contained herein are not intended to be, and do not constitute, advice within the meaning of the Municipal Advisor Rule. **Canada:** Distributed by UBS Securities Canada Inc., a registered investment dealer in Canada and a Member-Canadian Investor Protection Fund, or by another affiliate of UBS AG that is registered to conduct business in Canada or is otherwise exempt from registration. **Mexico:** This report has been distributed and prepared by UBS Casa de Bolsa, S.A. de C.V., UBS Grupo Financiero, an entity that is part of UBS Grupo Financiero, S.A. de C.V. and is a subsidiary of UBS AG. This document is intended for distribution to institutional or sophisticated investors only. Research reports only reflect the views of the analysts responsible for the reports. Analysts do not receive any compensation from persons or entities different from UBS Casa de Bolsa, S.A. de C.V., UBS Grupo Financiero, or different from entities belonging to the same financial group or business group of such. For Spanish translations of applicable disclosures, please go to www.ubs.com/disclosures. **Brazil:** Except as otherwise specified herein, this material is prepared by UBS Brasil CCTVM S.A. to persons who are eligible investors residing in Brazil, which are considered to be Investidores Profissionais, as designated by the applicable regulation, mainly the CVM Instruction No. 539 from the 13th of November 2013 (determines the duty to verify the suitability of products, services and transactions with regards to the client´s profile). **Hong Kong:** Distributed by UBS Securities Asia Limited and/or UBS AG, Hong Kong Branch. Please contact local licensed/registered representatives of UBS Securities Asia Limited and/or UBS AG, Hong Kong Branch in respect of any matters arising from, or in connection with, the analysis or document. **Singapore:** Distributed by UBS Securities Pte. Ltd. [MCI (P) 009/09/2018 and Co. Reg. No.: 198500648C] or UBS AG, Singapore Branch. Please contact UBS Securities Pte. Ltd., an exempt financial adviser under the Singapore Financial Advisers Act (Cap. 110); or UBS AG, Singapore Branch, an exempt financial adviser under the Singapore Financial Advisers Act (Cap. 110) and a wholesale bank licensed under the Singapore Banking Act (Cap. 19) regulated by the Monetary Authority of Singapore, in respect of any matters arising from, or in connection with, the analysis or document. The recipients of this document represent and warrant that they are accredited and institutional investors as defined in the Securities and Futures Act (Cap. 289). **Japan:** Distributed by UBS Securities Japan Co., Ltd. to professional investors (except as otherwise permitted). Where this document has been prepared by UBS Securities Japan Co., Ltd., UBS Securities Japan Co., Ltd. is the author, publisher and distributor of the document. Distributed by UBS AG, Tokyo Branch to Professional Investors (except as otherwise permitted) in relation to foreign exchange and other banking businesses when relevant. **Australia:** Clients of UBS AG: Distributed by UBS AG (ABN 47 088 129 613 and holder of Australian Financial Services License No. 231087). Clients of UBS Securities Australia Ltd: Distributed by UBS Securities Australia Ltd (ABN 62 008 586 481 and holder of Australian Financial Services License No. 231098). This Document contains general information and/or general advice only and does not constitute personal financial product advice. As such, the Information in this document has been prepared without taking into account any investor's objectives, financial situation or needs, and investors should, before acting on the Information, consider the appropriateness of the Information, having regard to their objectives, financial situation and needs. If the Information contained in this document relates to the acquisition, or potential acquisition of a particular financial product by a 'Retail' client as defined by section 761G of the Corporations Act 2001 where a Product Disclosure Statement would be required, the retail client should obtain and consider the Product Disclosure Statement relating to the product before making any decision about whether to acquire the product. The UBS Securities Australia Limited Financial Services Guide is available at: www.ubs.com/ecs-research-fsg. **New Zealand:** Distributed by UBS New Zealand Ltd. UBS New Zealand Ltd is not a registered bank in New Zealand. You are being provided with this UBS publication or material because you have indicated to UBS that you are a "wholesale client" within the meaning of section 5C of the Financial Advisers Act 2008 of New Zealand (Permitted Client). This publication or material is not intended for clients who are not Permitted Clients (non-permitted Clients). If you are a non-permitted Client you must not rely on this publication or material. If despite this warning you nevertheless rely on this publication or material, you hereby (i) acknowledge that you may not rely on the content of this publication or material and that any recommendations or opinions in such this publication or material are not made or provided to you, and (ii) to the maximum extent permitted by law (a) indemnify UBS and its associates or related entities (and their respective Directors, officers, agents and Advisors) (each a 'Relevant Person') for any loss, damage, liability or claim any of them may incur or suffer as a result of, or in connection with, your unauthorised reliance on this publication or material and (b) waive any rights or remedies you may have against any Relevant Person for (or in respect of) any loss, damage, liability or claim you may incur or suffer as a result of, or in connection with, your unauthorised reliance on this publication or material. **Korea:** Distributed in Korea by UBS Securities Pte. Ltd., Seoul Branch. This document may have been edited or contributed to from time to time by affiliates of UBS Securities Pte. Ltd., Seoul Branch. This material is intended for professional/institutional clients only and not for distribution to any retail clients. **Malaysia:** This material is authorized to be distributed in Malaysia by UBS Securities Malaysia Sdn. Bhd (Capital Markets Services License No.: CMSL/A0063/2007). This material is intended for professional/institutional clients only and not for distribution to any retail clients. **India:** Distributed by UBS Securities India Private Ltd. (Corporate Identity Number U67120MH1996PTC097299) 2/F, 2 North Avenue, Maker Maxity, Bandra Kurla Complex, Bandra (East), Mumbai (India) 400051. Phone: +912261556000. It provides brokerage services bearing SEBI Registration Numbers: NSE (Capital Market Segment): INB230951431, NSE (F&O Segment) INF230951431, NSE (Currency Derivatives Segment) INE230951431, BSE (Capital Market Segment) INB010951437; merchant banking services bearing SEBI Registration Number: INM000010809 and Research Analyst services bearing SEBI Registration Number: INH000001204. UBS AG, its affiliates or subsidiaries may have debt holdings or positions in the subject Indian company/companies. Within the past 12 months, UBS AG, its affiliates or subsidiaries may have received compensation for non-investment banking securities-related services and/or non-securities services from the subject Indian company/companies. The subject company/companies may have been a client/clients of UBS AG, its affiliates or subsidiaries during the 12 months preceding the date of distribution of the research report with respect to investment banking and/or non-investment banking securities-related services and/or non-securities services. With regard to information on associates, please refer to the Annual Report at: http://www.ubs.com/global/en/about_ubs/investor_relations/annualreporting.html**Taiwan:** Distributed by UBS Securities Pte. Ltd., Taipei Branch which is regulated by the Taiwan Securities and Futures Bureau. **Indonesia:** This report is being distributed by PT UBS Sekuritas Indonesia and is delivered by its licensed employee(s), including marketing/sales person, to its client. PT UBS Sekuritas Indonesia, having its registered office at Wisma GKBI, 22nd floor, JL. Jend. Sudirman, kav.28, Jakarta 10210, Indonesia, is a subsidiary company of UBS AG and licensed under Capital Market Law no. 8 year 1995, a holder of broker-dealer and underwriter licenses issued by the Capital Market and Financial Institution Supervisory Agency (now Otoritas Jasa Keuangan/OJK). PT UBS Sekuritas Indonesia is also a member of Indonesia Stock Exchange and supervised by Otoritas Jasa Keuangan (OJK). Neither this report nor any copy hereof may bedistributed in Indonesia or to any Indonesian citizens except in compliance with applicable Indonesian capital market laws and regulations. This report is not an offer of securities in Indonesia and may not be distributed within the territory of the Republic of Indonesia or to Indonesian citizens in circumstance whichconstitutes an offering within the meaning of Indonesian capital market laws and regulations.

The disclosures contained in research documents produced by UBS Limited shall be governed by and construed in accordance with English law.

UBS

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

March 23, 2020

Advice Letter 4168-E

Gary A. Stern
Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, CA 91770

SUBJECT: Implementation of Southern California Edison Company's 2020 Energy Resource Recovery Account Forecast Proceeding Revenue Requirement in Accordance with Decision 20-01-022

Dear Mr. Stern:

Advice Letter 4168-E is effective as of February 20, 2020

Sincerely,

Edward Randolph

Edward Randolph
Deputy Executive Director for Energy and Climate Policy/
Director, Energy Division

Gary A. Stern, Ph.D.
Managing Director, State Regulatory Operations

February 20, 2020

ADVICE 4168-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Implementation of Southern California Edison Company's 2020 Energy Resource Recovery Account Forecast Proceeding Revenue Requirement in Accordance with Decision 20-01-022

Southern California Edison Company (SCE) hereby submits to the California Public Utilities Commission (Commission or CPUC) the following changes to its tariffs. The revised tariff sheets are listed on Attachment A and are attached hereto.

PURPOSE

In accordance with Ordering Paragraph (OP) 9 of Decision (D.)20-01-022 (or the Decision), SCE is submitting this advice letter to implement its adopted 2020 Energy Resource Recovery Account (ERRA) Forecast revenue requirement and modify Preliminary Statement, Part ZZ, ERRA, to reflect the authorized generation service amount.

BACKGROUND

On June 3, 2019, SCE filed Application (A.)19-06-002, SCE's 2020 ERRA Forecast of Operations, and served associated testimony to request authorization of SCE's 2020 ERRA Forecast proceeding revenue requirement of $4.363 billion for incorporation into customers' rates in 2020. On July 5, 2019, SCE served supplemental testimony describing why a July 2019 update to the departing load / bundled service customer load forecast was no longer warranted. On September 13, 2019, SCE served updated testimony to reflect the implementation of SCE's 2018 General Rate Case (GRC) Phase 1 decision (D.19-05-020). On September 16, 2019, SCE conducted a public workshop to provide an overview of its 2020 ERRA Forecast application.

On November 8, 2019, SCE submitted testimony updating its 2020 ERRA Forecast revenue requirement and providing a true-up of its 2019 Cost Responsibility Surcharge (CRS) for incorporation into customers' rates in April 2020 (November Update). SCE's updated 2020 ERRA Forecast revenue requirement of $4.688 billion represented an increase of $324.7 million from the estimated 2020 ERRA Forecast revenue requirement submitted in the June 3, 2019 testimony, and a decrease of $180.3 million from the revenue requirement reflected in customers' 2019 ERRA rates.

2020 ERRA FORECAST PROCEEDING AUTHORIZED REVENUE REQUIREMENT

On January 16, 2020, the Commission adopted D.20-01-022, which authorized a 2020 ERRA Forecast revenue requirement of $4,715.582 million.[1] This represents a $50.603 million increase from the updated revenue requirement submitted in SCE's November Update to allow for a true-up of the Solar on Multifamily Affordable Housing (SOMAH) program for fiscal years 2016-2019. Consistent with testimony included in SCE's November Update, in this advice letter, SCE is updating the final 2019 year-end balances for the balancing accounts (BA) and memorandum accounts (MA) approved in the Decision.[2] Attachment B includes workpapers in support of the updated 2019 year-end balances.

Table 1, below, shows the change in the 2020 ERRA Forecast revenue requirement included in SCE's November Update and the 2020 ERRA Forecast revenue requirement as updated by the Decision and the final 2019 year-end BA and MA balances.

---

1 This amount includes Franchise Fees and Uncollectibles (FF&U).

2 Exhibit SCE-6, p. 66 ("SCE will include the actual December 31, 2019 year-end balancing account balances in the ERRA Forecast Proceeding revenue requirement rate change and advice letter submitted in compliance with a Commission decision in this proceeding.").

Table 1
Updated 2020 ERRA Forecast Proceeding Revenue Requirement
_($000)_

Line (a)	Description (b)	November Update (c)	Final BA/MA Balances and Decision Updates (d)	Change (e) = (d) - (c)
1.	**_Generation Service_**			
2.	Fuel and Purchased Power (includes GHG costs)			
3.	ERRA-related	$ 2,311,963	$ 2,311,963	$ -
4.	PABA-related	$ 1,415,868	$ 1,415,868	$ -
5.	GTSR-related	$ 2,032	$ 2,032	$ -
6.	ERRA Balancing Account	$ (17,452)	$ (22,882)	$ (5,430)
7.	PABA Balancing Account	$ 476,655	$ 543,608	$ 66,953
8.	Generator Refunds (net of litigation costs)	$ 1,558	$ 1,762	$ 204
9.	**TOTAL ERRA PROCEEDING GENERATION SERVICE**	**$ 4,190,624**	**$ 4,252,351**	**$ 61,727**
10.	**_Delivery Service_**			
11.	New System Generation Rate Component:			
12.	NSG Fuel and Purchased Power (includes GHG costs)	$ 645,659	$ 645,659	$ -
13.	NSG Balancing Account	$ 92,461	$ 85,914	$ (6,547)
14.	Total New System Generation	$ 738,120	$ 731,573	$ (6,547)
15.	Nuclear Decommissioning Rate Component:			
16.	Spent Nuclear Fuel	$ 4,382	$ 4,382	$ -
17.	Total Nuclear Decommissioning	$ 4,382	$ 4,382	$ -
18.	Distribution Rate Component			
19.	BRRBA-D F&PP	$ 11,396	$ 11,396	$ -
20.	GHG Allowance Revenues (includes SOMAH true-up)	$ (408,413)	$ (380,489)	$ 27,924
21.	Total Distribution	$ (397,017)	$ (369,093)	$ 27,924
22.	Public Purpose Programs Charge (PPPC)			
23.	PPPC F&PP (Includes TMNBC and LCR-PPP)	$ 80,092	$ 80,092	$ -
24.	TMNBC Balancing Account	$ 71,457	$ 71,884	$ 427
25.	Total Public Purpose Programs Charge	$ 151,549	$ 151,976	$ 427
26.	**TOTAL ERRA PROCEEDING DELIVERY SERVICE**	**$ 497,034**	**$ 518,838**	**$ 21,804**
27.	**TOTAL ERRA PROCEEDING REVENUE REQUIREMENT**	**$ 4,687,658**	**$ 4,771,189**	**$ 83,531**

The updates shown in Table 1 increase SCE's 2020 ERRA Forecast revenue requirement by $83.531 million, to $4.771 billion.

Generation Service

The Decision approves SCE's forecast Fuel and Purchase Power (F&PP) costs in the amount of $3,729.863 million.[3] The Decision also approves including the 2019 year-

[3] Decision, OP 1.

end balances from the ERRA BA,[4] Portfolio Allocation Balancing Account (PABA)[5] and the Energy Settlements Memorandum Account (ESMA).[6] These final balances are shown in Table 1, above.

A portion of the year-end balances comes from the $54.477 million revenue returned as a result of Commission approval of SCE's 2017 ERRA compliance application in D.19-10-039. This revenue return is credited to SCE's bundled service customers and 2017 vintage departing load customers on a pro-rate basis.[7] The Decision also approves the transfer of the 2019 ERRA BA overcollection to the 2019 vintage subaccount of the PABA.[8]

Delivery Service

The Decision approves SCE's forecast F&PP costs in the amount of $741.529 million, which consists of $645.659 million for the New System Generation (NSG) costs, $4.382 million in spent nuclear fuel costs, $11.396 million for economic Demand Response (DR) programs, and $80.092 million for both the Tree Mortality Non-Bypassable Charge (TMNBC) and SCE's Preferred Resources Pilot (PRP) #2.[9] The Decision also approves including the year-end balances from the NSGBA[10] and the TMNBCBA,[11] with the final balances shown in Table 1, above.

Pursuant to OP 9 of D.18-12-003 and Advice 3955-E,[12] SCE is establishing the TMNBC factor of the Public Purpose Programs Charge (PPPC), which is intended to recover the 2020 TMNBC revenue requirement of $122.061 million adopted by the Decision.[13] Attachment C provides the TMNBC rate design and rate calculation by customer class. The TMNBC rate component will be implemented in rates as part of the April 2020 consolidated rate change, as further discussed below.

---

[4] *Id.*, pp. 20-21.
[5] *Id.*, pp. 26, 30, 31-33.
[6] *Id.*, pp. 21-22.
[7] *See* Advice 4117-E, Implementation of the 2017 Energy Resource Recovery Account Review Proceeding in Accordance with Decision 19-10-039.
[8] Decision. pp. 20-21.
[9] *Id.*, OP 1.
[10] *Id.*, p. 34.
[11] *Id.*, p. 36. In approving SCE's request to recover expenses for record years 2017-2019 in its 2020 ERRA Forecast revenue requirement, the Decision directs SCE to submit the 2017-2019 record year changes transferred to the TMNBCBA in its 2019 ERRA compliance proceeding for reasonableness review.
[12] *See* Advice 3955-E, pp. 7-8.
[13] This revenue requirement includes both the 2020 forecast costs of $50.177 million plus the final 2019 year-end balance in the TMNBCBA of $71.884 million.

Greenhouse Gas (GHG) Costs, Revenues and Reconciliation

The Decision approves SCE's forecast GHG costs, revenues and reconciliation,[14] with modifications related to the SOMAH program, as follows:

- $251.256 million in GHG Cap-and-Trade costs;[15]
- $453.575 million in 2020 GHG forecast auction proceeds;[16] and,
- $380.489 million being returned to customers after setting aside funding for clean energy and energy efficiency (EE) programs, outreach and administrative costs.

SCE had proposed setting aside $45.358 million for the 2020 SOMAH program funding. However, the Decision reduces that amount by half ($22.679 million) to reflect that funding for SOMAH is only authorized for the first half of 2020. The Decision then orders a true-up of the SOMAH program from fiscal years 2016-2019, resulting in an additional $50.603 million set-aside. In aggregate, the adopted SOMAH set-aside is $73.282 million.[17] This results in $90.313 million in total clean energy and EE program set-asides and a total California Climate Credit return of $339.900 million. The Decision authorizes the amount of $36.92 per household for the California Climate Credit program to be returned to residential customers in 2020.[18] In accordance with OP 2 of the Decision, SCE has elected to round the semi-annual California Climate to $37.00 per household.

Cost Responsibility Surcharge

For departing load (DL) customers, the CRS is comprised of the Department of Water Resources (DWR) Bond Charge, the Power Charge Indifference Adjustment (PCIA) rates and the Competition Transition Charge (CTC). SCE included the 2020 Forecast CRS rates for DL customers in Appendix B of the November Update. These rates included the implementation of both D.18-10-019 and D.19-10-001. Attachment D to this advice letter includes updated CRS rates, which reflect the following:

- Updates to the final 2019 year-end balances in the ERRA BA and PABA, as reflected in Table 1, above.
- Updates to the utility-owned generation (UOG) capital and operations and maintenance (O&M) portion of the 2020 revenue requirement for the Legacy UOG and 2004-2009 subaccounts of the PABA to reflect D.19-12-056, the final

[14] Decision, OP 1.
[15] *Id.*, pp. 38, 41.
[16] This amount increases to $471.054 million in net auction proceeds after accounting for overcollection and FF&U.
[17] Decision, p. 50.
[18] *Id.*, p. 3.

decision in SCE's 2020 Cost of Capital proceeding (A.19-04-014).[19]

- The correction of an inadvertent formula error for the 2016 resource vintage in line 42 of the "IOU Portfolio by Resource Type" sheet.

As a result of these updates, SCE is now projecting a $72.531 million shortfall in DL revenues due to the implementation of capped PCIA rates. Attachment D includes the updated PCIA Undercollection Balancing Account (PUBA) "booking rates," which are used to record the revenue shortfall resulting from capped PCIA rates in the applicable PUBA subaccounts. The forecasted $72.531 million shortfall in DL customer revenues resulting from capped PCIA rates will be added to bundled service customers' generation rates. The actual amount "loaned" by bundled service customers to DL customers in 2020 will be tracked in the Bundled Service Financing (BSF) subaccount of the PUBA, with interest. SCE's seven percent trigger point related to capped PCIA rates is set at $29.060 million and the 10 percent trigger threshold is set at $41.514 million. As outlined in the Decision, if the revenue shortfall related to capped PCIA rates exceeds the seven percent trigger point, SCE is obligated to file an expedited PCIA trigger application (or advice letter) in accordance with D.18-10-019.[20]

Implementation

On April 13, 2020, SCE will implement its 2020 consolidated revenue requirement and rate change, which will include the 2020 ERRA Forecast revenue requirement, TMNBC and 2020 CRS rates discussed herein.[21] However, SCE proposes to implement the 2020 authorized semi-annual residential California Climate Credit in rates effective April 1, 2020, since, pursuant to D.13-12-003, these semi-annual credits must be provided in April and October of each year. In accordance with Preliminary Statement Part WW, SCE will submit the updated Billed Revenue Allocation Percentages Table associated with the implementation of this advice letter as part of the forthcoming consolidated revenue requirement and rate change advice letter.[22]

PROPOSED TARIFF CHANGES

In accordance with OP 9 of the Decision and the discussion above, SCE is modifying Preliminary Statement Part ZZ, ERRA, to reflect the adopted 2020 ERRA Forecast

---

[19] In the November Update (Exhibit SCE-6, p. 91), SCE noted that a final decision in A.19-04-014 would likely impact the UOG portion of the revenue requirement used in determining PCIA rates. Subsequent to submitting the November Update, on December 19, 2019, the Commission adopted D.19-12-056. SCE submitted Advice 4136-E on December 26, 2019 to implement the revenue requirement authorized in D.19-12-056. The Commission's Energy Division approved Advice 4136-E on February 6, 2020 with a January 1, 2020 effective date.

[20] Decision, pp. 60-61.

[21] This is consistent with the discussion included in Section 13 of the Decision (*i.e.,* "SCE anticipates implementation of the rate schedule[s] in this decision in April 2020, concurrent with removal of the 2018 ERRA BA under-collection of $824 million from its rates.").

[22] SCE anticipates submitting the consolidated advice letter on February 28, 2020.

Generation Service revenue requirement and system average ERRA generation rate applicable to bundled service customers. SCE will submit all other tariff sheets reflecting the adopted 2020 ERRA Forecast revenue requirement in the consolidated revenue requirement and rate change advice letter for rates effective in April 2020.

This advice letter will not cause the withdrawal of service or conflict with any other schedule or rule.

TIER DESIGNATION

Pursuant to OP 9 of the Decision, this advice letter is submitted with a Tier 1 designation.

EFFECTIVE DATE

This advice letter will become effective on February 20, 2020, the date submitted.

NOTICE

Anyone wishing to protest this advice letter may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice letter. Protests should be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, California 94102
E-mail: EDTariffUnit@cpuc.ca.gov

Copies should also be mailed to the attention of the Director, Energy Division, Room 4004 (same address above).

In addition, protests and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Gary A. Stern, Ph.D.
Managing Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Telephone (626) 302-9645
Facsimile: (626) 302-6396
E-mail: AdviceTariffManager@sce.com

Laura Genao
Managing Director, State Regulatory Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

There are no restrictions on who may submit a protest, but the protest shall set forth specifically the grounds upon which it is based and must be received by the deadline shown above.

In accordance with General Rule 4 of GO 96-B, SCE is serving copies of this advice letter to the interested parties shown on the attached GO 96-B and A.19-06-002 service lists. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-3719. For changes to all other service lists, please contact the Commission's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by submitting and keeping the advice letter at SCE's corporate headquarters. To view other SCE advice letters submitted with the Commission, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Erin Pulgar at (626) 302-2509 or by electronic mail at erin.pulgar@sce.com.

Southern California Edison Company

/s/ Gary A. Stern
Gary A. Stern, Ph.D.

GAS:ep:cm
Enclosures

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:
- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Darrah Morgan
Phone #: (626) 302-2086
E-mail: Darrah.Morgan@sce.com
E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE
ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 3927-E Tier Designation: 1

Subject of AL: Establishment of the Officer Compensation Memorandum Account Pursuant to Resolution E-4963

Keywords (choose from CPUC listing): Compliance, Memorandum Account

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Resolution E-4963

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: No. of tariff sheets: -4-

Estimated system annual revenue effect (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: See Attachment A

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: 3923-E

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

<table>
<tr>
<td rowspan="2">CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov</td>
<td>Name: Gary A. Stern, Ph.D.
Title: Managing Director, State Regulatory Operations
Utility Name: Southern California Edison Company
Address: 8631 Rush Street
City: Rosemead
State: California Zip: 91770
Telephone (xxx) xxx-xxxx: (626) 302-9645
Facsimile (xxx) xxx-xxxx: (626) 302-6396
Email: advicetariffmanager@sce.com</td>
</tr>
<tr>
<td>Name: Laura Genao c/o Karyn Gansecki
Title: Managing Director, State Regulatory Affairs
Utility Name: Southern California Edison Company
Address: 601 Van Ness Avenue, Suite 2030
City: San Francisco
State: California Zip: 94102
Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx: (415) 929-5544
Email: karyn.gansecki@sce.com</td>
</tr>
</table>

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

Cal. P.U.C. Sheet No.	Title of Sheet	Cancelling Cal. P.U.C. Sheet No.
Revised 68600-E	Preliminary Statements ZZ	Revised 66629-E
Revised 68601-E	Table of Contents	Revised 68567-E
Revised 68602-E	Table of Contents	Revised 68396-E

PRELIMINARY STATEMENT Sheet 8

(Continued)

ZZ. ENERGY RESOURCE RECOVERY ACCOUNT (Continued)

4. Tracking Mechanism

In accordance with Section XII.B.2 (page 65) of D.02-10-062, SCE shall track the difference between:

a. Recorded fuel and purchased power expenses in the ERRA; and
b. Annual fuel and purchased power expenses as adopted in D.02-04-016 (UG decision).

5. ERRA Forecast Proceeding Generation Service Adopted Fuel and Purchased Power Revenue Requirement and System Average Bundled Service Rate (T)

	2020 ($000)	
		(T)
Fuel and Purchased Power (includes GHG costs)		(T)
ERRA-Related	2,311,963	(N)
PABA-Related	1,415,868	|
GTSR-Related	2,032	| (N)
ERRA Balancing Account	(22,882)	(T)
PABA Balancing Account	543,608	(N)
Energy Settlement Refunds	1,762	(T)
ERRA Balancing Account Revenue Requirement	4,252,351	| | (T)

System Average ERRA Generation Rate
Applicable to Bundled Service Customers

Year	System Average Rate c/kWh	
2010	6.2	
2011	5.3	
2012	4.8	
2013	4.9	
2014	6.1	
2015	5.7	
2016	5.2	
2017	5.6	
2018	6.2	
2019	7.4	
2020	7.2	(N)

(Continued)

TABLE OF CONTENTS Sheet 1

Cal. P.U.C.
Sheet No.

PRELIMINARY STATEMENT:

(Continued)

TABLE OF CONTENTS Sheet 3

(Continued)

Cal. P.U.C.
Sheet No.

PRELIMINARY STATEMENT: (Continued)

(Continued)

Attachment B

2019

TABLE 1

Energy Resource Recovery Account
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Recorded October	Recorded November	Recorded December	Annual Summary
1.	**Beginning Balance**	815,432	768,745	949,424	927,214	960,371	1,066,906	635,810	376,828	222,644	205,382	115,432	58,486	815,432
2.	Transfers/Adjustments/Interest	(27,618)	-	505	-	221,993	66,678	-	-	84,241	-	16,718	(168)	362,350
3.	Adjusted Beginning Balance	787,814	768,745	949,929	927,214	1,182,364	1,133,584	635,810	376,828	306,885	205,382	132,151	58,318	1,177,782
4.	ERRA Revenue	(309,224)	(236,136)	(265,733)	(244,301)	(336,864)	(323,730)	(535,196)	(598,793)	(439,029)	(342,929)	(202,993)	(355,006)	(4,189,933)
5.	Expenses:													
6.	Fuel	7,349	26,944	13,875	5,975	50	154	171	156	(1,259)	-	-	-	53,415
7.	Purchased Power													
8.	CHP and Renewables[1/]	174,544	113,054	134,182	182,634	133,738	(325,576)	(49,839)	88,146	54,504	49,977	(63,338)	8,400	500,428
9.	Other Purchased Power[1/]	106,630	274,993	93,015	86,891	85,305	149,580	324,908	355,760	283,838	202,742	192,524	265,641	2,421,828
10.	Subtotal Purchased Power	288,522	414,992	241,072	275,501	219,093	(175,841)	275,241	444,062	337,084	252,719	129,185	274,041	2,975,670
	Less: FF&U													
11.	**Monthly (Over)/Under Collection**	(20,701)	178,855	(24,661)	31,200	(117,770)	(499,572)	(259,955)	(154,731)	(101,945)	(90,210)	(73,808)	(80,966)	(1,214,262)
12.	Total Interest:	1,633	1,824	1,946	1,956	2,312	1,797	974	547	441	260	143	24	13,857
13.	**Total ERRA Ending Balance**	**768,745**	**949,424**	**927,214**	**960,371**	**1,066,906**	**635,810**	**376,828**	**222,644**	**205,382**	**115,432**	**58,486**	**(22,624)**	**(22,624)**
14.	**Interest Rates**	2.52%	2.55%	2.49%	2.49%	2.47%	2.44%	2.31%	2.19%	2.07%	1.95%	1.80%	1.62%	

1/ "CHP and Renewables" line item includes Imputed REC Value Costs for Actual Retained RPS, and "Other Purchased Power Contracts" line item includes Imputed RA Value Costs for Actual Retained RA.

