CPUC Docket: A.23-05-010
Exhibit Number: TURN-02-Atch1
Witness: Jennifer Dowdell

PREPARED TESTIMONY OF JENNIFER DOWDELL

ADDRESSING AFFORDABILITY AND OTHER ISSUES IN SCE'S 2025 GRC

ATTACHMENTS

Submitted on Behalf of

THE UTILITY REFORM NETWORK

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Oakland, CA 94610

Telephone: (415) 929-8876
E-mail: jdowdell@turn.org

February 29, 2024

Southern California Edison
A.23-05-010 – SCE 2025 GRC

DATA REQUEST SET T U R N - S C E - 0 4 9

To: TURN
Prepared by: Lin Zhang
Job Title: Senior Advisor
Received Date: 1/11/2024

Response Date: 1/22/2024

Question 01:
Referring to WPSCE07V02BKA (SCE-07 Vol.02 Working Cash Workpapers), p. 222/241

Please provide the live excel spreadsheet showing the calculation of expense lag for goods and services PO and non-PO expense.

Response to Question 01:
The page numbers listed in the question do not align with SCE's Goods and Services Lead Lag Study. SCE assumes that TURN is seeking an explanation to p. 219 of WPSCE07V02BkA and responds as such.

Please see SCE's response PAO-SCE-Verbal-002, SCE-07 Results of Operations, Volume-02 Rate Base, Depreciation Expenses, and Taxes file titled "15. Goods and Services_Workpapers" for the live version of the workpaper.

Southern California Edison
A.23-05-010 – SCE 2025 GRC

DATA REQUEST SET T U R N - S C E - 0 7 7

To: TURN
Prepared by: Zachary W King
Job Title: Principal Manager, Tax
Received Date: 2/1/2024

Response Date: 2/12/2024

Question 03:
Please provide SCE's projected minimum cash tax liability for Federal income taxes (corporate alternative minimum tax) pursuant to the Inflation Reduction Act for each year of this 2025 GRC cycle (2025-2028).

Response to Question 03:

A breakdown of corporate alternative minimum tax pursuant to the Inflation Reduction Act (CAMT) was computed at Table A-4.17 of WP SCE-07, Vol. 2, Book B, page 40. Table A-4.17, a copy of which is reproduced below, is a forecast of the CAMT SCE will owe based on activities within this GRC cycle.

Corporate Alternative Minimum Tax (AMT)
Inflation Reduciton Act of 2022, Section 10101

TABLE A - 4.17

Line No.	ITEM		Recorded 2022	Estimated 2023	2024	2025	2026	2027	2028
1	Book income		5,600,454	6,250,862	6,797,544	7,697,868	8,240,492	8,814,406	9,475,705
2	Less: prior year CA franchise tax		(2,400)	(64,522)	(116,519)	(151,239)	(174,588)	(203,170)	(228,858)
3	Less: book depreciation - flow-through		(815,936)	(922,096)	(1,013,020)	(1,215,929)	(1,320,212)	(1,407,008)	(1,520,259)
4	Less: book depreciation COR		(415,000)	(415,000)	(415,000)	(415,000)	(415,000)	(415,000)	(415,000)
5	Less: tax depreciation M/L		(1,472,395)	(1,649,738)	(1,823,744)	(1,961,230)	(2,096,708)	(2,257,395)	(2,499,167)
6	Interest deduction		(766,740)	(795,981)	(850,868)	(905,746)	(968,266)	(1,034,783)	(1,109,571)
7	Adjusted Financial Statement Income		2,127,983	2,403,526	2,578,393	3,048,723	3,265,717	3,497,051	3,702,850
8	Subject to Corporate Alternative Miminum Tax (CAMT)		No	No	Yes	Yes	Yes	Yes	Yes
9	Book AMT @ 15%	15%			386,759	457,308	489,858	524,558	555,427
10	Regular tax [1]				358,061	396,999	415,754	461,262	507,087
11	AMT Tax				28,698	60,309	74,104	63,296	48,340
12	Total Tax Liability/(benefit)				386,759	457,308	489,858	524,558	555,427
13	AMT Tax				28,698	60,309	74,104	63,296	48,340
14	CPUC %				81.74%	81.74%	81.74%	81.74%	81.74%
15	AMT - CPUC				23,456	49,294	60,569	51,735	39,511
16	AMT - FERC				5,242	11,016	13,535	11,561	8,829
17	AMT - CPUC with gross up	1.3886			32,571	68,448	84,104	71,837	54,864

Note:
[1] CAMT @ 15% and regular tax are before credits, assuming credit amounts are the same for both

Southern California Edison
A.23-05-010 – SCE 2025 GRC

DATA REQUEST SET T U R N - S C E - 0 7 7

To: TURN
Prepared by: Zachary W King
Job Title: Principal Manager, Tax
Received Date: 2/1/2024

Response Date: 2/12/2024

Question 04:
Does SCE expect that it will pay or owe cash state income taxes during the 2025 GRC period?

Response to Question 04:

Yes.

Southern California Edison
A.23-05-010 – SCE 2025 GRC

DATA REQUEST SET T U R N - S C E - 0 7 7

To: TURN
Prepared by: Zachary W King
Job Title: Principal Manager, Tax
Received Date: 2/1/2024

Response Date: 2/13/2024

Question 05.a-b:
If the answer to Question 4 above is anything other than an unqualified "no," please give the tax year during the 2025 GRC cycle in which SCE expects to pay cash state income taxes.

a. If the answer to Question 4 above is anything other than an unqualified "no," please give each, and every reason why SCE expects to pay cash state income taxes for any tax year during the 2025 GRC cycle along with supporting documentation as to why this is the case.
b. If the answer to Question 4 above is anything other than an unqualified "no," please give SCE's estimate of the cash state income taxes it expects to pay during this 2025 GRC period (tax years 2025-2028).

Response to Question 05.a-b:

CONFIDENTIAL
The Attachment(s) Are Marked Confidential In Accordance With Applicable Law and Regulation. Basis for Confidentiality In Accompanying Confidentiality Declaration. Public Disclosure Restricted.

SCE expects to be a payer of cash state income taxes for each year starting with 2025 and continuing through 2028, i.e., the end of this GRC cycle.

a. As noted in response to Question 01.d, SCE did not pay California state income taxes from 2018 through 2023 due to NOLs. SCE expects this will not be the case during the 2025 GRC cycle for the following reasons:
   1. SCE expects to fully utilize California NOLs during this GRC cycle and therefore this deduction will no longer be available to reduce taxable income in the future
   2. Alternative minimum tax (AMT). A taxpayer's tax liability is the greater of the regular income tax or the AMT. California's AMT rules both limit the NOL carryforward available to offset taxable income and also limit the annual AMT NOL deduction to 90% of alternative minimum taxable income. Consequently, SCE will owe significant California AMT during the 2025 GRC cycle.

b. b. For SCE's estimate of cash state income taxes during this GRC cycle, please refer to the accompanying Excel file titled TURN SCE-077 Q5b Attachment.xlsx.

Southern California Edison
A.23-05-010 – SCE 2025 GRC

DATA REQUEST SET T U R N - S C E - 0 8 9

To: TURN
Prepared by: Jonathan Rumble
Job Title: Principal Manager
Received Date: 2/6/2024

Response Date: 2/22/2024

Question 01.a-c:
In SCE07V2 p. 49, Table IV-29, Customer Deposits Decline, SCE provides customer deposit ending balances by month for 2020-2022.

a. Please provide this information in the same monthly format for 2023.

b. Please provide all factor that SCE believes impact the level of customer deposit balances.

c. Please provide SCE's forecast the customer deposits ending balance for December 2024, December 2025, December 2026, December 2027, and December 2028. Please explain the methodology for the forecast. If SCE believes that it is unable to provide a forecast, please explain why it is unable to do so when SCE forecasted customer deposits in previous GRC proceeding(s).

Response to Question 01.a-c:

a. Please see attached Excel file – TABLE_TURN_SCE_089_01.a.xlsx

b. The factors that are impacting the level of customer deposit balances are the continued reduction in residential deposits held due to restrictions on collecting deposits for this customer segment along with a forecast increase in commercial deposits due to the resumption of collections post COVID protections.

c. Please see attached Excel file referenced in part a. SCE utilized deposit trends from 2023 to forecast future years. Decision 20-06-003 dated June 11, 2020 restricted SCE from the future collection of security deposits from residential customers. Due to this restriction, residential security deposits are on a downward trend and are anticipated to be depleted by the end of 2028. However, SCE continues to collect security deposits on commercial accounts. As a result, SCE split commercial and residential deposits allowing for independent calculations, then merged the figures for a final projection.

Table IV-20 Customer Deposit Decline ($ in millions)

	2023	2024	2025	2026	2027
January	173	182	174	175	182
February	175	181	174	176	183
March	179	180	174	176	183
April	179	179	174	176	184
May	180	178	174	177	185
June	179	177	174	177	186
July	180	176	174	178	187
August	181	176	174	179	187
September	182	175	174	179	188
October	183	175	174	180	189
November	184	174	174	180	190
December	183	174	175	181	191

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Table IV-20 Customer Deposit Decline ($ in millions)

	2023	2024	2025	2026	2027	2028
January	173	182	174	175	182	192
February	175	181	174	176	183	193
March	179	180	174	176	183	194
April	179	179	174	176	184	195
May	180	178	174	177	185	196
June	179	177	174	177	186	197
July	180	176	174	178	187	198
August	181	176	174	179	187	199
September	182	175	174	179	188	200
October	183	175	174	180	189	201
November	184	174	174	180	190	202
December	183	174	175	181	191	203

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) MONTHLY DISCONNECT DATA REPORT

ANNA VALDBERG
JANE LEE COLE

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SOUTHERN CALIFORNIA EDISON COMPANY

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Dated: **January 22, 2019**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) MONTHLY DISCONNECT DATA REPORT

Pursuant to the California Public Utilities Commission's (Commission) decision D.18-12-013, ordering paragraph (OP) 6, Southern California Edison Company (SCE) hereby submits its monthly report (in Appendix A) detailing specific disconnection data as specified in Appendix B of D.18-12-013, or in a form otherwise approved by the Energy Division. As ordered by the Commission in D.18-12-013, OP 6, the first monthly report will be filed on the 20th of the month[1] following the mailing of this order and further reports filed the 20th of each month (or the next business day) thereafter until the interim protections have ended or further direction is provided.

[1] Because January 20, 2019 is a Sunday and the first day thereafter is Martin Luther King Jr. Day, which is a CPUC observed holiday, the time limit for filing this report is extended to the day after which is January 22, 2019, pursuant to Rule 1.15 of the CPUC Rules of Practice and Procedure.

Respectfully submitted,

ANNA VALDBERG
JANE LEE COLE

/s/ Jane Lee Cole
By: Jane Lee Cole

Attorneys for
SOUTHERN CALIFORNIA EDISON COMPANY

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Date: January 22, 2019

Appendix A

January 2019 Monthly Disconnect Data Report

Section 1 - Payment arrangements and bill assistance

Number of customers requesting bill assistance					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	85,041	88,263	1,690	7,599	174,994
Sep-18	84,869	86,856	1,636	7,465	173,361
Oct-18	81,234	83,255	1,518	7,525	166,007
Nov-18	61,931	55,988	1,041	5,625	118,960
Dec-18	63,878	58,352	1,026	5,307	123,256

Number of customers with ongoing payment plans					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	4,672	3,068	62	126	7,802
Sep-18	4,556	2,915	67	128	7,538
Oct-18	4,636	2,928	68	151	7,632
Nov-18	4,733	2,871	66	152	7,670
Dec-18	5,240	3,122	77	210	8,439

Number of customers receiving payment extension of <30 days					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	40,638	41,491	737	2,516	82,866
Sep-18	40,030	39,837	706	2,386	80,573
Oct-18	35,213	34,879	592	2,267	70,684
Nov-18	28,620	24,526	452	1,750	53,598
Dec-18	31,746	28,503	468	1,738	60,717

Number of customers with 3 month payment arrangements					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	33,313	34,980	711	2,709	69,004
Sep-18	30,575	32,502	609	2,497	63,686
Oct-18	26,288	27,959	522	2,278	54,769
Nov-18	18,899	17,920	328	1,613	37,147
Dec-18	19,995	18,521	340	1,486	38,856

Number of customers with 3 month+ payment arrangements					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	2,757	1,934	76	332	4,767
Sep-18	3,005	2,095	77	373	5,177
Oct-18	3,657	2,535	100	440	6,292
Nov-18	2,624	1,603	69	343	4,296
Dec-18	2,502	1,613	69	330	4,184

Number of customers who were connected with outside bill payment assistance from organizations (IOU/Local Service Provider)					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	654	4,155	17	N/A	4,826
Sep-18	1,233	3,832	16	N/A	5,081
Oct-18	1,482	3,960	8	N/A	5,450
Nov-18	1,149	2,394	6	N/A	3,549
Dec-18	829	1,867	5	N/A	2,701

Number of customers who received outside bill payment assistance from organizations (IOU/Local Service Provider)					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	243	3,232	2	N/A	3,477
Sep-18	822	5,164	6	N/A	5,992
Oct-18	1,011	4,507	10	N/A	5,528
Nov-18	1,540	4,908	12	N/A	6,460
Dec-18	654	2,257	4	N/A	2,915

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 2 - Broken Payment Arrangements

Number of customers with late or broken 3 month payment arrangements					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	12,478	15,514	278	916	28,270
Sep-18	15,153	17,056	300	1,117	32,509
Oct-18	20,673	21,236	418	1,463	42,327
Nov-18	17,229	15,503	343	1,292	33,075
Dec-18	13,459	12,588	270	1,017	26,317

Number of customers with late or broken 3 month+ payment arrangements					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	1,303	1,041	43	194	2,387
Sep-18	1,346	1,086	36	174	2,468
Oct-18	2,172	1,549	48	266	3,769
Nov-18	2,174	1,402	67	302	3,643
Dec-18	2,025	1,259	44	267	3,328

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 3 - Arrearages

Number of customers in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	493,131	419,704	4,960	35,145	917,795
Sep-18	509,844	455,189	5,704	38,351	970,737
Oct-18	539,998	481,393	6,011	41,290	1,027,402
Nov-18	571,114	473,023	6,185	43,350	1,050,322
Dec-18	636,092	506,945	6,352	43,854	1,149,389

Number of customers 31-60 days in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	320,817	241,708	3,246	19,543	565,771
Sep-18	341,693	267,741	3,812	21,780	613,246
Oct-18	348,794	266,619	3,778	22,106	619,191
Nov-18	333,867	204,811	3,533	20,906	542,211
Dec-18	356,460	241,781	3,404	20,304	601,645

Number of customers 61-90 days in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	84,246	86,604	848	6,261	171,698
Sep-18	90,733	98,866	1,093	7,792	190,692
Oct-18	108,193	116,951	1,324	9,482	226,468
Nov-18	126,705	134,892	1,474	10,368	263,071
Dec-18	135,721	102,911	1,486	9,310	240,118

Number of customers 91-120 days in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	36,947	41,506	394	3,249	78,847
Sep-18	32,347	39,368	349	3,129	72,064
Oct-18	39,253	49,964	463	4,160	89,680
Nov-18	57,968	73,725	680	5,888	132,373
Dec-18	75,119	83,379	812	6,526	159,310

Number of customers 121+ days in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	51,121	49,886	472	6,092	101,479
Sep-18	45,071	49,214	450	5,650	94,735
Oct-18	43,758	47,859	446	5,542	92,063
Nov-18	52,574	59,595	498	6,188	112,667
Dec-18	68,792	78,874	650	7,714	148,316

Number of accounts paid 100% within 30 days from statement date					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	2,452,430	799,833	12,371	76,704	3,264,634
Sep-18	2,156,860	726,831	10,893	65,888	2,894,584
Oct-18	2,769,611	929,435	15,534	90,361	3,714,580
Nov-18	2,159,238	580,914	12,697	76,861	2,752,849
Dec-18	1,953,806	547,874	10,846	66,603	2,512,526

Number of accounts paid 50-99% within 30 days from statement date					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	281,170	168,114	3,039	6,672	452,323
Sep-18	222,244	132,018	2,500	16,486	356,762
Oct-18	145,276	71,679	1,400	9,366	218,355
Nov-18	153,151	67,855	956	5,406	221,962
Dec-18	270,851	144,925	1,820	10,066	417,596

Number of accounts paid <50% within 30 days from statement date					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	349,833	231,503	2,883	9,749	584,219
Sep-18	282,780	183,050	2,152	11,793	467,982
Oct-18	280,199	177,669	1,936	4,708	459,804
Nov-18	290,091	172,049	2,044	12,998	464,184
Dec-18	370,640	247,595	2,388	18,453	620,623

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 3 - Arrearages By Number of Days

Total Dollar amount of Residential accounts in arrears - Aug 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 73,646,020	44%
31-60 days	$ 72,882,940	44%
61-90 days	$ 10,807,968	6%
91-120 days	$ 4,231,268	3%
121-150 days	$ 1,796,373	1%
151-179 days	$ 1,318,789	1%
180+ days	$ 2,534,762	2%
Total	$ 167,218,119	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Aug 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 73,646,020	44%
31-60 days	$ 72,882,940	44%
61-90 days	$ 10,807,968	6%
91-120 days	$ 4,231,268	3%
121-150 days	$ 1,796,373	1%
151-179 days	$ 1,318,789	1%
180+ days	$ 2,534,762	2%
Total	$ 167,218,119	100%

Total Dollar amount of CARE accounts in arrears - Aug 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 73,646,020	44%
31-60 days	$ 72,882,940	44%
61-90 days	$ 10,807,968	6%
91-120 days	$ 4,231,268	3%
121-150 days	$ 1,796,373	1%
151-179 days	$ 1,318,789	1%
180+ days	$ 2,534,762	2%
Total	$ 167,218,119	100%

Total Dollar amount of FERA accounts in arrears - Aug 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 73,646,020	44%
31-60 days	$ 72,882,940	44%
61-90 days	$ 10,807,968	6%
91-120 days	$ 4,231,268	3%
121-150 days	$ 1,796,373	1%
151-179 days	$ 1,318,789	1%
180+ days	$ 2,534,762	2%
Total	$ 167,218,119	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Aug 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 73,646,020	44%
31-60 days	$ 72,882,940	44%
61-90 days	$ 10,807,968	6%
91-120 days	$ 4,231,268	3%
121-150 days	$ 1,796,373	1%
151-179 days	$ 1,318,789	1%
180+ days	$ 2,534,762	2%
Total	$ 167,218,119	100%

Total Dollar amount of Residential accounts in arrears - Sep 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 57,343,456	32%
31-60 days	$ 93,492,513	52%
61-90 days	$ 18,208,612	10%
91-120 days	$ 4,557,223	3%
121-150 days	$ 2,059,394	1%
151-179 days	$ 938,592	1%
180+ days	$ 2,283,227	1%
Total	$ 178,883,015	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Sep 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 40,596,637	35%
31-60 days	$ 61,295,054	52%
61-90 days	$ 9,816,042	8%
91-120 days	$ 2,360,837	2%
121-150 days	$ 1,102,963	1%
151-179 days	$ 554,107	0%
180+ days	$ 1,314,386	1%
Total	$ 117,040,025	100%

Total Dollar amount of CARE accounts in arrears - Sep 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 16,352,762	27%
31-60 days	$ 31,442,829	52%
61-90 days	$ 8,243,057	14%
91-120 days	$ 2,160,984	4%
121-150 days	$ 944,701	2%
151-179 days	$ 373,845	1%
180+ days	$ 960,431	2%
Total	$ 60,478,609	100%

Total Dollar amount of FERA accounts in arrears - Sep 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 394,057	29%
31-60 days	$ 754,630	55%
61-90 days	$ 149,513	11%
91-120 days	$ 35,401	3%
121-150 days	$ 11,730	1%
151-179 days	$ 10,639	1%
180+ days	$ 8,410	1%
Total	$ 1,364,381	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Sep 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 2,774,391	29%
31-60 days	$ 4,757,274	49%
61-90 days	$ 1,231,716	13%
91-120 days	$ 352,210	4%
121-150 days	$ 164,033	2%
151-179 days	$ 103,873	1%
180+ days	$ 336,464	3%
Total	$ 9,719,960	100%

Total Dollar amount of Residential accounts in arrears - Oct 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 29,602,392	21%
31-60 days	$ 71,636,939	52%
61-90 days	$ 24,211,577	18%
91-120 days	$ 7,365,135	5%
121-150 days	$ 2,154,813	2%
151-179 days	$ 1,042,764	1%
180+ days	$ 2,051,092	1%
Total	$ 138,064,711	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Oct 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 22,229,307	25%
31-60 days	$ 47,522,038	53%
61-90 days	$ 13,320,195	15%
91-120 days	$ 3,719,768	4%
121-150 days	$ 1,138,044	1%
151-179 days	$ 572,535	1%
180+ days	$ 1,251,792	1%
Total	$ 89,753,679	100%

Total Dollar amount of CARE accounts in arrears - Oct 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 7,153,252	15%
31-60 days	$ 23,554,364	50%
61-90 days	$ 10,694,401	23%
91-120 days	$ 3,590,779	8%
121-150 days	$ 1,000,322	2%
151-179 days	$ 464,427	1%
180+ days	$ 788,606	2%
Total	$ 47,246,151	100%

Total Dollar amount of FERA accounts in arrears - Oct 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 219,833	21%
31-60 days	$ 560,536	53%
61-90 days	$ 196,981	18%
91-120 days	$ 54,588	5%
121-150 days	$ 16,447	2%
151-179 days	$ 5,802	1%
180+ days	$ 10,695	1%
Total	$ 1,064,881	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Oct 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 1,646,272	20%
31-60 days	$ 3,666,796	44%
61-90 days	$ 1,767,558	21%
91-120 days	$ 611,422	7%
121-150 days	$ 195,177	2%
151-179 days	$ 95,926	1%
180+ days	$ 319,144	4%
Total	$ 8,302,295	100%

Total Dollar amount of Residential accounts in arrears - Nov 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 34,845,611	30%
31-60 days	$ 39,072,562	34%
61-90 days	$ 23,079,255	20%
91-120 days	$ 12,042,931	10%
121-150 days	$ 3,446,038	3%
151-179 days	$ 1,302,035	1%
180+ days	$ 2,108,684	2%
Total	$ 115,897,114	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Nov 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 25,419,334	33%
31-60 days	$ 28,361,071	37%
61-90 days	$ 12,924,056	17%
91-120 days	$ 6,121,962	8%
121-150 days	$ 1,760,934	2%
151-179 days	$ 688,745	1%
180+ days	$ 1,260,729	2%
Total	$ 76,536,831	100%

Total Dollar amount of CARE accounts in arrears - Nov 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 9,187,478	24%
31-60 days	$ 10,375,175	27%
61-90 days	$ 9,976,497	26%
91-120 days	$ 5,831,273	15%
121-150 days	$ 1,661,149	4%
151-179 days	$ 603,831	2%
180+ days	$ 838,633	2%
Total	$ 38,474,036	100%

Total Dollar amount of FERA accounts in arrears - Nov 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 238,798	27%
31-60 days	$ 336,315	38%
61-90 days	$ 178,701	20%
91-120 days	$ 89,697	10%
121-150 days	$ 23,955	3%
151-179 days	$ 9,459	1%
180+ days	$ 9,322	1%
Total	$ 886,247	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Nov 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 1,728,285	24%
31-60 days	$ 2,220,669	31%
61-90 days	$ 1,526,481	21%
91-120 days	$ 1,062,694	15%
121-150 days	$ 309,606	4%
151-179 days	$ 122,385	2%
180+ days	$ 302,611	4%
Total	$ 7,272,731	100%

Total Dollar amount of Residential accounts in arrears - Dec 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 36,816,535	31%
31-60 days	$ 47,446,575	40%
61-90 days	$ 13,580,528	11%
91-120 days	$ 11,302,298	9%
121-150 days	$ 5,949,988	5%
151-179 days	$ 2,046,154	2%
180+ days	$ 2,298,308	2%
Total	$ 119,440,387	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Dec 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 27,764,979	34%
31-60 days	$ 33,705,071	41%
61-90 days	$ 8,931,038	11%
91-120 days	$ 6,234,608	8%
121-150 days	$ 3,091,445	4%
151-179 days	$ 1,086,735	1%
180+ days	$ 1,407,216	2%
Total	$ 82,221,091	100%

Total Dollar amount of CARE accounts in arrears - Dec 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 8,822,239	24%
31-60 days	$ 13,392,383	37%
61-90 days	$ 4,522,173	12%
91-120 days	$ 4,984,981	14%
121-150 days	$ 2,818,732	8%
151-179 days	$ 947,946	3%
180+ days	$ 882,085	2%
Total	$ 36,370,538	100%

Total Dollar amount of FERA accounts in arrears - Dec 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 229,317	27%
31-60 days	$ 349,122	41%
61-90 days	$ 127,317	15%
91-120 days	$ 82,709	10%
121-150 days	$ 39,812	5%
151-179 days	$ 11,473	1%
180+ days	$ 9,007	1%
Total	$ 848,758	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Dec 2018		
Number of Days	All Balances	% of total outstanding
20-30 days	$ 1,793,888	26%
31-60 days	$ 2,211,384	32%
61-90 days	$ 898,514	13%
91-120 days	$ 871,533	13%
121-150 days	$ 623,104	9%
151-179 days	$ 226,031	3%
180+ days	$ 305,317	4%
Total	$ 6,929,771	100%

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 3 - Arrearages by Amount Owed

Total Dollar amount of Residential accounts in arrears - Aug 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 70,802,002	76%
$1000 - $500	$ 12,217,653	13%
$2000-1000	$ 5,433,492	6%
>$2000	$ 5,116,952	5%
Total	$ 93,570,099	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Aug 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 41,331,613	70%
$1000 - $500	$ 9,537,805	16%
$2000-1000	$ 4,230,288	7%
>$2000	$ 4,319,463	7%
Total	$ 59,419,169	100%

Total Dollar amount of CARE accounts in arrears - Aug 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 28,935,733	87%
$1000 - $500	$ 2,559,937	8%
$2000-1000	$ 1,156,702	3%
>$2000	$ 767,816	2%
Total	$ 33,420,188	100%

Total Dollar amount of FERA accounts in arrears - Aug 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 534,656	73%
$1000 - $500	$ 119,911	16%
$2000-1000	$ 46,502	6%
>$2000	$ 29,672	4%
Total	$ 730,741	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Aug 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 2,965,920	57%
$1000 - $500	$ 1,005,483	19%
$2000-1000	$ 613,290	12%
>$2000	$ 605,836	12%
Total	$ 5,190,529	100%

Total number of accounts in arrears by amount owed - Aug 2018					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
$200 <	NA	NA	NA	NA	NA
$500 - $200	NA	NA	NA	NA	NA
$1000 - $500	NA	NA	NA	NA	NA
$2000 - $1000	NA	NA	NA	NA	NA
$2000 >	NA	NA	NA	NA	NA

Total Dollar amount of Residential accounts in arrears - Sep 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 86,972,923	72%
$1000 - $500	$ 20,716,348	17%
$2000-1000	$ 8,080,183	7%
>$2000	$ 5,770,106	5%
Total	$ 121,539,559	100%

Total Dollar amount of Residential accounts in arrears - Sep 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 48,526,415	65%
$1000 - $500	$ 15,287,637	20%
$2000-1000	$ 6,269,846	8%
>$2000	$ 4,801,908	6%
Total	$ 74,885,807	100%

Total Dollar amount of CARE accounts in arrears - Sep 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 37,767,070	83%
$1000 - $500	$ 5,214,050	11%
$2000-1000	$ 1,717,317	4%
>$2000	$ 938,445	2%
Total	$ 45,636,881	100%

Total Dollar amount of FERA accounts in arrears - Sep 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 679,438	67%
$1000 - $500	$ 214,661	21%
$2000-1000	$ 93,020	9%
>$2000	$ 29,752	3%
Total	$ 1,016,871	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Sep 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 3,532,419	51%
$1000 - $500	$ 1,621,653	24%
$2000-1000	$ 915,359	13%
>$2000	$ 800,566	12%
Total	$ 6,869,997	100%

Total number of accounts in arrears by amount owed - Sep 2018					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
$200 <	NA	NA	NA	NA	NA
$500 - $200	NA	NA	NA	NA	NA
$1000 - $500	NA	NA	NA	NA	NA
$2000 - $1000	NA	NA	NA	NA	NA
$2000 >	NA	NA	NA	NA	NA

Total Dollar amount of Residential accounts in arrears - Oct 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 78,470,026	72%
$1000 - $500	$ 16,015,151	15%
$2000-1000	$ 7,723,856	7%
>$2000	$ 6,253,288	6%
Total	$ 108,462,319	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Oct 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 43,729,707	66%
$1000 - $500	$ 11,137,440	17%
$2000-1000	$ 5,930,609	9%
>$2000	$ 5,247,886	8%
Total	$ 66,045,643	100%