Transfer to PABA

Estimated ERRA Ending Balance	**(22,624)**
FF&U	**(258)**
Total ERRA w/ FF&U	**(22,881)**

2019

TABLE 2

Portfolio Allocation Balancing Account
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Recorded October	Recorded November	Recorded December	Annual Summary
1.	**Beginning Balance**	-	-	-	-	-	(172,433)	142,577	222,338	302,770	340,711	378,521	518,457	-
2.	Transfers/Adjustments/Interest	-	-	-	-	(221,993)	(93,666)	(7,936)	-	(84,427)	-	-	(2,891)	(410,913)
3.	Adjusted Beginning Balance	-	-	-	-	(221,993)	(266,099)	134,642	222,338	218,342	340,711	378,521	515,567	(410,913)
4.	Bundled Service PABA Revenue	-	-	-	-	-	(97,924)	(108,308)	(79,382)	(68,972)	(53,044)	(31,031)	(54,967)	(493,628)
5.	**Departing Load:**													
6.	PCIA Collected from departing load customers	-	-	-	-	-	(36,156)	(45,393)	21,108	(17,180)	(17,771)	(13,571)	(15,900)	(124,863)
7.	CTC collected from departing load customers	-	-	-	-	-	-	-	-	(921)	(1,014)	(784)	(906)	(3,624)
8.	PCIA Prepayments	-	-	-	-	-	-	-	-	-	-	-	(750)	(750)
9.	Current Month Accrual	-	-	-	-	-	-	-	(17,900)	(13,046)	(12,512)	(10,290)	(14,988)	(68,736)
10.	Last Month Reversal	-	-	-	-	-	-	-	-	17,900	13,046	12,512	10,290	53,748
11.	Change in Unbilled	-	-	-	-	-	-	-	(17,900)	4,854	534	2,222	(4,698)	(14,988)
12.	Subtotal - DL Revenue Transfer to PABA	-	-	-	-	-	(36,156)	(45,393)	3,208	(13,247)	(18,251)	(12,132)	(22,254)	(144,225)
13.	Less: Related FF&U	-	-	-	-	-	1,509	1,730	857	925	802	486	869	7,178
14.	**Total Revenue**	**-**	**-**	**-**	**-**	**-**	**(132,571)**	**(151,971)**	**(75,317)**	**(81,294)**	**(70,492)**	**(42,677)**	**(76,352)**	**(630,675)**
15.	Authorized Revenue (AL 4012-E)	-	-	-	-	-	57,939	77,032	95,467	83,616	69,790	39,504	36,870	460,219
16.	Utility Owned Generation	-	-	-	-	4,838	7,664	14,137	18,388	17,893	13,003	21,343	20,668	117,934
17.	Contracts	-	-	-	-	208,186	365,694	319,328	297,031	272,600	169,915	135,900	163,603	1,932,257
18.	Resource revenues													
19.	CAISO Market Revenues	-	-	-	-	(31,686)	(69,201)	(108,604)	(112,288)	(99,969)	(75,167)	(83,080)	(65,043)	(645,038)
20.	Bilateral Transactions of Products from Gen Res.	-	-	-	-	2,367	(2,550)	(6,062)	(4,816)	(4,676)	(2,298)	(8,159)	(14,614)	(40,808)
21.	Actual Retained RA Value Revenues	-	-	-	-	(24,312)	(24,312)	(27,184)	(61,410)	(28,196)	(33,463)	24,967	(54,426)	(228,336)
22.	Actual Retained RPS Value Revenues	-	-	-	-	(109,428)	350,056	(29,323)	(77,104)	(38,289)	(34,074)	51,467	10,495	123,801
23.	Common and Indirect Costs and Revenues	-	-	-	-	-	-	-	-	202	12	0	12	225
24.	**Total Expenses**	**-**	**-**	**-**	**-**	**49,966**	**627,351**	**162,292**	**59,802**	**119,565**	**37,928**	**142,438**	**60,695**	**1,260,036**
25.	**Total Over/Under Collection**	**-**	**-**	**-**	**-**	**49,966**	**552,718**	**87,353**	**79,953**	**121,887**	**37,226**	**139,264**	**21,213**	**1,089,580**
26.	Interest	-	-	-	-	(406)	21	343	479	482	584	672	710	2,886
27.	End of Month Transfers/Adjustment													
28.	2018 BRRBA Transfer (GRCMA Auth Rev Change)	-	-	-	-	-	(144,063)	-	-	-	-	-	-	(144,063)
29.	**Ending Balance**	**-**	**-**	**-**	**-**	**(172,433)**	**142,577**	**222,338**	**302,770**	**340,711**	**378,521**	**518,457**	**537,490**	**537,490**
30.	**Interest Rates**	2.52%	2.55%	2.49%	2.49%	2.47%	2.44%	2.31%	2.19%	2.07%	1.95%	1.80%	1.62%	

Estimated PABA Ending Balance	**537,490**
FF&U	**6,118**
Total PABA w/ FF&U	**543,608**

2019

TABLE 3

Energy Settlement Memorandum Account/Litigation Cost Tracking Account
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Forecast October	Forecast November	Forecast December	Annual Summary
1.	**Beginning Balance**	(29,661)	-	-	-	-	-	-	-	-	-	-	-	(29,661)
2.	Transfers/Adjustments/Interest	29,661	-	-	-	-	-	-	-	-	-	-	-	29,661
3.	Adjusted Beginning Balance	-	-	-	-	-	-	-	-	-	-	-	-	-
4.	**Monthly (Over)/Under Collection**													
5.	Total Refund Received (Cr)													
6.	Litigation Reimbursement Received	-	-	-	-	-	-	-	-	-	-	-	-	-
7.	Other Market Participant Amounts Paid	-	-	-	-	-	-	-	-	-	-	-	-	-
8.	Subtotal	-	-	-	-	-	-	-	-	-	-	-	-	-
9.	Settlement Refunds	-	-	-	-	-	-	-	-	-	-	-	-	-
10.	Total Amount to be Refunded to Customers	-	-	-	-	-	-	-	-	-	-	-	-	-
	Less: FF&U													
11.	Interest:	-	-	-	-	-	-	-	-	-	-	-	-	-
12.	**Ending Balance**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**	**-**
13.	**Interest Rates**	2.52%	2.55%	2.49%	2.49%	2.47%	2.44%	2.31%	2.19%	2.07%	1.95%	1.80%	1.62%	

Estimated ESMA Ending Balance	**-**
FF&U	**-**
Total ESMA w/ FF&U	**-**

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Recorded October	Recorded November	Recorded December	Annual Summary
14.	**LITIGATION COST TRACKING ACCOUNT**													
15.	**Beginning Balance**	2,043	4	159	268	480	654	846	961	1,052	1,233	1,353	1,534	2,043
16.	Transfer to PABA	(2,043)	-	-	-	-	-	-	-	-	-	-	-	(2,043)
17.	Adjusted Beginning Balance	-	4	159	268	480	654	846	961	1,052	1,233	1,353	1,534	-
18.	**Monthly (Over)/Under Collection**													
19.	Incurred Litigation Expense:													
20.	Law	139	155	109	211	172	191	-	-	258	3	418	111	1,766
21.	Accrual	(135)	-	-	-	-	-	113	89	(80)	116	(239)	95	(40)
22.	Subtotal	4	155	109	211	172	191	113	89	179	118	179	206	1,726
23.	Total Amount to be Recovered from Customers	4	155	109	211	172	191	113	89	179	118	179	206	1,726
24.	Interest:	0	0	0	1	1	2	2	2	2	2	2	2	16
25.	**Ending Balance**	**4**	**159**	**268**	**480**	**654**	**846**	**961**	**1,052**	**1,233**	**1,353**	**1,534**	**1,742**	**1,742**
26.	**Interest Rates**	2.52%	2.55%	2.49%	2.49%	2.47%	2.44%	2.31%	2.19%	2.07%	1.95%	1.80%	1.62%	

Estimated LCTA Ending Balance	**1,742**
FF&U	**20**
Total LCTA w/ FF&U	**1,762**

2019

TABLE 4

New System Generation Balancing Account
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Recorded October	Recorded November	Recorded December	Annual Summary
1.	**Beginning Balance**	(74,301)	(78,750)	(93,740)	(99,668)	(100,550)	(102,606)	(88,579)	(31,515)	38,947	92,071	91,595	100,155	(74,301)
2.	Transfers/Adjustments/Interest	-	-	(359)	-	350	19	-	-	-	-	-	-	10
3.	Adjusted Beginning Balance	(74,301)	(78,750)	(94,099)	(99,668)	(100,200)	(102,587)	(88,579)	(31,515)	38,947	92,071	91,595	100,155	(74,291)
4.	Revenue:													
5.	Billed	(32,860)	(28,690)	(30,167)	(28,503)	(31,474)	(32,290)	(42,457)	(47,490)	(43,175)	(42,340)	(31,868)	(37,214)	(428,527)
6.	Change in Unbilled													
7.	Current Month Accrual	(18,487)	(15,460)	(17,475)	(14,414)	(19,127)	(21,543)	(27,057)	(29,000)	(23,306)	(18,491)	(15,220)	(21,720)	(241,300)
8.	Last Month Reversal	15,878	18,487	15,460	17,475	14,414	19,127	21,543	27,057	29,000	23,306	18,491	15,220	235,458
9.	Change in Unbilled	(2,609)	3,027	(2,015)	3,061	(4,713)	(2,416)	(5,514)	(1,943)	5,694	4,815	3,271	(6,500)	(5,842)
10.	Less: FF&U	(407)	(294)	(369)	(292)	(407)	(391)	(540)	(556)	(422)	(422)	(322)	(492)	(4,915)
11.	NSGBA Revenue	(35,062)	(25,368)	(31,813)	(25,150)	(35,780)	(34,315)	(47,431)	(48,877)	(37,059)	(37,103)	(28,275)	(43,222)	(429,454)
12.	Authorized Peaker Rev. Rqm't	4,610	4,168	4,437	4,140	4,213	4,637	5,119	5,404	5,399	4,951	4,351	4,531	55,959
13.	Expenses	26,164	6,392	22,008	20,335	29,369	43,881	99,492	113,927	84,672	31,527	32,340	10,999	521,106
14.	**Monthly (Over)/Under Collection**	(4,288)	(14,807)	(5,368)	(674)	(2,198)	14,203	57,180	70,455	53,012	(626)	8,416	(27,693)	147,611
	Transfer to PABA													
15.	Total Interest:	(161)	(183)	(201)	(208)	(209)	(194)	(115)	7	113	149	144	117	(741)
16.	Aliso Canyon Energy Storage Transfer	-	-	-	-	-	-	-	-	-	-	-	12,368	12,368
17.	**Ending Balance**	**(78,750)**	**(93,740)**	**(99,668)**	**(100,550)**	**(102,606)**	**(88,579)**	**(31,515)**	**38,947**	**92,071**	**91,595**	**100,155**	**84,946**	**84,946**
18.	**Interest Rates**	2.52%	2.55%	2.49%	2.49%	2.47%	2.44%	2.31%	2.19%	2.07%	1.95%	1.80%	1.62%	

Estimated NSGBA Ending Balance	**84,946**
FF&U	**967**
Total NSGBA w/ FF&U	**85,913**

2019

TABLE 5

Tree Mortality Non-Bypassable Charge Balancing Account
(Thousands of Dollars)

Line No.	Description	Recorded January	Recorded February	Recorded March	Recorded April	Recorded May	Recorded June	Recorded July	Recorded August	Recorded September	Recorded October	Recorded November	Recorded December	Annual Summary
1.	**Beginning Balance**	-	-	-	-	-	62,144	67,081	70,074	75,041	78,501	81,142	67,773	-
	Transfers/Adjustments/Interest	-	-	-	-	58,819	-	-	-	-	-	(16,718)	-	42,101
2.	Adjusted Beginning Balance	-	-	-	-	58,819	62,144	67,081	70,074	75,041	78,501	64,424	67,773	42,101
3.	Sales for Resale	-	-	-	-	-	-	-	-	-	-	-	10	10
4.	CAISO Revenue	-	-	-	-	(964)	(1,156)	(973)	(328)	(1,410)	(1,345)	(1,792)	(1,984)	(9,954)
5.	Power Procurement Expenses	-	-	-	-	4,164	5,962	3,835	5,162	4,738	3,857	5,042	5,184	37,944
6.	**Current Under/(Over) Collection**	**0**	**0**	**0**	**0**	**3,200**	**4,806**	**2,862**	**4,834**	**3,328**	**2,511**	**3,250**	**3,209**	**28,000**
7.	**Interest Rate**	2.52%	2.55%	2.49%	2.49%	2.47%	2.44%	2.31%	2.19%	2.07%	1.95%	1.80%	1.62%	
8.	**Interest((Beg+End)/2*rate/12)**	**-**	**-**	**-**	**-**	**124**	**131**	**132**	**132**	**132**	**130**	**99**	**94**	**974**
	Less: FF&U													
9.	**Ending Balance**	**-**	**-**	**-**	**-**	**62,144**	**67,081**	**70,074**	**75,041**	**78,501**	**81,142**	**67,773**	**71,075**	**71,075**

Estimated TMNBCA Ending Balance	**71,075**
FF&U	**809**
Total TMNBCA w/ FF&U	**71,884**

Attachment C

TMNBC Rate Calculation

(a) TMNBCBA 2020 Revenue Requirement $ 122,061,000

	(b)	(c) = (a) x (b)	(d)	(e) = (c) / (d)
Rate Group	**12-CP Factors**	**TMNBCBA ($)**	**2020 ERRA System Sales Forecast (GWh)**	**TMNBC Rate ($/kWh)**
Domestic	43.06%	$ 52,554,663	27,012	$ 0.00195
GS-1	7.43%	$ 9,064,461	5,797	$ 0.00156
TC-1	0.05%	$ 58,420	57	$ 0.00102
GS-2	16.52%	$ 20,160,294	13,346	$ 0.00151
TOU-GS-3	8.60%	$ 10,496,592	7,463	$ 0.00141
TOU-8-SEC	8.61%	$ 10,509,082	8,056	$ 0.00130
TOU-8-PRI	5.59%	$ 6,823,085	5,440	$ 0.00125
TOU-8-SUB	6.34%	$ 7,732,664	5,983	$ 0.00129
TOU-8-Standby-SEC	0.09%	$ 106,300	187	$ 0.00057
TOU-8-Standby-PRI	0.19%	$ 227,174	674	$ 0.00034
TOU-8-Standby-SUB	0.39%	$ 472,764	2,379	$ 0.00020
TOU-PA-2	1.57%	$ 1,916,280	1,806	$ 0.00106
TOU-PA-3	1.21%	$ 1,474,493	1,452	$ 0.00102
Street Lighting	0.38%	$ 464,727	581	$ 0.00080
System	**100.00%**	**$ 122,061,000**	**80,234**	**$ 0.00152**

Evolution of the Net Energy Metering (NEM) Impact

CRRI Monterey Conference – June 2019

Authored By:

Reuben Behlihomji, Senior Manager – Modeling, Forecasting & Economic Analysis
Erin Pulgar, Senior Advisor – Rates
Southern California Edison (SCE)

Supporting Analysis Provided By:

Ray Liang, Rahab Mahfud, Hank Elgin, Sotan Im, Ruben Pardo and Kiphan Kan
Southern California Edison (SCE)

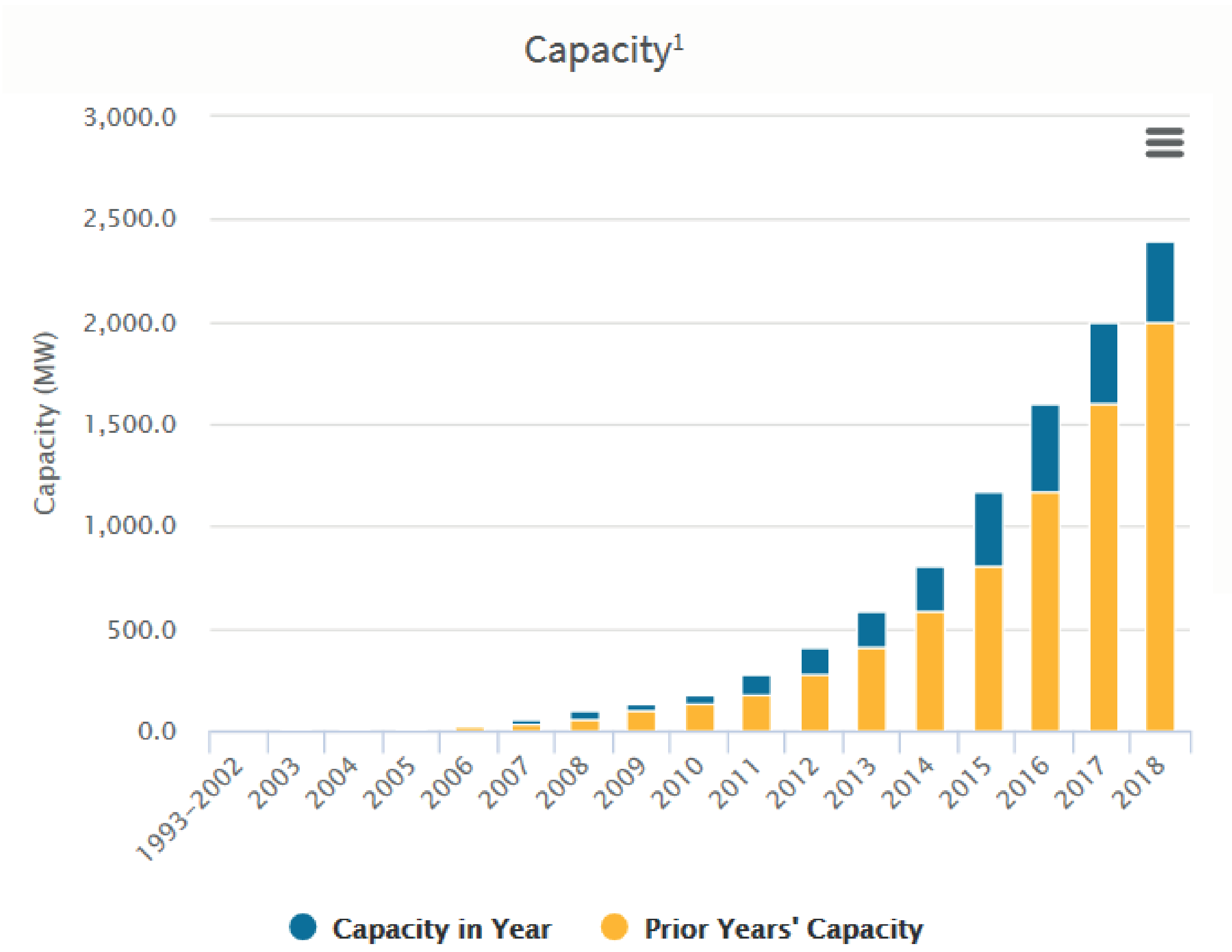
Note: The views and opinions expressed in this paper are for discussion purposes only and do not necessarily reflect official SCE positions in any proceeding.

Table of Contents

I. Introduction

California stands at the forefront in the fight against climate change, and has shown a deep commitment to achieving its climate change goals, in part, by requiring the decarbonization of the power sector by 2045 – at which time the state must obtain 100 percent of its electricity from clean sources such as solar, wind and hydropower.[1] California's leadership in the area of clean power and renewable energy dates back decades. In 1996, the state began a key policy of promoting the adoption of rooftop solar among individual customers by enacting legislation that required utilities to offer these customers compensation under a structure referred to as "net energy metering" (NEM). By most accounts, the use of the NEM compensation structure has been widely successful in facilitating the deployment of rooftop solar, as shown in Figure 1 below for Southern California Edison's (SCE) service territory through the end of 2018.

Figure 1 –
SCE's Distributed Generation Growth Over Time[2]



[1] Senate Bill (SB) 100 (De León, 2018).
[2] California Distributed Generation Statistics, at https://www.californiadgstats.ca.gov/. These figures include both residential and non-residential installations in SCE's service territory.

However, fast-forwarding from 1996 to 2019, grid conditions and the state of the rooftop solar industry have changed dramatically, but the policy of using NEM as the means to promote clean energy adoption at a localized level has remained virtually unchanged. As a result, the use of NEM has led to continually-increasing utility bills for customers who don't want to or are unable to utilize rooftop solar, and these bill impacts continue to grow at a significant and unsustainable rate.

Although little has changed with regard to the state's overall solar rooftop energy policy, more recent developments have helped to reduce the bill impacts that the NEM compensation structure has on non-adopting customers. The key factor driving this change was the passage of Assembly Bill (AB) 327 in 2013. AB 327 set in motion two necessary reform efforts:

1. Residential Rate Reform, and
2. NEM Reform.

Of the two, the modifications made to the residential retail rate structure in California over the last five years have had the biggest impact on mitigating the bill impacts of NEM borne by all customers. However, as demonstrated below, modifications to retail rates can only go so far, and tying rooftop solar compensation to retail rates can have unintended consequences. Therefore, to further reduce the rate and bill implications of rooftop solar on non-participating customers, meaningful reform of the rooftop solar compensation structure itself (*i.e.,* NEM) is needed.

To be clear, the intent and necessity of any future reform efforts is not to eliminate rooftop solar adoption or customer choice, or dramatically extend the payback period for new or existing rooftop solar system. Rooftop solar has played and will continue to play an important role in enabling California to achieve its clean energy goals, and customers should have the ability to be active participants in the state's clean power and electrification pathway. However, absent meaningful reform to the existing rooftop solar compensation structure, the likelihood of California achieving its overall decarbonization and wildfire mitigation efforts is threatened. The primary reason is affordability. Cleaning the power sector is only one component of decarbonization, and studies have shown that using rooftop solar is one of the most expensive means possible to do so.[3] Additionally, for California to meet its decarbonization target, significant emissions reductions are required from consumers of liquid and gas fuels in two other sectors – namely, the transportation and building sectors. One cost-effective way of achieving these necessary reductions is via the broad adoption of electrification technologies.[4] However, if electricity rates continue to be inflated to account for the unnecessarily high retail rate compensation currently paid for rooftop solar, the economics associated with increased electrification of the transportation and building sectors deteriorate to the detriment of California's decarbonization efforts. Finally, to mitigate the risks of future devastating wildfires caused by climate change, utilities are proposing increased investment in grid safety, reliability and resiliency measures. Rate structures that allow certain segments of customers to bypass these costs undermine these efforts by negatively impacting affordability for all customers.

[3] *See* "Preliminary RESOLVE Modeling Results for Integrated Resource Planning at the CPUC," dated July 19, 2017, at http://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/17/CPUC_IRP_Preliminary_RESOLVE_Results_2017-07-19_final.pdf, p. 137. *See also* "Lazard's Levelized Cost of Energy Analysis – Version 12.0," dated November 2018, at https://www.lazard.com/media/450773/lazards-levelized-cost-of-energy-version-120-vfinal.pdf.

[4] *See* SCE's "The Clean Power and Electrification Pathway: Realizing California's Environmental Goals, dated November 2017, at https://www.edison.com/home/our-perspective/clean-power-and-electrification-pathway.html.

In this paper, SCE examines the impact that recent residential rate and NEM reforms have had on the NEM revenue- and cost-shifts (referred to collectively as "NEM impacts") and evaluates various "toggles" that could be employed in either the underlying residential retail rate or distributed generation (DG) compensation structure, or both, to further rationalize the impact of rooftop solar adoption across all utility customers.[5]

II. Background

a. The Mechanics of NEM

At its core, NEM is a billing structure that uses the same retail energy (kWh) rate that a utility charges a customer for the services it provides as the compensation rate for energy generated by the customer's rooftop solar system. This is referred to as "full retail rate compensation." Customers who elect to participate in NEM are billed by the utility using a bi-directional, two-channel meter. Channel 1 of this meter records the energy supplied by the utility to serve load that is not served by the customer's rooftop solar system.[6] Channel 2 records the energy produced by the customer's rooftop solar system that exceeds the amount needed to serve on-site load at the time it is produced that is then exported to the utility's grid. When customers generate their own electricity, the customers' on-site electricity needs are served first. Any electricity not consumed onsite will be exported to the utility's grid. By participating in NEM, customers are able to offset the costs of the energy that is supplied by the utility with energy credits (valued at the full retail rate) that are received for the electricity that is exported by the customer's rooftop solar system to the utility's grid. Customers can use these retail rate energy credits to offset retail rate energy charges over a 12-month period.[7] The following graphics illustrate how the NEM billing structure works for residential customers on tiered and time-of-use (TOU) rates.

---

[5] While this paper focuses solely on the residential class and rooftop solar adoption, the NEM impacts discussed also apply to non-residential customers – though to a relatively lesser extent due to the fact that most non-residential rate structures recover revenue via multi-part rate design constructs (*e.g.,* fixed charges, volumetric energy charges, coincident and non-coincident demand charges) as opposed to purely volumetric rates. That said, the NEM impact from non-residential rooftop solar adoption is not insignificant and should similarly be considered and addressed as part of any future NEM reform efforts. Additionally, the NEM tariff is currently applicable to a number of behind-the-meter renewable technologies, but the focus of this paper is solely on rooftop solar adoption as that has overwhelmingly been the technology of choice installed by customers under the NEM program.

[6] A common misconception is that once a customer installs rooftop solar, they no longer rely on the utility for their electricity needs. In reality, on average, SCE still provides over 60 percent of a residential NEM customer's energy needs – particularly during times when the sun is not shining (*e.g.,* early morning, evening, night; rainy or overcast days).

[7] Other charges, including customer charges, demand charges, and other non-energy charges, cannot be offset by NEM credits. However, because demand charges are billed on Channel 1 usage – and Channel 1 usage can be reduced behind-the-meter to the extent the rooftop solar is producing coincident with the customer's high demand periods – demand charges can be reduced by the installation of rooftop solar, though this is not a result of the NEM credits received for exports (but, again, a result of reduced Channel 1 usage served by the utility).

Figure 2 –
Illustrative Example of a Residential Customer's 12-Month NEM 1.0 Relevant Period Energy Charges / Credits Only on a Tiered Rate (Schedule D)

Sample Relevant Period: October to September

	Month 1 Oct	Month 2 Nov	Month 3 Dec	Month 4 Jan	Month 5 Feb	Month 6 Mar	Month 7 Apr	Month 8 May	Month 9 Jun	Month 10 Jul	Month 11 Aug	Month 12 Sep	TOTAL Year
	Consumed	Consumed	Consumed	Consumed	Consumed	Consumed	Consumed	Consumed	Consumed	Consumed	Consumed	Consumed	Consumed
Channel 1 kWh	613	482	525	391	375	327	440	410	999	1160	1092	872	7686
	Exported	Exported	Exported	Exported	Exported	Exported	Exported	Exported	Exported	Exported	Exported	Exported	Exported
Channel 2 kWh	278	333	252	288	444	495	451	433	245	225	261	224	3929
	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed	Net Billed
Net Billed kWh	335	149	273	103	-69	-168	-11	-23	754	935	831	648	3757
	Energy Usage Charge	*Energy Usage Charge*	*Energy Usage Charge*	*Energy Usage Charge*	*Energy Usage Credit*	*Energy Usage Credit*	*Energy Usage Credit*	*Energy Usage Credit*	*Energy Usage Charge*	*Energy Usage Charge*	*Energy Usage Charge*	*Energy Usage Charge*	
Summer (Baseline Region 10)													
Tier 1 *(0 to 567 kWh at $0.19 / kWh)*									*$107.73*	*$107.73*	*$107.73*	*$107.73*	
Tier 2 *(568 to 2268 kWh at $0.24 / kWh)*									*$44.88*	*$88.32*	*$63.36*	*$19.44*	
HUC *(2269+ kWh at $0.42 / kWh)*													
Winter (Baseline Region 10)													
Tier 1 *(0 to 375 kWh at $0.19 / kWh)*	*$63.65*	*$28.31*	*$51.87*	*$19.57*	*($13.11)*	*($31.92)*	*($2.09)*	*($4.37)*					
Tier 2 *(376 to 1500 kWh at $0.24 / kWh)*													
HUC *(1500+ kWh at $0.42 / kWh)*													
Monthly Tracked Charge/Credit	**$63.65**	**$28.31**	**$51.87**	**$19.57**	**($13.11)**	**($31.92)**	**($2.09)**	**($4.37)**	**$152.61**	**$196.05**	**$171.09**	**$127.17**	**$758.83**
Cumulative Tracking	**$63.65**	**$91.96**	**$143.83**	**$163.40**	**$150.29**	**$118.37**	**$116.28**	**$111.91**	**$264.52**	**$460.57**	**$631.66**	**$758.83**	

Figure 3 –
Illustrative Example of a Residential Customer's 12-Month NEM 1.0 Relevant Period Energy Charges / Credits Only on a TOU Rate (Schedule TOU-D-4to9pm)

Sample Relevant Period: October to September

	Summer	Winter	Month 1 Oct	Month 2 Nov	Month 3 Dec	Month 4 Jan	Month 5 Feb	Month 6 Mar	Month 7 Apr	Month 8 May	Month 9 Jun	Month 10 Jul	Month 11 Aug	Month 12 Sep	TOTAL Year
Baseline kWh (Region 10)	567	375													
Consumed (Channel 1)															
On-Peak kWh											291	309	373	250	1223
Mid-Peak kWh			260	209	233	163	167	111	174	140	114	180	98	90	1939
Off-Peak kWh			248	225	264	208	197	209	230	233	594	671	621	532	4232
Super-Off-Peak kWh			105	48	28	20	11	7	36	37					292
															7686
Exported (Channel 2)															
On-Peak kWh											7	4	3	4	18
Mid-Peak kWh			5	1	1	1	4	28	29	38	3	1	4	3	118
Off-Peak kWh			1	10	4	2	9	6	5	5	235	220	254	217	968
Super-Off-Peak kWh			272	322	247	285	431	461	417	390					2825
															3929
Net															
On-Peak kWh											284	305	370	246	1205
Mid-Peak kWh			255	208	232	162	163	83	145	102	111	179	94	87	1821
Off-Peak kWh			247	215	260	206	188	203	225	228	359	451	367	315	3264
Super-Off-Peak kWh			-167	-274	-219	-265	-420	-454	-381	-353					-2533
Net Total (kWh)			335	149	273	103	-69	-168	-11	-23	754	935	831	648	**3757**
	Summer	**Winter**													
On-Peak	$ 0.40873										$ 116.08	$ 124.66	$ 151.23	$ 100.55	$ 492.52
Mid-Peak	$ 0.26423	$ 0.28891	$ 73.67	$ 60.09	$ 67.03	$ 46.80	$ 47.09	$ 23.98	$ 41.89	$ 29.47	$ 29.33	$ 47.30	$ 24.84	$ 22.99	$ 514.48
Off-Peak	$ 0.22095	$ 0.27554	$ 68.06	$ 59.24	$ 71.64	$ 56.76	$ 51.80	$ 55.93	$ 62.00	$ 62.82	$ 79.32	$ 99.65	$ 81.09	$ 69.60	$ 817.91
Super-Off-Peak		$ 0.16816	$ (28.08)	$ (46.08)	$ (36.83)	$ (44.56)	$ (70.63)	$ (76.34)	$ (64.07)	$ (59.36)					$ (425.95)
Baseline Credit	($0.06774)		$ (22.69)	$ (10.09)	$ (18.49)	$ (6.98)	$ 4.67	$ 11.38	$ 0.75	$ 1.56	$ (38.41)	$ (38.41)	$ (38.41)	$ (38.41)	$ (193.53)
Monthly Tracked Charge/Credit			$ 90.95	$ 63.17	$ 83.35	$ 52.03	$ 32.94	$ 14.95	$ 40.56	$ 34.49	$ 186.32	$ 233.20	$ 218.75	$ 154.73	$ 1,205.43
Cumulative Tracking			**$ 90.95**	**$ 154.12**	**$ 237.47**	**$ 289.49**	**$ 322.43**	**$ 337.38**	**$ 377.95**	**$ 412.44**	**$ 598.76**	**$ 831.96**	**$ 1,050.71**	**$ 1,205.43**	**$ 1,205.43**

Thus, the key to the NEM compensation structure is the customer's underlying retail rate – and, more specifically, the kWh (or volumetric) component of the retail rate. A higher kWh retail rate will result in higher compensation for the renewable energy produced by the customer's rooftop solar system. Conversely, a lower kWh retail rate will result in lower compensation. Said another way, the compensation provided under NEM has little to do with the actual value that the rooftop solar energy provides and everything to do with the retail rate under which the customer is billed for the services provided by the utility.

In California, residential rates are almost exclusively volumetric – meaning that all costs, including those that are fixed or demand driven – are recovered on a $-per-kWh basis. By including fixed and capacity-based costs in volumetric energy charges, the NEM compensation structure allows rooftop solar adopters to bypass almost all utility costs – even though certain portions of these costs may not be reduced at all by the solar energy provided by the rooftop solar system. This bypass of these non-avoided costs is then borne by all other utility customers, as further discussed below.

b. Residential Retail Rate Reform and Changing Grid Needs

The evolution of the NEM impact on other utility customers to-date is primarily the result of recent reforms to the residential retail rate structure. Dating back to 1976,[8] residential customers in California have been served on an "inclining block" tiered rate structure that relies almost exclusively on volumetric energy charges (kWh) to recover both the fixed and variable costs the utility incurs to provide safe and reliable electricity. Under this type of rate structure, customers are charged an increasing rate per kWh as they go up in each successive usage tier. Tier 1 is the lowest cost energy, often referred to as a customer's "baseline" amount.

As a result of the 2000-2001 energy crisis in California,[9] rate increases to a residential customer's lowest two tiers of energy usage were not permitted. This resulted in artificially higher rates in the remaining Tiers 3, 4 and 5, which provided an incentive – albeit not a cost-based one – for customers to reduce the amount of consumption billed at a utility's upper tier rates. And one of the ways higher usage (and generally higher income)[10] customers found to do this was by installing rooftop solar under the NEM program.

Residential rate freeze restrictions began to thaw slightly in 2009 with the passage of SB 395, which allowed limited increases to the Tier 1 and 2 rates, and with the adoption of D.10-05-051 in 2010, which consolidated Tiers 4 and 5 into a single Tier 4. However, the enactment of AB 327 in 2013 is what ultimately lifted many of the historical restrictions on residential rate design that had led to artificially low rates in the lowest tiers and artificially high rates in the upper tiers. The California Public Utilities Commission (Commission or CPUC) has utilized Rulemaking (R.)12-06-013[11] to implement many of AB 327's residential rate reform measures, including with the issuance of D.15-07-001. This decision resulted in further tier collapsing to two tiers,[12] an increased minimal bill,[13] a pathway to modifying residential fixed charges to remove some of the fixed cost recovery from volumetric rates,[14] and a pathway to

[8] A result of the Miller-Warren Energy Lifeline Act.

[9] On February 1, 2001, AB 1X was enacted and subsequently implemented by the Commission in D.01-05-064.

[10] In Appendix C, SCE provides demographic information on NEM customers in its service territory.

[11] *Order Instituting Rulemaking on the Commission's Own Motion to Conduct a Comprehensive Examination of Investor Owned Electric Utilities' Residential Rate Structures, the Transition to Time Varying and Dynamic Rates, and Other Statutory Obligations*, filed June 21, 2012.

[12] In addition to Tiers 1 and 2, the current tiered rate structure also includes a high usage charge (HUC), which effectively functions as a third tier. D.15-07-001 also adopted a tier differential glidepath (*i.e.,* the percentage of difference between the rates in each tier and how they change over time) and a composite tier ratio, which means that the customer charge is added to Tier 1 before determining the differential between tiers.