Total Dollar amount of CARE accounts in arrears - Oct 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 34,136,213	82%
$1000 - $500	$ 4,708,752	11%
$2000-1000	$ 1,703,501	4%
>$2000	$ 978,420	2%
Total	$ 41,526,886	100%

Total Dollar amount of FERA accounts in arrears - Oct 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 604,105	68%
$1000 - $500	$ 168,958	19%
$2000-1000	$ 89,746	10%
>$2000	$ 26,982	3%
Total	$ 889,790	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Oct 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 3,352,236	51%
$1000 - $500	$ 1,481,947	22%
$2000-1000	$ 946,477	14%
>$2000	$ 811,697	12%
Total	$ 6,592,357	100%

Total number of accounts in arrears by amount owed - Oct 2018					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
$200 <	NA	NA	NA	NA	NA
$500 - $200	NA	NA	NA	NA	NA
$1000 - $500	NA	NA	NA	NA	NA
$2000 - $1000	NA	NA	NA	NA	NA
$2000 >	NA	NA	NA	NA	NA

Total Dollar amount of Residential accounts in arrears - Nov 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 56,170,406	69%
$1000 - $500	$ 11,708,283	14%
$2000-1000	$ 7,133,054	9%
>$2000	$ 6,039,760	7%
Total	$ 81,051,504	100%

Total Dollar amount of Residential accounts in arrears - Nov 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 31,579,934	63%
$1000 - $500	$ 8,044,072	16%
$2000-1000	$ 5,479,785	11%
>$2000	$ 5,040,787	10%
Total	$ 50,144,578	100%

Total Dollar amount of CARE accounts in arrears - Nov 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 24,155,144	80%
$1000 - $500	$ 3,523,331	12%
$2000-1000	$ 1,583,155	5%
>$2000	$ 958,521	3%
Total	$ 30,220,152	100%

Total Dollar amount of FERA accounts in arrears - Nov 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 435,328	63%
$1000 - $500	$ 140,880	21%
$2000-1000	$ 70,114	10%
>$2000	$ 40,452	6%
Total	$ 686,774	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Nov 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 2,662,822	48%
$1000 - $500	$ 1,156,288	21%
$2000-1000	$ 874,495	16%
>$2000	$ 805,810	15%
Total	$ 5,499,415	100%

Total number of accounts in arrears by amount owed - Nov 2018					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
$200 <	NA	NA	NA	NA	NA
$500 - $200	NA	NA	NA	NA	NA
$1000 - $500	NA	NA	NA	NA	NA
$2000 - $1000	NA	NA	NA	NA	NA
$2000 >	NA	NA	NA	NA	NA

Total Dollar amount of Residential accounts in arrears - Dec 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 61,324,602	74%
$1000 - $500	$ 9,222,946	11%
$2000-1000	$ 6,198,408	8%
>$2000	$ 5,877,895	7%
Total	$ 82,623,852	100%

Total Dollar amount of Residential accounts in arrears - Dec 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 37,179,932	70%
$1000 - $500	$ 6,479,454	12%
$2000-1000	$ 4,805,962	9%
>$2000	$ 4,922,338	9%
Total	$ 53,387,686	100%

Total Dollar amount of CARE accounts in arrears - Dec 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 23,699,797	83%
$1000 - $500	$ 2,643,980	9%
$2000-1000	$ 1,318,864	5%
>$2000	$ 910,073	3%
Total	$ 28,572,713	100%

Total Dollar amount of FERA accounts in arrears - Dec 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 444,873	67%
$1000 - $500	$ 99,512	15%
$2000-1000	$ 73,582	11%
>$2000	$ 45,484	7%
Total	$ 663,452	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Dec 2018		
Amount Owed	All Balances	% of total outstanding
$500 <	$ 2,624,806	52%
$1000 - $500	$ 936,483	18%
$2000-1000	$ 753,919	15%
>$2000	$ 749,969	15%
Total	$ 5,065,177	100%

Total number of accounts in arrears by amount owed - Dec 2018					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
$200 <	302,207	235,955	3,058	15,403	541,220
$500 - $200	46,958	27,590	612	4,295	75,160
$1000 - $500	9,546	3,994	148	1,353	13,688
$2000 - $1000	3,520	982	57	554	4,559
$2000 >	1,326	277	14	210	1,617

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 4 - Disconnection/Termination

Number of customers sent disconnection notices					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	243,325	169,179	2,429	5,921	414,933
Sep-18	258,776	188,142	2,649	6,521	449,567
Oct-18	326,513	228,118	3,447	8,498	558,078
Nov-18	246,643	143,783	2,653	8,491	393,079
Dec-18	130,398	80,432	3,363	3,946	214,193

Number of customers experiencing disconnection for non-payment					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	28,446	8,380	208	156	37,034
Sep-18	32,626	7,585	244	131	40,455
Oct-18	46,271	9,594	379	198	56,244
Nov-18	33,088	6,780	275	203	40,143
Dec-18	15,321	4,028	135	92	19,484

Out of those disconnected in the month please show those for whom it is their 2nd or more disconnection that year					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	11,678	3,527	108	49	15,313
Sep-18	13,940	3,319	117	40	17,376
Oct-18	20,363	4,442	187	70	24,992
Nov-18	16,831	3,548	155	51	20,534
Dec-18	8,309	2,174	82	40	10,565

Number of customers reconnected within 24 hours					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	23,023	8,351	210	103	31,584
Sep-18	26,647	7,615	238	73	34,500
Oct-18	30,386	7,322	338	141	38,046
Nov-18	28,294	6,145	291	77	34,730
Dec-18	12,777	3,573	131	61	16,481

Number of customers reconnected within 48 hours					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	773	266	-	2	1,039
Sep-18	935	270	5	4	1,210
Oct-18	979	295	6	5	1,280
Nov-18	976	304	10	2	1,290
Dec-18	450	216	1	1	667

Number of customers reconnected within 72 hours					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	304	80	2	2	386
Sep-18	304	80	1	1	385
Oct-18	365	82	5	3	452
Nov-18	332	94	-	1	426
Dec-18	119	65	-	1	184

Number of customers reconnected within 72+ hours					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	285	101	1	1	387
Sep-18	395	113	1	1	509
Oct-18	310	89	1	3	400
Nov-18	290	94	1	-	385
Dec-18	152	56	4	-	212

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 5 - Security Deposits

Number of customers with security deposits					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	414,673	270,632	4,248	9,766	689,553
Sep-18	414,298	273,089	4,512	9,899	691,899
Oct-18	412,270	277,635	4,423	10,267	694,328
Nov-18	418,617	273,785	4,394	9,977	696,796
Dec-18	436,674	253,277	4,159	9,903	694,110

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 6 - Notices

Number of customers who received an initial disconnection notice (15 day or similar)					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	478,637	358,803	5,524	17,714	842,964
Sep-18	455,470	349,519	5,431	18,008	810,420
Oct-18	445,454	293,717	5,472	18,723	744,643
Nov-18	355,964	227,402	4,220	18,719	587,586
Dec-18	397,330	260,095	4,329	14,779	661,754

Number of customers who received an initial disconnection notice (48 day or similar)					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	243,325	169,179	2,429	5,921	414,933
Sep-18	258,776	188,142	2,649	6,521	449,567
Oct-18	326,513	228,118	3,447	8,498	558,078
Nov-18	246,643	143,783	2,653	8,491	393,079
Dec-18	130,398	80,432	3,363	3,946	214,193

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 7 - Basic Information

Number of active customer accounts in IOU territory					
Month	Non CARE/Non FERA**	CARE***	FERA ***	Medical Baseline *	Total**
Aug-18	3,186,129	1,243,471	19,680	92,727	4,417,509
Sep-18	3,183,851	1,246,926	19,360	94,167	4,417,963
Oct-18	3,198,623	1,234,611	19,160	94,905	4,420,615
Nov-18	3,227,860	1,212,306	19,203	95,184	4,427,589
Dec-18	3,234,622	1,205,539	19,141	95,122	4,427,132

Number of customers involuntarily returned to utility service from CCA					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Aug-18	0	0	0	0	0
Sep-18	0	0	0	0	0
Oct-18	0	0	0	0	0
Nov-18	0	0	0	0	0
Dec-18	0	0	0	0	0

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

** Non-CARE/Non-FERA and Total Accounts do not include submetered accounts.

*** CARE and FERA Accounts include submetered accounts.

Section 7 - Zip Code Segmented Information

- A list of zip codes within the IOU territory by disconnection rate for that month, descending, Excel format
- A list of zip codes within the IOU territory by total number of disconnections for that month, descending, Excel format

Aug-18				Sep-18				Oct-18				Nov-18				Dec-18			
ZIP CODE	CUSTOMER COUNT	TOTAL DISCONNECTIONS	RATE	ZIP CODE	CUSTOMER COUNT	TOTAL DISCONNECTIONS	RATE	ZIP CODE	CUSTOMER COUNT	TOTAL DISCONNECTIONS	RATE	ZIP CODE	CUSTOMER COUNT	TOTAL DISCONNECTIONS	RATE	ZIP CODE	CUSTOMER COUNT	TOTAL DISCONNECTIONS	RATE
93670	22	1	4.55%	93258	16	1	6.25%	92318	56	3	5.36%	93258	16	1	6.25%	92318	56	2	3.57%
92318	56	2	3.57%	92401	588	27	4.59%	90038	284	15	5.28%	92318	56	2	3.57%	92258	147	3	2.04%
93227	607	20	3.29%	92318	56	2	3.57%	91769	19	1	5.26%	92404	18676	478	2.56%	92401	588	12	2.04%
92401	581	19	3.27%	93227	605	20	3.31%	92401	581	29	4.99%	92501	433	11	2.54%	93250	984	15	1.52%
92327	195	6	3.08%	92801	67	2	2.99%	93670	23	1	4.35%	92401	581	14	2.41%	92327	199	3	1.51%
90038	285	8	2.81%	92230	877	25	2.85%	93505	4858	166	3.42%	90002	3256	76	2.33%	91342	451	6	1.33%
93250	979	25	2.55%	90038	285	8	2.81%	93250	975	29	2.97%	92240	13322	304	2.28%	92551	7023	91	1.30%
93562	876	21	2.40%	93512	116	3	2.59%	92405	9351	271	2.90%	93501	2090	46	2.20%	93562	876	11	1.26%
93523	508	12	2.36%	93523	506	13	2.57%	92394	9608	278	2.89%	93287	91	2	2.20%	92555	6832	84	1.23%
92301	9589	210	2.19%	93261	627	16	2.55%	92410	13082	373	2.85%	92301	9578	203	2.12%	92553	20011	236	1.18%
92404	18628	393	2.11%	93501	2086	53	2.54%	92301	9574	272	2.84%	92571	13297	281	2.11%	93552	10164	119	1.17%
93235	1331	28	2.10%	90731	520	12	2.31%	92220	863	24	2.78%	92376	22090	464	2.10%	92404	18686	215	1.15%
92405	9367	197	2.10%	92404	18645	407	2.18%	92240	13314	370	2.78%	92408	3680	75	2.04%	92301	9590	107	1.12%
90061	2598	53	2.04%	92410	13091	284	2.17%	90045	436	12	2.75%	91342	452	9	1.99%	92571	13295	147	1.11%
93501	2079	42	2.02%	93505	4846	102	2.10%	93550	22456	605	2.69%	93550	22488	445	1.98%	93202	1177	13	1.10%
92571	13279	265	2.00%	91387	14248	295	2.07%	92404	18652	495	2.65%	93227	607	12	1.98%	93505	4865	52	1.07%
93256	1434	28	1.95%	93591	2035	42	2.06%	93202	1171	31	2.65%	92230	870	17	1.95%	92240	13312	142	1.07%
90731	520	10	1.92%	91764	15568	317	2.04%	92311	11576	306	2.64%	92411	6614	129	1.95%	90038	284	3	1.06%
92553	20035	382	1.91%	93235	1332	27	2.03%	93501	2084	55	2.64%	93562	880	17	1.93%	92410	13114	137	1.04%
93505	4862	91	1.87%	92571	13284	267	2.01%	92230	874	23	2.63%	92407	18740	362	1.93%	92567	2683	28	1.04%
92410	13094	244	1.86%	93550	22442	451	2.01%	92571	13286	349	2.63%	92405	9378	181	1.93%	91340	5789	60	1.04%
92394	9582	178	1.86%	93272	900	18	2.00%	90059	3503	91	2.60%	92377	5446	103	1.89%	91387	14287	147	1.03%
90044	8160	151	1.85%	92405	9365	184	1.96%	92551	7021	182	2.59%	92553	20036	377	1.88%	92311	11584	119	1.03%
93543	3791	70	1.85%	92240	13315	260	1.95%	92376	22095	568	2.57%	92551	7022	132	1.88%	90044	8259	84	1.02%
93550	22441	413	1.84%	92301	9581	185	1.93%	90002	3249	82	2.52%	93505	4867	91	1.87%	92377	5447	55	1.01%
92557	15299	279	1.82%	93215	11210	209	1.86%	92557	15318	385	2.51%	92368	324	6	1.85%	93501	2089	21	1.01%
92551	7019	128	1.82%	92570	14426	264	1.83%	92553	20026	502	2.51%	92410	13092	242	1.85%	92395	12641	127	1.00%
90059	3501	63	1.80%	93562	876	16	1.83%	90061	2596	65	2.50%	92557	15348	282	1.84%	93523	504	5	0.99%
93257	23670	417	1.76%	92551	7016	127	1.81%	93256	1434	35	2.44%	90242	11992	215	1.79%	93227	608	6	0.99%
92548	2296	40	1.74%	93267	1720	31	1.80%	90723	12866	314	2.44%	90723	12863	228	1.77%	92346	18041	175	0.97%
93512	115	2	1.74%	92311	11608	209	1.80%	92407	18725	454	2.42%	93553	683	12	1.76%	92408	3674	35	0.95%
90032	58	1	1.72%	92313	4427	78	1.76%	92395	12609	302	2.40%	91792	9305	163	1.75%	93223	2772	26	0.94%
93202	1167	20	1.71%	93552	10167	179	1.76%	91387	14278	337	2.36%	93512	115	2	1.74%	92372	1928	18	0.93%
92311	11585	198	1.71%	90002	3250	57	1.75%	92335	23482	551	2.35%	92220	863	15	1.74%	92335	23516	217	0.92%
93219	2068	35	1.69%	93256	1435	25	1.74%	90222	7432	170	2.29%	92311	11587	199	1.72%	92394	9625	88	0.91%
92347	296	5	1.69%	90602	8004	139	1.74%	92309	175	4	2.29%	93244	236	4	1.69%	92405	9375	85	0.91%
93560	6875	116	1.69%	92553	20037	343	1.71%	93591	2035	46	2.26%	92570	14456	239	1.65%	93527	1010	9	0.89%
93267	1722	29	1.68%	92407	18679	314	1.68%	90602	8013	180	2.25%	93250	975	16	1.64%	90302	10929	97	0.89%
90732	244	4	1.64%	92408	3700	62	1.68%	93543	3789	85	2.24%	91768	8249	135	1.64%	90723	12859	114	0.89%
92395	12600	206	1.63%	92395	12597	211	1.68%	93261	627	14	2.23%	90262	14687	240	1.63%	92316	5940	52	0.88%
93552	10172	166	1.63%	92335	23474	391	1.67%	92408	3681	82	2.23%	90059	3515	56	1.59%	93544	459	4	0.87%
92220	861	14	1.63%	91768	8241	136	1.65%	92225	6834	150	2.19%	90047	4607	73	1.58%	93267	1723	15	0.87%
92501	434	7	1.61%	92557	15309	252	1.65%	91764	15787	346	2.19%	90221	11257	178	1.58%	92557	15351	131	0.85%
93292	13903	224	1.61%	93219	2069	34	1.64%	93552	10163	217	2.14%	92530	16915	264	1.56%	91761	16512	138	0.84%
90222	7427	119	1.60%	92394	9598	157	1.64%	93219	2066	44	2.13%	91730	24479	376	1.54%	92543	12588	102	0.81%
92530	16814	269	1.60%	93270	1659	27	1.63%	93244	235	5	2.13%	90305	6056	93	1.54%	92374	13545	109	0.80%
92316	5943	94	1.58%	93292	13927	226	1.62%	92530	16891	356	2.11%	92398	653	10	1.53%	92230	877	7	0.80%
93215	11193	177	1.58%	92220	863	14	1.62%	93235	1330	28	2.11%	92394	9619	147	1.53%	92342	3008	24	0.80%
92376	22101	347	1.57%	92555	6831	110	1.61%	92377	5446	114	2.09%	92337	9475	144	1.52%	90602	8025	64	0.80%
91387	14211	221	1.56%	92411	6599	106	1.61%	91730	24479	512	2.09%	90040	3229	49	1.52%	92548	2292	18	0.79%
93274	22789	353	1.55%	92376	22084	353	1.60%	92567	2678	56	2.09%	92225	6837	103	1.51%	93550	22572	175	0.78%
93277	19278	298	1.55%	90305	6058	96	1.58%	92582	4784	99	2.07%	91763	10054	151	1.50%	90056	3232	25	0.77%
93291	18185	281	1.55%	92337	9481	149	1.57%	93553	681	14	2.06%	93552	10159	152	1.50%	91764	15816	122	0.77%
91342	454	7	1.54%	90241	14196	223	1.57%	92570	14435	296	2.05%	92327	201	3	1.49%	92376	22167	170	0.77%
92570	14421	221	1.53%	90303	7229	113	1.56%	93562	878	18	2.05%	90201	23076	340	1.47%	92532	7880	60	0.76%
92408	3707	56	1.51%	92678	192	3	1.56%	92555	6830	140	2.05%	92544	15549	229	1.47%	91746	6578	50	0.76%
92225	6814	102	1.50%	91351	9760	152	1.56%	92392	19358	394	2.04%	92392	19362	285	1.47%	92225	6861	52	0.76%
92335	23481	351	1.49%	92398	647	10	1.55%	92411	6610	134	2.03%	90241	14198	205	1.44%	93560	6861	52	0.76%
93230	21749	322	1.48%	93516	845	13	1.54%	92337	9480	192	2.03%	92543	12590	181	1.44%	90023	3837	29	0.76%
92378	203	3	1.48%	93257	23684	363	1.53%	90706	23236	469	2.02%	91766	18231	261	1.43%	92596	8345	63	0.75%
90047	4604	68	1.48%	93543	3789	58	1.53%	93277	19279	385	2.00%	92316	5944	85	1.43%	93291	18327	138	0.75%
93223	2773	40	1.44%	93291	18209	275	1.51%	91786	19355	386	1.99%	92832	8893	127	1.43%	90222	7444	56	0.75%
91764	15567	224	1.44%	91340	5784	87	1.50%	91790	13292	264	1.99%	92335	23497	335	1.43%	92324	1204	9	0.75%
92359	2992	43	1.44%	92567	2680	40	1.49%	93535	21014	417	1.98%	93215	11228	160	1.43%	92313	4420	33	0.75%
92346	17993	258	1.43%	93534	15050	222	1.48%	92509	19559	385	1.97%	93543	3790	54	1.42%	92509	19577	146	0.75%
93261	629	9	1.43%	92530	16833	246	1.46%	93544	460	9	1.96%	93235	1334	19	1.42%	91708	3088	23	0.74%
93591	2039	29	1.42%	93274	22819	330	1.45%	92543	12578	246	1.96%	93591	2039	29	1.42%	90008	673	5	0.74%
90002	3252	46	1.41%	90723	12867	185	1.44%	90001	9809	191	1.95%	93516	849	12	1.41%	92234	21180	157	0.74%
92392	19316	273	1.41%	93535	20980	300	1.43%	93274	22855	442	1.93%	90038	284	4	1.41%	92563	21377	158	0.74%
92543	12573	176	1.40%	93250	980	14	1.43%	92532	7858	151	1.92%	93535	21024	296	1.41%	93015	4895	36	0.74%

92371	7203	100	1.39%	90221	11253	158	1.40%	91766	18225	350	1.92%	92344	5615	79	1.41%	92590	2040	15	0.74%
92567	2682	37	1.38%	91763	10048	141	1.40%	90201	23081	440	1.91%	90001	9833	138	1.40%	90242	11989	88	0.73%
93218	290	4	1.38%	92548	2294	32	1.39%	92879	13534	258	1.91%	90304	6077	85	1.40%	90601	11024	80	0.73%
90045	436	6	1.38%	92501	432	6	1.39%	93516	848	16	1.89%	93256	1435	20	1.39%	93215	11227	81	0.72%
92407	18660	254	1.36%	90262	14672	203	1.38%	92336	25416	479	1.88%	92555	6831	95	1.39%	91744	17759	128	0.72%
90211	3760	51	1.36%	92509	19545	270	1.38%	91340	5787	109	1.88%	91351	9755	135	1.38%	90220	12832	92	0.72%
92372	1922	26	1.35%	92377	5447	75	1.38%	91763	10051	189	1.88%	93523	507	7	1.38%	91730	24483	174	0.71%
92555	6830	92	1.35%	90045	436	6	1.38%	93534	15053	283	1.88%	92509	19572	270	1.38%	92407	18767	132	0.70%
90305	6055	81	1.34%	93230	21789	299	1.37%	90221	11256	210	1.87%	92258	147	2	1.36%	93256	1433	10	0.70%
90008	675	9	1.33%	93277	19284	263	1.36%	90220	12823	239	1.86%	91762	17591	239	1.36%	93230	21848	151	0.69%
90220	12817	170	1.33%	90240	7780	106	1.36%	92345	25861	481	1.86%	90023	3840	52	1.35%	90061	2605	18	0.69%
93553	680	9	1.32%	91730	24475	331	1.35%	93267	1721	32	1.86%	93219	2069	28	1.35%	91767	14206	97	0.68%
92337	9487	122	1.29%	92879	13537	183	1.35%	92313	4419	82	1.86%	90061	2599	35	1.35%	92347	295	2	0.68%
90303	7242	93	1.28%	90001	9789	132	1.35%	93292	13928	258	1.85%	90731	520	7	1.35%	90301	12014	81	0.67%
90301	11959	153	1.28%	92392	19343	260	1.34%	92501	432	8	1.85%	93277	19286	259	1.34%	93274	22914	154	0.67%
91739	11783	150	1.27%	92256	1861	25	1.34%	91761	16450	302	1.84%	91744	17759	238	1.34%	92328	149	1	0.67%
91786	19334	246	1.27%	92344	5604	75	1.34%	93215	11228	206	1.83%	91321	10915	146	1.34%	92584	16250	109	0.67%
93244	236	3	1.27%	91733	9876	132	1.34%	91762	17503	321	1.83%	91764	15792	211	1.34%	93292	13973	93	0.67%
92411	6611	84	1.27%	90605	10587	141	1.33%	91768	8237	151	1.83%	90706	23286	311	1.34%	92653	4396	29	0.66%
92544	15528	194	1.25%	90706	23225	308	1.33%	93291	18235	331	1.82%	91739	11794	157	1.33%	91768	8233	54	0.66%
91752	9310	116	1.25%	91342	455	6	1.32%	91351	9757	177	1.81%	93247	5189	69	1.33%	91792	9313	61	0.65%
90221	11264	140	1.24%	93553	683	9	1.32%	93040	608	11	1.81%	92365	1133	15	1.32%	90240	7822	51	0.65%
90023	3828	47	1.23%	90059	3502	46	1.31%	91746	6579	119	1.81%	91767	14184	186	1.31%	90221	11254	73	0.65%
93272	897	11	1.23%	92587	6322	83	1.31%	91792	9306	168	1.81%	90222	7440	97	1.30%	90606	8481	55	0.65%
92879	13537	165	1.22%	93247	5138	67	1.30%	92548	2286	41	1.79%	93544	461	6	1.30%	92277	8985	58	0.65%
92509	19530	238	1.22%	90044	8163	106	1.30%	93523	503	9	1.79%	90301	12002	156	1.30%	92570	14471	93	0.64%
92707	13565	165	1.22%	92277	8961	116	1.29%	90280	23284	416	1.79%	90044	8251	107	1.30%	93255	312	2	0.64%
92374	13524	164	1.21%	90201	23067	298	1.29%	92346	18020	321	1.78%	92282	542	7	1.29%	91790	13293	85	0.64%
90040	3223	39	1.21%	91766	18211	235	1.29%	90262	14676	260	1.77%	90280	23289	299	1.28%	93591	2041	13	0.64%
90242	11939	144	1.21%	92868	8479	109	1.29%	91342	452	8	1.77%	91786	19370	248	1.28%	90201	23096	147	0.64%
93286	2660	32	1.20%	93560	6872	88	1.28%	91752	9392	166	1.77%	90270	6177	79	1.28%	91752	9436	60	0.64%
91351	9755	117	1.20%	93244	235	3	1.28%	93223	2774	49	1.77%	90670	5091	65	1.28%	93543	3789	24	0.63%
90302	10937	131	1.20%	92532	7846	100	1.27%	91723	6628	117	1.77%	93202	1176	15	1.28%	92880	19481	123	0.63%
93247	5142	61	1.19%	91723	6627	84	1.27%	92868	8477	149	1.76%	90805	25264	321	1.27%	91737	8428	53	0.63%
91730	24481	290	1.18%	93060	9042	114	1.26%	90242	11946	209	1.75%	92395	12623	160	1.27%	92544	15558	97	0.62%
92590	2041	24	1.18%	92701	12093	152	1.26%	90670	5091	89	1.75%	91706	17695	224	1.27%	92337	9470	59	0.62%
90262	14671	172	1.17%	91786	19359	243	1.26%	91744	17757	309	1.74%	91733	9888	125	1.26%	92879	13535	84	0.62%
91768	8230	96	1.17%	91722	9750	122	1.25%	92359	2990	52	1.74%	90650	26700	337	1.26%	91766	18225	113	0.62%
93555	13825	161	1.16%	93555	13835	173	1.25%	93560	6870	119	1.73%	92596	8320	105	1.26%	93551	17277	107	0.62%
92240	13314	155	1.16%	93221	5248	65	1.24%	92354	7985	138	1.73%	92234	21160	264	1.25%	92368	324	2	0.62%
93534	15043	174	1.16%	92543	12570	155	1.23%	90044	8172	141	1.73%	92359	2993	37	1.24%	92398	650	4	0.62%
91763	10045	116	1.15%	90061	2596	32	1.23%	93257	23670	408	1.72%	90732	243	3	1.23%	92882	20060	123	0.61%
91321	10923	126	1.15%	92336	25373	312	1.23%	90605	10582	181	1.71%	92336	25442	314	1.23%	92707	13574	83	0.61%
93270	1657	19	1.15%	90732	244	3	1.23%	92234	21143	361	1.71%	92374	13533	167	1.23%	91739	11795	72	0.61%
90723	12862	146	1.14%	93015	4888	60	1.23%	92347	294	5	1.70%	90303	7227	89	1.23%	93257	23705	143	0.60%
90043	3569	40	1.12%	93240	3018	37	1.23%	90302	10938	184	1.68%	92868	8474	104	1.23%	92359	2995	18	0.60%
92325	6173	69	1.12%	91739	11788	144	1.22%	90304	6069	102	1.68%	93223	2773	34	1.23%	92587	6332	38	0.60%
91708	2974	33	1.11%	92346	18001	219	1.22%	92832	8886	149	1.68%	93272	899	11	1.22%	90248	1501	9	0.60%
91767	14158	157	1.11%	92316	5948	72	1.21%	91767	14170	236	1.67%	90255	17658	216	1.22%	92336	25450	152	0.60%
93535	20977	232	1.11%	93286	2659	32	1.20%	90640	19229	320	1.66%	92882	20049	245	1.22%	90746	8457	50	0.59%
93532	997	11	1.10%	92345	25854	311	1.20%	92707	13577	225	1.66%	92585	7186	87	1.21%	92530	16929	100	0.59%
93510	2452	27	1.10%	90292	6091	73	1.20%	92563	21306	353	1.66%	93291	18281	220	1.20%	90706	23268	137	0.59%
93117	15384	168	1.09%	90255	17641	211	1.20%	92880	19467	321	1.65%	91381	6924	83	1.20%	93553	685	4	0.58%
92587	6321	69	1.09%	90301	11967	143	1.19%	90241	14191	232	1.63%	93274	22885	273	1.19%	91786	19386	113	0.58%
90001	9803	107	1.09%	90604	12079	144	1.19%	90601	11026	180	1.63%	92545	15489	184	1.19%	92832	8957	52	0.58%
90201	23091	252	1.09%	91767	14179	167	1.18%	91791	10722	175	1.63%	90063	9262	110	1.19%	92220	865	5	0.58%
92880	19463	211	1.08%	90063	9259	109	1.18%	90255	17650	288	1.63%	90715	6322	75	1.19%	91706	17711	101	0.57%
91790	13290	144	1.08%	91752	9349	110	1.18%	91722	9750	159	1.63%	93257	23689	280	1.18%	92583	9666	55	0.57%
90056	3231	35	1.08%	90047	4603	54	1.17%	90715	6322	103	1.63%	90211	3764	44	1.17%	92392	19374	110	0.57%
91761	16353	177	1.08%	92234	21103	245	1.16%	91706	17685	286	1.62%	91732	14539	169	1.16%	92701	12091	68	0.56%
92563	21223	228	1.07%	92324	1206	14	1.16%	93205	1239	20	1.61%	92584	16195	188	1.16%	93536	22597	127	0.56%
92277	8980	96	1.07%	90640	19220	223	1.16%	92544	15528	247	1.59%	92879	13535	157	1.16%	92703	11940	67	0.56%
92322	749	8	1.07%	90023	3828	44	1.15%	91732	14519	230	1.58%	91791	10726	124	1.16%	92411	6610	37	0.56%
90292	6086	65	1.07%	90805	25253	290	1.15%	90650	26696	420	1.57%	92309	174	2	1.15%	92595	10586	59	0.56%
93516	847	9	1.06%	90040	3224	37	1.15%	93555	13831	217	1.57%	90045	436	5	1.15%	92371	7232	40	0.55%
91766	18196	193	1.06%	92309	175	2	1.14%	91355	13135	206	1.57%	92277	8984	103	1.15%	90270	6173	34	0.55%
90706	23217	246	1.06%	90069	9922	113	1.14%	92316	5944	93	1.56%	90601	11028	125	1.13%	92282	545	3	0.55%
92804	3986	42	1.05%	90242	11945	136	1.14%	93230	21803	340	1.56%	92880	19460	220	1.13%	93277	19291	105	0.54%
91744	17749	186	1.05%	91321	10917	122	1.12%	93272	899	14	1.56%	93230	21812	245	1.12%	92585	7188	39	0.54%
90401	4883	51	1.04%	91761	16377	183	1.12%	91702	2833	44	1.55%	90220	12822	144	1.12%	92262	18079	98	0.54%
92284	11688	122	1.04%	90302	10931	122	1.12%	92583	9647	149	1.54%	92345	25890	290	1.12%	93247	5189	28	0.54%
91746	6523	68	1.04%	91737	8424	94	1.12%	90731	520	8	1.54%	92707	13571	152	1.12%	90059	3530	19	0.54%
92595	10562	110	1.04%	90280	23289	259	1.11%	92398	651	10	1.54%	91387	14288	160	1.12%	90262	14692	79	0.54%
92585	7120	74	1.04%	90046	11311	125	1.11%	93551	17285	263	1.52%	90640	19238	215	1.12%	92591	14221	76	0.53%
92532	7848	81	1.03%	92342	2996	33	1.10%	90047	4605	70	1.52%	93551	17284	193	1.12%	93221	5250	28	0.53%
91732	14440	149	1.03%	90270	6181	68	1.10%	93270	1658	25	1.51%	92507	2245	25	1.11%	92365	1129	6	0.53%
91702	2835	29	1.02%	92544	15523	170	1.10%	90604	12084	182	1.51%	92562	21550	239	1.11%	90621	11119	59	0.53%
93551	17272	176	1.02%	90043	3568	39	1.09%	92831	13335	200	1.50%	92371	7231	80	1.11%	91311	1131	6	0.53%