[13] The minimum bill was set at ~$5/month for income-qualified customers on the California Alternate Rates for Energy (CARE) program and ~$10/month for non-CARE customers.

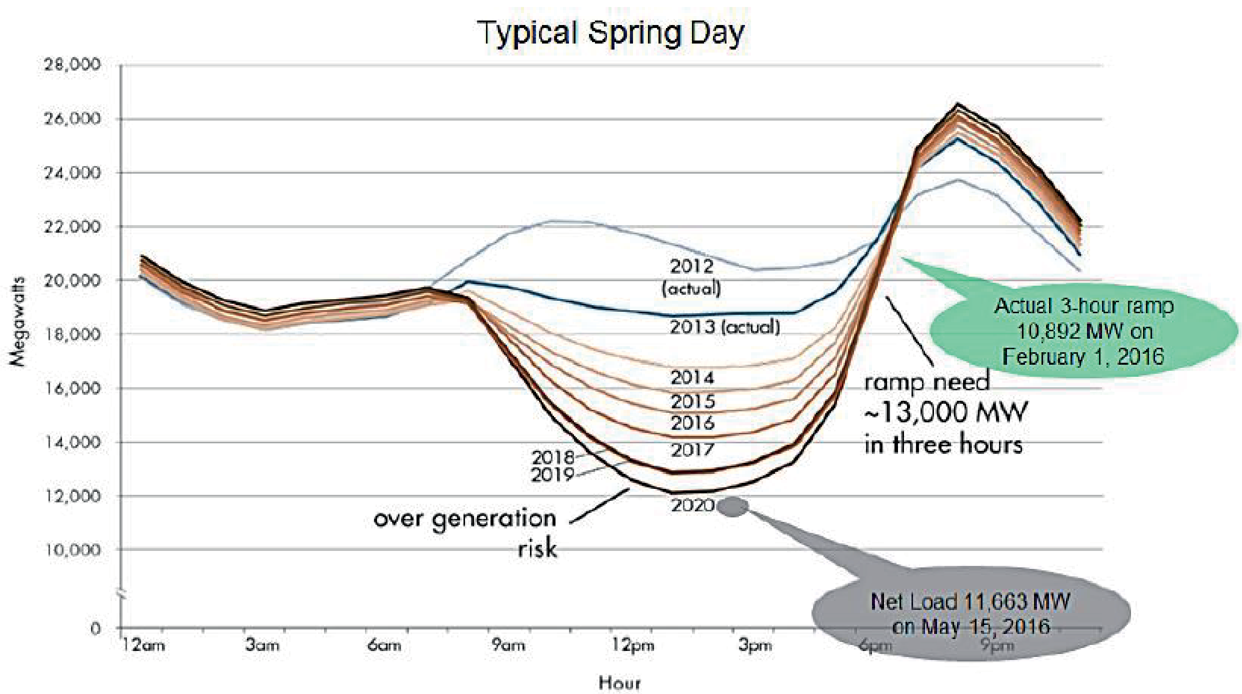
[14] SCE's existing fixed charge is ~$0.93/month for a single-family home. SCE has proposed to increase the fixed charge to $6.85 beginning in October 2021.

implementing default TOU rates.[15]

c. Changing TOU Periods and TOU Rates

In addition to (and sometimes in combination with) tiered rates, utilities also offer TOU rates. Unlike tiered rates, which increase based on increased consumption regardless of when that usage occurs, TOU rates vary by the time of day and season, and are generally regarded as being more cost-based because they work to align actual high cost periods with higher rates and actual lower cost periods with lower rates. For over three decades in California, utilities' TOU rates had been highest in the middle of the day (*e.g.,* June-September weekdays, 12-6 p.m.) and lower in all other periods. However, as a result of changing grid conditions that have occurred primarily due to the state's increased use of renewables[16], the highest cost-to-serve periods have now shifted to later in the day (*e.g.,* 4-9pm) and a new very low cost-to-serve period has emerged in the middle of the day (*e.g.,* October-May, 8am-4pm) that is supplied increasingly from carbon-free power. This phenomenon is reflected in the California Independent System Operator's (CAISO) "duck curve" graphic, which shows how the net load is changing in California due to the use of increased renewables.

Figure 4 –
CAISO's Duck Curve



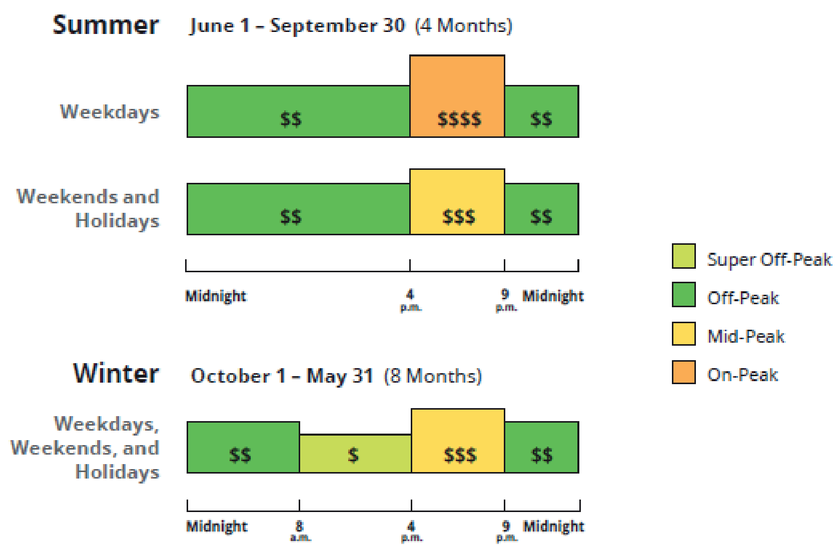
As a result, utilities have recently modified their TOU periods to reflect these changing grid conditions. The standard TOU periods now available to SCE's residential customers are shown in Figure 5, below.

---

[15] Default TOU rates are not the same as mandatory TOU rates. Under a default structure, absent another election, the customer is placed on a TOU rate but is not required to stay on a TOU rate (the latter, when a customer is required to stay on a TOU rate, is referred to as "mandatory TOU"). The three California IOUs are moving toward default TOU for residential customers in the 2020-2022 timeframe.

[16] Increased use of utility-scale and rooftop solar generation are the primary contributor to the duck curve

Figure 5 –
SCE's Standard TOU Periods as of March 1, 2019



However, the adoption and implementation of these more accurate TOU periods do not immediately impact existing rooftop solar customers. This is because the vast majority of existing NEM customers are not required to take service on a TOU rate.[17] And, for those who are, the Commission required five years of grandfathering on rates with legacy TOU periods,[18] which mutes the impact this change has on the NEM impact in the near-term.

d. Realigned NEM – aka "NEM 2.0"

In addition to allowing for meaningful reform to residential retail rates, AB 327 also required the Commission to develop a standard contract or tariff for customers with behind-the-meter (BTM) DG that adheres to the following key requirements:

- Must ensure that BTM DG continues to grow sustainably;
- Must be based on the costs and benefits of the BTM DG system; and,
- Must ensure that the total benefits to all customers and the electrical system are approximately equal to the total costs.[19]

[17] For SCE, only residential customers taking service on NEM on or after July 1, 2017 ("NEM 2.0" customers) are required to be served on a TOU rate.
[18] The legacy TOU periods bill at retail rates that are no longer aligned with the present day costs to serve (*e.g.,* the on-peak periods are either 12-6pm or 2-8pm, despite the fact that some of the lowest cost-to-serve hours now fall during those same hours).
[19] Public Utilities Code Section 2827.1(b). Notably, Section 2827.1(b)(7) also allows for fixed charges for residential DG customers that differ from any fixed charges adopted for all other residential customers, though the Commission must ensure that DG customers are provided electric service at rates that are just and reasonable.

In January 2016, the Commission adopted D.16-01-044, which established "realigned NEM" as an "interim" implementation of the standard contract or tariff required under AB 327. "Realigned NEM" is more commonly referred to as "NEM 2.0" (with the pre-D.16-01-044 program now referred to as "NEM 1.0"), and has the following key features for residential rooftop solar adopters:

- Requires that customers begin paying an interconnection fee, which is currently set at $75 for customers in SCE's service territory (with very limited exception, NEM 1.0 customers pay none of the utility costs incurred to interconnect their systems to the grid);[20]
- Minimally increases the kWh on which nonbypassable charges (NBCs) are applied; and, most significantly,
- Requires customers to take service on a TOU rate (referred to as "mandatory TOU").

In adopting realigned NEM, the Commission identified 2019 as the appropriate time to review NEM 2.0 to consider if further changes were warranted after more quantitative analysis could be completed on (1) the benefits of DG to the electrical system and all customers, and (2) a more accurate valuation of the services provided by the grid when the DG customer is importing power.[21]

SCE implemented NEM 2.0 in its service territory on July 1, 2017. However, due to the 20-year grandfathering provisions adopted by the Commission, the vast majority of existing NEM 1.0 customers are not required to transfer to NEM 2.0 (or any other successor tariff) until the 2030s.[22] NEM 2.0 customers received similar 20-year grandfathering provisions.[23] These 20-year grandfathering provisions only apply to the NEM compensation structure itself (*i.e.,* the netting of Channels 1 and 2), and not to the customers' underlying retail rate on which the NEM compensation is based.

III. NEM Impact Analyses

SCE recognizes that there are numerous ways to measure the impact that the NEM compensation structure has on both NEM participants and non-participants. To explore this topic more broadly, SCE performed both an "Avoided Cost" analysis and a "Cost-to-Serve" analysis, with the majority of the remaining narrative focused on the "Avoided Cost" approach.

a. Avoided Cost Analysis

Under the Avoided Cost analysis, SCE defines the "NEM impact" as the difference in rooftop solar customers' bills before installing solar compared to after installing solar, with avoided costs based on the rooftop solar generation credited back to the rooftop solar customer. To the extent that the rooftop solar customers' bill reductions are greater than the corresponding utility avoided cost savings, these customers will create a bill impact to other customers as utilities must adjust rates to compensate for the overall revenue recovery shortfall from rooftop solar adopters.

Under the Avoided Cost analysis, the revenue recovery shortfall is generally comprised of two parts: (1) a **revenue-shift** that occurs from load that is served onsite by the rooftop solar system instead of by the

[20] For customers with larger systems exceeding 1 MW served on NEM 2.0, the interconnection fee is $800 and other interconnection costs may apply, but this is not really applicable to the residential class given that NEM rooftop solar installations must be sized to not exceed a customer's annual energy usage.
[21] D.16-01-044, pp. 58, 60-61.
[22] D.14-03-041, Ordering Paragraph (OP) 2.
[23] D.16-01-044, Section 2.15.

utility (referred to as "onsite displacements"),[24] and (2) a **cost-shift** that occurs from using retail rate credits (which are higher than the utility avoided costs provided by exported rooftop solar generation) to compensate exported solar energy that are then used to offset other months' bills (referred to as "exports"). SCE purposely uses the terms "revenue-shift" and "cost-shift" differently here. A **"revenue-shift"** occurs when the amount of revenue that a utility collects from a customer is reduced by an act of the customer (*e.g.,* reducing usage), provided the customer's cost to serve remains relatively the same. This reduction in revenue must then be collected from other customers, which causes the other customers' bills to increase. A **"cost-shift"** occurs when the amount of revenue that a utility collects from a customer is reduced due to a rate and/or compensation structure that allows a customer to receive bill reductions that exceed the benefit provided by the customer. Again, those bill reductions must also be collected from other customers, which also causes other customers' bills to increase.

These two NEM impacts can be assessed in the aggregate or separately.[25] When assessed in the aggregate, the Avoided Cost analysis is referred to as "All Generation." When assessed separately to only look at the cost-shift portion, the Avoided Cost analysis is referred to as "Exports Only." These two analyses are summarized by the following formulas:

Avoided Cost Analysis (All Generation) =
Bill Savings of All Generation $_{\text{Avg Res Rooftop Solar Adopter}}$ – Avoid Costs of All Generation

Avoided Cost Analysis (Exports Only) =
Bill Savings of Exports Only $_{\text{Avg Res Rooftop Solar Adopter}}$ – Avoid Costs of Exports Only

The key benefit of the "All Generation" analysis is that it provides the most complete picture of the impact that the adoption of rooftop solar has on non-participating customers as both the revenue-shift and cost-shift associated with the NEM rooftop solar installation create an increase in the amount of revenues that must be collected from non-participants in the form of higher retail rates and bills. However, for comparison purposes, SCE has presented an "Exports Only" analysis in Appendix B for some of the results discussed below. This type of analysis can help ascertain and isolate the impacts of the NEM cost-shift that is largely based on the compensation rate provided for exports, and also reflects the fact that "revenue-shifting" is not unique to rooftop solar adoption and can occur due to various other reasons.

i. Avoided Costs

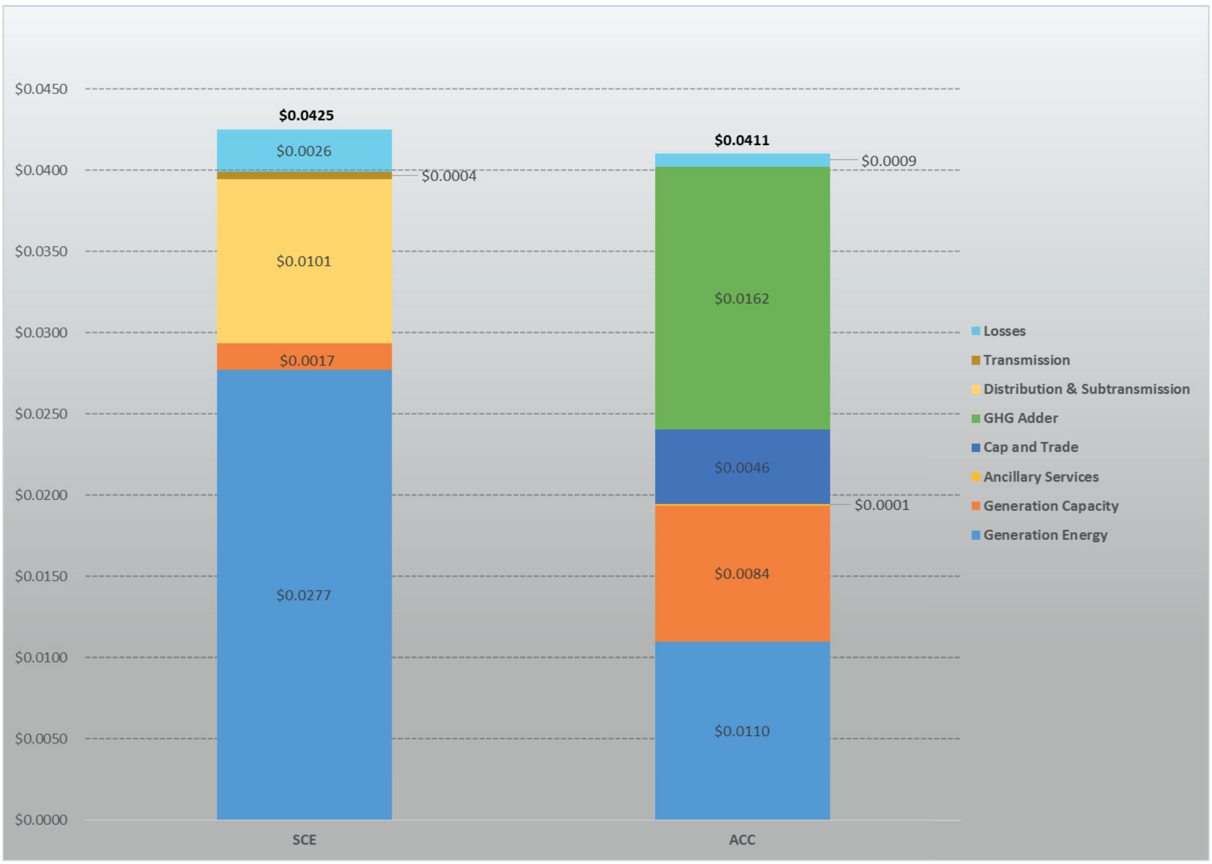
A key component of the Avoided Cost analysis is the determination of the costs that rooftop solar generation allows a utility to avoid. For this study, SCE computed utility avoided costs as the sum of all generation, transmission and distribution avoided costs inclusive of losses from a typical residential customer who installs rooftop solar – both for the "All Generation" and "Export Only" analyses. Generation and distribution avoided costs are based on the marginal cost analysis submitted in SCE's 2018

[24] A cost-shift can also occur from onsite displacements to the extent that a utility is not able to recover its costs (both marginal and/or embedded) to serve the rooftop solar adopter given the structure of the customer's retail rate. This is most likely to occur under all- (or close to all) volumetric rate structures, which is what is currently exists for residential customers in SCE's service territory.

[25] This is similar to the approach used by Energy and Environmental Economics, Inc. (E3) in its 2013 "California Net Energy Metering Ratepayer Impacts Evaluation," which was prepared for the Commission in accordance with AB 2514 (Bradford, 2012), and can be found at: http://www.cpuc.ca.gov/uploadedFiles/CPUC_Website/Content/Utilities_and_Industries/Energy/Reports_and_White_Papers/NEMReportwithAppendices.pdf.

General Rate Case (GRC) Phase 2 proceeding (A.17-06-030).[26] For transmission avoided costs, SCE used the cost analysis submitted in its 2016 Rate Design Window (RDW) proceeding (A.16-09-003).[27] SCE applied these cost factors to a normalized PV Watts hourly solar generation shape based on an average residential solar system size of 5.5 kW-DC (nameplate) with a total annual solar generation of 9,363 kWh.[28] As a sensitivity analysis, SCE also applied the cost factors from the Commission's avoided cost calculator (ACC). The results for both the All Generation and Exports Only scenarios are shown in Figures 6 and 7, below.[29]

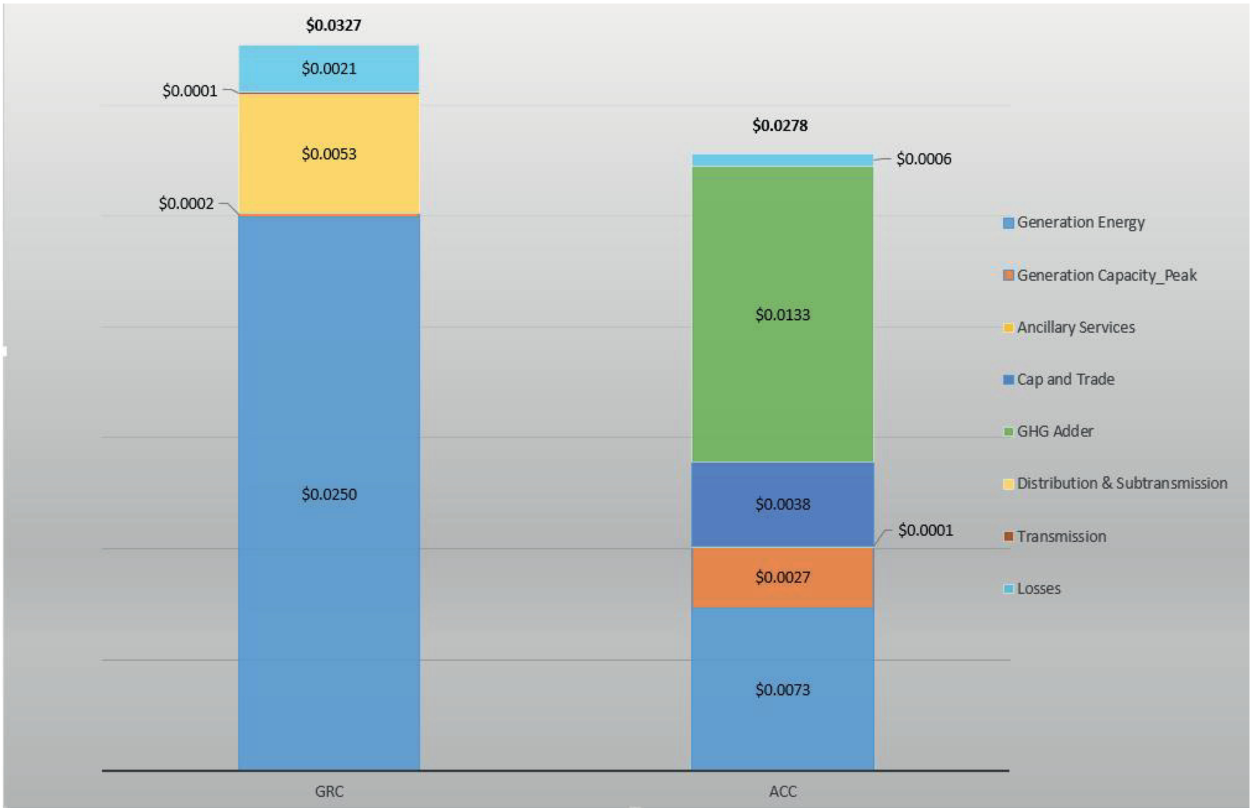
Figure 6 –
Avoided Cost of BTM Solar Generation ($/kWh) – All Generation Scenario



---

[26] A.17-06-030, Exhibit SCE-02A. (SCE's generation energy cost includes cap and trade and estimates of transmission congestion)
[27] A.16-09-003, Exhibit SCE-03, Section III-A.
[28] This analysis used a tilt of 14 degrees and an azimuth of 190 degrees (slightly southwest). The resulting capacity factor is 18.4 percent.
[29] Costs in the ACC are mostly generation-related. The cost factors used in the SCE analysis more broadly include distribution and transmission; however, they exclude the flex/ramp portion of generation capacity included in SCE's 2018 GRC Phase 2 analysis since the need for flex capacity is largely caused by the adoption of more renewables. All analyses use a reference year of 2021.

Figure 7 –
Avoided Cost of BTM Solar Generation ($/kWh) – Exports Only Scenario



Under the All Generation scenario analyses, a customer who adopts rooftop solar contributes approximately $0.04/kWh in utility avoided costs. This avoided cost amount is approximately five times lower than (*i.e.,* only 20 percent of) the current average compensation rate of approximately $0.19/kWh provided to residential NEM customers in SCE's service Under the Exports Only scenario, the contribution to utility avoided costs from a customer adopting rooftop solar is approximately $0.03/kWh. This is again about 80 percent less than the current average derived export compensation rate of approximately $0.16/kWh provided to residential NEM customers for exported rooftop solar generation.[30]

b. Cost-to-Serve Analysis

As a complement to the Avoided Cost analysis, SCE also completed a Cost-to-Serve analysis for rooftop solar adopters. A Cost-to-Serve analysis looks at the utility's costs to serve the average residential rooftop solar adopter before the customer installed DG along with the customer's pre-DG bill. This is then compared to the utility's cost to serve that same customer after the customer installed DG along with the customer's post-DG bill. This type of analysis is informative in assessing if a rate and/or compensation

[30] The average total compensation rate provided to NEM 2.0 residential customers served on TOU-D-4to9pm for both on-site displacements and exported energy is approximately $0.193/kWh. The effective compensation rate for exports only is ~$0.163/kWh. These compensation rates are higher for NEM 1.0 customers on tiered rates and NEM 2.0 customers on rates with legacy TOU periods.

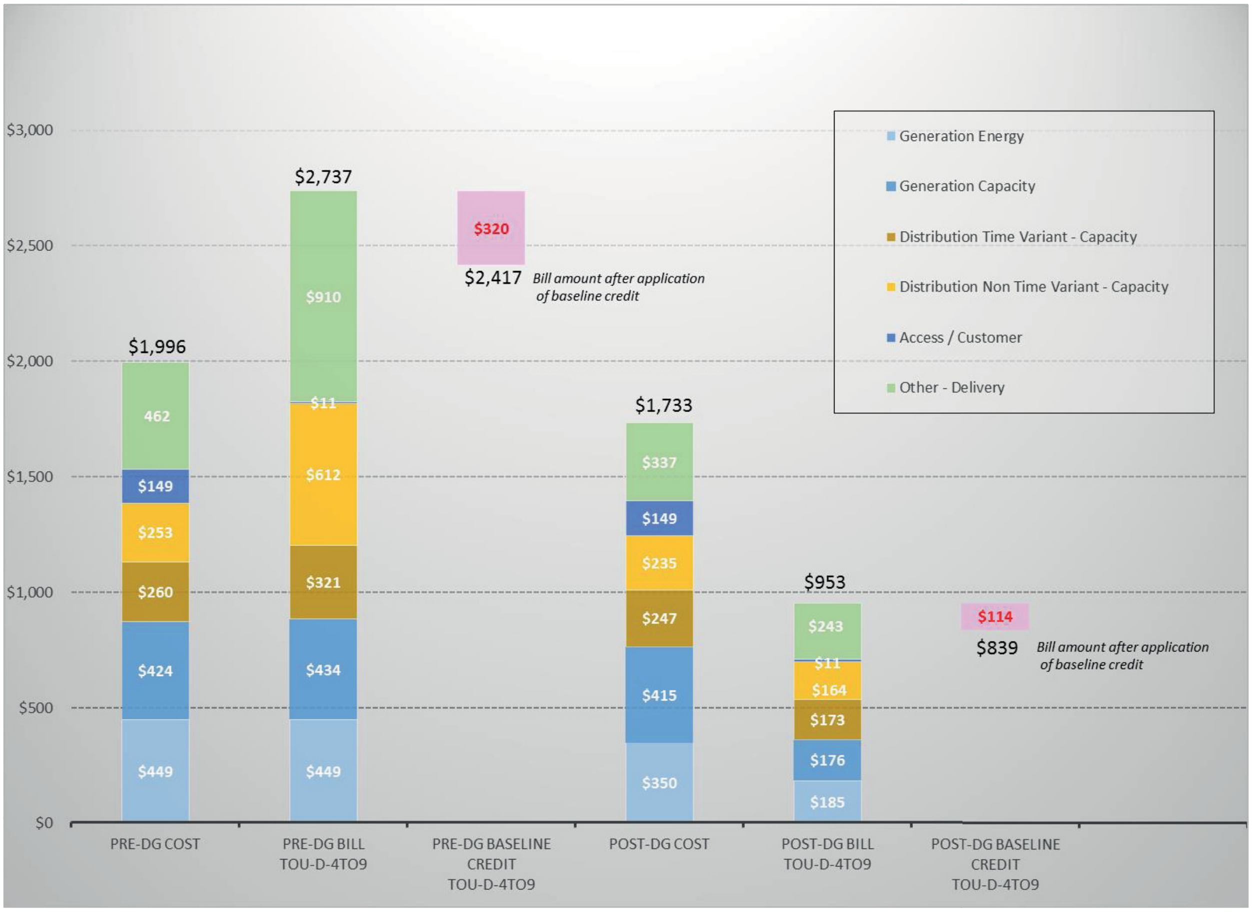
structure results in a utility fully recovering its marginal costs to serve a rooftop solar adopter (recognizing that utilities must recover embedded costs in addition to marginal costs).

This analysis used the 2014 recorded average residential load shape for customers who installed rooftop solar systems in SCE's service territory ("before DG load") and who then began service on SCE's NEM tariff in 2015. For the "after DG load," the 2016 recorded Channel 1 and Channel 2 metered data was then pulled for these same customers. The data was normalized to account for changes in weather between the two years. To determine SCE's cost to serve, SCE used cost factors that were developed using the marginal costs proposed in SCE's 2018 GRC Phase 2 proceeding and then applied these factors to the previously described usage dataset.[31] Non-marginal and nonbypassable costs were included in this analysis at the current retail rates. Both the pre- and post-DG bills use SCE's TOU-D-4to9pm rate option, which is the new default rate for NEM 2.0 customers in SCE's service territory as of March 1, 2019.

Figure 8, below, illustrates the effect of customers adopting rooftop solar on both SCE's cost to serve them and the amount the customer pays for these various functional services, both pre- and post-solar adoption. These functional cost changes are not in proportion to each other. For example, the rooftop solar system's energy production does not provide any access/customer cost savings and only limited generation capacity savings as the rooftop solar production is typically quite small at the time of the "net" system peak.

[31] Cost factors were scaled for revenue neutrality based on equal percent of marginal cost (EPMC) factors used in SCE's 2018 GRC Phase 2 filing.

Figure 8 –
Comparison of Typical Residential Solar Adopters Cost-to-Serve and Annual Electric Utility Pre- and Post-Solar Adoption[32]



As shown, the impact of a customer adopting rooftop solar reduces SCE's marginal cost to serve the customer by approximately 12 percent, from $1,996 before the installation of rooftop solar to $1,733 after installation.[33] However, under the NEM compensation structure, the customer's bill is reduced by approximately 65 percent, from $2,417 to $839 – well below SCE's cost to serve. In Section V.d, below, post-DG bill comparisons are provided for alternate retail rate designs and DG compensation structures.

---

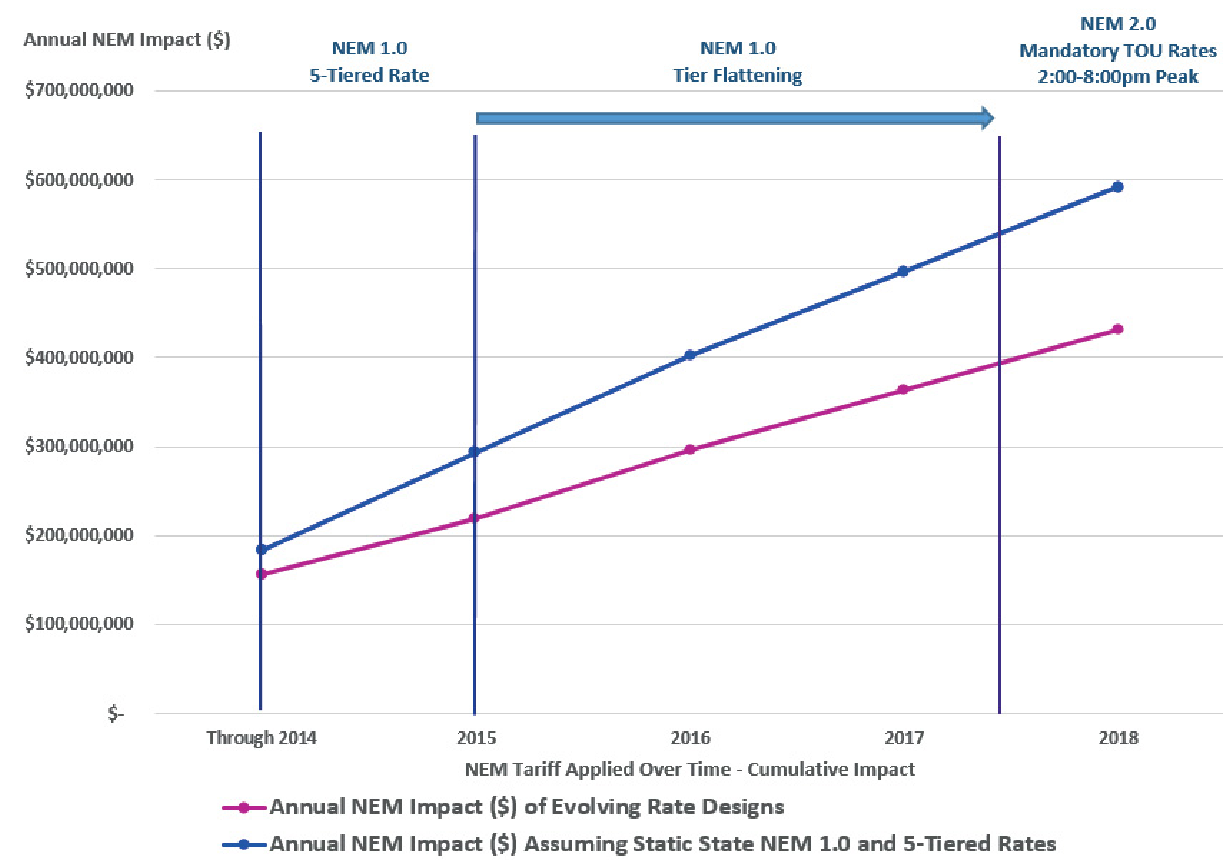
[32] The following items are included in the "Other – Delivery" category: Transmission, Transmission Owner Tariff Charge Adjustments (TOTCA), New System Generation (NSG), Nuclear Decommissioning (NDC), Department of Water Resources (DWR) Bond, Public Utilities Commission Reimbursement Fee (PUCRF), California Solar Initiative / Self-Generation Incentive Program (CSI/SGIP), Public Purpose Programs Charge (PPPC), CARE surcharge, and the baseline credit surcharge.

[33] SCE recognizes that the average residential customer adopting rooftop solar paid more than their marginal cost-to-serve pre-installation, if they had been served on the TOU-D-4to9pm rate (there are other rate options available). This is primarily the result of the all-volumetric rate structure currently in place for residential rates and the fact that SCE's total revenue requirement includes embedded costs that are higher than the utility's marginal costs. Customers who have installed solar tend to have higher-than-average usage compared to the residential class as a whole, and therefore don't fare as well under all-volumetric rate structures pre-installation.

IV. Evolution of the NEM Impact To-Date

As discussed above, various changes to the underlying residential retail rate structure and the implementation of NEM 2.0 (with its mandatory TOU requirement) have occurred over the last five years. The annual impact of these reforms on the NEM impact to non-adopters is shown as the pink line in Figure 9, below.[34] For comparison purposes, the top blue line illustrates the annual NEM impact to non-adopters if no reforms had occurred. (*i.e.,* a five-tier underlying retail rate structure + NEM 1.0 had remained in place throughout the analyzed period).[35]

Figure 9 –
Evolution of the Annual NEM Impact To-Date Based on Residential Retail Rate and NEM 2.0 Reforms



In addition to providing a total cumulative annual NEM impact to non-adopters over time, Figure 10, below, also shows the NEM impact by $/installed rooftop solar kW-yr. Since the average residential system size in SCE's service territory is 5.5 kW-DC, the overall per customer NEM impact (*i.e.,* the combination of the revenue-shift and cost-shift that must be recovered from customers) is the $/installed kW-yr amount multiplied by 5.5 kW. When reviewing this analysis, it is important to understand that, unlike in Figure 9, above, which shows the cumulative impact of the various rates and DG compensation structures that NEM customers are actually served on given grandfathering, the $/installed kW-yr figures

[34] Note that this comparison only shows the reform impact through 2018, and therefore does not reflect the move to updated TOU periods that implemented on March 1, 2019 in SCE's service territory.
[35] These results generally align with E3's findings in its previously cited 2013 "California Net Energy Metering Ratepayer Impacts Evaluation" Report.

used throughout this paper assume that all NEM customers are served on the "Post-Solar DG Tariff + Retail Rate" noted in the table below. In reality, only a very small portion of current NEM customers are served on the final "NEM 2.0 + TOU-D-4to9pm" step due to grandfathering.

Figure 10 –
Evolution of the NEM Impact To-Date ($/installed kW-yr)

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual NEM Impact per Installed kW ($/yr) (All Generation)	Annual NEM Impact per Adopter ($/yr) (All Generation)
5-Tiered Retail Rate	NEM 1.0 + 5-Tiered Rate	($322)	($1,771)
Initial 2-Tiered Rate w/ HUC	NEM 1.0 + Initial 2-Tiered Rate w/ HUC	($282)	($1,551)
Glidepath 2-Tiered Rate w/ HUC	NEM 1.0 + Glidepath 2-Tiered Rate w/ HUC	($268)	($1,474)
Glidepath 2-Tiered Rate w/ HUC	NEM 2.0 + TOU-D-A	($267)	($1,469)
TOU-D-4to9pm	**NEM 2.0 + TOU-D-4to9pm**	**($243)**	**($1,337)**

This metric is useful in isolating how the various reform efforts have impacted the NEM impact to non-participants, as follows:[36]

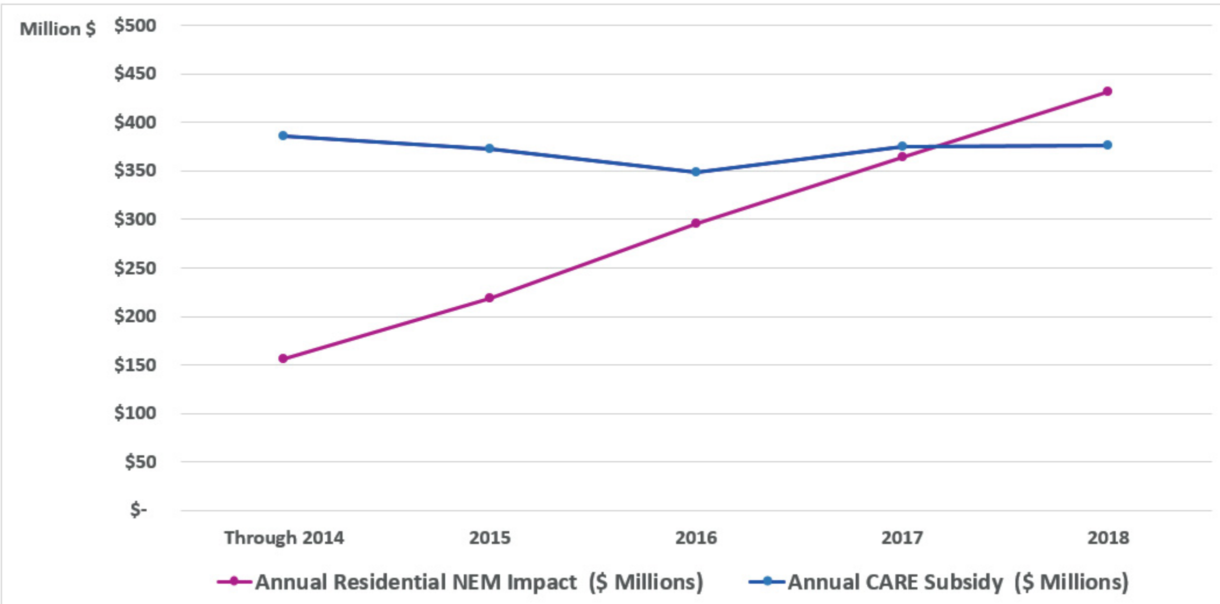
- Under the original five-tier rate structure and NEM 1.0, the average non-adopter impact was $322/installed kW-yr. For an average 5.5 kW-DC residential rooftop solar system, this equates to $1,771 per average residential NEM customer per year – meaning this is the total additional amount per NEM customer that non-adopters would have to absorb via increased rates and utility bills.
- By moving to a more cost-based two-tiered rate structure, the non-adopter impact was reduced by over 18 percent, to $268/installed kW-yr.
- The implementation of NEM 2.0 under the legacy 2-8pm TOU-D-A rate option had minimal impact. This highlights an additional issue with tying rooftop solar compensation to retail rates. Often, retail rates (especially new ones) are modified to mitigate bill impacts and help ensure rate stability over time, as opposed to being purely cost-based from the onset. This can have the unintended consequence of muting intended NEM reform measures that rely on underlying retail rate changes.
- However, with the implementation of the updated TOU periods that better reflect high- and low-cost-to-serve periods (*i.e.,* SCE's TOU-D-4to9pm rate) coupled with the NEM 2.0 mandatory TOU requirement, the impact to non-adopters is further reduced to $243/installed kW-yr.

To summarize, the reforms to both the underlying residential retail rate structure and the mandatory TOU requirement implemented under NEM 2.0 (provided customers are served on TOU periods that align with costs) have resulted in a decrease in the impacts to other customers of approximately 28 percent (from $322/installed kW-yr to $243/installed kW-yr). While this is meaningful progress toward reducing the bill impacts borne by non-adopters, it still results in an annual NEM impact of over $400 million – which will continue to increase year over year if more rooftop solar is installed under the current NEM program. In fact, as shown in Figure 11, below, the current annual NEM impact to non-adopters resulting from approximately 300,000 NEM customers now exceeds the annual subsidy provided to SCE's lowest income customers (representing approximately 1.2 million customers), who are served on the CARE program.[37]

---

[36] Again, these represent the "All Generation" Avoided Cost analysis. The "Export Only" Avoided Cost analysis is provided in Appendix B.
[37] Residential CARE customers receive an effective discount of 32.5 percent off their utility bills.

Figure 11 –
Comparison of Annual Residential NEM Impact and CARE Subsidy



V. <u>Continued Evolution</u>

The following section of this paper examines various rate design "toggles" that could be explored to better rationalize the compensation provided to rooftop solar adopters and further reduce the bill impacts to non-adopters discussed above. Again, the benefit in doing this is both in affordability considerations for all customers and removing potential roadblocks to the achievement of the state's decarbonization and climate change goals. SCE does not necessarily support the adoption of all of these toggles, recognizing that some are likely more feasible, understandable and/or implementable than others, but rather tested these various rate options to better learn and understand the potential impacts.

a. <u>NEM 2.0 + Further Modifications to the Retail Rate Structure</u>

In this first set of scenarios, SCE kept the NEM 2.0 compensation structure in place and only modified the underlying retail rate structure. SCE tested the following residential retail rate design toggles as modifications to the TOU-D-4to9pm rate structure:

- **Increased Customer Charge**[38] ($1, $6.85, $10.09, $15.15): a fixed monthly customer charge does not vary by customer usage and is applied to a customer's bill on a $/day or $/month basis. SCE's current residential customer charge is a little under $1/month. As part of its 2017 Residential RDW Application (A.17-12-011, et al.), SCE has proposed to increase this charge for most

[38] Sacramento Municipal Utility District (SMUD) currently has $20 monthly fixed charge of $20

residential customers to approximately $6.85/month beginning in 2021.[39] However, if the marginal customer costs presented in SCE's 2018 GRC Phase 2 were used to establish the monthly customer charge, the amount would be $10.09. SCE also tested a monthly customer charge of $15.15, which is the EPMC-scaled version of the $10.09 amount.[40]

- **Increased Minimum Bill Charge** ($10, $30, $50): the minimum bill charge applies, per billing period, when the combination of the delivery service energy (kWh) charges and the customer charge is less than the minimum charge. For example, if a NEM customer net generates in a month such that the delivery service energy charges are $0 or a credit, and the $1 customer charge is applied, under a $10 minimum bill construct, a $9 "balance of minimum" charge is applied to the customer's bill so that the customer pays a minimum of $10 that month.[41]
- **New Facilities-Related Demand (FRD) Charge** (0%, 50%, 100%): an FRD charge is applied to the highest level of demand (kW) recorded during a customer's billing period, regardless of when that peak demand occurs. None of SCE's existing residential rates have an FRD charge. For these scenarios, SCE moved recovery of the corresponding percentage (*i.e.,* 0%, 50% or 100%) of fixed distribution costs (all distribution grid costs[42] + residual customer costs) to an FRD charge.
- **New Time-Related Demand (TRD) Charge** (0%, 25%, 50%, 100%): a TRD charge is applied to the highest level of demand (kW) recorded during a specific TOU period. None of SCE's existing residential rates have a TRD charge. For these scenarios, SCE moved recovery of the corresponding percentage (0%, 25%, 50% or 100%) of generation capacity costs to a TRD charge applied to the summer on-peak (weekdays, 4-9pm) and winter mid-peak (4-9pm) periods.
- **New Daily Demand Charge**: a daily demand charge is applied to the highest level of demand (kW) recorded during each day in the monthly billing period. It can be designed to function as an FRD, meaning it doesn't matter when the highest demand occurs in each day, or like a TRD, where the highest demand in only certain TOU periods within the day is subject to the charge. None of SCE's existing residential rates have a daily demand charge. For these scenarios, SCE moved recovery of 100 percent of the grid component of distribution marginal costs into a daily demand charge that is not time-sensitive (*i.e.,* FRD-type of daily demand charge).

For all of these scenarios, SCE started with the TOU-D-4to9pm rate proposed in a Settlement Agreement in SCE's 2017 Residential RDW proceeding.[43] TOU-D-4to9pm is a TOU rate structure that includes two seasons (summer and winter), SCE's updated TOU periods (*e.g.,* 4-9pm peak periods, 8am-4pm winter super-off-peak period) and a baseline credit (BLC).[44] This rate also includes peak load risk factor (PLRF)

---

[39] *See* Supplemental Testimony on Impact of Federal Tax Legislation on Proposed Rates and Fixed Charges, submitted March 29, 2019 in A.17-12-011, et al.

[40] Because a utility's marginal costs are often less than the total approved revenue amount that must be collected from customers to operate the utility (*e.g.,* to recover embedded costs), EPMC scalers are used to assign the recovery of embedded costs to each customer group based on each group's percentage share of marginal costs.

[41] The generation portion of the bill is not impacted/considered under the existing minimum bill construct.

[42] In its 2018 GRC Phase 2 proceeding, SCE bifurcated distribution marginal costs between two functions: (1) a peak capacity function to meet time-sensitive peak customer demand, and (2) a grid or network function that enables the bi-directional transfer of energy to and from customers. The distribution costs associated with the grid function are the portion being recovered by the FRD charge in this analysis.

[43] All rates used in this analysis are included in Appendix A.

[44] The BLC applies up to 100 percent of the customer's baseline allocation, regardless of TOU. In D.15-07-001, the Commission provided its rationale for including a baseline credit in default TOU rates, as follows (pp. 136-137): "The most important [reason for including a BLC] is that, because the baseline amount takes into account the climate zone in which the customer lives in, including a baseline credit allows the TOU rate to be differentiated by climate zone. Second, a baseline credit will provide more opportunity for low usage customers to benefit from a TOU rate.

flattening of the peak distribution costs across TOU periods,[45] the "composite methodology" for determining the BLC,[46] and a one cent average rate seasonal delta.

Figure 12, below, shows the results to the $/installed kW-yr non-adopter impact when the various toggles outlined above are added to the TOU-D-4to9pm rate.[47] In all cases, the starting point of the NEM impact is $243/installed kW-yr (*i.e.,* existing impact today). The amount the other numbers deviate from $243 demonstrates the impact of that toggle on the NEM impact to other customers.

Figure 12 –
NEM Impact Under Various Residential Retail Rate Design Toggles ($/Installed kW-yr)

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual NEM Impact per Installed kW ($/yr) (All Generation)			
TOU-D-4to9pm	NEM 2.0 + TOU-D-4to9pm (Current)	**Current (Starting Point)** **($243)**			
TOU-D-4to9pm	Current + Customer Charge Toggle	**Current ($1 Cust Charge)** ($243)	**$6.85 Cust Charge** ($238)	**$10.09 Cust Charge** ($236)	**$15.15 Cust Charge** ($232)
TOU-D-4to9pm	Current + Minimum Bill Toggle	**Current ($10 Min Bill)** ($243)	**$30 Min Bill** ($238)	**$50 Min Bill** ($228)	
TOU-D-4to9pm	Current + FRD Toggle	**Current (0% FRD)** ($243)	**50% FRD** ($239)	**100% FRD** ($235)	
TOU-D-4to9pm	Current + TRD Toggle	**Current (0% TRD)** ($243)	**25% TRD** ($241)	**50% TRD** ($239)	**100% TRD** ($234)
TOU-D-4to9pm	Current + Daily Demand Charge Toggle	**Current (0% DD)** ($243)	**100% DD** ($233)		

After reviewing these results, SCE was surprised by the limited impact that the majority of the rate design toggles had on reducing the burden to non-adopters. In further studying the mechanics of the model, SCE hypothesized that the composite tier structure and the pre-defined tier differentials were having the effect of dampening any gains from the toggles. This is because each of the toggles results in a larger BLC relative to the starting point, which is then only applied to lower levels of usage. So while a toggle did collect additional revenue, this increase was then offset by the larger BLC.[48] To test this hypothesis, SCE

Without a baseline credit in the TOU rate, these customers would likely opt for a tiered rate that includes a baseline credit. Similarly, without a baseline credit, the TOU rate rewards large customer[s] who switch to TOU even without a load shift."

[45] SCE uses a PLRF methodology to allocate peak distribution marginal costs across TOU periods. The PLRFs must then be mapped to the appropriate reference year, which can result in "PLRF flattening" depending on the mapping methodology used.

[46] The BLC included in the TOU rate is impacted by the Schedule D tiered residential rate structure, and is the difference between Tier 1 and the weighted average of Tier 2 and the HUC. To comply with D.15-07-001, SCE is obligated to use a "composite methodology" when designing its tiered rates. Under this composite methodology, the customer charge is added to the Tier 1 rate as a cent/kWh adder – resulting in a composite Tier 1 rate. Tier 2 and the HUC are then determined by the ratios adopted in D.15-07-001 using the Composite Tier 1 rate times the ratios for Tier 2 and the HUC (*e.g.,* Tier 2 = Composite Tier 1 X Tier 2 ratio). Because the Composite Tier 1 rate is the sum of the Tier 1 rate plus the customer charge, any increase to the customer charge (which results in an increased cent/kWh Tier 1 composite adder) necessitates a corresponding decrease in the actual (non-composite) Tier 1 rate to maintain revenue neutrality.

[47] Again, these represent the "All Generation" Avoided Cost analysis. The "Export Only" Avoided Cost analysis is provided in Appendix B.

[48] Because the BLC is the difference between the composite Tier 1 and the weighted average of Tier 2 and the HUC, as the customer charge increases, the actual Tier 1 rate decreases. As Tier 1 decreases, the BLC increases. A BLC

redesigned the TOU-D-4to9pm rate to remove the constraints that may have been muting the intended effect of the toggles. This included eliminating the PLRF flattening, pre-defined tier ratios and composite methodology in calculating the BLC. SCE also increased the seasonal delta to three cents for rate moderation. SCE then applied the same toggles as before. The results are provided in Figure 13, below.

Figure 13 –
NEM Impact Under Various "Unconstrained" Residential Retail Rate Design Toggles
($/Installed kW-yr)

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual NEM Impact per Installed kW ($/yr) (All Generation)			
Redesigned TOU-D-4to9pm	NEM 2.0 + TOU-D-4to9pm (Current)	**Current (Starting Point)** **($223)**			
Redesigned TOU-D-4to9pm	Redesigned TOU-D-4to9pm + Customer Charge Toggle	**Current ($1 Cust Charge)** ($223)	**$6.85 Cust Charge** ($215)	**$10.09 Cust Charge** ($211)	**$15.15 Cust Charge** ($205)
Redesigned TOU-D-4to9pm	Redesigned TOU-D-4to9pm + FRD Toggle	**Current (0% FRD)** ($223)	**50% FRD** ($215)	**100% FRD** ($207)	
Redesigned TOU-D-4to9pm	Redesigned TOU-D-4to9pm + TRD Toggle	**Current (0% TRD)** ($223)	**25% TRD** ($227)	**50% TRD** ($230)	**100% TRD** ($237)
Redesigned TOU-D-4to9pm	Redesigned TOU-D-4to9pm + Daily Demand Charge Toggle	**Current (0% DD)** ($223)	**100% DD** ($213)		

For this analysis, the starting point shifted from $243/installed kW-yr to $223/installed kW-yr. Similar to the analysis above, the amount the other numbers deviate from $223 demonstrates the impact of that toggle on other customers.

Finally, as an additional sensitivity, SCE also explored how the NEM impact fared under its new TOU-D-PRIME rate. TOU-D-PRIME is a rate designed for customers with higher usage due to the adoption of certain electrification technologies including electric vehicles, BTM energy storage, and electric heat pumps for space and/or water heating. It does <u>not</u> include a BLC, has higher peak differentials, and has a higher customer charge of approximately $12/month, with the same TOU periods as TOU-D-4to9. Using TOU-D-PRIME coupled with NEM 2.0, the $243/installed kW-yr non-adopter impact was reduced to $196/installed kW-yr.

Figure 14, below, summarizes the effects of all the scenarios discussed above.

Figure 14 –
Summary of NEM Impact Under Various Residential Retail Rate Design Toggles
($/Installed kW-yr)

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual NEM Impact per Installed kW ($/yr) (All Generation) - "<u>Constrained</u> Retail Rate"				Annual NEM Impact per Installed kW ($/yr) (All Generation) - "<u>Unconstrained</u> Retail Rate"			
TOU-D-4to9pm	NEM 2.0 + TOU-D-4to9pm (Current)	**Current (Starting Point)** **($243)**				**Current (Starting Point)** **($223)**			
TOU-D-4to9pm	Current + Customer Charge Toggle	**Current ($1 Cust Charge)** ($243)	**$6.85 Cust Charge** ($238)	**$10.09 Cust Charge** ($236)	**$15.15 Cust Charge** ($232)	**Current ($1 Cust Charge)** ($223)	**$6.85 Cust Charge** ($215)	**$10.09 Cust Charge** ($211)	**$15.15 Cust Charge** ($205)
TOU-D-4to9pm	Current + Minimum Bill Toggle	**Current ($10 Min Bill)** ($243)	**$30 Min Bill** ($238)	**$50 Min Bill** ($228)		**Current ($10 Min Bill)**	**$30 Min Bill**	**$50 Min Bill**	
TOU-D-4to9pm	Current + FRD Toggle	**Current (0% FRD)** ($243)	**50% FRD** ($239)	**100% FRD** ($235)		**Current (0% FRD)** ($223)	**50% FRD** ($215)	**100% FRD** ($207)	
TOU-D-4to9pm	Current + TRD Toggle	**Current (0% TRD)** ($243)	**25% TRD** ($241)	**50% TRD** ($239)	**100% TRD** ($234)	**Current (0% TRD)** ($223)	**25% TRD** ($227)	**50% TRD** ($230)	**100% TRD** ($237)
TOU-D-4to9pm	Current + Daily Demand Charge Toggle	**Current (0% DD)** ($243)	**100% DD** ($233)			**Current (0% DD)** ($223)	**100% DD** ($213)		
TOU-D-4to9pm	NEM 2.0 + TOU-D-PRIME		**TOU-D-PRIME** ($196)						

surcharge, which recovers the BLC, is applied as a flat energy (kWh) charge across all TOU periods. As the BLC increases, the surcharge reflected in rates also increases. The overall net effect is that any increases to the customer charge (or other toggles) are negated because of the increases to the BLC, and, subsequently, the increases in all TOU rates to recover the BLC surcharge.

While SCE did see slightly greater reductions in the NEM impact when using the more cost-based, unconstrained rate design or the TOU-D-PRIME structure with its higher customer charge and no baseline credit, the overarching conclusion was that further modifications to the residential retail default TOU rate alone, especially one with a BLC, were unlikely to have a meaningful impact on mitigating the bill increases borne by non-adopters.

b. Status Quo Retail Rate Structure + Changes to DG Compensation Structure

Because the impact to non-adopters is impacted both by the underlying retail rate and the NEM compensation structure itself, SCE next explored holding the retail rate structure constant (*i.e.,* using the TOU-D-4to9pm rate with no modifications or toggles) and instead moving from a NEM 2.0 compensation structure to a net billing compensation structure. Under net billing, all energy (kWh) consumed from the grid (Channel 1) is billed at the customer's retail rate. All energy exported to the grid from the customer's rooftop solar system (Channel 2) is billed at an export compensation rate (ECR) that is decoupled from the retail rate and instead is based on the utility avoided costs (or some other value) of the exports provided. As such, there is no netting of Channel 1 and Channel 2, since different rates apply to each metered amount. The generation from the rooftop solar system that is used on-site is not metered or billed by SCE (i.e. it provides full retail rate reductions, similar to NEM).

Figure 15 –
Illustrative Example of a Residential Customer's 12-Month Net Billing Energy Charges / Credits Only on a TOU Rate (Schedule TOU-D-4to9pm)

Sample Period: October to September

			Month 1 Oct	Month 2 Nov	Month 3 Dec	Month 4 Jan	Month 5 Feb	Month 6 Mar	Month 7 Apr	Month 8 May	Month 9 Jun	Month 10 Jul	Month 11 Aug	Month 12 Sep	TOTAL Year
	Summer	Winter													
Baseline kWh (Region 10)	567	375													
Consumed (Channel 1)															
On-Peak kWh											291	309	373	250	1223
Mid-Peak kWh			260	209	233	163	167	111	174	140	114	180	98	90	1939
Off-Peak kWh			248	225	264	208	197	209	230	233	594	671	621	532	4232
Super-Off-Peak kWh			105	48	28	20	11	7	36	37					292
			613	482	525	391	375	327	440	410	999	1160	1092	872	**7686**
Exported (Channel 2)															
On-Peak kWh											7	4	3	4	18
Mid-Peak kWh			5	1	1	1	4	28	29	38	3	1	4	3	118
Off-Peak kWh			1	10	4	2	9	6	5	5	235	220	254	217	968
Super-Off-Peak kWh			272	322	247	285	431	461	417	390					2825
			278	333	252	288	444	495	451	433	245	225	261	224	**3929**
	Summer	Winter													
On-Peak	$0.40873										$ 118.94	$ 126.30	$ 152.46	$ 102.18	$ 499.88
Mid-Peak	$0.26423	$0.28891	$ 75.12	$ 60.38	$ 67.32	$ 47.09	$ 48.25	$ 32.07	$ 50.27	$ 40.45	$ 30.12	$ 47.56	$ 25.89	$ 23.78	$ 548.30
Off-Peak	$0.22095	$0.27554	$ 68.33	$ 62.00	$ 72.74	$ 57.31	$ 54.28	$ 57.59	$ 63.37	$ 64.20	$ 131.24	$ 148.26	$ 137.21	$ 117.55	$ 1,034.09
Super-Off-Peak		$0.16816	$ 17.66	$ 8.07	$ 4.71	$ 3.36	$ 1.85	$ 1.18	$ 6.05	$ 6.22					$ 49.10
Baseline Credit		($0.06774)	$ (25.40)	$ (25.40)	$ (25.40)	$ (25.40)	$ (25.40)	$ (22.15)	$ (25.40)	$ (25.40)	$ (38.41)	$ (38.41)	$ (38.41)	$ (38.41)	$ (353.60)
Export Compensation		($0.0425)	$ (11.82)	$ (14.15)	$ (10.71)	$ (12.24)	$ (18.87)	$ (21.04)	$ (19.17)	$ (18.40)	$ (10.41)	$ (9.56)	$ (11.09)	$ (9.52)	**$ (166.98)**
Monthly Charge/Credit			$ 123.89	$ 90.90	$ 108.65	$ 70.13	$ 60.11	$ 47.65	$ 75.13	$ 67.07	$ 231.49	$ 274.15	$ 266.06	$ 195.58	$ 1,610.78
Cumulative Charges/Credits			**$ 123.89**	**$ 214.79**	**$ 323.44**	**$ 393.57**	**$ 453.67**	**$ 501.32**	**$ 576.45**	**$ 643.51**	**$ 875.00**	**$1,149.14**	**$1,415.20**	**$1,610.78**	**$1,610.78**

For this scenario, SCE elected to test ECRs of 4 cents, 11 cents and 16.3 cents. The 4 cents is SCE's calculation of the amount of avoided costs provided by the rooftop solar system (refer to Section III.A.i). 16.3 cents is the derived effective ECR under the existing NEM compensation structure.[49] 11 cents represents a mid-point case in between the 4 and 16.3 cent bookends. Figure 16, below, shows the impact of switching to a net billing structure with the different ECR levels.

[49] To derive the effective ECR under the current NEM compensation structure, SCE divided the annual average NEM bill savings (annual bill after installing rooftop solar less the Channel 1 annual average bill) by the average annual Channel 2 kWh.

Figure 16 –
Impact of Net Billing Compensation Structure on $/installed kW-yr NEM Impact[50]

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual DG Impact per Installed kW ($/yr) (All Generation)			
		Current (NEM 2.0)	$0.0425 ECR	$0.11 ECR	$0.163 ECR
TOU-D-4to9pm	Net Billing + TOU-D-4to9pm	($243)	($133)	($194)	($243)

Similar to the analyses above, the starting point of the NEM impact remains the same at $243/installed kW-yr. There is no movement using an ECR of 16.3 cents because this represents the same level of compensation that is received for exports under the existing NEM 2.0 compensation structure (under the TOU-D-4to9pm rate). The reason a non-adopter impact still exists even under the 4 cent ECR scenario is because the net billing structure only addresses the cost-shift associated with the amount of rooftop solar energy that is exported to the grid. It does not impact the portion of revenue- and/or cost-shifting that results from the BTM on-site displacements. As such, moving to a net billing compensation structure that compensates rooftop solar customers for their exports based on utility avoided costs (as opposed to the retail rate) shows positive movement towards a more equitable structure, but still results in an annual impact to other customers of over $1 billion by 2030, as shown in Figure 18 below. However, this is an almost $500 million reduction to the estimated NEM impact in 2030 if no further reforms are adopted, as show in Figure 17.[51] Again, the grandfathering provisions adopted for existing NEM customers drive a significant portion of this cumulative impact.

[50] The net billing impact scenarios assume no reduction in installed system size resulting from lower ECR.
[51] Figure 17 does assume an increase in the customer charge to $6.85 for non-CARE customers, with implementation in 2021, as this customer charge increase would apply to all residential customers on TOU-D-4to9pm.

Figure 17 –
Evolution of the NEM Impact by 2030 Assuming No Further Reforms Post-2019

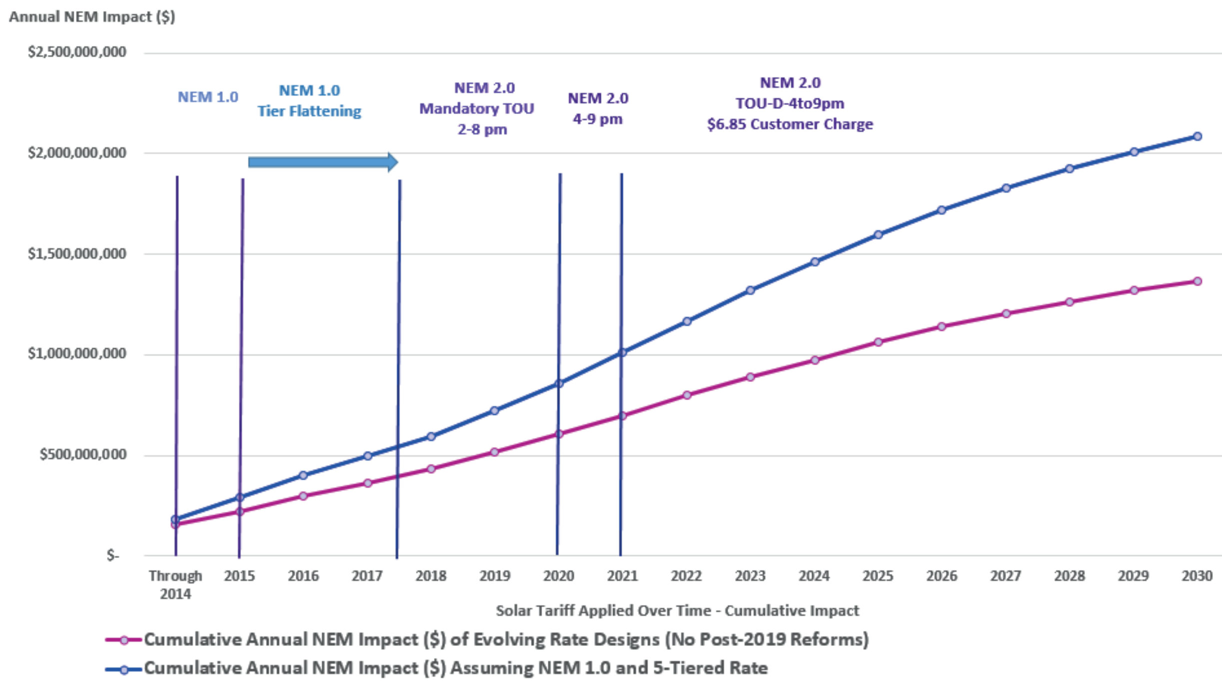
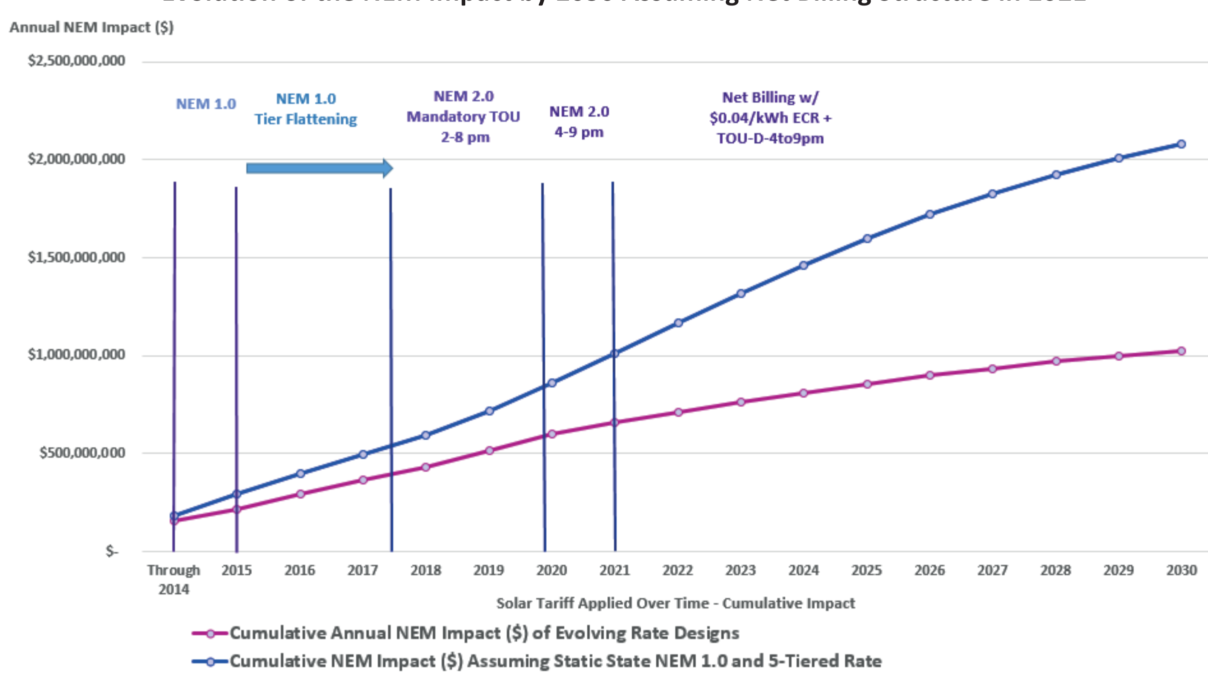


Figure 18 –
Evolution of the NEM Impact by 2030 Assuming Net Billing Structure in 2021



c. Other Approaches

i. Grid Access Charge

One way to further address impacts to non-participants is via a grid access charge (GAC).[52] A GAC is based on the installed capacity (kW nameplate rating) of the rooftop solar system and does not vary based on customer usage, but still allows the utility to recover costs associated with access and other facilities that a rooftop solar customer utilizes when consuming power from the grid and exporting power to the grid.[53] For example, if using a $3/kW GAC, a rooftop solar customer with a 5.5 kW system would pay a monthly GAC charge of $16.50 (*i.e.,* $3*5.5). SCE does not currently have a GAC charge.