92345	25817	262	1.01%
92545	15493	156	1.01%
92831	13329	134	1.01%
90255	17649	176	1.00%
90746	8451	84	0.99%
92313	4428	44	0.99%
90250	28050	278	0.99%
92868	8479	84	0.99%
92321	404	4	0.99%
90304	6064	60	0.99%
92832	8897	87	0.98%
93221	5241	51	0.97%
91311	1134	11	0.97%
92342	2999	29	0.97%
93036	12617	122	0.97%
92612	13909	134	0.96%
93255	313	3	0.96%
93240	3030	29	0.96%
91733	9874	94	0.95%
92584	15875	151	0.95%
91791	10728	102	0.95%
91792	9307	88	0.95%
90022	16381	154	0.94%
92591	14200	133	0.94%
91340	5778	54	0.93%
92336	25369	237	0.93%
91706	17679	165	0.93%
93033	15446	144	0.93%
91762	17377	162	0.93%
90240	7773	72	0.93%
92583	9645	89	0.92%
92324	1204	11	0.91%
91008	439	4	0.91%
90270	6179	56	0.91%
93030	15019	136	0.91%
90640	19230	174	0.90%
92701	12080	109	0.90%
90813	17226	155	0.90%
90805	25247	226	0.90%
92354	7936	71	0.89%
92344	5603	50	0.89%
90602	8016	71	0.89%
92703	11908	105	0.88%
90241	14188	125	0.88%
90802	20467	180	0.88%
91731	7391	65	0.88%
91737	8423	74	0.88%
91723	6619	58	0.88%
90063	9259	81	0.87%
92596	8172	71	0.87%
93544	462	4	0.87%
92317	347	3	0.86%
92399	17471	151	0.86%
92377	5441	47	0.86%
93536	22545	193	0.86%
90755	4556	39	0.86%
92562	21518	184	0.86%
92647	21587	184	0.85%
90810	9204	78	0.85%
92706	9447	80	0.85%
90601	11026	93	0.84%
91710	23844	201	0.84%
92252	4986	42	0.84%
90631	22286	187	0.84%
90621	11100	93	0.84%
90603	6839	57	0.83%
93063	18614	155	0.83%
90806	12639	105	0.83%
90280	23290	193	0.83%
90745	14753	122	0.83%
93225	2933	24	0.82%
92860	7121	58	0.81%
92881	9027	73	0.81%
92373	14477	117	0.81%
90650	26692	215	0.81%
92256	1865	15	0.80%
92230	875	7	0.80%
92882	20045	160	0.80%
90048	1835	20	1.09%
91740	8347	90	1.08%
91792	9303	100	1.07%
92591	14208	152	1.07%
92356	2622	28	1.07%
90650	26695	284	1.06%
91762	17412	185	1.06%
91732	14461	153	1.06%
91706	17684	187	1.06%
91724	8378	88	1.05%
90813	17249	181	1.05%
93223	2773	29	1.05%
90220	12818	134	1.05%
92374	13524	141	1.04%
90304	6064	63	1.04%
90631	22290	231	1.04%
91708	3016	31	1.03%
93218	292	3	1.03%
92706	9442	97	1.03%
90022	16354	168	1.03%
93202	1169	12	1.03%
92327	196	2	1.02%
93536	22552	230	1.02%
92707	13571	138	1.02%
90601	11021	112	1.02%
92347	297	3	1.01%
92545	15494	156	1.01%
92883	9621	96	1.00%
92262	18054	180	1.00%
92585	7131	71	1.00%
91790	13286	132	0.99%
92372	1924	19	0.99%
93040	608	6	0.99%
92583	9640	95	0.99%
92378	203	2	0.99%
90670	5085	50	0.98%
92831	13327	131	0.98%
92595	10557	103	0.98%
92284	11689	114	0.98%
91311	1134	11	0.97%
92832	8888	86	0.97%
93205	1244	12	0.96%
90802	20473	197	0.96%
93255	312	3	0.96%
92860	7118	68	0.96%
93036	12624	120	0.95%
90250	28044	265	0.94%
90606	8479	80	0.94%
90806	12622	119	0.94%
92882	20051	189	0.94%
92780	17205	162	0.94%
91710	23873	223	0.93%
90212	5804	54	0.93%
92563	21260	197	0.93%
92596	8205	76	0.93%
92282	541	5	0.92%
92368	325	3	0.92%
91702	2830	26	0.92%
92507	2179	20	0.92%
91746	6561	60	0.91%
91791	10725	98	0.91%
91381	6923	63	0.91%
90621	11113	101	0.91%
92225	6828	62	0.91%
90211	3759	34	0.90%
90222	7424	67	0.90%
92606	8484	76	0.90%
93527	1006	9	0.89%
92880	19456	174	0.89%
91731	7402	66	0.89%
90008	673	6	0.89%
92866	5761	51	0.89%
92881	9042	80	0.88%
92223	18662	165	0.88%
93030	15060	133	0.88%
92365	1134	10	0.88%
92582	4764	42	0.88%
92703	11920	105	0.88%
90813	17246	258	1.50%
91739	11789	176	1.49%
92324	1206	18	1.49%
92327	201	3	1.49%
92801	67	1	1.49%
93221	5244	78	1.49%
92587	6320	94	1.49%
92595	10565	157	1.49%
90805	25240	375	1.49%
92882	20058	298	1.49%
93227	606	9	1.49%
90305	6061	90	1.48%
90008	674	10	1.48%
90301	12003	178	1.48%
91724	8379	124	1.48%
91710	23865	351	1.47%
90048	1838	27	1.47%
90022	16374	240	1.47%
90802	20477	298	1.46%
92371	7224	105	1.45%
92317	345	5	1.45%
92344	5608	81	1.44%
90303	7230	104	1.44%
92241	1747	25	1.43%
92780	17204	245	1.42%
90240	7815	111	1.42%
92703	11927	169	1.42%
90063	9251	129	1.39%
90270	6177	86	1.39%
90631	22284	307	1.38%
91381	6923	95	1.37%
91708	3061	42	1.37%
92545	15493	212	1.37%
93247	5189	71	1.37%
92258	147	2	1.36%
92374	13529	184	1.36%
92507	2207	30	1.36%
90606	8488	115	1.35%
92372	1926	26	1.35%
90069	9947	134	1.35%
93510	2452	33	1.35%
92591	14207	191	1.34%
92262	18066	242	1.34%
90716	3152	42	1.33%
90023	3834	51	1.33%
92342	3008	40	1.33%
93015	4891	65	1.33%
92389	151	2	1.32%
91731	7410	98	1.32%
90804	15086	199	1.32%
91740	8348	110	1.32%
92399	17459	230	1.32%
90401	4940	65	1.32%
90046	11310	148	1.31%
92584	16120	210	1.30%
92585	7153	93	1.30%
91733	9874	128	1.30%
92256	1858	24	1.29%
93240	3021	39	1.29%
93527	1010	13	1.29%
90292	6093	78	1.28%
92701	12087	154	1.27%
92590	2042	26	1.27%
91321	10919	139	1.27%
92562	21538	273	1.27%
90621	11129	141	1.27%
92883	9639	122	1.27%
92596	8251	104	1.26%
90746	8458	106	1.25%
93286	2657	33	1.24%
93283	1132	14	1.24%
92365	1133	14	1.24%
92676	729	9	1.23%
92706	9440	116	1.23%
93536	22564	277	1.23%
92277	8979	110	1.23%
92626	19859	242	1.22%
92358	411	5	1.22%
92591	14212	157	1.10%
93015	4894	54	1.10%
93267	1723	19	1.10%
92831	13335	147	1.10%
93532	998	11	1.10%
93560	6867	75	1.09%
90621	11124	121	1.09%
90240	7822	85	1.09%
90022	16357	177	1.08%
92567	2681	29	1.08%
92532	7871	85	1.08%
92324	1204	13	1.08%
93292	13944	150	1.08%
93555	13839	147	1.06%
93510	2456	26	1.06%
92595	10580	112	1.06%
91702	2836	30	1.06%
93534	15087	158	1.05%
92706	9438	98	1.04%
91708	3090	32	1.04%
91340	5794	60	1.04%
92583	9664	100	1.03%
92587	6325	65	1.03%
91016	15862	163	1.03%
93240	3024	31	1.03%
92881	9051	92	1.02%
90716	3158	32	1.01%
92703	11932	120	1.01%
92780	17210	173	1.01%
92804	3991	40	1.00%
91761	16479	165	1.00%
90802	20512	203	0.99%
91746	6576	65	0.99%
92704	18702	184	0.98%
90631	22307	219	0.98%
90804	15086	148	0.98%
90813	17269	169	0.98%
92508	1969	19	0.96%
92563	21332	205	0.96%
90604	12081	116	0.96%
93261	627	6	0.96%
91752	9406	90	0.96%
93060	9038	86	0.95%
91710	23867	225	0.94%
92701	12085	113	0.94%
91731	7407	69	0.93%
93536	22589	210	0.93%
92860	7114	66	0.93%
92354	7979	74	0.93%
92503	6056	56	0.92%
90810	9217	85	0.92%
90638	14867	137	0.92%
92548	2290	21	0.92%
92241	1747	16	0.92%
90302	10935	100	0.91%
92883	9674	88	0.91%
90046	11324	103	0.91%
90712	11011	100	0.91%
91723	6633	60	0.90%
90745	14783	133	0.90%
92590	2042	18	0.88%
91001	12492	110	0.88%
90680	8187	72	0.88%
92356	2631	23	0.87%
92866	5758	50	0.87%
91701	13146	114	0.87%
90212	5801	50	0.86%
92223	18821	161	0.86%
92841	8943	76	0.85%
90602	8017	68	0.85%
93030	15094	128	0.85%
92782	11015	92	0.84%
92342	3006	25	0.83%
92833	15789	131	0.83%
91354	11018	91	0.83%
92626	19862	164	0.83%
92612	14295	118	0.83%
92262	18081	149	0.82%
90250	28073	148	0.53%
92354	7983	42	0.53%
92562	21583	113	0.52%
90002	3258	17	0.52%
91321	10927	57	0.52%
92678	193	1	0.52%
90255	17654	91	0.52%
92241	1750	9	0.51%
90604	12089	62	0.51%
91732	14547	73	0.50%
90022	16355	82	0.50%
90063	9260	46	0.50%
92545	15505	77	0.50%
92356	2622	13	0.50%
92860	7113	35	0.49%
92378	204	1	0.49%
92284	11705	57	0.49%
91731	7416	36	0.49%
91710	23964	116	0.48%
93219	2070	10	0.48%
92345	25919	125	0.48%
92780	17214	83	0.48%
91722	9751	47	0.48%
92656	18364	88	0.48%
92823	1672	8	0.48%
93261	628	3	0.48%
91763	10056	48	0.48%
91724	8382	40	0.48%
92536	629	3	0.48%
92804	3994	19	0.48%
92586	9696	46	0.47%
90069	9957	47	0.47%
93516	848	4	0.47%
90806	12653	59	0.47%
91791	10727	50	0.47%
90241	14198	66	0.46%
91351	9755	45	0.46%
93063	18658	86	0.46%
90755	4560	21	0.46%
90745	14792	68	0.46%
90638	14870	68	0.46%
91762	17774	81	0.46%
90670	5092	23	0.45%
91701	13142	59	0.45%
92840	14067	63	0.45%
92503	6056	27	0.45%
90304	6066	27	0.45%
90280	23286	103	0.44%
92504	2488	11	0.44%
90640	19249	84	0.44%
90048	1840	8	0.43%
90650	26703	116	0.43%
90047	4608	20	0.43%
91381	6927	30	0.43%
90305	6054	26	0.43%
92320	3288	14	0.43%
90211	3761	16	0.43%
91001	12495	53	0.42%
90802	20517	87	0.42%
92706	9435	40	0.42%
91702	2837	12	0.42%
91723	6629	28	0.42%
93555	13846	58	0.42%
93534	15084	63	0.42%
92260	21126	88	0.42%
92655	2404	10	0.42%
90680	8180	34	0.42%
93036	12764	53	0.42%
90303	7225	30	0.42%
92868	8481	35	0.41%
90631	22331	92	0.41%
93030	15094	62	0.41%
90620	13737	56	0.41%
92508	1971	8	0.41%
90401	4940	20	0.40%
92592	25375	102	0.40%
90292	6288	25	0.40%
92223	18919	75	0.40%