SCE tested the impact of adding a GAC under both the NEM 2.0 and net billing compensation structures using GAC values of $3/kW, $8/kW and $12/kW. The impacts are shown in Figure 19, below.

Figure 19 –
Impact of Grid Access Charges on $/installed kW-yr NEM Impact

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual NEM Impact per Installed kW ($/yr) (All Generation)			
TOU-D-4to9pm	NEM 2.0 + TOU-D-4to9pm (Current)	Current ($0 GAC) **($243)**	$3 GAC ($207)	$8 GAC ($147)	$12 GAC ($99)
TOU-D-4to9pm	Net Billing w/ 4¢ ECR + TOU-D-4to9pm	$0 GAC ($133)	$3 GAC ($97)	$8 GAC ($37)	$12 GAC $11

The starting point remains $243/installed kW-yr. Under a net billing structure that pays rooftop solar customers for their exported energy based on the utility's avoided costs coupled with a GAC (in this case $12/kW), the entire existing bill impact to non-adopters can be eliminated. That said, the proposed GAC should not be punitive to rooftop solar adopters to the extent that it recovers more than the utility's cost to serve these types of customers (taking into consideration both marginal and embedded costs based on the utility's overall revenue requirement and the services provided by the utility to the rooftop solar adopter to accommodate the two-way power flow on the grid).

ii. Separate DG Class

Another option that can meaningfully address non-adopter impacts is segmenting rooftop solar customers (including those with paired storage) into their own customer class and sequestering the

---

[52] In the 2015 NEM 2.0 proceeding, the Commission's Public Advocates Office proposed an installed capacity fee (ICF) structure (the ICF and GAC terminology can be used interchangeably). Further, D.16-01-044 directed the Commission's Energy Division staff to "investigate…tariff duration and methodologies for calculating installed capacity fees for customer-sited renewable DG installations" (p. 104).

[53] In March 2019, the Sacramento Municipal Utility District (SMUD) proposed an $8-kW/month GAC (escalating to $11-kW/month by 2025). In its proposal, SMUD explained that as a result of the "back-and-forth" between a customer's rooftop solar system and the grid, customers who generate their own electricity use the grid more frequently and in different ways than other customers, and the new GAC helped to ensure that rooftop solar customers continue to pay for grid maintenance, wildfire mitigation and other costs that are unrelated to the amount of energy used. In its proposal, SMUD also proposed to maintain the NEM structure – meaning that customer generation sent back to the grid continues to be compensated at the customer's retail TOU rate. *See* https://www.smud.org/en/Rate-Information/Rate-Action/2019-rate-change-proposal/Residential.

recovery of any revenue- or costs-shifts within that class. Under the separate class approach, the utility would allocate revenues and design rates specific to rooftop solar adopters based on the utility's cost-to-serve this group of customers only.

Because this paper is focusing solely on the residential class, SCE did not complete a full separate class analysis that would have involved allocating SCE's revenue requirement across all of SCE's customer classes. Instead, as a proxy, SCE allocated a portion of the total residential revenue requirement to a separate hypothetical residential DG class and then performed its standard GRC Phase 2 marginal cost and revenue allocation processes to determine this new residential DG class' marginal cost revenue responsibility (MCRR). SCE then designed a TOU rate that mimics Option TOU-D-4to9pm in structure to recover the MCRR, with EPMC scaling. As shown in Figure 20, below, under a net billing structure where the compensation for exports is set at the utility's avoided cost, any impacts to non-participants are eliminated.

Figure 20 –
Impact of Separate Residential DG Class on $/installed kW-yr NEM Impact

Pre-Solar Retail Rate	Post-Solar Retail Rate	Annual NEM Impact per Installed kW ($/yr) (All Generation)	
		Current	**Net Billing w/ 4¢ ECR**
TOU-D-4to9pm	Residential DG Separate Class on TOU-D-4to9pm	**($243)**	$0

iii. <u>Paired Storage</u>

As a result of the new TOU periods, the economics associated with solar+storage ("paired storage") configurations are likely to increase relative to the economics associated with standalone solar – depending on installed system costs.[54] This is because a BTM storage device enables a customer to store solar energy produced during lower-cost periods (which are now primarily when the rooftop solar system is generating, *i.e.,* 8am-4pm) and utilize that solar energy on-site or export it to the grid during higher-cost periods (which are now generally when output from a rooftop solar system is minimal or zero, *i.e.,* 4pm-9pm). Thus, paired storage can help maximize the value of the solar energy for the customer, in particular depending on the price delta between the customer's on-peak and off-peak periods and if that delta is sufficient to address capital costs and conversion losses.

For this paper, SCE analyzed paired storage installations using the following toggles, with the NEM impact results shown in Figure 21, below:

- Daily demand charge (FRD-type) coupled with both the NEM 2.0 and net billing compensation structures; and,

[54] For example, *see* "Case Study: When Solar+Storage Operating in Time-of-Use Arbitrage Mode Beats the Economics of Standalone Solar," published in Solar Power World by Adam Gerza on March 28, 2019 at https://www.solarpowerworldonline.com/2019/03/case-study-when-solarstorage-operating-in-time-of-use-arbitrage-mode-beats-the-economics-of-standalone-solar/.

- GAC coupled with a net billing compensation structure where the compensation for exports is set at the utility avoided costs.

Figure 21 –
Impact of Paired Storage on $/installed kW-yr NEM Impact

Pre-Solar Retail Rate	Post-Paired Storage DG Tariff + Retail Rate	Annual Impact per Installed kW ($/yr) (All Generation)		
TOU-D-4to9pm	Net Billing w/ 4¢ ECR + TOU-D-4to9pm w/ GAC	**$3 GAC** ($247)	**$8 GAC** ($187)	**$12 GAC** ($139)
TOU-D-4to9pm	Net Billing w/ 4¢ ECR + TOU-D-4to9pm w/ Daily FRD (100%)	**100% Daily FRD** ($282)		
TOU-D-4to9pm	NEM 2.0 + TOU-D-4to9pm w/ Daily FRD (100%)	**100% Daily FRD** ($285)		

As can be observed, the impacts to non-adopters can be higher with paired-storage installations, even when modifying both the underlying retail rate and the DG compensation structure. Compared to using a daily demand charge, a GAC approach appears more effective at reducing the impacts to non-participating customers when evaluating paired-storage installations. As this data demonstrates, any potential future reforms to DG compensation structures will need to consider paired storage use cases as the results differ significantly when compared to standalone solar installations.

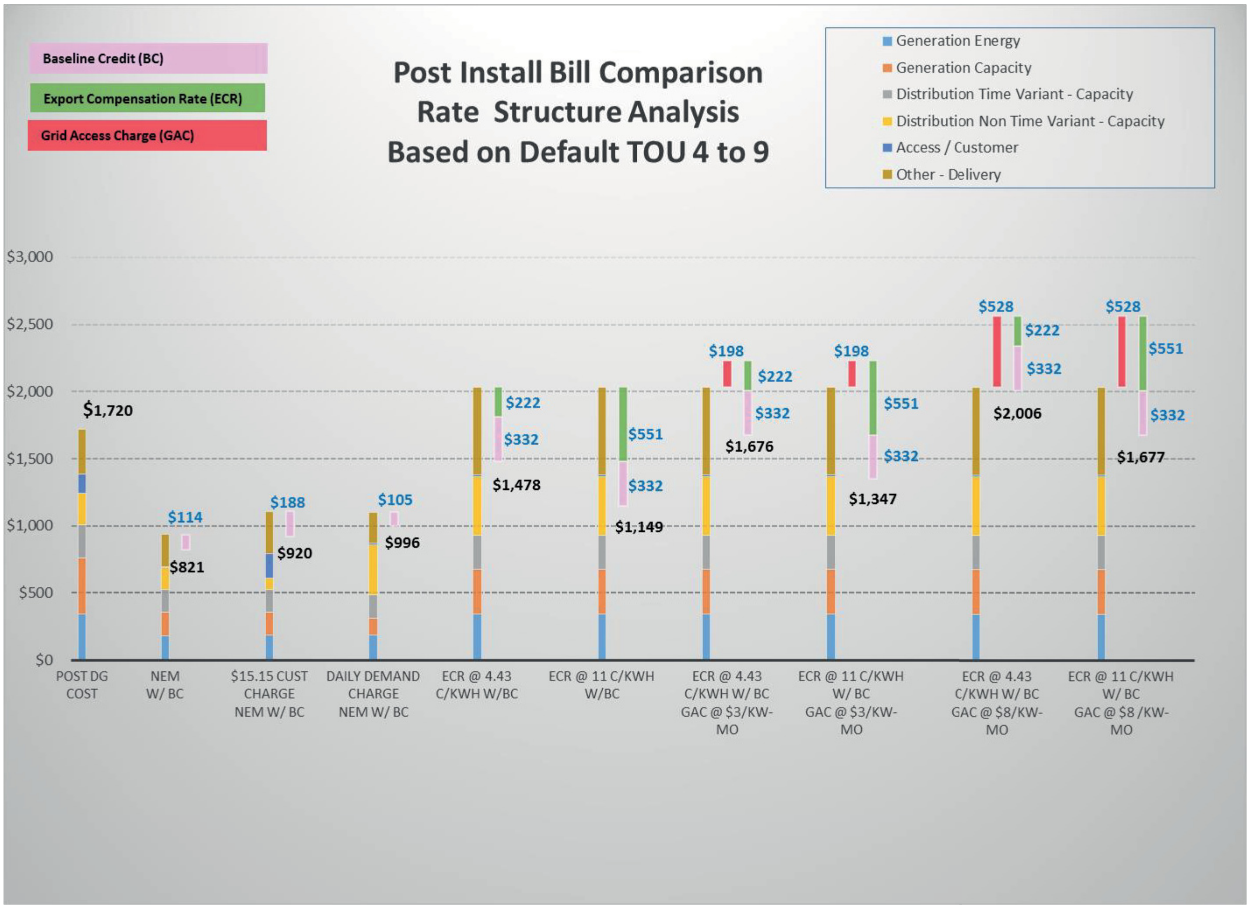
iv. Locational Pricing

This paper does not explore locational pricing for rooftop solar generation, but recognizes that such an approach could be explored to better align rooftop solar installations and deployment with specific grid needs. However, SCE believes a step-wise approach is most prudent, in that any system-level DG successor tariff should be addressed first before more nuanced modifications are made to account for locational differences across the system.

d. Cost-to-Serve Impacts

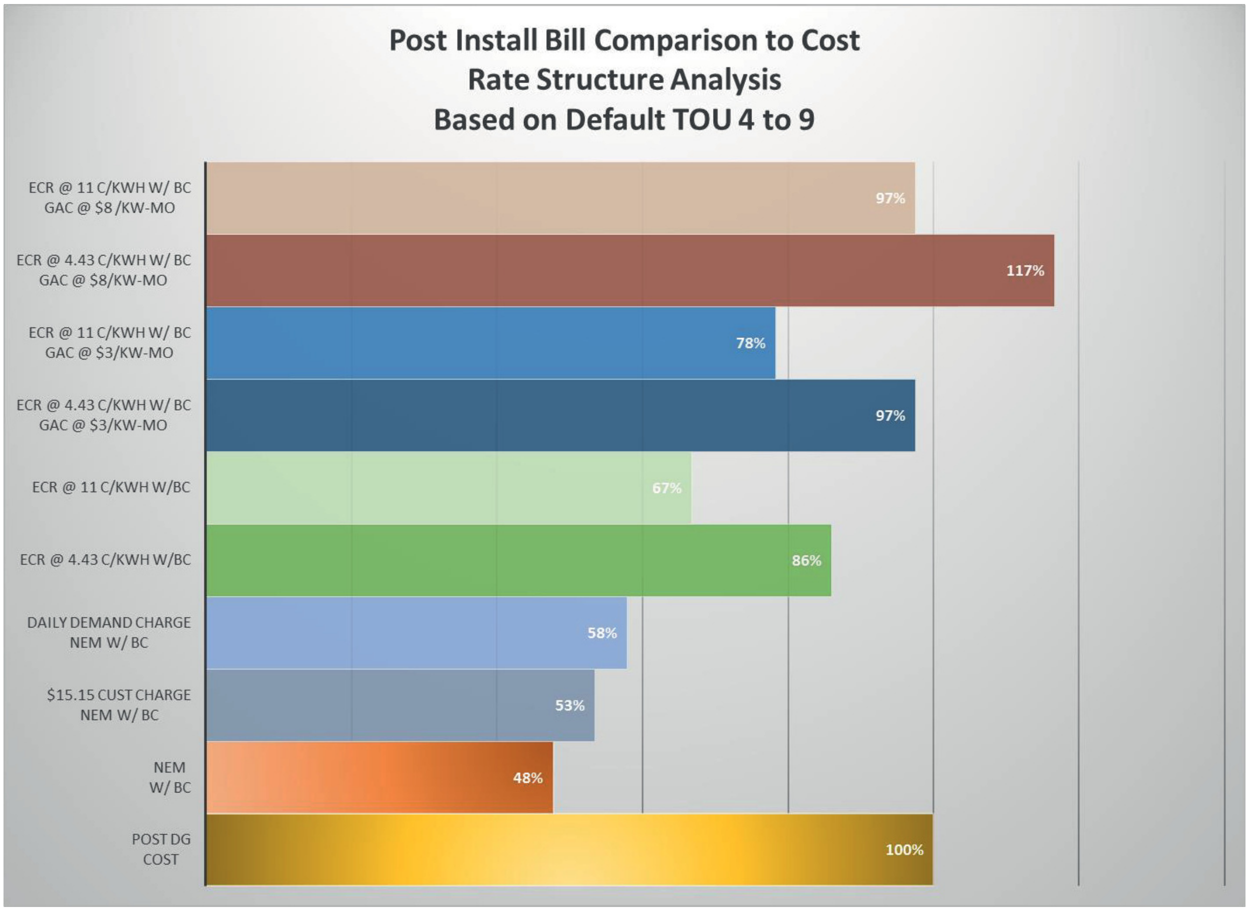
In addition to assessing the various toggles outlined above using the $/installed-kW impact from the Avoided Cost analysis, SCE also looked at how certain toggles impacted the Cost-to-Serve analysis. Figures 22 and 23, below, summarize the cost-to-serve impacts. Note that this analysis relies on averaging from the data set outlined in Section III, above, which is why the starting points (*i.e.,* post-DG costs and post-DG bill (with no toggles)) are slightly different. The purpose of this analysis is to demonstrate the *relative* change across the various toggles, as opposed to focusing on specific figures due to the use of averaging to allow the results to be produced more expeditiously.

Figure 22 –
Cost-to-Serve Impacts Due to Further Modifications to Retail Rate and/or DG Compensation Structure



As shown in Figure 22, above, the annual post-DG cost to serve the average residential solar rooftop adopter is $1,720. Under the current NEM 2.0 structure coupled with the TOU-D-4to9pm rate, the annual post-DG bill falls to $821 – which is only approximately 48 percent of SCE's costs to serve the customer. SCE has functionalized (*i.e.,* separated generation, distribution, etc.) the amounts recovered via rooftop solar adopters' bills under the various toggles. The relative difference to the current state is illustrated in Figure 23, below. As can be observed, the use of a GAC and/or the movement to a net billing compensation structure much better align rooftop solar adopters' bills with SCE's cost-to-serve them compared to the existing NEM compensation structure.

Figure 23 –
Cost-to-Serve Impacts Due to Further Modifications to Retail Rate and/or DG Compensation Structure Relative to the Existing NEM 2.0, TOU-D-4to9pm Structure



VI. <u>Customer Impacts</u>

SCE concluded its analysis by studying how the various scenarios outlined above impact rooftop solar adopters (in terms of payback periods) and non-participating customers (in terms of bill impacts).

a. <u>Impacts to Rooftop Solar Adopters</u>

There are a number of ways to determine impacts on the economics of rooftop solar adoption when changes are made to the rates and/or compensation structure under which the adopting customer will be billed and credited. One such metric is payback period. A simple payback period analysis looks at the number of years, on average, that it would take a customer to recoup the investment in rooftop solar based on the rates and compensation structure under which the customer is billed and credited. For the purposes of this paper, SCE used the following assumptions when determining a rooftop solar customer's investment costs:

- Installed Cost w/ Investment Tax Credit (ITC): $2.73/watt ($3.90/watt without ITC)[55]
- Average System Size: 5.5 kW
- Assumed Life: 20 years

Using these assumptions and the rates and compensation structures from Sections IV and V, above, Figure 24, below, summarizes the impact to payback periods under the different scenarios.

Figure 24 –
Rooftop Solar Adoption Simple Payback Period Analysis Under Different Billing and Compensation Structures (years)

Scenario		w/ ITC	w/o ITC
NEM 1.0 + 5-Tiered Rate		7.0	N/A
NEM 1.0 + Initial 2-Tiered Rate w/ HUC		7.8	N/A
NEM 1.0 + Glidepath 2-Tiered Rate w/ HUC		8.1	N/A
NEM 2.0 + TOU-D-A		8.1	N/A
NEM 2.0 + TOU-D-4to9pm		8.8	N/A
NEM 2.0 + Customer Charges	$6.85	8.9	12.7
	$10.09	9.0	12.8
	$15.15	9.1	13.0
NEM 2.0 + Minimum Bills	$30	8.9	12.7
	$50	9.2	13.2
NEM 2.0 + FRD	50%	8.9	12.7
	100%	9.0	12.8
NEM 2.0 + TRD	25%	8.8	12.6
	50%	8.9	12.7
	100%	9.0	12.9
NEM 2.0 + Daily Demand		9.9	14.2
Net Billing + TOU-D-4to9pm	4.25¢	13.5	19.3
	11¢	10.4	14.8
	16.3¢	8.8	12.5
Net Billing w/ 4.25¢ ECR + TOU-D-4to9pm w/ GAC	$3 GAC	16.5	23.5
	$8 GAC	25.8	36.9
	$12 GAC	47.3	67.6
NEM 2.0 + TOU-D-4to9pm w/ GAC	$3 GAC	9.9	14.2
	$8 GAC	12.7	18.1
	$12 GAC	16.3	23.3

As shown, payback periods have increased from approximately 7 years under the historical NEM 1.0, 5-tiered rate construct to approximately 8.8 years now, as a result of the to-date residential rate and NEM reforms. None of the payback periods associated with the scenarios tested exceeded the estimated useful

[55] *See* Lawrence Berkeley National Laboratory "Tracking the Sun: Installed Price Trends for Distributed Photovoltaic Systems in the United States – 2018 Edition," p. 32 (Residential Systems Installed in 2017, State of California).

life of the rooftop solar system assuming an ITC, with the exception of some Net Billing + GAC scenarios. This also held true even when the ITC was removed, with, again, the limited exception of the Net Billing + GAC scenarios, though the payback periods without the ITC were approximately 3 to 7 years longer for all the other scenarios. Moving forward, SCE recognizes that payback period – and other metrics addressing the economics of adopting rooftop solar – will have to be considered in light of the passage of recent updates to building codes and standards (*i.e.,* Title 24),[56] which mandate that all new residential construction and major retrofits include the installation of rooftop solar. Certain costs associated with the installation of rooftop solar are more likely to be amortized over a standard 30-year mortgage, if included in the price of the home.

b. Impacts to Non-Adopters

To better understand and help quantify how the analysis presented above impacts non-adopting customers, SCE first converted the estimated annual NEM impact (all generation) to a $/residential customer amount (Bundled Service customers only) for each of the scenarios tested. The results are shown in Figure 25, below.

Figure 25 – Annual NEM Impact per Household To-Date
(Residential Bundled Service Customers Only)

	$/Household (Annual)
NEM 1.0 + 5-Tiered Rate	$70.32
NEM 1.0 + Initial 2-Tiered Rate w/ HUC	$61.44
NEM 1.0 + Glidepath 2-Tiered Rate w/ HUC	$58.32
NEM 2.0 + TOU-D-A	$58.32
NEM 2.0 + TOU-D-4to9pm	$52.92

Under the historical 5-tiered, NEM 1.0 construct, a residential customer's annual electricity bills were increased by approximately $70 per household due to the NEM impact. This amount decreases to approximately $53/year if all rooftop solar adopters were served on NEM 2.0 under the TOU-D-4to9om rate (which is not the case given the previously discussed grandfathering provisions adopted by the Commission). The bill impacts under the other various scenarios tested are shown in Figure 26, below.

[56] California's 2019 building efficiency standards are adopted in the California Code of Regulations (Title 24, Part 6), and are effective beginning January 1, 2020.

Figure 26 – Annual NEM Impact per Household Assuming Additional Reforms

		$/Household (Annual)
NEM 2.0 + Customer Charges	$6.85	$51.96
	$10.09	$51.48
	$15.15	$50.64
NEM 2.0 + Minimum Bills	$30	$51.96
	$50	$49.68
NEM 2.0 + FRD	50%	$52.20
	100%	$51.36
NEM 2.0 + TRD	25%	$52.56
	50%	$52.08
	100%	$51.12
NEM 2.0 + Daily Demand		$45.00
Net Billing + TOU-D-4to9pm	4.25¢	$29.04
	11¢	$42.36
	16.3¢	$52.92
Net Billing w/ 4.25¢ ECR + TOU-D-4to9pm w/ GAC	$3 GAC	$21.12
	$8 GAC	$8.04
	$12 GAC	($2.40)
NEM 2.0 + TOU-D-4to9pm w/ GAC	$3 GAC	$45.12
	$8 GAC	$32.04
	$12 GAC	$21.60

VII. Conclusion

As demonstrated, while recent reforms to both residential retail rates and NEM have helped to minimize the bill increases borne by non-participating customers, the annual impact of rooftop solar adoption is still estimated to approach $1.5 billion in SCE's service territory by 2030 absent further reforms. This level of impact is likely to have negative and unintended consequences related to California's achievement of its decarbonization and climate change goals. The Commission has indicated its intent to begin the evaluation of the existing NEM tariffs and the consideration of the development and adoption of successor DG tariffs before the third quarter of 2019.[57] SCE's analysis in this paper provides insight into potential future paths forward and the relative impact each is likely to have on both customers adopting rooftop solar and on those who don't (or can't). As shown, future changes to the underlying retail rate are unlikely to have a significant impact on the bill increases borne by non-participating customers, with more impactful change resulting from the decoupling of the compensation paid for exports from the retail rate and potentially the addition of a grid access charge to ensure all customers are contributing to the costs associated with maintaining a safe and reliable electric grid. At the same time, SCE recognizes that rooftop solar adoption and the facilitation of customer choice will continue to play an important role in the state's climate change efforts. Any potential future reforms will need to carefully balance the interests of all utility customers, and look to a solution that maximizes decarbonization, affordability and reliability.

[57] *See* Fifth Amended Scoping Memo and Ruling of Assigned Commissioner, p. 5, issued on December 21, 2018 in R.14-07-002.

Appendix A – Rates

The following rates were used to complete the analysis described in this paper.[58]

Figure A – 5-Tiered Rate (Non-CARE and CARE)

	Non-CARE Rates			CARE Rates		
Energy Charge - $/kWh	**Del**	**Gen**	**Total**	**Del**	**Gen**	**Total**
Baseline - Summer	0.04843	0.08006	0.12849	0.00527	0.08006	0.08533
- Winter	0.04843	0.08006	0.12849	0.00527	0.08006	0.08533
101% - 130% of Baseline - Summer	0.07970	0.08006	0.15976	0.02662	0.08006	0.10668
- Winter	0.07970	0.08006	0.15976	0.02662	0.08006	0.10668
131% - 200% of Baseline - Summer	0.24227	0.08006	0.32233	0.16936	0.08006	0.24942
- Winter	0.24227	0.08006	0.32233	0.16936	0.08006	0.24942
201% - 300% of Baseline - Summer	0.27727	0.08006	0.35733	0.16936	0.08006	0.24942
- Winter	0.27727	0.08006	0.35733	0.16936	0.08006	0.24942
Over 300% of Baseline - Summer	0.31227	0.08006	0.39233	0.16936	0.08006	0.24942
- Winter	0.31227	0.08006	0.39233	0.16936	0.08006	0.24942
Basic Charge - $/day						
Single-Family Residence	0.031		0.031	0.024		0.024
Multi-Family Residence	0.024		0.024	0.018		0.018
Minimum Charge - $/day						
Single-Family Residence	0.338		0.338	0.169		0.169
Multi-Family Residence	0.338		0.338	0.169		0.169

Notes:
55% Baseline Allocation w/ 2013 5-Tier Structure (Frozen T1/T2, 7¢ T3-T5 Delta, CARE T3 20% Discount of Non-CARE)

Figure B – Initial 2-Tiered Rate w/ HUC (Non-CARE and CARE)

	Non-CARE Rates			CARE Rates		
Energy Charge - $/kWh	Del	Gen	Total	Del	Gen	Total
Baseline - Summer	0.08479	0.08006	0.16485	0.03121	0.08006	0.11127
- Winter	0.08479	0.08006	0.16485	0.03121	0.08006	0.11127
101% - 130% of Baseline - Summer	0.17063	0.08006	0.25069	0.08915	0.08006	0.16921
- Winter	0.17063	0.08006	0.25069	0.08915	0.08006	0.16921
131% - 200% of Baseline - Summer	0.17063	0.08006	0.25069	0.08915	0.08006	0.16921
- Winter	0.17063	0.08006	0.25069	0.08915	0.08006	0.16921
201% - 300% of Baseline - Summer	0.17063	0.08006	0.25069	0.08915	0.08006	0.16921
- Winter	0.17063	0.08006	0.25069	0.08915	0.08006	0.16921
Over 300% of Baseline - Summer	0.23709	0.08006	0.31715	0.13402	0.08006	0.21408
- Winter	0.23709	0.08006	0.31715	0.13402	0.08006	0.21408
Basic Charge - $/day						
Single-Family Residence	0.031		0.031	0.024		0.024
Multi-Family Residence	0.024		0.024	0.018		0.018
Minimum Charge - $/day						
Single-Family Residence	0.338		0.338	0.169		0.169
Multi-Family Residence	0.338		0.338	0.169		0.169

Notes:
2017 2-Tier Structure + HUC (with 2017 Glidepath Ratio)

[58] To limit confusion, SCE is not providing the "unconstrained" rates discussed in Section V.a, but can provide those upon request. Those rates were not used in any of the other analyses, and were included as a sensitivity only.