90606	8475	67	0.79%
92507	2151	17	0.79%
92582	4728	37	0.78%
92503	6020	47	0.78%
90715	6321	49	0.78%
90249	8195	63	0.77%
92626	19848	152	0.77%
92844	6548	50	0.76%
92508	1967	15	0.76%
92356	2624	20	0.76%
92307	14057	106	0.75%
90717	7725	58	0.75%
92618	20842	156	0.75%
90712	10997	82	0.75%
90604	12087	90	0.74%
92630	21820	162	0.74%
92883	9614	71	0.74%
93015	4881	36	0.74%
92653	4394	32	0.73%
92780	17201	125	0.73%
93205	1240	9	0.73%
90260	9951	72	0.72%
91355	13131	95	0.72%
91722	9746	70	0.72%
91724	8373	60	0.72%
92365	1130	8	0.71%
93060	9043	64	0.71%
92840	14078	99	0.70%
92320	3272	23	0.70%
90680	8186	57	0.70%
92704	18689	129	0.69%
92258	145	1	0.69%
90701	4377	30	0.69%
90069	9926	68	0.69%
90605	10582	72	0.68%
92223	18593	126	0.68%
91701	13153	89	0.68%
93041	7577	51	0.67%
92606	8483	57	0.67%
92655	2389	16	0.67%
92614	11548	77	0.67%
92705	14435	96	0.67%
92627	21574	143	0.66%
92389	151	1	0.66%
91016	15770	104	0.66%
92833	15780	104	0.66%
90804	15086	99	0.66%
90212	5803	38	0.65%
93265	2143	14	0.65%
92610	4142	27	0.65%
91384	6750	44	0.65%
92397	2916	19	0.65%
92308	15092	98	0.65%
92841	8937	58	0.65%
92592	25342	164	0.65%
93285	2328	15	0.64%
92866	5753	37	0.64%
93065	24123	153	0.63%
91010	7757	49	0.63%
92241	1747	11	0.63%
91740	8346	52	0.62%
92398	646	4	0.62%
90046	11338	70	0.62%
91750	11199	69	0.62%
93003	18837	116	0.62%
92368	325	2	0.62%
90290	2294	14	0.61%
93035	11498	70	0.61%
93022	2137	13	0.61%
91381	6920	42	0.61%
93527	1005	6	0.60%
93101	11902	71	0.60%
90248	1510	9	0.60%
91709	24906	148	0.59%
90502	5911	35	0.59%
91301	9374	55	0.59%
91759	341	2	0.59%
93001	12507	73	0.58%
92503	6027	53	0.88%
92373	14476	127	0.88%
90746	8454	74	0.88%
91384	6749	59	0.87%
93551	17280	151	0.87%
91801	20462	176	0.86%
90745	14770	127	0.86%
92241	1746	15	0.86%
91001	12488	107	0.86%
90603	6837	58	0.85%
92614	11607	98	0.84%
93022	2139	18	0.84%
92612	14029	118	0.84%
92647	21658	182	0.84%
93265	2144	18	0.84%
92371	7210	60	0.83%
92865	6516	54	0.83%
93066	971	8	0.82%
92676	730	6	0.82%
91701	13147	108	0.82%
93285	2332	19	0.81%
91773	11340	92	0.81%
93238	1112	9	0.81%
90401	4945	40	0.81%
91744	17755	143	0.81%
92840	14075	113	0.80%
92870	16823	135	0.80%
92359	2995	24	0.80%
92584	15957	127	0.80%
92536	631	5	0.79%
91354	10985	87	0.79%
92354	7958	63	0.79%
91750	11201	88	0.79%
90810	9211	72	0.78%
92704	18694	146	0.78%
92562	21521	168	0.78%
90715	6317	49	0.78%
92653	4394	34	0.77%
92399	17478	135	0.77%
91016	15797	121	0.77%
93033	15436	118	0.76%
92508	1966	15	0.76%
93063	18634	141	0.76%
92705	14428	109	0.76%
90260	9953	75	0.75%
91745	16067	121	0.75%
90638	14876	112	0.75%
90620	13739	103	0.75%
90247	12313	92	0.75%
92618	21023	157	0.75%
90056	3231	24	0.74%
92321	404	3	0.74%
92307	14064	104	0.74%
92630	21843	161	0.74%
93510	2450	18	0.73%
92590	2042	15	0.73%
90680	8181	60	0.73%
90249	8184	60	0.73%
92592	25343	185	0.73%
92358	411	3	0.73%
92325	6172	45	0.73%
92804	3987	29	0.73%
92504	2484	18	0.72%
91709	24981	181	0.72%
91362	13603	98	0.72%
91803	10164	73	0.72%
91748	13591	97	0.71%
90066	2107	15	0.71%
92260	21102	150	0.71%
91030	10848	76	0.70%
92339	715	5	0.70%
91307	1007	7	0.70%
91355	13129	91	0.69%
92258	145	1	0.69%
90755	4559	31	0.68%
92602	9864	67	0.68%
90804	15085	102	0.68%
93065	24119	163	0.68%
90250	28035	339	1.21%
92307	14052	168	1.20%
92223	18776	223	1.19%
92653	4395	52	1.18%
92612	14255	168	1.18%
90745	14776	174	1.18%
90040	3227	38	1.18%
93022	2142	25	1.17%
90701	4375	51	1.17%
90806	12644	147	1.16%
92704	18707	217	1.16%
93285	2331	27	1.16%
92503	6049	69	1.14%
93030	15087	171	1.13%
91745	16070	181	1.13%
90043	3568	40	1.12%
92284	11686	131	1.12%
90212	5803	65	1.12%
93060	9030	101	1.12%
91737	8421	94	1.12%
93065	24177	269	1.11%
92705	14429	160	1.11%
92881	9052	100	1.10%
93036	12724	139	1.09%
92833	15787	172	1.09%
92592	25354	275	1.08%
93225	2973	32	1.08%
92866	5762	62	1.08%
92320	3284	35	1.07%
90260	9947	106	1.07%
90810	9218	98	1.06%
91311	1134	12	1.06%
92804	3988	42	1.05%
91773	11347	119	1.05%
92618	21299	223	1.05%
92586	9686	101	1.04%
90680	8184	85	1.04%
91350	12841	133	1.04%
90620	13740	142	1.03%
92688	13947	144	1.03%
92840	14076	145	1.03%
93218	293	3	1.02%
90056	3232	33	1.02%
92647	21664	220	1.02%
90249	8185	83	1.01%
90211	3759	38	1.01%
90717	7732	78	1.01%
91384	6750	68	1.01%
93532	995	10	1.01%
93033	15432	154	1.00%
92865	6514	65	1.00%
91801	20470	204	1.00%
92627	21601	215	1.00%
91016	15811	155	0.98%
92656	18266	179	0.98%
92308	15128	148	0.98%
91390	6211	60	0.97%
93063	18652	180	0.97%
91001	12491	120	0.96%
92373	14480	139	0.96%
91107	3647	35	0.96%
92655	2398	23	0.96%
90290	2299	22	0.96%
91362	13614	130	0.95%
90066	2110	20	0.95%
92602	9918	94	0.95%
92663	10981	104	0.95%
92844	6551	62	0.95%
91709	25043	236	0.94%
92325	6172	58	0.94%
90210	5658	53	0.94%
91354	11016	103	0.94%
92368	322	3	0.93%
91776	12046	112	0.93%
92614	11623	108	0.93%
92506	431	4	0.93%
90807	12239	113	0.92%
92282	542	5	0.92%
91355	13121	108	0.82%
93221	5251	43	0.82%
92346	18024	147	0.82%
91104	2332	19	0.81%
93285	2333	19	0.81%
92313	4422	36	0.81%
92865	6514	53	0.81%
90605	10588	86	0.81%
92256	1851	15	0.81%
92618	21448	173	0.81%
92504	2487	20	0.80%
92307	14065	113	0.80%
92252	4985	40	0.80%
93065	24182	194	0.80%
92373	14485	116	0.80%
91010	7757	62	0.80%
91754	11741	93	0.79%
90606	8487	67	0.79%
92705	14425	113	0.78%
91790	13288	104	0.78%
92653	4394	34	0.77%
90069	9960	77	0.77%
90746	8457	65	0.77%
90502	5910	45	0.76%
90048	1843	14	0.76%
93286	2655	20	0.75%
92260	21110	159	0.75%
92284	11707	88	0.75%
90401	4936	37	0.75%
91722	9751	73	0.75%
90249	8183	61	0.75%
92586	9690	72	0.74%
93021	12133	90	0.74%
92840	14071	104	0.74%
90250	28050	206	0.73%
92647	21667	155	0.72%
92614	11625	83	0.71%
91750	11205	80	0.71%
92592	25361	181	0.71%
90056	3232	23	0.71%
91020	2531	18	0.71%
90701	4375	31	0.71%
91302	9781	69	0.71%
90755	4557	32	0.70%
92602	9983	70	0.70%
90620	13739	96	0.70%
93033	15468	108	0.70%
92325	6175	43	0.70%
92506	431	3	0.70%
91740	8362	58	0.69%
91748	13595	94	0.69%
93036	12732	88	0.69%
93527	1013	7	0.69%
92285	1453	10	0.69%
90603	6840	47	0.69%
92867	13341	90	0.67%
91384	6750	45	0.67%
92655	2403	16	0.67%
91775	8371	55	0.66%
93022	2142	14	0.65%
92627	21592	141	0.65%
91789	12864	84	0.65%
92308	15126	98	0.65%
93004	10218	66	0.65%
91390	6210	40	0.64%
93205	1242	8	0.64%
90247	12314	79	0.64%
92844	6553	42	0.64%
93063	18652	119	0.64%
93225	2982	19	0.64%
90742	630	4	0.63%
92211	13717	87	0.63%
90713	9796	62	0.63%
92688	13951	88	0.63%
92399	17462	110	0.63%
92870	16838	106	0.63%
92845	5738	36	0.63%
91765	15837	99	0.63%
92582	4813	19	0.39%
92399	17518	69	0.39%
90249	8190	32	0.39%
92647	21671	84	0.39%
90805	25292	98	0.39%
92833	15783	61	0.39%
90001	9835	38	0.39%
91733	9886	38	0.38%
92831	13340	51	0.38%
93033	15468	59	0.38%
92252	4985	19	0.38%
91355	13120	50	0.38%
90212	5804	22	0.38%
90605	10589	40	0.38%
90813	17255	65	0.38%
93235	1329	5	0.38%
93022	2142	8	0.37%
91745	16067	60	0.37%
92663	10990	41	0.37%
92373	14475	54	0.37%
90040	3225	12	0.37%
92883	9711	36	0.37%
92841	8942	33	0.37%
91007	11718	43	0.37%
92307	14070	51	0.36%
90046	11328	41	0.36%
93535	21027	76	0.36%
93001	12583	45	0.36%
92344	5618	20	0.36%
92881	9066	32	0.35%
92688	13952	49	0.35%
92843	10865	38	0.35%
92704	18703	65	0.35%
92821	14389	50	0.35%
92867	13339	46	0.34%
93285	2327	8	0.34%
91214	5017	17	0.34%
92835	8578	29	0.34%
91740	8365	28	0.33%
90804	15103	50	0.33%
91709	25276	82	0.32%
90717	7750	25	0.32%
92626	19881	64	0.32%
90603	6840	22	0.32%
90710	938	3	0.32%
93060	9081	29	0.32%
90742	629	2	0.32%
90712	11011	35	0.32%
92870	16841	53	0.31%
92507	2257	7	0.31%
92397	2925	9	0.31%
92211	13722	42	0.31%
92627	21592	66	0.31%
92705	14434	44	0.30%
92692	11581	35	0.30%
93225	2980	9	0.30%
93532	998	3	0.30%
90713	9791	29	0.30%
91776	12047	35	0.29%
92844	6551	19	0.29%
92677	4142	12	0.29%
91390	6215	18	0.29%
92317	346	1	0.29%
91360	14945	43	0.29%
92630	21937	63	0.29%
93561	12886	37	0.29%
90066	2116	6	0.28%
91016	15897	45	0.28%
91384	6753	19	0.28%
91789	12864	36	0.28%
92264	15104	42	0.28%
92866	5765	16	0.28%
91020	2533	7	0.28%
92865	6517	18	0.28%
92869	11979	33	0.28%
92325	6175	17	0.28%
91775	8366	23	0.27%
92285	1455	4	0.27%