Figure C – Glidepath 2-Tiered Rate w/ HUC (Non-CARE and CARE)

Non-CARE Rates

Energy Charge - $/kWh	Del	Gen	Total
Baseline - Summer	0.10250	0.08006	0.18256
- Winter	0.10250	0.08006	0.18256
101% - 130% of Baseline - Summer	0.15298	0.08006	0.23304
- Winter	0.15298	0.08006	0.23304
131% - 200% of Baseline - Summer	0.15298	0.08006	0.23304
- Winter	0.15298	0.08006	0.23304
201% - 400% of Baseline - Summer	0.15298	0.08006	0.23304
- Winter	0.15298	0.08006	0.23304
Over 400% of Baseline - Summer	0.33043	0.08006	0.41049
- Winter	0.33043	0.08006	0.41049
Basic Charge - $/day			
Single-Family Residence	0.031		0.031
Multi-Family Residence	0.024		0.024
Minimum Charge - $/day			
Single-Family Residence	0.338		0.338
Multi-Family Residence	0.338		0.338

CARE Rates

Energy Charge - $/kWh	Del	Gen	Total
Baseline - Summer	0.04287	0.08006	0.12293
- Winter	0.04287	0.08006	0.12293
101% - 130% of Baseline - Summer	0.07705	0.08006	0.15711
- Winter	0.07705	0.08006	0.15711
131% - 200% of Baseline - Summer	0.07705	0.08006	0.15711
- Winter	0.07705	0.08006	0.15711
201% - 400% of Baseline - Summer	0.07705	0.08006	0.15711
- Winter	0.07705	0.08006	0.15711
Over 400% of Baseline - Summer	0.19741	0.08006	0.27747
- Winter	0.19741	0.08006	0.27747
Basic Charge - $/day			
Single-Family Residence	0.024		0.024
Multi-Family Residence	0.018		0.018
Minimum Charge - $/day			
Single-Family Residence	0.169		0.169
Multi-Family Residence	0.169		0.169

Notes:
60% Baseline Allocation

Figure D – TOU-D-A Rates

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.29902	0.19843	0.49745
Off-Peak	0.21378	0.06785	0.28163
Super-Off-Peak	0.06927	0.05243	0.12170
Winter Season - On-Peak	0.20824	0.11724	0.32548
Off-Peak	0.18593	0.05902	0.24495
Super-Off-Peak	0.06935	0.05329	0.12264
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
Baseline Credit - $/kWh	(0.06512)	0.00000	(0.06512)

Notes:
Legacy TOU Periods

Figure E – TOU-D-4to9pm Rates

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.19880	0.15182	0.35062
Mid-Peak	0.19880	0.08608	0.28488
Off-Peak	0.15575	0.06339	0.21914
Winter Season - Mid-Peak	0.19880	0.10391	0.30272
Off-Peak	0.15575	0.07390	0.22965
Super-Off-Peak	0.15063	0.05814	0.20877
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
Baseline Credit - $/kWh	(0.06512)		(0.06512)

Figure F – TOU-D-PRIME Rates

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.15926	0.19811	0.35737
Mid-Peak	0.15926	0.10092	0.26018
Off-Peak	0.08308	0.04687	0.12995
Winter Season - Mid-Peak	0.16268	0.16761	0.33029
Off-Peak	0.08081	0.04331	0.12412
Super-Off-Peak	0.08081	0.04331	0.12412
Basic Charge - $/day			
Single-Family Residence	0.395	0.000	0.395
Multi-Family Residence	0.395	0.000	0.395

Figure G – TOU-D-4to9pm Rates w/ $30 Minimum Charge

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.19398	0.14995	0.34393
Mid-Peak	0.19398	0.08547	0.27945
Off-Peak	0.15092	0.06404	0.21496
Winter Season - Mid-Peak	0.19398	0.10273	0.29671
Off-Peak	0.15092	0.07416	0.22509
Super-Off-Peak	0.14580	0.05882	0.20463
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.986	0.000	0.986
Multi-Family Residence	0.986	0.000	0.986
Baseline Credit - $/kWh	(0.06512)		(0.06512)

Figure H – TOU-D-4to9pm Rates w/ $50 Minimum Charge

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.17456	0.14245	0.31701
Mid-Peak	0.17456	0.08301	0.25757
Off-Peak	0.13150	0.06663	0.19813
Winter Season - Mid-Peak	0.17456	0.09795	0.27251
Off-Peak	0.13150	0.07523	0.20673
Super-Off-Peak	0.12638	0.06155	0.18793
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	1.644	0.000	1.644
Multi-Family Residence	1.644	0.000	1.644
Baseline Credit - $/kWh	(0.06512)		(0.06512)

Figure I – TOU-D-4to9pm w/ $6.85 Customer Charge

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.19873	0.15180	0.35054
Mid-Peak	0.19873	0.08608	0.28481
Off-Peak	0.15568	0.06341	0.21909
Winter Season - Mid-Peak	0.19873	0.10391	0.30264
Off-Peak	0.15568	0.07392	0.22959
Super-Off-Peak	0.15056	0.05816	0.20872
Basic Charge - $/day			
Single-Family Residence	0.225	0.000	0.225
Multi-Family Residence	0.174	0.000	0.174
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
Baseline Credit - $/kWh	(0.08214)		(0.08214)

Figure J – TOU-D-4to9pm w/ $10.09 Customer Charge

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.19907	0.15192	0.35098
Mid-Peak	0.19907	0.08611	0.28517
Off-Peak	0.15601	0.06336	0.21936
Winter Season - Mid-Peak	0.19907	0.10398	0.30304
Off-Peak	0.15601	0.07389	0.22989
Super-Off-Peak	0.15089	0.05811	0.20900
Basic Charge - $/day			
Single-Family Residence	0.332	0.000	0.332
Multi-Family Residence	0.257	0.000	0.257
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
Baseline Credit - $/kWh	(0.09216)		(0.09216)

Figure K – TOU-D-4to9pm w/ $15.15 Customer Charge

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.19964	0.15214	0.35178
Mid-Peak	0.19964	0.08618	0.28582
Off-Peak	0.15658	0.06328	0.21986
Winter Season - Mid-Peak	0.19964	0.10412	0.30376
Off-Peak	0.15658	0.07386	0.23044
Super-Off-Peak	0.15146	0.05803	0.20949
Basic Charge - $/day			
Single-Family Residence	0.498	0.000	0.498
Multi-Family Residence	0.386	0.000	0.386
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
Baseline Credit - $/kWh	(0.10780)		(0.10780)

Figure L – TOU-D-4to9pm w/ 50% FRD

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.17102	0.14109	0.31211
Mid-Peak	0.17102	0.08257	0.25359
Off-Peak	0.12796	0.06710	0.19507
Winter Season - Mid-Peak	0.17102	0.09708	0.26810
Off-Peak	0.12796	0.07542	0.20338
Super-Off-Peak	0.12284	0.06205	0.18489
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
FRD $/kW	4.39		4.39
Baseline Credit - $/kWh	(0.06512)		(0.06512)

Figure M – TOU-D-4to9pm w/ 100% FRD

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.14324	0.13035	0.27359
Mid-Peak	0.14324	0.07905	0.22229
Off-Peak	0.10018	0.07081	0.17100
Winter Season - Mid-Peak	0.14324	0.09024	0.23348
Off-Peak	0.10018	0.07694	0.17712
Super-Off-Peak	0.09506	0.06596	0.16102
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
FRD $/kW	8.78		8.78
Baseline Credit - $/kWh	(0.06512)		(0.06512)

Figure N – TOU-D-4to9pm w/ 25% TRD

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.19880	0.13712	0.33592
Mid-Peak	0.19880	0.07413	0.27294
Off-Peak	0.15575	0.05420	0.20995
Winter Season - Mid-Peak	0.19880	0.10030	0.29910
Off-Peak	0.15575	0.07116	0.22691
Super-Off-Peak	0.15063	0.05565	0.20628
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
TRD S-On-Peak $/kW		2.29	2.29
TRD W-Mid-Peak $/kW		0.45	0.45
Baseline Credit - $/kWh	(0.06512)		(0.06512)

Figure O – TOU-D-4to9pm w/ 50% TRD

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.19880	0.12242	0.32123
Mid-Peak	0.19880	0.06219	0.26100
Off-Peak	0.15575	0.04502	0.20077
Winter Season - Mid-Peak	0.19880	0.09669	0.29549
Off-Peak	0.15575	0.06842	0.22417
Super-Off-Peak	0.15063	0.05316	0.20379
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
TRD S-On-Peak $/kW		4.57	4.57
TRD W-Mid-Peak $/kW		0.89	0.89
Baseline Credit - $/kWh	(0.06512)		(0.06512)

Figure P –TOU-D-4to9pm w/ 100% TRD

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.19880	0.09303	0.29183
Mid-Peak	0.19880	0.03831	0.23711
Off-Peak	0.15575	0.02665	0.18239
Winter Season - Mid-Peak	0.19880	0.08946	0.28826
Off-Peak	0.15575	0.06293	0.21868
Super-Off-Peak	0.15063	0.04818	0.19880
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
TRD S-On-Peak $/kW		9.14	9.14
TRD W-Mid-Peak $/kW		1.78	1.78
Baseline Credit - $/kWh	(0.06512)		(0.06512)

Figure Q –TOU-D-4to9pm w/ Daily Demand Charge

Energy Charge - $/kWh	Del	Gen	Total
Summer Season - On-Peak	0.20327	0.22662	0.42989
Mid-Peak	0.12159	0.06927	0.19086
Off-Peak	0.10767	0.03217	0.13984
Winter Season - Mid-Peak	0.10899	0.13452	0.24350
Off-Peak	0.08398	0.07480	0.15878
Super-Off-Peak	0.09209	0.04794	0.14002
Basic Charge - $/day			
Single-Family Residence	0.031	0.000	0.031
Multi-Family Residence	0.024	0.000	0.024
Minimum Charge - $/day			
Single-Family Residence	0.338	0.000	0.338
Multi-Family Residence	0.338	0.000	0.338
Daily Demand Charge - $/kW	0.55		0.55
Baseline Credit - $/kWh	(0.06036)		(0.06036)

Appendix B – Exports Only Results

As discussed above, this section provides the NEM impact if only the "cost-shift" portion resulting from generation that is exported to the grid is considered. These results help to isolate how various toggles can impact the compensation paid for exports. When comparing the "Exports Only" scenario, the starting point is $110/installed kW-yr.

Figure 10A –
Evolution of the NEM Impact (Exports Only) To-Date ($/installed kW-yr)

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual NEM Impact per Installed kW ($/yr) (Export Only)	Annual NEM Impact per Adopter ($/yr) (Export Only)
5-Tiered Retail Rate	NEM 1.0 + 5-Tiered Rate	($115)	($633)
Initial 2-Tiered Rate w/ HUC	NEM 1.0 + Initial 2-Tiered Rate w/ HUC	($134)	($737)
Glidepath 2-Tiered Rate w/ HUC	NEM 1.0 + Glidepath 2-Tiered Rate w/ HUC	($133)	($732)
Glidepath 2-Tiered Rate w/ HUC	NEM 2.0 + TOU-D-A	($76)	($418)
TOU-D-4to9pm	**NEM 2.0 + TOU-D-4to9pm**	**($110)**	**($605)**

Figure 12A –
NEM Impact (Exports Only) Under Various Residential Retail Rate Design Toggles ($/Installed kW-yr)

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual NEM Impact per Installed kW ($/yr) (Export Only)			
TOU-D-4to9pm	NEM 2.0 + TOU-D-4to9pm (Current)	**Current (Starting Point)** **($110)**			
TOU-D-4to9pm	Current + Customer Charge Toggle	**Current ($1 Cust Charge)** ($110)	**$6.85 Cust Charge** ($102)	**$10.09 Cust Charge** ($98)	**$15.15 Cust Charge** ($92)
TOU-D-4to9pm	Current + Minimum Bill Toggle	**Current ($10 Min Bill)** ($110)	**$30 Min Bill** ($98)	**$50 Min Bill** ($63)	
TOU-D-4to9pm	Current + FRD Toggle	**Current (0% FRD)** ($110)	**50% FRD** ($88)	**100% FRD** ($66)	
TOU-D-4to9pm	Current + TRD Toggle	**Current (0% TRD)** ($110)	**25% TRD** ($105)	**50% TRD** ($101)	**100% TRD** ($92)
TOU-D-4to9pm	Current + Daily Demand Charge Toggle	**Current (0% DD)** ($110)	**100% DD** ($66)		

Figure 16A –
Impact of Net Billing Compensation Structure on $/installed kW-yr NEM Impact (Exports Only)

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual DG Impact per Installed kW ($/yr) (Export Only)			
TOU-D-4to9pm	Net Billing + TOU-D-4to9pm	**Current (NEM 2.0)** ($110)	**$0.0425 ECR** $0	**$0.11 ECR** ($61)	**$0.163 ECR** ($110)

Figure 19A –
Impact of Grid Access Charge on $/installed kW-yr NEM Impact (Exports Only)

Pre-Solar Retail Rate	Post-Solar DG Tariff + Retail Rate	Annual NEM Impact per Installed kW ($/yr) (Export Only)			
TOU-D-4to9pm	NEM 2.0 + TOU-D-4to9pm (Current)	**Current ($0 GAC)** **($110)**	**$3 GAC** ($74)	**$8 GAC** ($14)	**$12 GAC** $34

Appendix C – Demographics of Rooftop Solar Adopters

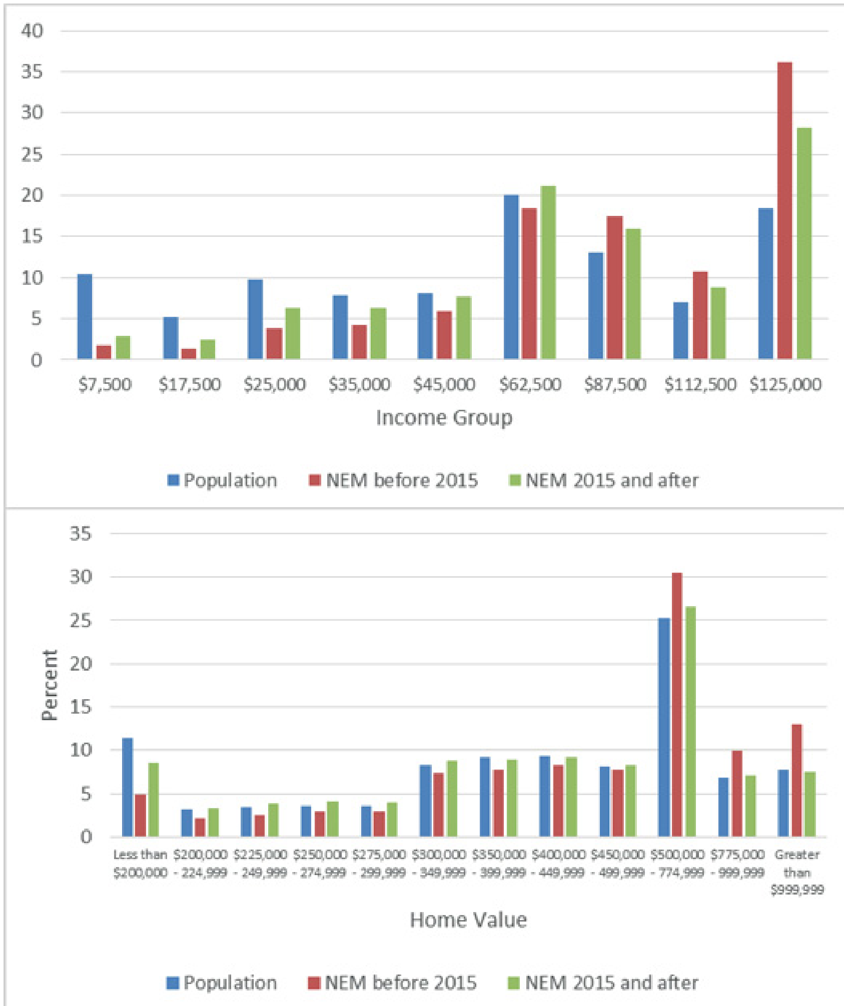
To better understand the characteristics of customers adopting rooftop solar in SCE's service territory and if these characteristics have changed over time, SCE utilized available demographic data to segment existing NEM customers by those who installed their rooftop solar systems prior to 2015 and those who installed systems in 2015 and later.

In conducting this analysis, SCE observed the following overall trends, with more details provided in the individual graphs below:

- NEM customers were initially concentrated in warmer areas and experienced higher tiered-rate bills compared to the average residential customer, and also had higher income levels and greater levels of home ownership compared to non-adopters.
- Post-2015 adopters cover a more diverse and wider portion of SCE's customer base, though rooftop solar adopters overwhelming continue to own their own homes and fall into the middle and higher income levels.

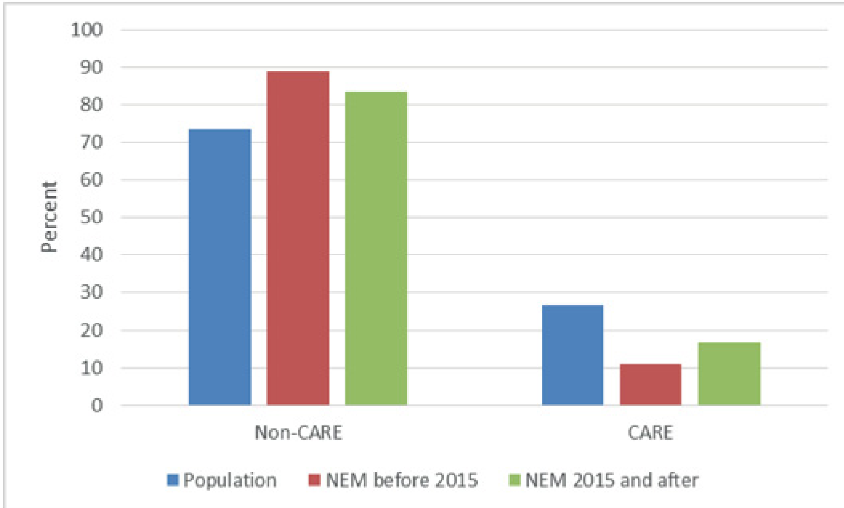
<u>Distribution by Economic Indicators</u>

- NEM customers tend to have higher incomes and home values than non-adopters, but rooftop solar adoption is spreading towards more middle-income customers post-2015.



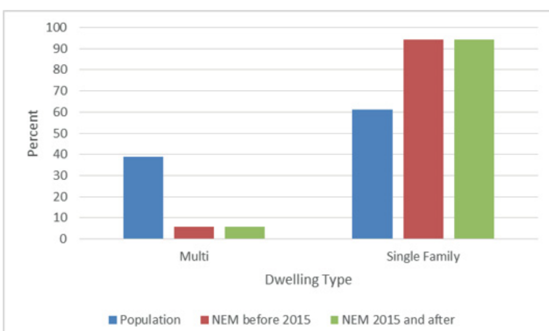
Acxiom Data

- NEM continues to be utilized more by non-CARE customers compared to CARE customers.

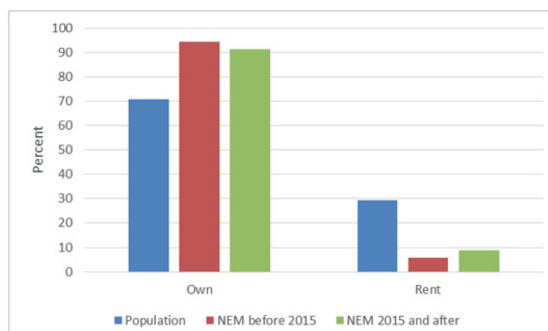


<u>Distribution by Dwelling Types and Ownership Status</u>

- Rooftop solar is overwhelming installed on single-family homes by customers who own their homes, though a slight increase can be observed in single-family rentals post-2015.
- Highest penetration rates tended to be on newer homes pre-2015, but this dispersion is wider post-2015.

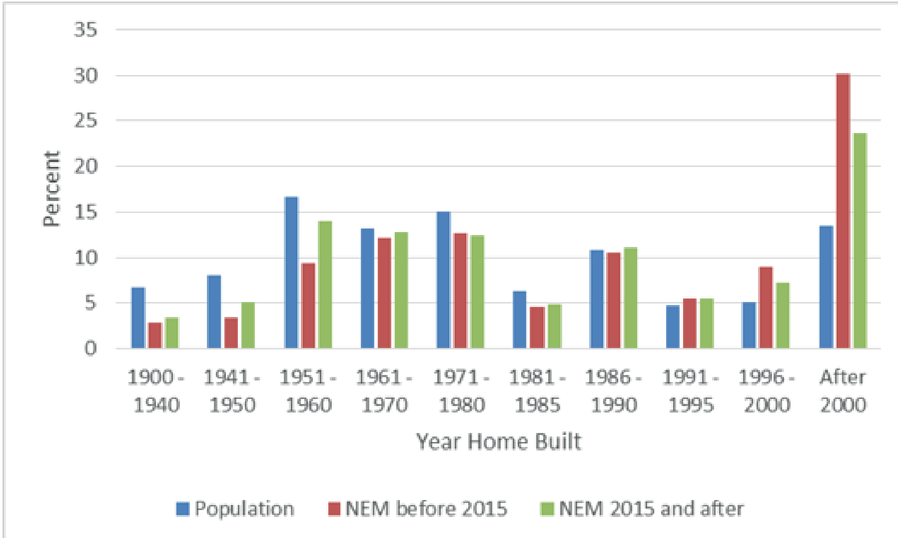


SCE Data



Acxiom Data

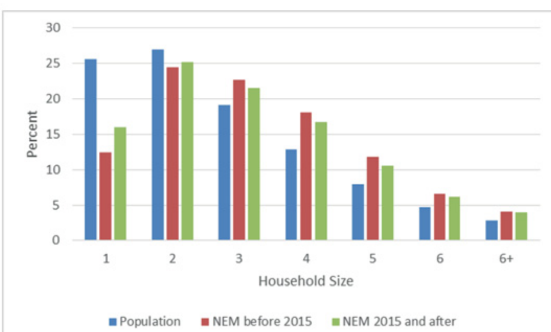
Distribution by Year when Home was Built



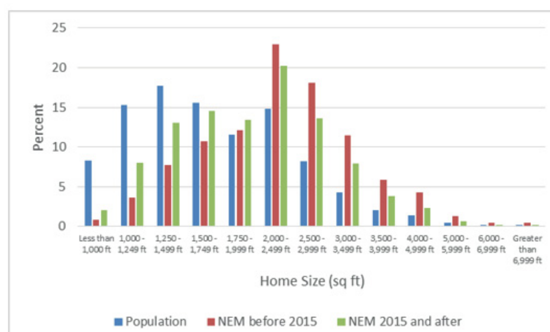
Acxiom Data

<u>Distribution by Household Size</u>

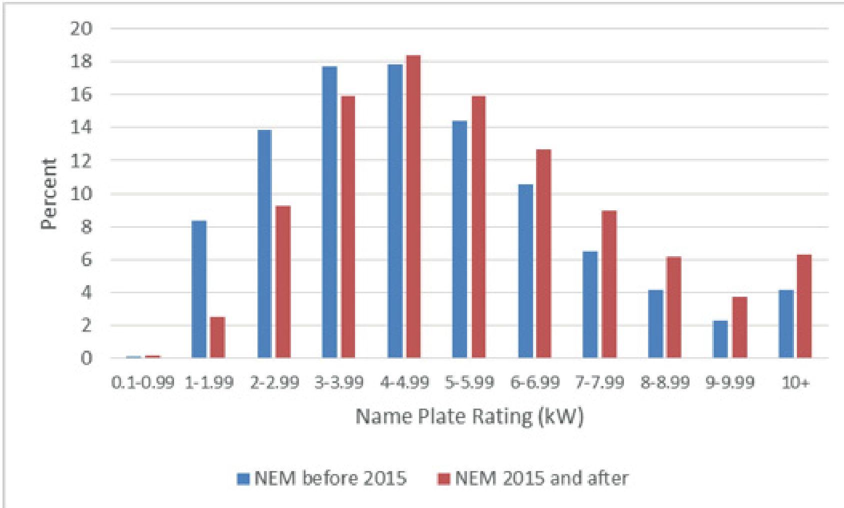
- Rooftop solar adoption is highest among larger households, but smaller households are starting to adopt more post-2015. Similarly, earliest rooftop solar adoption occurred in homes with a larger square footage footprint, but post-2015 adoption has occurred on houses with smaller footprints.
- However, the size of rooftop solar installations have grown larger with the post-2015 adopters.



Acxiom Data



Acxiom Data

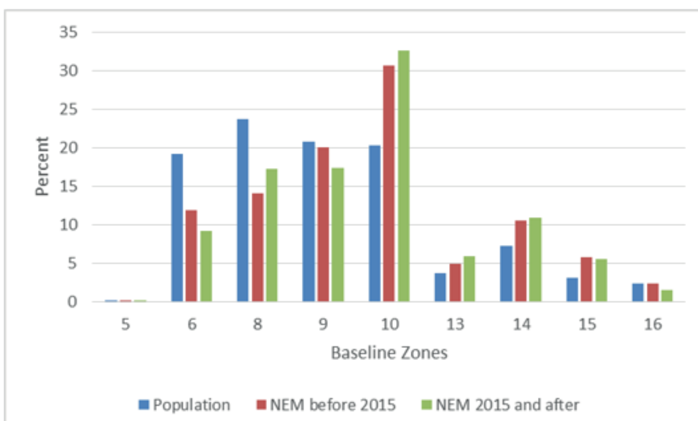


SCE Data

<u>Distribution by Location (*i.e.,* Baseline Regions)</u>

- The highest level of rooftop solar adoption has occurred in baseline regions designated as "hot zones": 10 (Inland Empire), 13 (SJV), 14 (high desert) and 15 (Coachella).
- Penetration is increasing in coastal Orange County (zones 10 and 8).

Distribution by Baseline Zones



SCE Data

DATA REQUEST SET T U R N - S C E - 0 2 6

To: 75
Prepared by: Pamela Arnold
Job Title: Senior Advisor
Received Date: 3/4/2020

Response Date: 5/13/2020

Question 09.a Supplemental:
Regarding Edison's response to TURN DR 010 Q. 2 STIP KCIP NOEIP Att. 1,
a. please expand the worksheet to reflect target and, where available actual 2019 values, 2020 target values, and forecast 2021 target values.

Response to Question 09.a Supplemental:
Please see attachment, *TURN-SCE-026 Q09a STIP KCIP NOEIP Updated Att 1*, which has the 2019 STIP plan targets and actual payouts recorded in 2020.

	2019 STIP		2019 Augment		2018 KCIP 2nd Payout	2019 KCIP 1st Payout	2019 NOEIP	
	Target	Actual	Target	Actual	Actual	Actual	Target	Actual
588 T&D	77,924,335	89,583,020			410,000	447,500	1,233,850	1,445,635
905 CS	14,959,317	17,196,617			152,500	222,000	613,420	710,716
500 Gen	6,891,202	7,928,929			124,700	150,641	423,500	472,037
920 A&G	46,242,956	53,169,953			1,819,250	1,749,520	4,276,364	4,954,033
Total	146,017,810	167,878,519			2,506,450	2,569,661	6,547,135	7,582,421

	2018 STIP		2018 Augment		2018 KCIP	2018 NOEIP	
	Target	Actual	Target	Actual	Actual	Target	Actual
588 T&D	65,658,975	67,899,550			865,000	1,075,769	1,106,162
905 CS	14,025,489	14,279,357			210,000	704,724	713,808
500 Gen	6,603,593	6,908,963			269,400	204,629	194,170
920 A&G	40,603,010	41,327,260			3,711,500	4,383,323	4,653,087
Total	126,891,067	130,415,130			5,055,900	6,368,445	6,667,227

	2017 STIP		2017 Augment		2017 KCIP	2017 NOEIP	
	Target	Actual	Target	Actual	Actual	Target	Actual
588 T&D	60,847,187	63,579,672	1,141,306	1,166,609		1,235,905	1,346,971
905 CS	12,081,930	12,543,670	358,310	391,404		592,934	633,329
500 Gen	5,860,456	6,047,008	236,901	226,501		203,863	209,527
920 A&G	34,958,777	36,355,709	2,851,571	2,905,267		4,585,940	4,861,404
Total	113,748,350	118,526,059	4,588,088	4,689,781		6,618,642	7,051,231

	2016 STIP		2016 Augment		2016 KCIP	2016 NOEIP	
	Target	Actual	Target	Actual	Actual	Target	Actual
588 T&D	53,559,925	47,629,632	989,634	892,969		1,028,473	940,617
905 CS	10,282,448	9,170,212	390,583	338,221		490,397	456,815
500 Gen	5,564,483	5,015,096	75,010	65,192		322,757	282,892
920 A&G	32,725,252	28,419,452	2,777,764	2,196,543		4,222,910	3,813,988
Total	102,132,108	90,234,392	4,232,991	3,492,925		6,064,537	5,494,312

	2015 STIP		2015 Augment		2015 KCIP	2015 NOEIP	
	Target	Actual	Target	Actual	Actual	Target	Actual
588 T&D	52,837,595	54,921,193	723,066	758,622		1,059,493	1,085,183
905 CS	13,868,788	14,341,660	421,910	460,882		524,243	565,495
500 Gen	6,401,605	6,810,253	85,725	88,662		371,946	400,189
920 A&G	35,437,591	36,295,742	2,831,698	2,609,408		4,459,946	4,654,273
Total	108,545,579	112,368,848	4,062,399	3,917,574		6,415,628	6,705,140

	2014 STIP		2014 Augment		2014 KCIP	2014 NOEIP	
	Target	Actual	Target	Actual	Actual	Target	Actual
588 T&D	47,881,433	67,996,644	552,470	807,591		972,598	1,337,023
905 CS	13,319,214	19,068,247	391,340	592,886		529,099	719,436
500 Gen	5,354,768	7,698,293	66,271	95,172		444,208	632,572
920 A&G	39,924,663	56,057,488	2,772,169	3,602,175		4,581,816	6,445,203
Total	106,480,078	150,820,672	3,782,250	5,097,824		6,527,721	9,134,234

Impact of Benefit Plan Changes
Pension, 401(k), PBOP

May 28, 2020

Prepared by Aon
Retirement and Investment

Presentation to Edison International

Empower Results®

Plan Changes—Pension, 401(k)

Pension
401(k)
PBOP

Pension

The following plan design changes were implemented effective December 31, 2017:

- Discontinued cash balance (CB) plan to new hires
- Changed long-term disability accruals

401(k)

- New hires not participating in CB plan are eligible for an enhancement beginning 2018
  - In addition to 100% match on up to 6% of pay deferred into the 401(k)
- Represented employees – Graded match based on age/service, as follows:

Age + Service Points	Additional 401(k) Contribution
45 and under	4%
46 to 59	5%
60 and over	6%

- Non-Represented employees – 6% additional contribution each year

Plan Changes—Pension, 401(k)

Pension
401(k)
PBOP

Utility Expense
($ millions)

	2018	2019	2020	2021	2022	2023
SCE Retirement Plan						
After Changes	32.2	55.3	25.0	22.6	21.3	28.2
Before Changes	36.0	63.2	38.6	39.5	41.6	52.1
(Savings from Plan Changes)	(3.8)	(7.9)	(13.6)	(16.9)	(20.3)	(23.9)
SCE 401(k) Plan						
Cost of Enhancements	1.7	5.2	8.5	11.3	13.3	15.7
Overall Impact	**(2.1)**	**(2.7)**	**(5.1)**	**(5.6)**	**(7.0)**	**(8.2)**

- Net Periodic Postretirement Benefit Costs/(Credits) for 2018 through 2019 are final amounts for the "After Changes" scenario
- Projected Net Periodic Postretirement Benefit Costs/(Credits) for 2020 and beyond are based on the December 31, 2019 disclosure information

AON Empower Results®

Plan Changes—PBOP

Retiree Medical

The following plan design changes were implemented effective January 1, 2018:

- Discontinued traditional retiree medical to new hires
  - Previous plan provided that Edison contribute a certain amount each year toward the retiree's coverage
- New hires are instead provided a notional account for retiree medical purposes equal to $200 per month of service
  - Healthcare Reimbursement Account (HRA)
  - Account vests at retirement (age 55 with 10 years of service)
  - No interest credited on account

	Healthcare Reimbursement Account		
Retirement Age	Age 20 at Hire	Age 30 at Hire	Age 40 at Hire
55	$84,000	$60,000	$36,000
60	$96,000	$72,000	$48,000
65	$108,000	$84,000	$60,000

Plan Changes—PBOP

Net Periodic Postretirement Benefit Costs/(Credits) (ASC 715-60)
($ millions)

	2018	2019	2020	2021	2022	2023
After Changes	(6.5)	(23.5)	(33.0)	(33.3)	(34.9)	(34.4)
Before Changes	(6.5)	(22.0)	(28.2)	(26.7)	(26.3)	(23.9)
(Savings from Plan Changes)	0	(1.5)	(4.8)	(6.6)	(8.6)	(10.5)

- Net Periodic Postretirement Benefit Costs/(Credits) for 2018 through 2019 are final amounts for the “After Changes” scenario
- Projected Net Periodic Postretirement Benefit Costs/(Credits) for 2020 and beyond are based on the December 31, 2019 disclosure information

From: Grant Martin <grant.martin@aon.com>
Sent: Tuesday, June 2, 2020 7:28 PM
To: Mark Bennett <Mark.Bennett@sce.com>
Subject: (External):RE: Impact of January 1 2018 Benefit Plan Changes

CAUTION EXTERNAL EMAIL
Mark,

We have extended the forecast period to 20 years, as requested below. Here a summary of the savings/costs for each plan over 10 years, 15 years, and 20 years:

Estimated Impact of Benefit Changes on Net Periodic Postretirement Benefit Cost Expense ($ Millions)

Years	2021-2030	2021-2035	2021-2040
Pension	(339.8)	(677.2)	(1,155.9)
401(k)	224.4	449.7	768.9
PBOP	(179.1)	(396.3)	(733.3)
Total	**(294.5)**	**(623.8)**	**(1,120.3)**

Please note the numbers shown in the table above are nominal dollars. That is, the savings have not been discounted back to 2020 to arrive at a present value. Please let us know if you had something else in mind, or if you have any questions/comments.

Thank you,

Grant Martin, FSA, EA, CERA
Aon
425 Market Street | Suite 2800 | San Francisco, CA 94105
t +1.415.486.6947 | m +1.336.462.8337
grant.martin@aon.com

Southern California Edison

Study Data as of 12/31/18

2021 General Rate Case—Total Compensation Study

Competitive Summary (SCE versus Market)

2021 TCS Study

Job Category	SCE Population	SCE Payroll Dollars ($000s)	SCE In Study +/- Market *SCE Demographic* Total Comp
Physical/Technical	3,628	$389,605.1	13.1%
Clerical	2,574	$184,417.7	-7.9%
Professional/Technical	4,421	$546,100.5	-12.8%
Manager/Supervisor	1,816	$335,356.8	-5.1%
Executive	37	$19,089.7	-17.4%
2021 Overall (Payroll Wtd)	**12,476**	**$1,474,569.9**	**-3.0%**

Incremental STIP for 2019 & 2020		**$19,331**	
Incremental STIP as a % of Payroll			**1.3%**
Adjusted SCE +/- Market with Incremental STIP			**-1.7%**

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

ENERGY DIVISION

AGENDA ID: 16978
RESOLUTION E-4963
November 29, 2018

R E S O L U T I O N

Resolution E-4963. Commission Resolution to establish memorandum accounts to track compensation paid to an officer of an electrical or gas corporation pursuant to Senate Bill 901.

PROPOSED OUTCOME:

- This resolution requires gas and electric corporations to establish memorandum accounts to track officer compensation.

SAFETY CONSIDERATIONS:

- There is no impact on safety.

ESTIMATED COST:

- The resolution is expected to lead to reduced ratepayer costs by removing from the annual revenue requirement ratepayer funding for officer compensation.

By the Commission's own motion.

SUMMARY

This Resolution orders Pacific Gas and Electric Company (PG&E), Southern California Edison Company (SCE), San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), Bear Valley Electric Services, PacifiCorp, Liberty Utilities, Southwest Gas, West Coast Gas Company, and Alpine Natural Gas Operating Company (collectively IOUs) to open memorandum accounts to track compensation paid to IOU officers pursuant to Public Utilities Code Section 706, as enacted by Senate Bill (SB) 901 (2018, Dodd).

BACKGROUND

Overview of Assembly Bill (AB) 1266

The California Legislature passed AB 1266 on September 11, 2015 and Governor Edmund Brown Jr. signed it into law on October 8, 2015. AB 1266 added Public Utilities Code Section 706, which provided in part:

> (b) For a five-year period following a triggering event, no electrical corporation or gas corporation shall recover expenses for excess compensation from ratepayers unless the utility complies with the requirements of this section and obtains the approval of the commission pursuant to this section.

Public Utilities Code Section 706 defines both "excess compensation" and a "triggering event"[1] and directs the California Public Utilities Commission (Commission) to implement these provisions in General Rate Case (GRC) proceedings. Public Utilities Code Section 706(f) mandates that the Commission, "[i]n every decision on a general rate case, shall require all authorized executive compensation to be placed in a balancing account, memorandum account, or other appropriate mechanism so that this section can be implemented without violating any prohibition on retroactive ratemaking."

In response to AB 1266, during the subsequent GRC proceedings for SDG&E, SoCalGas and PG&E,[2] the Commission required the utilities to establish

[1] "'Excess compensation' means any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation or gas corporation that is in excess of one million dollars ($1,000,000)." Pub. Util. Code § 706(a)(1).

"A 'triggering event' occurs if, after January 1, 2013, an electric corporation or gas corporation violates a federal or state safety regulation with respect to the plant and facility of the utility and, as a proximate cause of that violation, ratepayers incur a financial responsibility in excess of five million dollars ($5,000,000)." Pub. Util. Code § 706(a)(2).

[2] Due to the timing of SCE's rate case cycle, the Commission had not directed SCE to open a similar memorandum account at the time SB 901 was enacted.

memorandum accounts to track executive compensation.[3] The Commission ordered the utilities to file Tier 2 Advice Letters (AL) in order to "track all monies authorized in today's decision for the annual salaries, bonuses, benefits, and all other consideration of any value, set aside to be paid to the officers of the utility, and to track that against the salaries, bonuses, benefits, and all other consideration of any value, paid to its officers."[4] SDG&E, SoCalGas and PG&E were also required to define the term "'officers' of each company who are subject to the provisions of Public Utilities Code Section 706."[5]

SDG&E and SoCalGas filed AL 2904-E/2503-G on August 8, 2016 to establish the Officer Compensation Memorandum Accounts in accordance with D.16-06-054. To establish its Executive Compensation Memorandum Accounts, PG&E filed AL 3586-G/5102-E on June 23, 2017 pursuant to D.17-05-013. These accounts track (1) the amounts authorized for compensation to executive officers of the utility in GRCs; and (2) the amounts paid to executive officers of the utility.

Overview of Senate Bill (SB) 901

On August 31, 2018, the California Legislature passed SB 901, and Governor Edmund Brown Jr. signed it into law on September 21, 2018. SB 901 repeals the language in Public Utilities Code Section 706, and adds new language prohibiting an electrical or gas corporation from recovering from ratepayers any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of the electrical corporation or gas corporation, and requires that compensation instead be funded solely by shareholders of the utility. Revised Section 706 states:

> (a) For purposes of this section, "compensation" means any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation or gas corporation.

---

[3] "Executive compensation" and "officer compensation" are frequently used interchangeably in GRC testimony and decisions.

[4] D.16-06-054, OP 9 and D.17-05-013 OP 13.

[5] *Id.*

(b) An electrical corporation or gas corporation shall not recover expenses for compensation from ratepayers. Compensation shall be paid solely by shareholders of the electrical corporation or gas corporation.

NOTICE

Notice of this Draft Resolution was made by publication on the Commission's Daily Calendar. This Draft Resolution was distributed to the Service List for proceedings Application (A.) 15-09-001, A.17-10-007, A.17-10-008, A.16-09-001, A.18-04-002, A.15-08-008, A.17-05-004, A.12-12-024, and A.15-03-004.

DISCUSSION

This resolution partially implements Public Utilities Code Section 706 as revised by SB 901, which requires, among other things, that all forms of compensation for officers of electrical or gas corporations shall be paid solely by shareholders.

The current authorized revenue requirement for the IOUs includes recovery for a portion of officer compensation. In order to remove ratepayer funding of officer compensation without violating the statutory prohibition against retroactive ratemaking, the Commission should first require all authorized officer compensation to be placed in a memorandum account. Sample tariff language is included in Appendix A: Sample Preliminary Statement for Officer Compensation Memorandum Account. In accordance Public Utilities Code Section 706, "compensation" means any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation or gas corporation. For the purposes of the memorandum accounts, the term "officer" shall mean those employees in positions with titles of Vice President or above, consistent with Rule 240.3b-7 of the Securities Exchange Act. The amounts reported in the memorandum accounts will be reviewed and refunded to ratepayers in future GRC proceedings, or as soon as feasible.

COMMENTS

Public Utilities Code Section 311(g)(1) provides that this resolution must be served on all parties and subject to at least 30 days public review. Please note that comments are due 20 days from the mailing date of this resolution. Section

311(g)(2) provides that this 30-day review period and 20-day comment period may be reduced or waived upon the stipulation of all parties in the proceeding.

The 30-day review and 20-day comment period for the draft of this resolution was neither waived nor reduced. Accordingly, this draft resolution was mailed to parties for comments, and will be placed on the Commission's agenda no earlier than 30 days from today.

FINDINGS

1. Senate Bill (SB) 901 was signed into law on September 21, 2018.
2. SB 901 requires, among other things, that all forms of compensation for officers of electrical or gas corporations shall be paid solely by shareholders.
3. SB 901 applies to all electrical and gas corporations, regardless of size.
4. In accordance Public Utilities Code Section 706, "compensation" means any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation or gas corporation.
5. The term "officer" means those employees in positions with titles of Vice President or above, consistent with Rule 240.3b-7 of the Securities Exchange Act.
6. Pursuant to SB 901, the Commission should require the IOUs to establish memorandum accounts to track officer compensation so that it can be refunded to ratepayers through future proceedings.
7. Southern California Edison Company has no existing memorandum account to track officer compensation.
8. San Diego Gas & Electric Company and Southern California Gas Company's existing Officer Compensation Memorandum Accounts reflect pre-SB 901 Public Utilities Code Section 706 and should be closed.
9. Pacific Gas & Electric Company's existing Executive Compensation Memorandum Account reflects pre-SB 901 Public Utilities Code Section 706 and should be closed.

THEREFORE IT IS ORDERED THAT:

1. San Diego Gas & Electric Company and Southern California Gas Company shall each file a Tier 1 Advice Letter to close their existing Officer Compensation Memorandum Accounts effective December 31, 2018.
2. Pacific Gas and Electric Company shall file a Tier 1 Advice Letter to close its Executive Compensation Memorandum Account effective December 31, 2018.
3. San Diego Gas & Electric Company, Southern California Gas Company, Pacific Gas and Electric Company, Southern California Edison Company, Bear Valley Electric Services, PacifiCorp, Liberty Utilities, Southwest Gas, West Coast Gas Company, and Alpine Natural Gas Operating Company shall establish Officer Compensation Memorandum Accounts consistent with the language in Appendix A: Sample Preliminary Statement for Officer Compensation Memorandum Account (OCMA).
4. San Diego Gas & Electric Company, Southern California Gas Company, Pacific Gas and Electric Company, Southern California Edison Company, Bear Valley Electric Services, PacifiCorp, Liberty Utilities, Southwest Gas, West Coast Gas Company, and Alpine Natural Gas Operating Company shall file Tier 1 Advice Letters implementing the Officer Compensation Memorandum Account no later than 30 days from the date of this resolution.
   a. For each utility, the Advice Letter shall have an effective date of January 1, 2019.

This Resolution is effective today.

I certify that the foregoing resolution was duly introduced, passed and adopted at a conference of the Public Utilities Commission of the State of California held on November 29, 2018; the following Commissioners voting favorably thereon:

____

ALICE STEBBINS
Executive Director

APPENDIX A: Sample Preliminary Statement for Officer Compensation Memorandum Account (OCMA)

1. PURPOSE:

The OCMA is a memorandum account established pursuant to Public Utilities Code Section 706, as enacted by Senate Bill 901 (2018, Dodd). Public Utilities Code Section 706 requires, among other things, that all forms of compensation for officers of electrical or gas corporations shall be paid solely by shareholders. The purpose of the OCMA is to track the difference between (1) compensation for officers of the utility that is authorized in General Rate Cases (GRCs) and; (2) the amounts paid to officers of the utility.

2. APPLICABILITY:

The OCMA is effective January 1, 2019 until closed at the direction of the Commission.

3. ACCOUNTING PROCEDURE:

The OCMA consists of two sub-accounts:

The "Authorized Compensation Sub-Account" tracks salaries, bonuses, benefits, and all other consideration of any value paid to officers as authorized in [GRC DECISION AUTHORIZING RATES FOR 2019 AND BEYOND].

The "Paid Compensation Sub-Account" tracks salaries, bonuses, benefits, and all other consideration of any value paid to officers.

Salaries: [FILL IN AS APPROPRIATE, e.g. Payroll data for Executive Officer base salaries]
Bonuses: [FILL IN AS APPROPRIATE, e.g. Variable Pay/Incentive Compensation Plan (ICP).]
Benefits: [FILL IN AS APPROPRIATE, e.g. Employer portion of health and welfare premiums.]
Other Consideration: [FILL IN AS APPROPRIATE, e.g. Executive perquisites in payroll data and/or invoices, 401(k) company match, deferred compensation company match.]

[UTILITY] shall maintain this account by making monthly entries (or annual entries where applicable and monthly data is not available) as follows:

A. Authorized Compensation Sub-Account

1. A credit entry equal to the salaries, bonuses, benefits, and all other consideration of any value set aside to be paid to its officers as authorized in [GRC DECISION AUTHORIZING RATES FOR 2019 AND BEYOND].

B. Paid Compensation Sub-Account

1. A debit entry equal to the salaries, bonuses, benefits, and all other consideration of any value paid to its officers.

4. DISPOSITION

Amounts tracked in the OCMA may be addressed in [Utility Name's] GRC or other appropriate Commission proceeding and should be refunded to customers in rates.

STATE OF CALIFORNIA GAVIN NEWSOM, *Governor*

PUBLIC UTILITIES COMMISSION
505 VAN NESS AVENUE
SAN FRANCISCO, CA 94102-3298

January 29, 2019

Advice Letter 3927-E

Gary A. Stern, Ph.D.
Managing Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, CA 91770

SUBJECT: Establishment of the Officer Compensation Memorandum Account pursuant to Resolution E-4963.

Dear Dr. Stern:

Advice Letter 3927-E is effective as of January 1, 2019.

Sincerely,

Edward Randolph

Edward Randolph
Director, Energy Division

SOUTHERN CALIFORNIA EDISON
An EDISON INTERNATIONAL® Company

Gary A. Stern, Ph.D.
Managing Director, State Regulatory Operations

December 21, 2018

ADVICE 3927-E
(U 338-E)

PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA
ENERGY DIVISION

SUBJECT: Establishment of the Officer Compensation Memorandum Account Pursuant to Resolution E-4963

Southern California Edison Company (SCE) hereby submits for approval by the California Public Utilities Commission (Commission) the following changes to its tariffs. The revised tariffs are listed on Attachment A and are attached hereto.

PURPOSE

In compliance with Resolution E-4963 (Resolution) and Senate Bill (SB) 901, this advice letter establishes Preliminary Statement Part N.20, Officer Compensation Memorandum Account (OCMA), allowing SCE to track: (1) compensation for SCE officers authorized in SCE's 2018 General Rate Case (GRC) Application (A.)16-09-001,[1] and (2) all compensation paid to SCE officers as defined by Public Utilities Code (PUC) Section 706, as revised by SB 901.[2]

DISCUSSION

On August 31, 2018, the California Legislature passed SB 901, and Governor Edmund Brown Jr. signed it into law on September 21, 2018. SB 901 repeals the language in Public Utilities Code (PUC) Section 706 and adds new language prohibiting IOUs from recovering from customers "any annual salary, bonus, benefits, or other consideration of any value, paid to an officer of an electrical corporation," and requires that compensation instead be funded solely by shareholders of the utility. The law takes

1 Although the Resolution indicates that the IOUs are to "track[] both compensation for officers authorized in GRCs *and resolutions* as well as compensation as defined by Public Utilities Code Section 706" (Resolution, p. 6, emphasis added), SCE did not receive, and is not anticipating receiving, authorization for officer compensation outside of its general rate cases.

2 For the purposes of the OCMA, the term "officer" is defined as those employees of SCE in positions with titles of Vice President or above who are Rule 3b-7 officers of SCE under the Securities Exchange Act.

effect on January 1, 2019 during the pendency of SCE's 2018 General Rate Case, where SCE has sought recovery for some officer compensation from customers.

Pursuant to Ordering Paragraph (OP) 1 of the Resolution, SCE shall establish an Officer Compensation Memorandum Account so that customer funding for officer compensation authorized in SCE's 2018 GRC can be refunded to customers consistent with the new law. As discussed in the Resolution and provided in the draft tariff language provided in Appendix A of the Resolution, the memorandum account will track both compensation for officers authorized in SCE's 2018 GRC as well as compensation paid to officers as defined by PUC Section 706 (as modified by SB 901). SCE will then refund to customers revenues collected in rates that the Commission had authorized for officer compensation.

PROPOSED TARIFF CHANGES

Pursuant to the Resolution and as discussed above, SCE is establishing the OCMA to track, effective January 1, 2019: (1) compensation for SCE officers authorized in the 2018 GRC A.16-09-001; and (2) all compensation paid to SCE officers as defined by PUC Section 706. SCE's Preliminary Statements are revised to include the addition of the OCMA as Part N, Memorandum Accounts, Section 20. The attached Preliminary Statement is substantially similar to the sample Appendix A attached to the Resolution.

No cost information is required for this advice letter.

This advice letter will not increase any rate or charge, cause the withdrawal of service, or conflict with any other schedule or rule. SCE anticipates that the officer compensation amounts authorized by the Commission in the 2018 GRC decision will be refunded to customers when SCE implements the 2019 Post-Test Year revenue requirement in rates either on a stand-alone basis or through its first consolidated revenue requirement and rate change advice letter submitted in 2019.

TIER DESIGNATION

Pursuant to OP 2 of Resolution E-4963, this Advice Letter is submitted with a Tier 1 designation.

EFFECTIVE DATE

This advice letter will become effective January 1, 2019, pursuant to OP 2a of Resolution E-4963.

NOTICE

Anyone wishing to protest this advice letter may do so by letter via U.S. Mail, facsimile, or electronically, any of which must be received no later than 20 days after the date of this advice letter. Protests should be submitted to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue, 4th Floor
San Francisco, California 94102
Facsimile: (415) 703-2200
E-mail: EDTariffUnit@cpuc.ca.gov

Copies of protests should also be mailed to the attention of the Director, Energy Division, Room 4004, at the address shown above.

The protest and all other correspondence regarding this advice letter should also be sent by letter and transmitted via facsimile or electronically to the attention of:

Gary A. Stern, Ph.D.
Managing Director, State Regulatory Operations
Southern California Edison Company
8631 Rush Street
Rosemead, California 91770
Telephone: (626) 302-9645
Facsimile: (626) 302-6396
E-mail: AdviceTariffManager@sce.com

Laura Genao
Managing Director, State Regulatory Affairs
c/o Karyn Gansecki
Southern California Edison Company
601 Van Ness Avenue, Suite 2030
San Francisco, California 94102
Facsimile: (415) 929-5544
E-mail: Karyn.Gansecki@sce.com

There are no restrictions on who may submit a protest, but the protest shall set forth specifically the grounds upon which it is based and must be received by the deadline shown above.

In accordance with General Rule 4 of General Order (GO) 96-B, SCE is serving copies of this advice letter to the interested parties shown on the attached GO 96-B and A.16-09-001 and R.18-10-007 service lists. Address change requests to the GO 96-B service list should be directed by electronic mail to AdviceTariffManager@sce.com or at (626) 302-3719. For changes to all other service lists, please contact the CPUC's Process Office at (415) 703-2021 or by electronic mail at Process_Office@cpuc.ca.gov.

Further, in accordance with Public Utilities Code Section 491, notice to the public is hereby given by submitting and keeping the advice letter at SCE's corporate headquarters. To view other SCE advice letters submitted with the CPUC, log on to SCE's web site at https://www.sce.com/wps/portal/home/regulatory/advice-letters.

For questions, please contact Kimwuana Blebu at (626) 302-2403 or by electronic mail at Kimwuana.Blebu@sce.com.

Southern California Edison Company

/s/ Gary A. Stern
Gary A. Stern, Ph.D.

GAS:kb:cm
Enclosures

California Public Utilities Commission

ADVICE LETTER SUMMARY

ENERGY UTILITY

MUST BE COMPLETED BY UTILITY (Attach additional pages as needed)

Company name/CPUC Utility No.: Southern California Edison Company (U 338-E)

Utility type:

- [x] ELC
- [ ] GAS
- [ ] WATER
- [ ] PLC
- [ ] HEAT

Contact Person: Darrah Morgan
Phone #: (626) 302-2086
E-mail: Darrah.Morgan@sce.com
E-mail Disposition Notice to: AdviceTariffManager@sce.com

EXPLANATION OF UTILITY TYPE

ELC = Electric GAS = Gas WATER = Water
PLC = Pipeline HEAT = Heat

(Date Submitted / Received Stamp by CPUC)

Advice Letter (AL) #: 3927-E

Tier Designation: 1

Subject of AL: Establishment of the Officer Compensation Memorandum Account Pursuant to Resolution E-4963

Keywords (choose from CPUC listing): Compliance, Memorandum Account

AL Type: [ ] Monthly [ ] Quarterly [ ] Annual [x] One-Time [ ] Other:

If AL submitted in compliance with a Commission order, indicate relevant Decision/Resolution #:
Resolution E-4963

Does AL replace a withdrawn or rejected AL? If so, identify the prior AL:

Summarize differences between the AL and the prior withdrawn or rejected AL:

Confidential treatment requested? [ ] Yes [x] No

If yes, specification of confidential information:
Confidential information will be made available to appropriate parties who execute a nondisclosure agreement. Name and contact information to request nondisclosure agreement/ access to confidential information:

Resolution required? [ ] Yes [x] No

Requested effective date: 1/1/19

No. of tariff sheets: -4-

Estimated system annual revenue effect (%):

Estimated system average rate effect (%):

When rates are affected by AL, include attachment in AL showing average rate effects on customer classes (residential, small commercial, large C/I, agricultural, lighting).

Tariff schedules affected: See Attachment A

Service affected and changes proposed[1]:

Pending advice letters that revise the same tariff sheets: 3923-E

[1]Discuss in AL if more space is needed.

Clear Form

Protests and all other correspondence regarding this AL are due no later than 20 days after the date of this submittal, unless otherwise authorized by the Commission, and shall be sent to:

CPUC, Energy Division
Attention: Tariff Unit
505 Van Ness Avenue
San Francisco, CA 94102
Email: EDTariffUnit@cpuc.ca.gov

Name: Gary A. Stern, Ph.D.
Title: Managing Director, State Regulatory Operations
Utility Name: Southern California Edison Company
Address: 8631 Rush Street
City: Rosemead
State: California Zip: 91770
Telephone (xxx) xxx-xxxx: (626) 302-9645
Facsimile (xxx) xxx-xxxx: (626) 302-6396
Email: advicetariffmanager@sce.com

Name: Laura Genao c/o Karyn Gansecki
Title: Managing Director, State Regulatory Affairs
Utility Name: Southern California Edison Company
Address: 601 Van Ness Avenue, Suite 2030
City: San Francisco
State: California Zip: 94102
Telephone (xxx) xxx-xxxx:
Facsimile (xxx) xxx-xxxx: (415) 929-5544
Email: karyn.gansecki@sce.com

Clear Form

ENERGY Advice Letter Keywords

Affiliate	Direct Access	Preliminary Statement
Agreements	Disconnect Service	Procurement
Agriculture	ECAC / Energy Cost Adjustment	Qualifying Facility
Avoided Cost	EOR / Enhanced Oil Recovery	Rebates
Balancing Account	Energy Charge	Refunds
Baseline	Energy Efficiency	Reliability
Bilingual	Establish Service	Re-MAT/Bio-MAT
Billings	Expand Service Area	Revenue Allocation
Bioenergy	Forms	Rule 21
Brokerage Fees	Franchise Fee / User Tax	Rules
CARE	G.O. 131-D	Section 851
CPUC Reimbursement Fee	GRC / General Rate Case	Self Generation
Capacity	Hazardous Waste	Service Area Map
Cogeneration	Increase Rates	Service Outage
Compliance	Interruptible Service	Solar
Conditions of Service	Interutility Transportation	Standby Service
Connection	LIEE / Low-Income Energy Efficiency	Storage
Conservation	LIRA / Low-Income Ratepayer Assistance	Street Lights
Consolidate Tariffs	Late Payment Charge	Surcharges
Contracts	Line Extensions	Tariffs
Core	Memorandum Account	Taxes
Credit	Metered Energy Efficiency	Text Changes
Curtailable Service	Metering	Transformer
Customer Charge	Mobile Home Parks	Transition Cost
Customer Owned Generation	Name Change	Transmission Lines
Decrease Rates	Non-Core	Transportation Electrification
Demand Charge	Non-firm Service Contracts	Transportation Rates
Demand Side Fund	Nuclear	Undergrounding
Demand Side Management	Oil Pipelines	Voltage Discount
Demand Side Response	PBR / Performance Based Ratemaking	Wind Power
Deposits	Portfolio	Withdrawal of Service
Depreciation	Power Lines	

Clear Form

Cal. P.U.C. Sheet No.	Title of Sheet	Cancelling Cal. P.U.C. Sheet No.
Revised 65676-E	Preliminary Statement Part N	Revised 65541-E
Revised 65677-E	Preliminary Statement Part N	Revised 61171-E
Revised 65678-E	Preliminary Statement Part N	Revised 42856-E
Revised 65679-E	Table of Contents	Revised 65514-E

PRELIMINARY STATEMENT Sheet 2

(Continued)

N. MEMORANDUM ACCOUNTS (Continued)

2. Definitions. (Continued)

d. Specified Project (Continued)

Section No.	Specified Project	Interest Bearing Memorandum Account*	
(1)	Purpose – Not a Specified Project		
(2)	Definitions – Not a Specified Project		
(3)	Self-Generation Program Incremental Cost (SGPIC) Memorandum Account	Yes	
(4)	Catastrophic Event	Yes	
(5)	Wheeler North Reef Expansion Project Memorandum Account	Yes	
(6)	NEM Online Application System Memorandum Account (NEMOASMA)	Yes	
(7)	Demand Response Load Shift Working Group Memorandum Account (DRLSWGMA)	Yes	
(8)	Result Sharing Memorandum Account (RSMA)	Yes	
(9)	Plug-In Electric Vehicle Submetering Pilot Memorandum Account (PEVSPMA)	Yes	
(10)	Research, Development, and Demonstration Royalties	Yes	
(11)	Distributed Resources Plan Memorandum Account (DRPMA)	Yes	
(12)	Emergency Customer Protections Memorandum Account (ECPMA)	Yes	
(13)	California Power Exchange Wind-Up Charge Memorandum Account (PXWUC)	Yes	
(14)	Income Tax Component of Contribution Memorandum Account	Yes	
(15)	GRC Revenue Requirement Memorandum Account (GRCRRMA) Yes	Yes	
(16)	DWR Franchise Fee Obligation Memorandum Account Yes		
(17)	Integrated Resource Planning Costs Memorandum Account	Yes	(P)
(18)	Power Charge Indifference Adjustment Memorandum Account (PCIAMA)	Yes	(P)
(19)	Building Benchmarking Data Memorandum Account	Yes	
(20)	Officer Compensation Memorandum Account (OCMA)	Yes	(N)
(21)	Nuclear Claims Memorandum Account (NCMA) Memorandum Account (DFG Memorandum Account)	Yes	
(22)	Disadvantaged Communities - Single-family Solar Homes Memorandum Account (DACSASHMA)	Yes	(P)
(23)	San Joaquin Valley Data Gathering Plan Memorandum Account (SJVDGPMA)	Yes	(P)
(24)	Agricultural Account Aggregation Study Memorandum Account	Yes	(P)
(25)	Marine Corps Air Ground Combat Center Memorandum Account (MCAGCCMA)	Yes	
(26)	Energy Data Request Program Memorandum Account	Yes	
(27)	Not Used		
(28)	Energy Settlements Memorandum Account (ESMA)	Yes	
(29)	Affiliate Transfer Fee Memorandum Account	Yes	
(30)	Avoided Cost Calculator Memorandum Account (ACCMA)	Yes	
(31)	Nuclear Fuel Cancellation Incentive Memorandum Account	Yes	
(32)	Integrated Distributed Energy Resources Administrative Costs Memorandum Account (iDERACMA)	Yes	
(33)	Mitsubishi Net Litigation Memorandum Account	Yes	

* Interest shall accrue monthly to interest-bearing Memorandum Accounts by applying the Interest Rate to the average of the beginning and ending balance.

(Continued)

N. MEMORANDUM ACCOUNTS (Continued)

20. Officer Compensation Memorandum Account (OCMA) (N)

a. Purpose

The Officer Compensation Memorandum Account (OCMA) is established pursuant to Public Utilities Code (PUC) Section 706, as enacted by Senate Bill 901 (2018, Dodd). PUC Section 706 requires, among other things, that all forms of compensation for officers of SCE be paid solely by shareholders. The purpose of the OCMA is to track (1) compensation for SCE officers authorized in the 2018 General Rate Case (GRC); and (2) all compensation for SCE officers as defined by PUC Section 706.

(1) Definitions

a. Officer

The term "officer" shall be defined as those employees of SCE in positions with titles of Vice President or above who are Rule 3b-7 officers of SCE under the Securities Exchange Act. As of the date of this filing, SCE's officers for purposes of this OCMA are its:

(1) Chief Executive Officer, (2) President, (3) Senior Vice President (SVP) & Chief Financial Officer, (4) SVP & General Counsel, (5) SVP Customer and Operational Services, (6) SVP Transmission and Distribution, and (7) SVP Regulatory Affairs.

b. Authorized Compensation Sub-Account

The Authorized Compensation Sub-Account tracks salaries, bonuses, benefits, and all other consideration of any value for officers in rates as authorized in SCE's 2018 General Rate Case.

c. Total Compensation Sub-Account

The Total Compensation Sub-Account tracks salaries, bonuses, benefits, and all other consideration of any value paid to officers, including:

i. Salaries: Base pay.
ii. Bonuses: Annual bonus.
iii. Benefits: Employer portion of health and welfare premiums; employer contribution to 401(k) plan; disability and other benefits.
iv. Other Consideration: Long-term incentives; executive perquisites; other periodic or one-time payments. (N)

PRELIMINARY STATEMENT Sheet 23

(Continued)

N. MEMORANDUM ACCOUNTS (Continued)

20. Officer Compensation Memorandum Account (OCMA) (Continued) (N)

b. Operation of the OCMA

On a monthly basis (or annually if monthly data is not available), entries to each sub-account shall be determined as follows:

(1) Authorized Compensation Sub-Account:

A credit entry equal to salaries, bonuses, benefits, and all other consideration for officers in rates as authorized in SCE's 2018 General Rate Case (annual authorized amount divided by 12) Interest shall accrue monthly to the Authorized Compensation Sub-Account balance by applying one-twelfth of the three-month Commercial Paper Rate – Non-Financial, from Federal Reserve Statistical Release H.15 (expressed as an annual rate), to the average monthly balance in the Authorized Compensation Sub-Account. If in any month a non-financial Rate is not published, SCE shall use the Federal Reserve three-month Commercial Paper Rate – Financial.

(2) Total Compensation Sub-Account:

a. A debit entry equal to salaries, bonuses, benefits, and all other consideration of any value paid to officers.

c. Disposition and Review Procedures

The OCMA is effective January 1, 2019 until closed at the direction of the Commission. SCE anticipates that the officer compensation amounts authorized by the Commission in the 2018 GRC decision, for 2019, will be refunded to customers when SCE implements the 2019 Post-Test Year revenue requirement in rates either on a stand-alone basis or through its first consolidated revenue requirement and rate change advice letter submitted in 2019. (N)

21. Nuclear Claims Memorandum Account (NCMA)

The purpose of the NCMA is to record assessments, retroactive premiums, and costs associated with claims by workers and/or third parties, including, but not limited to, allegation of exposure to nuclear radiation and/or electric and magnetic fields (EMF) associated with incidents or exposures at any location or relating to SONGS 2&3 nuclear plant decommissioning.

Entries shall be made to the NCMA at the end of each month. The monthly debit entry shall be made to the NCMA to record the costs associated with claims discussed above. The monthly credit entry shall be made to the NCMA to record any insurance proceeds received by SCE associated with these claims, less any fees paid to outside legal counsel incurred to obtain payment.

Interest shall accrue monthly to the NCMA by applying the interest rate to the average of the beginning and ending balance.

SCE may request recovery of the balance in the NCMA in the Revenue Adjustment Proceeding (RAP), or any other proceeding deemed appropriate by the Commission.

(Continued)

TABLE OF CONTENTS Sheet 1

Cal. P.U.C.
Sheet No.

PRELIMINARY STATEMENT:

|

(Continued)

Southern California Edison
A.16-09-001 – 2018 GRC

DATA REQUEST SET E D - S C E - V e r b a l - 0 3 3

To: Energy Division
Prepared by: Sherrie Le Houang
Job Title: Modelg, Fcstg & Econ Anlys, Sr Spec
Received Date: 3/6/2019

Response Date: 3/20/2019

Question 01: Pursuant to Resolution E-4963 and Senate Bill (SB) 901, electrical or gas corporations are prohibited from recovering from ratepayers any annual salary, bonus, benefits, or other consideration of any value, paid to an officer, and requires that compensation instead be funded solely by shareholders of the utility.
For employees of SCE in positions of Vice President or above who are Rule 3b-7 officers of SCE under the Securities Exchange Act, please provide the amount forecast in attrition years 2019-2020, all salaries, bonuses, benefits, and all other consideration of any value paid to officers, including:
i. Salaries: Base Pay
ii. Bonuses: Annual bonus
iii. Benefits: Employer portion of health and welfare premiums; employer contribution to 401(k) plan; disability and other benefits
iv. Other Consideration: Long-term incentives; executive perquisites; other periodic or one-time payments,
For the amounts provided above, please include the specific forecast location in SCE's Results of Operations (RO) model where the amounts are forecast (e.g. GRC Activity: Executive Officers 920-921, Executive Benefits – 926, 401(k) Savings Plan – 926, etc.). If specific forecast amounts cannot be readily identified, please provide a detailed methodology for ensuring the amounts associated with the categories above are excluded from the 2019-2020 forecast period.

Response to Question 01:

Please see the attached excel workbook for a list of RO model adjustments pursuant to Resolution E-4963 and Senate Bill (SB) 901 for SCE's General Rate Case forecast request in the attrition years 2019-2020.