92660	14914	87	0.58%	92688	13945	94	0.67%	92260	21118	194	0.92%	91803	10169	63	0.62%	92676	729	2	0.27%
92663	10978	64	0.58%	92843	10860	73	0.67%	92870	16825	154	0.92%	93283	1131	7	0.62%	93103	7327	20	0.27%
91773	11347	66	0.58%	92264	15088	101	0.67%	91010	7760	71	0.91%	90043	3563	22	0.62%	92602	10011	27	0.27%
92602	9831	57	0.58%	92683	24407	163	0.67%	92356	2625	24	0.91%	92843	10853	67	0.62%	93065	24212	65	0.27%
92870	16821	97	0.58%	92867	13333	89	0.67%	92843	10854	99	0.91%	91737	8428	52	0.62%	92691	13048	35	0.27%
90620	13736	79	0.58%	90713	9790	65	0.66%	91008	439	4	0.91%	90066	2109	13	0.62%	90210	5660	15	0.27%
92603	7832	45	0.57%	93101	11906	79	0.66%	90603	6836	62	0.91%	92630	21902	135	0.62%	93283	1133	3	0.26%
91776	12051	69	0.57%	90701	4377	29	0.66%	92603	7834	71	0.91%	91350	12872	79	0.61%	91773	11345	30	0.26%
91801	20455	117	0.57%	92252	4988	33	0.66%	92252	4988	45	0.90%	92606	8481	52	0.61%	93041	7566	20	0.26%
92309	175	1	0.57%	91390	6211	41	0.66%	92860	7114	64	0.90%	91709	25173	153	0.61%	93240	3028	8	0.26%
90670	5084	29	0.57%	93041	7576	50	0.66%	91765	15834	142	0.90%	92656	18260	109	0.60%	92782	11014	29	0.26%
93561	12847	73	0.57%	93544	462	3	0.65%	90247	12299	110	0.89%	92264	15098	90	0.60%	91741	9514	25	0.26%
90720	7960	45	0.57%	93021	12141	78	0.64%	92504	2485	22	0.89%	90260	9949	59	0.59%	93035	11505	30	0.26%
90638	14872	84	0.56%	91301	9373	60	0.64%	92841	8939	79	0.88%	92683	24427	144	0.59%	91801	20476	53	0.26%
91320	15266	86	0.56%	90710	939	6	0.64%	91748	13587	119	0.88%	90630	16246	95	0.58%	92679	7370	19	0.26%
92688	13941	78	0.56%	90712	11001	70	0.64%	92606	8481	74	0.87%	91320	15275	89	0.58%	91104	2329	6	0.26%
93271	1436	8	0.56%	92391	1260	8	0.63%	90638	14867	129	0.87%	91361	8466	49	0.58%	91748	13593	35	0.26%
92867	13336	74	0.55%	92833	15783	100	0.63%	91007	11717	100	0.85%	91301	9237	53	0.57%	91354	11033	28	0.25%
91765	15838	87	0.55%	90716	3159	20	0.63%	90710	939	8	0.85%	91776	12053	69	0.57%	90807	12233	31	0.25%
93004	10204	56	0.55%	91350	12813	81	0.63%	92630	21890	186	0.85%	92372	1924	11	0.57%	90815	15401	39	0.25%
92676	730	4	0.55%	90742	633	4	0.63%	92211	13711	116	0.85%	90660	16093	91	0.57%	92363	795	2	0.25%
92586	9676	53	0.55%	93271	1432	9	0.63%	92782	11010	92	0.84%	92582	4801	27	0.56%	90720	7958	20	0.25%
91007	11695	64	0.55%	92610	4154	26	0.63%	92382	3991	33	0.83%	90806	12651	71	0.56%	91362	13587	34	0.25%
91748	13589	74	0.54%	92821	14279	89	0.62%	90732	243	2	0.82%	92835	8576	48	0.56%	92321	405	1	0.25%
90630	16183	87	0.54%	93004	10210	63	0.62%	93066	972	8	0.82%	92869	11979	66	0.55%	92612	14308	35	0.24%
93103	7313	39	0.53%	90720	7960	49	0.62%	92821	14374	118	0.82%	91377	5269	29	0.55%	91010	7773	19	0.24%
93514	4912	26	0.53%	92841	8941	55	0.62%	91302	9788	80	0.82%	92676	730	4	0.55%	92649	13968	34	0.24%
93067	567	3	0.53%	92691	13049	80	0.61%	91361	8468	69	0.81%	92660	15179	83	0.55%	92358	412	1	0.24%
92648	20365	107	0.53%	92887	7178	44	0.61%	93021	12175	99	0.81%	91773	11346	62	0.55%	92603	7835	19	0.24%
92504	2482	13	0.52%	92211	13706	84	0.61%	92867	13335	108	0.81%	93238	1110	6	0.54%	93205	1240	3	0.24%
92845	5739	30	0.52%	91302	9791	60	0.61%	90712	10996	89	0.81%	92603	7833	42	0.54%	91011	7035	17	0.24%
91302	9788	51	0.52%	90814	9393	57	0.61%	91754	11738	94	0.80%	91030	10844	58	0.53%	90260	9948	24	0.24%
90713	9793	51	0.52%	90815	15387	93	0.60%	91711	12114	97	0.80%	90710	939	5	0.53%	93270	1658	4	0.24%
90808	14462	75	0.52%	92626	19856	120	0.60%	91301	9369	75	0.80%	92887	7177	38	0.53%	91750	11202	27	0.24%
92782	11008	56	0.51%	93532	996	6	0.60%	90404	10267	82	0.80%	91311	1134	6	0.53%	90630	16262	39	0.24%
91361	8457	43	0.51%	92692	11582	69	0.60%	90248	1505	12	0.80%	93067	567	3	0.53%	90245	7134	17	0.24%
92656	18263	92	0.50%	92835	8576	51	0.59%	90742	630	5	0.79%	91360	14946	79	0.53%	90502	5912	14	0.24%
91362	13608	68	0.50%	91020	2523	15	0.59%	92869	11977	95	0.79%	92663	10988	58	0.53%	91320	15275	36	0.24%
92691	13041	65	0.50%	93117	15419	91	0.59%	91701	13144	104	0.79%	91780	11620	61	0.52%	93265	2148	5	0.23%
93040	608	3	0.49%	91776	12047	71	0.59%	90703	16102	127	0.79%	91770	16333	85	0.52%	92506	431	1	0.23%
92358	411	2	0.49%	90717	7722	45	0.58%	92683	24422	190	0.78%	92648	20372	106	0.52%	92648	20367	47	0.23%
91741	9500	46	0.48%	92317	346	2	0.58%	92677	4138	32	0.77%	92678	193	1	0.52%	93021	12136	28	0.23%
91803	10151	49	0.48%	90502	5916	34	0.57%	91770	16327	126	0.77%	90292	6191	32	0.52%	93003	18867	43	0.23%
90815	15394	74	0.48%	92663	10981	63	0.57%	90630	16230	125	0.77%	90717	7740	40	0.52%	91008	439	1	0.23%
90501	8570	41	0.48%	93514	4909	28	0.57%	91750	11204	86	0.77%	92320	3290	17	0.52%	90810	9222	21	0.23%
92382	3977	19	0.48%	92308	15112	86	0.57%	91741	9515	73	0.77%	90404	10262	53	0.52%	91024	4875	11	0.23%
90742	631	3	0.48%	91780	11608	66	0.57%	92648	20362	156	0.77%	92649	13971	72	0.52%	91108	4436	10	0.23%
92391	1263	6	0.48%	93561	12851	73	0.57%	91360	14946	114	0.76%	93041	7576	39	0.51%	90404	10262	23	0.22%
90807	12222	58	0.47%	92844	6549	37	0.56%	92264	15082	115	0.76%	91307	981	5	0.51%	90043	3570	8	0.22%
90066	2109	10	0.47%	92660	14912	84	0.56%	91024	4877	37	0.76%	90803	17486	89	0.51%	93272	897	2	0.22%
92536	633	3	0.47%	92627	21585	120	0.56%	92363	794	6	0.76%	93529	791	4	0.51%	91770	16326	36	0.22%
93023	7818	37	0.47%	92320	3275	18	0.55%	92285	1456	11	0.76%	93035	11493	58	0.50%	91006	10888	24	0.22%
92869	11970	56	0.47%	90210	5657	31	0.55%	93561	12859	97	0.75%	92363	794	4	0.50%	92646	21423	47	0.22%
91775	8360	39	0.47%	90807	12228	67	0.55%	91755	8886	67	0.75%	91007	11720	59	0.50%	92618	21570	47	0.22%
91001	12479	58	0.46%	91741	9509	52	0.55%	92620	22401	168	0.75%	90720	7963	40	0.50%	91350	12905	28	0.22%
92506	431	2	0.46%	91770	16322	89	0.55%	91030	10841	81	0.75%	92321	401	2	0.50%	92256	1856	4	0.22%
90247	12306	57	0.46%	92782	11009	60	0.55%	92679	7401	55	0.74%	90807	12232	61	0.50%	92614	11632	25	0.21%
92708	18651	86	0.46%	91010	7757	41	0.53%	90502	5913	43	0.73%	91801	20471	102	0.50%	91711	12134	26	0.21%
92843	10858	50	0.46%	92586	9678	51	0.53%	90808	14468	105	0.73%	91745	16068	80	0.50%	92620	22425	48	0.21%
91789	12851	59	0.46%	93001	12529	65	0.52%	90713	9788	71	0.73%	92620	22412	111	0.50%	92610	4240	9	0.21%
92683	24398	111	0.45%	91775	8365	43	0.51%	93023	7815	56	0.72%	93040	607	3	0.49%	92308	15136	32	0.21%
92835	8573	39	0.45%	90404	10278	52	0.51%	92508	1966	14	0.71%	92378	204	1	0.49%	92886	16685	35	0.21%
90277	17368	78	0.45%	93225	2965	15	0.51%	90814	9378	66	0.70%	91724	8383	41	0.49%	93271	1433	3	0.21%
90404	10260	46	0.45%	92845	5742	29	0.51%	90755	4555	32	0.70%	92358	411	2	0.49%	92549	3868	8	0.21%
91745	16066	72	0.45%	91007	11711	59	0.50%	93117	15446	108	0.70%	93010	16655	80	0.48%	91780	11623	24	0.21%
91354	10976	49	0.45%	91754	11737	59	0.50%	91320	15273	106	0.69%	93101	11921	57	0.48%	91301	9211	19	0.21%
91350	12787	57	0.45%	93010	16516	83	0.50%	90501	8574	59	0.69%	93023	7813	37	0.47%	90232	5845	12	0.21%
92865	6513	29	0.45%	92655	2398	12	0.50%	90232	5844	40	0.68%	91755	8890	42	0.47%	92683	24428	50	0.20%
93283	1135	5	0.44%	90232	5851	29	0.50%	91020	2530	17	0.67%	93561	12871	60	0.47%	91754	11746	24	0.20%
90048	1836	8	0.44%	92708	18652	92	0.49%	92691	13049	87	0.67%	91107	3649	17	0.47%	93260	493	1	0.20%
90265	8126	35	0.43%	90501	8572	42	0.49%	90720	7961	53	0.67%	93012	13543	63	0.47%	91784	9484	19	0.20%
93010	16488	71	0.43%	93003	18832	92	0.49%	91214	5018	33	0.66%	90248	1505	7	0.47%	92660	15184	30	0.20%
92620	22366	96	0.43%	92677	4140	20	0.48%	90815	15392	101	0.66%	92679	7406	34	0.46%	93066	1013	2	0.20%
90278	16337	70	0.43%	92285	1454	7	0.48%	93004	10220	67	0.66%	92677	4140	19	0.46%	91803	10176	20	0.20%
92821	14283	61	0.43%	93222	1680	8	0.48%	91789	12858	84	0.65%	92610	4186	19	0.45%	91107	3647	7	0.19%
90803	17485	74	0.42%	90630	16208	77	0.48%	93041	7578	49	0.65%	91741	9515	43	0.45%	93012	13553	26	0.19%
92823	1660	7	0.42%	90623	5272	25	0.47%	93255	311	2	0.64%	92382	3992	18	0.45%	91755	8892	17	0.19%
91360	14943	63	0.42%	93023	7814	37	0.47%	93010	16528	106	0.64%	91006	10878	49	0.45%	90623	5268	10	0.19%