Willis Towers Watson

United States

2018 General Industry Salary Budget Survey Report

Data in Effect: April 1, 2018

Turnover Rates

Turnover Rates (continued)

2018 PROJECTED TURNOVER RATES	25th Percentile	Median	75th Percentile	Average	# of Responses
Entire Sample Combined					
Voluntary Turnover	5.0%	9.0%	12.0%	9.9%	648
Involuntary Turnover	2.0%	3.0%	6.1%	4.9%	617
Overall Turnover	7.5%	12.0%	18.0%	14.6%	648
PROFIT STATUS					
For-Profit Organizations					
Voluntary Turnover	5.0%	8.6%	12.0%	9.9%	553
Involuntary Turnover	2.0%	3.5%	7.0%	5.1%	531
Overall Turnover	7.7%	12.0%	18.0%	14.8%	553
Not-For-Profit Organizations					
Voluntary Turnover	5.0%	9.7%	12.7%	10.1%	95
Involuntary Turnover	1.2%	2.0%	3.8%	3.5%	86
Overall Turnover	7.0%	12.0%	15.9%	13.3%	95
INDUSTRY SECTOR					
Durable Goods Manufacturing					
Voluntary Turnover	5.0%	8.0%	10.3%	9.0%	138
Involuntary Turnover	2.0%	3.6%	7.0%	5.3%	129
Overall Turnover	7.2%	12.0%	18.0%	14.0%	138
Non-Durable Goods Manufacturing					
Voluntary Turnover	7.0%	10.0%	12.0%	10.4%	86
Involuntary Turnover	3.0%	5.0%	8.0%	5.8%	82
Overall Turnover	10.0%	15.0%	19.6%	16.0%	86
High Tech					
Voluntary Turnover	6.0%	9.3%	13.2%	9.8%	50
Involuntary Turnover	2.0%	3.0%	7.0%	4.5%	47
Overall Turnover	8.5%	12.5%	20.3%	14.1%	50
Energy					
Voluntary Turnover	2.7%	4.5%	7.0%	5.6%	80
Involuntary Turnover	1.0%	2.0%	4.0%	3.4%	77
Overall Turnover	4.0%	7.0%	10.8%	8.9%	80
Retail and Wholesale Trade					
Voluntary Turnover	9.0%	11.0%	28.0%	20.6%	31
Involuntary Turnover	4.0%	8.6%	10.0%	8.3%	31
Overall Turnover	13.0%	24.0%	35.0%	28.9%	31
Services					
Voluntary Turnover	5.2%	9.0%	12.0%	9.8%	170
Involuntary Turnover	2.0%	3.0%	5.0%	4.2%	159
Overall Turnover	7.0%	12.0%	16.0%	13.7%	170
Health Care					
Voluntary Turnover	11.1%	13.0%	15.0%	15.5%	37
Involuntary Turnover	1.8%	2.8%	7.8%	5.8%	36
Overall Turnover	13.6%	16.0%	24.0%	21.2%	37

Table continues on next page.

Willis Towers Watson Data Services

Willis Towers Watson Data Services is a leading provider of compensation, benefit and employment practice information to the global employer community. Our databases are recognized worldwide as a premier source of current data for compensation planning.

About Willis Towers Watson

Willis Towers Watson (NASDAQ: WLTW) is a leading global advisory, broking and solutions company that helps clients around the world turn risk into a path for growth. With roots dating to 1828, Willis Towers Watson has over 40,000 employees serving more than 140 countries. We design and deliver solutions that manage risk, optimize benefits, cultivate talent, and expand the power of capital to protect and strengthen institutions and individuals. Our unique perspective allows us to see the critical intersections between talent, assets and ideas — the dynamic formula that drives business performance. Together, we unlock potential. Learn more at willistowerswatson.com.

wtwdataservices.com

Willis Towers Watson

SOUTHERN CALIFORNIA EDISON®

An EDISON INTERNATIONAL® Company

Total Compensation Study
2021 General Rate Case
Total Compensation Review

June 7, 2019

CONFIDENTIAL

Agenda for Today's Meeting

- Review May 22 & 29 meeting notes
- Recap of follow up items from May 22 & 29 meetings
- Competitive market summary – benefits (all job categories)
- Preliminary results of executive benefits valuations
- Preliminary review of total compensation results (all job categories)
- Next steps
- Appendix
  - Final results of non-executive benefits valuations

Follow-up Items from May 22 & 29 Meeting

Aon follow-up items

- Send an email to Stacey Hunter at CPUC to determine if we can obtain benefits and compensation data. (Completed, no reply)
- Complete the benefits valuation and review at the next team meeting on May 29th (Completed)
- Complete the executive compensation analysis and the total compensation analysis and review with the team on June 7th (Completed)
- Include a summary of the change in benefits design strategy in the Study report (In Progress)
- Revise the benefit value illustration tables presented in the meeting to include labels and to add a column showing the cost as a total percentage of pay (Completed)

SCE follow-up items

- Circulate the benefits comparator group list to the interveners for comment (Completed)
  - Determined that this was unnecessary since Interveners did not respond to the request in the last Study
- Review practices of reporting pay data for single incumbent jobs and report back to the Study team at the next meeting (Completed)

Competitive Market Summary – Benefits

- Benefits values moved to be aligned to the general industry market for non-executives in the 2021 study compared to the 2018 study. Values and moved below this market for executives dropping significantly from the 2018 Study.
  - SCE replaced DB pension with DC retirement
  - SCE replaced final average pay SERP with Executive Retirement Account
  - SCE eliminated nonqualified match from EDCP
  - SCE eliminated Executive Survivor Benefit Plan
  - SCE replaced retiree medical with employer-provided credits for retiree health care account

2021 TCS Study (Preliminary)

	SCE versus Market	
Job Category	**Utility Industry**	**General Industry**
Manager/Supervisor (medium)	-13.3%	3.2%
Professional/Technical (medium)	-14.6%	0.1%
Physical/Technical (high)	-13.2%	3.1%
Clerical (high)	-15.0%	0.1%
Executive (medium) (blended peers)	-12.3%	-12.3%

2018 TCS Study (From Final Report)

	SCE versus Market	
Job Category	**Utility Industry**	**General Industry**
Manager/Supervisor (medium)	-3.3%	17.6%
Professional/Technical (medium)	-3.9%	16.0%
Physical/Technical (high)	-1.6%	18.7%
Clerical (high)	-5.5%	13.6%
Executive (medium) (blended peers)	111.2%	111.2%

2021 vs. 2018

	SCE versus Market	
Job Category	**Utility Industry**	**General Industry**
Manager/Supervisor (medium)	-10.0%	-14.4%
Professional/Technical (medium)	-10.7%	-15.9%
Physical/Technical (high)	-11.6%	-15.6%
Clerical (high)	-9.5%	-13.5%
Executive (medium) (blended peers)	-123.5%	-123.5%

Preliminary Results: Executive Benefits Valuations
June 7, 2019

Overview: Executive Benefits Valuations

- One set of Executive Benefits values was produced
  - A single peer group was used, which includes both utility and general industry companies
  - SCE population and assumptions were used
    - This is the same approach as the 2018 study
  - Nonqualified benefits have been included
- The peer group changed slightly due to mergers, acquisitions, and revenue size; LADWP did not submit data in time to be included in this study group
  - 20 companies are included in the 2018 study
  - 19 companies are included in the 2021 study
- In general, in the 2021 study, compared to the 2018 study, the SCE benefits values for executives have decreased to a lower percentage of compensation compared to the blended peer group
  - 96% to 123% above market in the 2018 study
  - 8% to 12% below market in the 2021 study
  - Change in values is driven primarily by the changes in SCE benefits over the past three years

Changes in Methods and Assumptions from the 2018 Study to the 2021 Study: Medical

- The following changes tend to **increase** benefit values for all companies
  - Medical inflation
    - E.g., active medical costs increased by 8% to 9% since the last study
  - Employer-funded HRA/HSAs may increase values since first claims of the year are "covered" vs. paid out of pocket by employee
  - There were fewer opt-outs based on SCE experience
    - 5% in 2018 study
    - 3% in 2021 study
- The following changes tend to **decrease** benefit values for all companies
  - Medical family tier enrollment increased at Employee and Employee+Spouse coverage tiers and decreased at Employee+Family tier
    - 2018: 10% EE, 29% EE+SP, 0% EE+CH, 61% EE+FAM
    - 2021: 14% EE, 31% EE+SP, 0% EE+CH, 55% EE+FAM
  - Plan design changes such as moving to HRA for post-retirement medical, increases in co-payments and deductibles and lower coinsurance (passes cost increases along to employees)
  - Addition or increases of spousal and smoker surcharges
  - Retiree health care accounts are valued as pensions and have decreased due to the increase in discount rate

Changes in Methods and Assumptions from the 2018 Study to the 2021 Study: Retirement

- Retirement benefits generally account for about 90% of pay values
  - Retirement benefits are a much larger portion (and medical benefit values are a much smaller portion) of the total benefit values for executives than for other employees
- The most important features of retirement plans are accrual, employer contributions to defined contribution plans, definition of pay, treatment of IRC benefit limits
  - Retirement benefits fluctuate as a percent of pay as pay increases while medical benefits are the same flat dollar amount for all study positions
  - Nonqualified benefits have been included
- The following changes tend to decrease benefit values for all companies
  - Increase in the discount rate used to value long-term liabilities
    - SCE increased its discount rate from 3.85% in the 2018 study to 4.19% in the 2021 study
  - Change in assumed salary increase rates
    - SCE changed its salary increase rate from 4.0% in the 2018 study to an age-graded schedule that begins at 7.0% and decreases by age to an ultimate level of 2.0% at age 55

Changes in Methods and Assumptions from the 2018 Study to the 2021 Study: SCE

- The following changes tend to **decrease** benefit values for SCE
  - Moving from traditional final average pay SERP to Executive Retirement Account design
  - Eliminated match element from Executive Deferred Compensation Plan
  - Eliminated Executive Survivor Benefit Plan
  - High HMO enrollment
    - SCE has 77% normalized HMO enrollment, while the peer group averages 17% to 23% HMO enrollment
  - Moving plan design changes such as moving to HRA for post-retirement medical

Changes in Peer Groups from the 2018 Study to the 2021 Study

- 2021 Study (19 companies)
  - 95% of companies provide qualified and nonqualified defined benefit or defined contribution retirement benefits
    - Similar result in the 2018 Study of 95%
      - 9 defined benefit with matched savings
      - 9 defined contribution with matched savings
    - 5% of companies only provide a matched savings plan
  - 26% of companies provide an enhanced nonqualified plan that differs from the underlying qualified plan (as does SCE)
    - Comparable to 30% in the 2018 study; however, the mix of defined benefit and defined contribution arrangements is different
      - 2018 study: 50% defined benefit; 50% defined contribution
      - 2021 study: 40% defined benefit; 60% defined contribution
    - 2 companies reduced retirement
      - 1 of these companies replaced final average pay pension including restoration with cash balance pension including restoration
      - 1 replaced cash balance pension including restoration with DC retirement including restoration

Changes in Peer Groups from the 2018 Study to the 2021 Study

- 2021 Study (19 companies)
  - 100% of companies provide a matched savings plan and 68% provide a nonqualified voluntary deferred compensation plan
    - Compared to 95% and 65% in the 2018 study
  - The average 401k match is 4.9% of pay (68% include bonus) vs. SCE's 6.0% of base pay only
    - Compared to 4.6% in the 2018 study
  - 79% of companies provide a match on nonqualified deferrals
    - Compared to 68% in the 2015 study
    - SCE eliminated the nonqualified match since the last study

Summary of Illustrative Values

- The following slide compares the benefit values for selected illustrative executives
  - These results are not adjusted for actual differences in total cash compensation but focus on the benefit values provided by each company
- The following information is illustrated
  - Average value for all peer company plans shown
  - Data points represent total cash by position
  - Two values are shown
    - 2018 study
    - 2021 study
  - Comparisons between these values are also shown

Executive Benefits Valuations

Job Category Executives

	2018 Study SCE Population Assumptions					2021 Study SCE Population Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Executive Group Average										
Low (VP)	319,991	14.4%	20,283	66,231	20.7%	319,991	13.3%	19,899	62,413	19.5%
Medium (SVP)	472,754	15.4%	20,283	92,915	19.7%	472,754	14.0%	19,899	86,138	18.2%
High (SVP)	587,410	15.0%	20,283	108,468	18.5%	587,410	13.8%	19,899	101,051	17.2%
SCE										
Low (VP)	319,991	35.9%	14,997	129,842	40.6%	319,991	12.8%	16,101	57,191	17.9%
Medium (SVP)	472,754	38.3%	14,997	196,213	41.5%	472,754	12.6%	16,101	75,578	16.0%
High (SVP)	587,410	38.7%	14,997	242,100	41.2%	587,410	12.5%	16,101	89,701	15.3%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	96.0%	-8.4%
Medium	111.2%	-12.3%
High	123.2%	-11.2%

Preliminary Total Compensation Results for All Job Categories

- Study Coverage of SCE Population
- Competitive Market Summary
- Analysis of Results
- Detailed Results by Category

Study Coverage of SCE Population

2021 TCS Study (Preliminary)

	In Total		In Study[1]			
Job Category	SCE Population	# of Jobs	# of Incumbents	% of SCE Population	# of Jobs	% of SCE Jobs
Physical/Technical	3,628	144	2,349	64.7%	28	19.4%
Clerical	2,574	107	2,201	85.5%	46	43.0%
Professional/Technical	4,421	418	3,663	82.9%	312	74.6%
Manager/Supervisor	1,816	276	1,179	64.9%	153	55.4%
	37	37	17	45.9%	17	45.9%
2021 Overall	**12,476**	**982**	**9,409**	**75.4%**	**556**	**56.6%**

2018 TCS Study (From Final Report)

	In Total		In Study[1]			
Job Category	SCE Population	# of Jobs	# of Incumbents	% of SCE Population	# of Jobs	% of SCE Jobs
Physical/Technical	3,767	181	2,389	63.4%	31	17.1%
Clerical	3,075	107	2,559	83.2%	25	23.4%
Professional/Technical	4,118	151	3,242	78.7%	44	29.1%
Manager/Supervisor	2,215	359	1,459	65.9%	107	29.8%
Executive	43	41	15	34.9%	15	36.6%
2018 Overall	**13,218**	**839**	**9,664**	**73.1%**	**222**	**26.5%**
2021 vs 2018 Overall	**-6%**	**17%**	**-3%**	**2%**	**150%**	**30%**

1 - For purposes of this analysis, "In Study" incumbents and jobs for the 2018 and 2021 Study are based on job codes where we were able to get market data

Competitive Market Summary

2021 TCS Study (Preliminary)

Job Category	SCE Population	SCE Payroll Dollars ($000s)	Payroll Weighting	SCE In Study +/- Market Base	TCC	LTI[1]	Benefits	Total Comp
Physical/Technical	3,628	$389,605.1	26.4%	15.1%	17.7%		-5.6%	13.1%
Clerical	2,574	$184,417.7	12.5%	-5.1%	-7.2%		-10.4%	-7.9%
Professional/Technical	4,421	$546,100.5	37.0%	-9.4%	-11.7%	-100.0%	-10.1%	-12.8%
Manager/Supervisor	1,816	$335,356.8	22.7%	-0.3%	1.2%	-93.4%	-5.0%	-5.1%
Executive	37	$19,089.7	1.3%	-7.9%	-16.6%	-17.8%	-19.8%	-17.4%
2021 Overall[2]	**12,476**	**$1,474,569.9**	**100.0%**	**-0.2%**	**-0.4%**	**-5.1%**	**-8.0%**	**-3.0%**

2018 GRC Study (From Final Report)

Job Category	SCE Population	SCE Payroll Dollars ($000s)	Payroll Weighting	SCE In Study +/- Market Base	TCC	LTI	Benefits	Total Comp
Physical/Technical	3,767	$366,678.1	24.8%	11.1%	16.5%		6.1%	15.0%
Clerical	3,075	$208,895.5	14.1%	-4.5%	-5.0%		2.6%	-3.2%
Professional/Technical	4,118	$495,080.2	33.5%	-13.2%	-11.2%	-100.0%	1.7%	-9.6%
Manager/Supervisor	2,215	$379,450.8	25.7%	-9.4%	-6.3%	-94.6%	0.5%	-7.6%
Executive	43	$26,205.2	1.8%	-10.3%	-17.7%	-21.5%	96.4%	-8.3%
2018 Overall	**13,218**	**$1,476,309.8**	**100.0%**	**-5.0%**	**-2.5%**	**-6.1%**	**4.3%**	**-1.9%**

2021 vs. 2018

Job Category	SCE Population	SCE Payroll Dollars ($000s)	Payroll Weighting	SCE In Study +/- Market Base	TCC	LTI	Benefits	Total Comp
Physical/Technical	-3.7%	6.3%		4.0%	1.2%		-11.7%	-1.9%
Clerical	-16.3%	-11.7%		-0.6%	-2.2%		-13.0%	-4.7%
Professional/Technical	7.4%	10.3%		3.8%	-0.5%		-11.9%	-3.1%
Manager/Supervisor	-18.0%	-11.6%		9.1%	7.5%	1.2%	-5.5%	2.5%
Executive	-14.0%	-27.2%		2.4%	1.1%	3.6%	-116.2%	-9.1%
2021 vs 2018 Overall	**-5.6%**	**-0.1%**		**4.9%**	**2.1%**	**1%**	**-12.3%**	**-1.0%**

(1) LTI statistics apply only to 110 eligible positions (below executive).

Analysis of Results: Executives

- The Study population for the Executive group has changed significantly from the 2018 Study, making it difficult to isolate the change in position to market Study over Study
  - 12 jobs are new to the Study
  - 1 job has the same match and incumbent
  - 4 jobs have the different matches or a new incumbent

			Total Comp			
2018 Job #	2021 Job #	Job Title	SCE	Market	Variance	Note
210	548	SVP & General Counsel	$1,029.1	$1,045.1	-1.5%	Same incumbent, new match
	549	EVP & General Counsel, EIX	$2,249.7	$2,772.8	-18.9%	New to Study
	550	VP Investor Relations, EIX	$652.5	$768.7	-15.1%	New to Study
214	551	VP & Treasurer	$601.9	$815.5	-26.2%	New incumbent, same match
211	552	SVP Corp Communications	$716.1	$837.9	-14.5%	Same incumbent, same match
	553	VP Local Public Affairs	$549.0	$740.0	-25.8%	New to Study
	554	Chief Executive Officer SCE	$2,329.4	$1,940.2	20.1%	New to Study
	555	EVP, CFO EIX	$2,751.8	$3,245.6	-15.2%	New to Study
	556	President and CEO, EIX	$9,204.2	$11,271.5	-18.3%	New to Study
	557	SVP, Human Resources, SCE/EIX	$1,242.1	$1,420.2	-12.5%	New to Study
209	558	SVP & CFO, SCE	$942.1	$2,120.9	-55.6%	New incumbent, same match
	559	SVP Transmission & Distribution	$947.4	$995.8	-4.9%	New to Study
	560	VP Distribution	$606.1	$548.7	10.5%	New to Study
215	561	VP Customer Programs & Services	$452.3	$901.9	-49.8%	New incumbent, new match
	562	VP, IT Enterprise Services	$481.4	$600.4	-19.8%	New to Study
	563	VP Tax	$731.9	$863.1	-15.2%	New to Study
	564	VP Transmission, Substations & Ops	$596.0	$702.9	-15.2%	New to Study

Analysis of Results: Executives

Analysis for non-executives was presented in the May 22 cash data review

Contributing Factors to the Shift in Position to Market: Executives

- Executive compensation has moved closer to market due to increases in base, total cash and LT
- Executive benefit values have dropped significantly to market primarily due to changes in executive retirement plans
- Overall, executives are -17.4% below the market in the 2021 Study

Executives Only					
Study Year	**Base**	**TCC**	**LTI**	**Benefits**	**Total Comp**
2021	-7.9%	-16.6%	-17.8%	-19.8%	-17.4%
2018	-10.3%	-17.7%	-21.5%	96.4%	-8.3%
Variance	**+2.4%**	**+1.1%**	**+3.6%**	**-116.2%**	**-9.1%**

Next Steps

- Discuss and resolve questions or issues
- Edit and distribute meeting notes
- Begin editing report

Appendix:
Final Results: Non-Executive Benefits Valuations
Originally Presented May 29, 2019

Overview

- Benefits are valued using two basic methods
  - Those related to pay are determined as a percentage of pay
  - Those unrelated to pay (such as medical benefits) are determined as a dollar amount
- The total compensation attributable to benefits is determined for each individual as follows:
  - Total compensation times the percentage of pay for pay related benefits
    Plus
  - Dollar amount for non-pay related benefits
- For example, consider an employee earning $60,000, with the following benefits values:
  - 10% of pay for pay-related benefits
    Plus
  - $15,000 for non-pay-related benefits
  - The total compensation attributable to benefits equals
    10% × $60,000 + $15,000 = $21,000
  - This represents 35% of pay for this sample employee

Overview

In general, in the 2021 study, the SCE benefits values for non-executives are:

- A lower percentage of compensation compared to utilities
  - For Manager/Supervisor and Professional/Technical job categories, now approximately
    - 11% to 17% below market (except for high-paid Manager/Supervisor which is 3% below market)
  - For Physical/Technical and Clerical, now approximately
    - 13% to 18% below market
- A higher percentage of compensation, except for low-paid, compared to general industry
  - For Manager/Supervisor and Professional/Technical job categories, now approximately
    - 6% below market to 8% above market (except for high-paid Manager/Supervisor which is 15% above market)
  - For Physical/Technical and Clerical, now approximately
    - 8% below market to 3% above market

Changes in Methods and Assumptions from the 2018 Study to the 2021 Study: Medical

- The following changes tend to **increase** benefit values for all companies
  - Medical inflation
    - E.g., active medical costs increased by 8% to 9% since the last study
  - Employer-funded HRA/HSAs may increase values since first claims of the year are "covered" vs. paid out of pocket by employee
- The following changes tend to **decrease** benefit values for all companies
  - Plan design changes such as moving to HRA for post-retirement medical, increases in co-payments and deductibles and lower coinsurance (passes cost increases along to employees)
  - Addition or increases of spousal and smoker surcharges
  - Medical family enrollment increased slightly for single coverage and decreased slightly at Employee+Child(ren) tier
    - 2018: 31% EE, 14% EE+SP, 16% EE+CH, 39% EE+FAM
    - 2021: 32% EE, 14% EE+SP, 15% EE+CH, 39% EE+FAM
  - There were more opt-outs based on SCE experience
    - 5% in 2018 study
    - 6% in 2021 study
  - Retiree health care accounts are valued as pensions and have decreased due to the increase in discount rate

Changes in Methods and Assumptions from the 2018 Study to the 2021 Study: Medical

- The following changes tend to **decrease** benefit values for SCE
  - High HMO enrollment
    - SCE has 77% normalized HMO enrollment, while the peer group averages 17% to 23% HMO enrollment
  - With lower cost structure, SCE values have not increased as much as general industry
  - Plan design changes such as moving to HRA for post-retirement medical

Changes in Methods and Assumptions from the 2018 Study to the 2021 Study: Retirement

- Retirement benefits generally account for about 90% of the total percent of pay values
  - Other pay related benefits include disability and life insurance
- The most important features of retirement plans are definition of pay, pension accruals and defined contribution employer contributions
  - Traditional defined benefit pension plans are usually more valuable than cash balance and defined contribution arrangements
  - Nonqualified benefits have not been valued for the non-executive group
- The following changes tend to decrease benefit values for all companies
  - Increase in the discount rate used to value long-term liabilities
    - SCE increased its discount rate from 3.85% in the 2018 study to 4.19% in the 2021 study
  - Change in assumed salary increase rates
    - SCE changed its salary increase rate from 4.0% in the 2018 study to an age-graded schedule that begins at 7.0% and decreases by age to an ultimate level of 2.0% at age 55

Changes in Peer Groups from the 2018 Study to the 2021 Study: Retirement

- Utility company peer group (19 companies)
  - Designs of the companies changed between the 2018 and 2021 studies
  - Of these:
    - 18 provide a retirement plan in addition to a matched savings plan
      - 11 defined benefit with matched savings
        - 1 closed their traditional defined benefit pension plan and implemented a cash balance plan since the last study
      - 7 defined contribution with matched savings
        - 1 closed their cash balance defined benefit plan and implemented a defined contribution plan since the last study
    - 1 provides a defined benefit pension plan with no matched savings
  - 79% include bonus in the definition of pay in their non-matching retirement plans while SCE excludes bonus
  - Average employer contribution to defined contribution retirement is 1.4% of pay
  - Average 401k match is 4.8% of pay (61% include bonus) vs. SCE's 6.0% (base pay only)

Changes in Peer Groups from the 2018 Study to the 2021 Study: Retirement

- General industry peer group (19 companies)
  - Designs of the companies in both the 2018 and 2021 studies stayed relatively constant
  - Of these:
    - 11 provide a retirement plan in addition to a matched savings plan
      - 1 defined benefit with matched savings
      - 10 defined contribution with matched savings
        - 1 closed their defined benefit plan
    - 1 provides defined benefit pension and defined contribution with no matched savings
    - 1 provides defined contribution with no matched savings
    - 6 provide only a matched savings plan
  - 77% include bonus in the definition of pay in their non-matching retirement plans while SCE excludes bonus
  - Average employer contribution to defined contribution retirement is 3.2% of pay
  - Average 401k match is 4.8% of pay (76% include bonus) vs. SCE's 6.0% (base pay only)

Summary of Illustrative Values

- The following slides compare the benefit values for selected illustrative employees in each job category
- The following information is illustrated
  - Average value for all peer company plans shown
  - Data points represent ranges of pay by job category
    - "Low", "middle," and "high" points of the pay ranges for manager/supervisor and professional/technical jobs
    - "Low" and "high" for physical/technical and clerical jobs, because range is not as wide
  - Two values are shown
    - 2018 study – SCE population and assumptions
    - 2021 study – SCE population and assumptions
  - Comparisons between these values are also shown

Utility Industry Manager/Supervisor

Job Category Manager/Supervisor

	2018 Study SCE Population/Assumptions					2021 Study SCE Population/Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Pay Level	**Utility Industry Group Average**									
Low	62,700	11.5%	17,755	24,974	39.8%	62,700	10.6%	18,290	24,928	39.8%
Medium	153,900	11.6%	17,636	35,457	23.0%	153,900	10.8%	18,133	34,732	22.6%
High	313,500	9.7%	17,530	47,971	15.3%	313,500	9.6%	18,023	48,107	15.3%
	SCE									
Low	62,700	17.3%	13,613	24,442	39.0%	62,700	9.8%	14,524	20,698	33.0%
Medium	153,900	13.4%	13,613	34,301	22.3%	153,900	10.1%	14,524	30,117	19.6%
High	313,500	10.3%	13,613	46,057	14.7%	313,500	10.3%	14,524	46,815	14.9%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	-2.1%	-17.0%
Medium	-3.3%	-13.3%
High	-4.0%	-2.7%

Utility Industry Professional/Technical

Job Category Professional/Technical

	2018 Study SCE Population/Assumptions					2021 Study SCE Population/Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Pay Level	**Utility Industry Group Average**									
Low	62,700	10.7%	16,148	22,870	36.5%	62,700	9.7%	16,995	23,078	36.8%
Medium	85,500	10.7%	16,148	25,326	29.6%	85,500	9.8%	16,995	25,334	29.6%
High	165,300	10.3%	15,958	32,999	20.0%	165,300	9.8%	16,910	33,111	20.0%
	SCE									
Low	62,700	15.1%	12,432	21,879	34.9%	62,700	9.5%	13,402	19,379	30.9%
Medium	85,500	13.9%	12,432	24,350	28.5%	85,500	9.6%	13,402	21,632	25.3%
High	165,300	12.0%	12,432	32,327	19.6%	165,300	9.7%	13,402	29,502	17.8%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	-4.3%	-16.0%
Medium	-3.9%	-14.6%
High	-2.0%	-10.9%

Utility Industry Physical/Technical

Job Category Physical/Technical

	2018 Study SCE Population/Assumptions					2021 Study SCE Population/Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Pay Level	**Utility Industry Group Average**									
Low	45,000	10.2%	14,460	19,030	42.3%	45,000	9.0%	14,934	18,999	42.2%
High	85,000	10.2%	14,424	23,060	27.1%	85,000	9.1%	14,861	22,573	26.6%
	SCE									
Low	45,000	16.4%	11,118	18,511	41.1%	45,000	9.3%	11,578	15,742	35.0%
High	85,000	13.6%	11,118	22,691	26.7%	85,000	9.4%	11,578	19,598	23.1%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	-2.7%	-17.1%
High	-1.6%	-13.2%

Utility Industry Clerical

Job Category Clerical

	2018 Study SCE Population/Assumptions					2021 Study SCE Population/Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Pay Level	**Utility Industry Group Average**									
Low	36,000	9.5%	15,932	19,359	53.8%	36,000	8.5%	17,104	20,176	56.0%
High	77,600	9.5%	15,857	23,233	29.9%	77,600	8.6%	17,031	23,689	30.5%
	SCE									
Low	36,000	16.0%	12,229	18,004	50.0%	36,000	8.4%	13,439	16,463	45.7%
High	77,600	12.5%	12,229	21,956	28.3%	77,600	8.6%	13,439	20,143	26.0%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	-7.0%	-18.4%
High	-5.5%	-15.0%

General Industry Manager/Supervisor

Job Category Manager/Supervisor

	2018 Study SCE Population/Assumptions					2021 Study SCE Population/Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Pay Level	**General Industry Group Average**									
Low	62,700	8.5%	15,877	21,235	33.9%	62,700	7.9%	17,028	21,969	35.0%
Medium	153,900	8.9%	15,506	29,171	19.0%	153,900	8.2%	16,563	29,181	19.0%
High	313,500	7.9%	15,414	40,258	12.8%	313,500	7.7%	16,451	40,571	12.9%
	SCE									
Low	62,700	17.3%	13,613	24,442	39.0%	62,700	9.8%	14,524	20,698	33.0%
Medium	153,900	13.4%	13,613	34,301	22.3%	153,900	10.1%	14,524	30,117	19.6%
High	313,500	10.3%	13,613	46,057	14.7%	313,500	10.3%	14,524	46,815	14.9%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	15.1%	-5.8%
Medium	17.6%	3.2%
High	14.4%	15.4%

General Industry
Professional/Technical

Job Category Professional/Technical

	2018 Study SCE Population/Assumptions					2021 Study SCE Population/Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Pay Level	**General Industry Group Average**									
Low	62,700	7.8%	14,277	19,185	30.6%	62,700	6.9%	15,824	20,131	32.1%
Medium	85,500	7.9%	14,231	20,991	24.6%	85,500	6.9%	15,695	21,613	25.3%
High	165,300	8.0%	13,920	27,166	16.4%	165,300	7.2%	15,342	27,280	16.5%
	SCE									
Low	62,700	15.1%	12,432	21,879	34.9%	62,700	9.5%	13,402	19,379	30.9%
Medium	85,500	13.9%	12,432	24,350	28.5%	85,500	9.6%	13,402	21,632	25.3%
High	165,300	12.0%	12,432	32,327	19.6%	165,300	9.7%	13,402	29,502	17.8%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	14.0%	-3.7%
Medium	16.0%	0.1%
High	19.0%	8.1%

General Industry Physical/Technical

Job Category Physical/Technical

	2018 Study SCE Population/Assumptions					2021 Study SCE Population/Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Pay Level	**General Industry Group Average**									
Low	45,000	7.3%	12,973	16,254	36.1%	45,000	6.2%	13,830	16,636	37.0%
High	85,000	7.4%	12,856	19,117	22.5%	85,000	6.3%	13,690	19,012	22.4%
	SCE									
Low	45,000	16.4%	11,118	18,511	41.1%	45,000	9.3%	11,578	15,742	35.0%
High	85,000	13.6%	11,118	22,691	26.7%	85,000	9.4%	11,578	19,598	23.1%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	13.9%	-5.4%
High	18.7%	3.1%

General Industry Clerical

Job Category Clerical

	2018 Study SCE Population/Assumptions					2021 Study SCE Population/Assumptions				
	Total Cash	Other	Medical	Total $	Total %	Total Cash	Other	Medical	Total $	Total %
	A	B	C	D=(AxB)+C	E=D/A	A	B	C	D=(AxB)+C	E=D/A
Pay Level	**General Industry Group Average**									
Low	36,000	6.7%	14,264	16,664	46.3%	36,000	5.6%	15,934	17,958	49.9%
High	77,600	6.7%	14,100	19,326	24.9%	77,600	5.6%	15,756	20,124	25.9%
	SCE									
Low	36,000	16.0%	12,229	18,004	50.0%	36,000	8.4%	13,439	16,463	45.7%
High	77,600	12.5%	12,229	21,956	28.3%	77,600	8.6%	13,439	20,143	26.0%

SCE Relative to the Peer Group Average = SCE Total $ / Comparators Total $

	2018	2021
Low	8.0%	-8.3%
High	13.6%	0.1%

SCE ONLY						
Separation Type	**2014**	**2015**	**2016**	**2017**	**2018**	**Total**
Involuntary - RIF	6	14	9	5	9	43
Voluntary - Other	2	2	3	1	0	8
Voluntary - Retirement	3	2	5	5	9	24
TOTAL	**11**	**18**	**17**	**11**	**18**	**75**