93111	6179	26	0.42%
92886	16645	70	0.42%
91390	6212	26	0.42%
91755	8884	37	0.42%
92262	18043	75	0.42%
92649	13963	58	0.42%
90814	9393	39	0.42%
93518	723	3	0.41%
92692	11579	48	0.41%
92604	9894	41	0.41%
90716	3158	13	0.41%
92285	1458	6	0.41%
90210	5661	23	0.41%
92887	7178	29	0.40%
93105	10148	40	0.39%
90232	5853	23	0.39%
91754	11730	46	0.39%
92657	5360	21	0.39%
91784	9466	37	0.39%
92518	514	2	0.39%
92260	21089	82	0.39%
90504	11608	45	0.39%
91104	2332	9	0.39%
90503	16962	65	0.38%
92305	524	2	0.38%
92679	7402	28	0.38%
92646	21427	80	0.37%
91711	12120	45	0.37%
92651	10881	40	0.37%
91006	10883	40	0.37%
90403	14085	51	0.36%
90623	5271	19	0.36%
92234	21096	76	0.36%
90703	16108	58	0.36%
93238	1112	4	0.36%
92211	13698	49	0.36%
93021	12133	43	0.35%
91030	10836	38	0.35%
91770	16332	57	0.35%
92861	2016	7	0.35%
93012	13299	45	0.34%
92549	3868	13	0.34%
90405	14104	47	0.33%
91780	11594	38	0.33%
90505	14040	46	0.33%
91011	7025	23	0.33%
90275	16244	53	0.33%
91377	5287	17	0.32%
90710	939	3	0.32%
90254	9408	30	0.32%
92677	4139	13	0.31%
92661	2330	7	0.30%
93546	9661	29	0.30%
93109	4665	14	0.30%
90402	4678	14	0.30%
93222	1679	5	0.30%
93013	6202	18	0.29%
93110	5538	16	0.29%
92625	6362	18	0.28%
92341	1074	3	0.28%
91020	2521	7	0.28%
90245	7108	19	0.27%
90660	16157	43	0.27%
90704	2289	6	0.26%
92268	383	1	0.26%
92363	795	2	0.25%
91107	3643	9	0.25%
91024	4875	12	0.25%
92352	9211	22	0.24%
90266	14276	33	0.23%
91214	5018	11	0.22%
90230	8797	19	0.22%
93208	466	1	0.21%
90740	14013	29	0.21%
93066	970	2	0.21%
93260	496	1	0.20%
91307	1007	2	0.20%
92282	539	1	0.19%
91361	8461	40	0.47%
93109	4663	22	0.47%
92648	20363	96	0.47%
91711	12117	57	0.47%
91360	14944	70	0.47%
93013	6200	29	0.47%
91789	12857	60	0.47%
92549	3869	18	0.47%
92620	22385	103	0.46%
92869	11972	55	0.46%
91008	438	2	0.46%
92603	7832	35	0.45%
92397	2917	13	0.45%
92656	18260	81	0.44%
93283	1136	5	0.44%
90290	2298	10	0.44%
92604	9894	43	0.43%
92651	10880	47	0.43%
92270	12743	55	0.43%
92661	2331	10	0.43%
92382	3983	17	0.43%
90660	16086	68	0.42%
91214	5017	21	0.42%
90405	14099	59	0.42%
93035	11492	48	0.42%
91755	8887	37	0.42%
91765	15833	65	0.41%
92649	13960	57	0.41%
90504	11627	47	0.40%
92322	749	3	0.40%
90703	16106	64	0.40%
91006	10882	43	0.40%
90230	8799	34	0.39%
91104	2330	9	0.39%
91107	3639	14	0.38%
90254	9415	36	0.38%
92363	793	3	0.38%
91784	9468	35	0.37%
91320	15265	56	0.37%
93105	10153	37	0.36%
92886	16661	60	0.36%
90265	8125	29	0.36%
90275	16251	58	0.36%
93546	9660	34	0.35%
90245	7119	25	0.35%
93012	13451	47	0.35%
93103	7316	25	0.34%
90503	16957	57	0.34%
90403	14083	47	0.33%
90248	1507	5	0.33%
90277	17357	57	0.33%
93517	628	2	0.32%
90278	16342	51	0.31%
93111	6177	19	0.31%
92823	1661	5	0.30%
92646	21422	63	0.29%
91108	4429	13	0.29%
91024	4874	14	0.29%
91011	7031	20	0.28%
91377	5286	15	0.28%
92679	7404	21	0.28%
90803	17492	49	0.28%
90402	4677	13	0.28%
90505	14049	39	0.28%
90808	14466	40	0.28%
92352	9212	25	0.27%
92657	5360	14	0.26%
92617	3937	10	0.25%
90266	14269	34	0.24%
92506	431	1	0.23%
93110	5539	12	0.22%
93260	496	1	0.20%
93108	4990	10	0.20%
92861	2016	4	0.20%
92210	4617	9	0.19%
92518	514	1	0.19%
92305	523	1	0.19%
92341	1075	2	0.19%
92886	16664	106	0.64%
92391	1261	8	0.63%
91775	8366	53	0.63%
92660	15174	96	0.63%
93003	18854	119	0.63%
90623	5271	33	0.63%
91784	9470	59	0.62%
91803	10163	63	0.62%
90503	16963	104	0.61%
93260	493	3	0.61%
92604	9895	60	0.61%
93001	12548	76	0.61%
90230	8797	53	0.60%
91104	2327	14	0.60%
93103	7320	44	0.60%
93035	11490	69	0.60%
91307	1008	6	0.60%
93222	1684	10	0.59%
90504	11643	69	0.59%
92692	11574	67	0.58%
92835	8582	49	0.57%
93101	11910	68	0.57%
93514	4917	28	0.57%
90803	17493	99	0.57%
92649	13967	79	0.57%
93265	2145	12	0.56%
92845	5741	32	0.56%
91377	5285	29	0.55%
92708	18653	100	0.54%
92322	749	4	0.53%
92646	21417	113	0.53%
90405	14105	74	0.52%
92678	193	1	0.52%
90265	8124	42	0.52%
91006	10880	56	0.51%
92397	2921	15	0.51%
92651	10878	55	0.51%
90660	16077	81	0.50%
91780	11620	58	0.50%
92321	402	2	0.50%
93012	13468	67	0.50%
92549	3868	19	0.49%
92610	4162	20	0.48%
92625	6355	30	0.47%
90254	9405	44	0.47%
90278	16344	76	0.47%
90245	7121	33	0.46%
92887	7177	33	0.46%
92657	5358	24	0.45%
92267	698	3	0.43%
91011	7036	30	0.43%
92339	714	3	0.42%
93271	1432	6	0.42%
93105	10154	42	0.41%
90275	16252	67	0.41%
92861	2016	8	0.40%
93013	6204	24	0.39%
92305	523	2	0.38%
93529	792	3	0.38%
90505	14060	52	0.37%
92210	4618	17	0.37%
90403	14074	51	0.36%
93238	1110	4	0.36%
93513	282	1	0.35%
93067	567	2	0.35%
90402	4660	16	0.34%
90266	14271	48	0.34%
90274	9816	32	0.33%
93110	5538	18	0.33%
90277	17362	56	0.32%
92270	12769	41	0.32%
93517	626	2	0.32%
92661	2326	7	0.30%
92823	1662	5	0.30%
91108	4431	13	0.29%
92352	9218	26	0.28%
93109	4662	13	0.28%
93518	720	2	0.28%
90814	9387	42	0.45%
90008	673	3	0.45%
90703	16102	71	0.44%
93003	18858	82	0.43%
92691	13051	55	0.42%
92339	714	3	0.42%
90501	8578	36	0.42%
90403	14084	59	0.42%
92604	9894	41	0.41%
90808	14471	59	0.41%
90210	5659	23	0.41%
93001	12564	51	0.41%
92322	748	3	0.40%
90623	5270	21	0.40%
91362	13593	54	0.40%
92886	16666	66	0.40%
92391	1266	5	0.39%
90743	254	1	0.39%
90245	7133	28	0.39%
92821	14378	56	0.39%
90504	11643	45	0.39%
93117	15436	59	0.38%
93103	7326	28	0.38%
92692	11581	44	0.38%
92651	10882	41	0.38%
92708	18657	70	0.38%
90505	14063	52	0.37%
91784	9482	35	0.37%
92646	21421	79	0.37%
92823	1663	6	0.36%
90815	15398	55	0.36%
93222	1683	6	0.36%
93514	4922	17	0.35%
90402	4662	16	0.34%
93218	294	1	0.34%
90275	16253	55	0.34%
92347	296	1	0.34%
90503	16966	57	0.34%
90254	9401	31	0.33%
91024	4879	16	0.33%
91711	12134	39	0.32%
90278	16355	51	0.31%
93013	6203	19	0.31%
92352	9214	28	0.30%
92210	4624	14	0.30%
93270	1658	5	0.30%
93066	1012	3	0.30%
91108	4432	13	0.29%
91759	341	1	0.29%
92317	347	1	0.29%
93265	2145	6	0.28%
93271	1430	4	0.28%
93109	4664	13	0.28%
93518	721	2	0.28%
90232	5852	16	0.27%
92268	385	1	0.26%
91214	5017	13	0.26%
92549	3869	10	0.26%
90405	14132	36	0.25%
93110	5537	14	0.25%
92625	6356	16	0.25%
91011	7036	17	0.24%
91008	439	1	0.23%
93105	10171	23	0.23%
90277	17371	38	0.22%
90265	7796	17	0.22%
93208	465	1	0.22%
93111	6182	13	0.21%
92657	5362	11	0.21%
90230	8795	18	0.20%
93260	493	1	0.20%
92518	515	1	0.19%
92305	523	1	0.19%
92397	2923	5	0.17%
92536	631	1	0.16%
93546	9674	15	0.16%
90274	9828	15	0.15%
92270	12773	19	0.15%
90715	6324	12	0.19%
91361	8462	16	0.19%
93286	2645	5	0.19%
93004	10222	19	0.19%
92887	7178	13	0.18%
93110	5535	10	0.18%
91765	15842	28	0.18%
93067	567	1	0.18%
90501	8576	15	0.17%
90704	2287	4	0.17%
93117	15446	27	0.17%
90290	2303	4	0.17%
90814	9385	16	0.17%
93040	607	1	0.16%
93510	2456	4	0.16%
90247	12324	20	0.16%
90277	17369	28	0.16%
93101	11941	19	0.16%
90808	14473	23	0.16%
92391	1267	2	0.16%
92845	5741	9	0.16%
92651	10888	17	0.16%
90803	17493	27	0.15%
90266	14286	22	0.15%
92708	18660	27	0.14%
93010	16654	24	0.14%
90660	16098	23	0.14%
90403	14077	20	0.14%
93023	7811	11	0.14%
93108	4986	7	0.14%
92339	714	1	0.14%
93518	719	1	0.14%
91030	10838	15	0.14%
90504	11644	16	0.14%
90701	4377	6	0.14%
92322	748	1	0.13%
90274	9828	13	0.13%
92657	5364	7	0.13%
90503	16973	22	0.13%
90278	16357	21	0.13%
93105	10167	13	0.13%
90405	14133	18	0.13%
92382	4001	5	0.12%
93222	1687	2	0.12%
90265	7710	9	0.12%
90505	14062	16	0.11%
90230	8802	10	0.11%
93013	6200	7	0.11%
91302	9781	11	0.11%
92604	9892	11	0.11%
92352	9227	10	0.11%
90402	4663	5	0.11%
90703	16100	17	0.11%
90275	16252	17	0.10%
91307	980	1	0.10%
92606	8483	8	0.09%
92625	6366	6	0.09%
92341	1071	1	0.09%
92661	2326	2	0.09%
92210	4625	3	0.06%
93109	4665	3	0.06%
90740	14013	9	0.06%
90716	3158	2	0.06%
92270	12798	8	0.06%
90254	9408	5	0.05%
92617	3938	2	0.05%
92861	2018	1	0.05%
92637	12493	5	0.04%
91377	5273	2	0.04%
93514	4926	1	0.02%
93111	6187	1	0.02%
90032	57	0	0.00%
90045	436	0	0.00%
90251	22	0	0.00%
90731	520	0	0.00%
90732	243	0	0.00%
90743	254	0	0.00%
91759	341	0	0.00%

90274	9814	17	0.17%	90274	9819	18	0.18%	92617	3937	9	0.23%	92267	697	1	0.14%	91769	19	0	0.00%
93108	4990	8	0.16%	93067	567	1	0.18%	93111	6180	14	0.23%	93108	4994	7	0.14%	92267	696	0	0.00%
93517	628	1	0.16%	92625	6356	10	0.16%	93108	4991	11	0.22%	90266	14283	19	0.13%	92268	385	0	0.00%
92267	697	1	0.14%	90704	2282	3	0.13%	93208	465	1	0.22%	90290	2301	3	0.13%	92305	524	0	0.00%
92339	717	1	0.14%	90740	14018	16	0.11%	93546	9669	19	0.20%	92661	2326	3	0.13%	92309	171	0	0.00%
91108	4432	6	0.14%	93664	1916	2	0.10%	90740	14014	27	0.19%	90740	14009	17	0.12%	92389	151	0	0.00%
92210	4618	6	0.13%	92637	12483	7	0.06%	92341	1075	2	0.19%	93664	1911	2	0.10%	92501	431	0	0.00%
93529	791	1	0.13%	90032	58	0	0.00%	90704	2289	4	0.17%	92617	3937	4	0.10%	92518	515	0	0.00%
92637	12476	15	0.12%	90251	22	0	0.00%	92637	12483	10	0.08%	92861	2017	1	0.05%	92801	67	0	0.00%
92270	12726	15	0.12%	90743	254	0	0.00%	93664	1914	1	0.05%	90704	2285	1	0.04%	93208	464	0	0.00%
92264	15082	16	0.11%	91759	340	0	0.00%	90032	58	0	0.00%	92637	12489	5	0.04%	93218	293	0	0.00%
93664	1917	2	0.10%	91769	20	0	0.00%	90251	22	0	0.00%	90032	58	0	0.00%	93238	1110	0	0.00%
92617	3931	4	0.10%	92267	697	0	0.00%	90743	254	0	0.00%	90251	22	0	0.00%	93244	237	0	0.00%
90251	22	0	0.00%	92268	384	0	0.00%	91759	340	0	0.00%	91769	19	0	0.00%	93258	16	0	0.00%
90743	254	0	0.00%	92328	148	0	0.00%	92268	385	0	0.00%	92328	149	0	0.00%	93287	91	0	0.00%
91769	21	0	0.00%	92389	149	0	0.00%	92328	149	0	0.00%	92341	1076	0	0.00%	93301	25	0	0.00%
92328	149	0	0.00%	93208	466	0	0.00%	92378	204	0	0.00%	92389	151	0	0.00%	93512	114	0	0.00%
92678	192	0	0.00%	93287	90	0	0.00%	92518	515	0	0.00%	92801	67	0	0.00%	93513	283	0	0.00%
92801	67	0	0.00%	93301	24	0	0.00%	92536	631	0	0.00%	93255	312	0	0.00%	93517	624	0	0.00%
93258	16	0	0.00%	93513	282	0	0.00%	93258	16	0	0.00%	93301	25	0	0.00%	93529	792	0	0.00%
93287	92	0	0.00%	93518	722	0	0.00%	93287	92	0	0.00%	93513	283	0	0.00%	93546	9679	0	0.00%
93301	25	0	0.00%	93529	792	0	0.00%	93301	24	0	0.00%	93517	625	0	0.00%	93558	59	0	0.00%
93513	284	0	0.00%	93558	58	0	0.00%	93512	116	0	0.00%	93558	58	0	0.00%	93664	1910	0	0.00%
93558	59	0	0.00%	93670	22	1	4.55%	93558	58	0	0.00%	93670	23	0	0.00%	93670	23	0	0.00%

Section 8 - Interim measures information

2019 Residential Disconnections Limitation Goal		
2017 Disconnection Rate	A	9.75%
SCE's Total Residential Customer Population (as of 12/01/2018)	B	4,427,589
2019 Disconnections Limitation Goal (A x B = C) <=	C	431,690

Instances in the last quarter in which your utility has invoked temperature related limits on disconnections	
Month	Number
Aug-18	NA
Sep-18	NA
Oct-18	NA
Nov-18	NA
Dec-18	NA

Average amount owed of customers who were disconnected		
Month	Average Amount	
Aug-18	$	206
Sep-18	$	232
Oct-18	$	260
Nov-18	$	254
Dec-18	$	254

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) MONTHLY DISCONNECT DATA REPORT DECEMBER 2023

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Dated: January 19, 2024

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE

STATE OF CALIFORNIA

Order Instituting Rulemaking to Consider New Approaches to Disconnections and Reconnections to Improve Energy Access and Contain Costs.	R.18-07-005

SOUTHERN CALIFORNIA EDISON COMPANY'S (U 338-E) MONTHLY DISCONNECT DATA REPORT DECEMBER 2023

Pursuant to the California Public Utilities Commission's (Commission) Decision Adopting Interim Rules to Reduce Residential Customer Disconnections for California-Jurisdictional Energy Utilities (D.) 18-12-013 (hereinafter, the "Disconnections Decision"), Ordering Paragraph (OP) 6, Southern California Edison Company (SCE) hereby submits its monthly report in Appendix A— detailing (a) disconnections data as specified in the Disconnections Decision, and (2) data pursuant to Resolution E-5169, OP 5, relating to Medical Baseline Allowance (MBL) households.

As always, this monthly report follows the format outlined in the Disconnections Decision or in a form otherwise approved by the Energy Division. As ordered by the Commission, monthly reports will be filed by the 20th of each month (or the next business day thereafter) until the interim protections have ended or further direction is provided. The numbers contained herein should be considered the most up-to-date and fully supersede the information provided in prior months' reports.

Respectfully submitted,

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JOEL MALLORD

/s/ Joel Mallord
By: Joel Mallord

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Dated: January 19, 2024

Appendix A

December 2023 Monthly Disconnect Data Report

Section 1 - Payment Arrangements and Bill Assistance

Number of customers requesting bill assistance **					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	46,934	48,152	1,481	2,405	96,567
Feb-23	40,102	36,167	1,125	1,780	77,394
Mar-23	53,097	42,503	1,392	1,769	96,992
Apr-23	61,157	51,460	1,681	1,637	114,298
May-23	74,744	56,490	1,831	2,440	133,065
Jun-23	75,949	61,072	2,074	2,596	139,095
Jul-23	68,792	59,704	1,982	2,498	130,478
Aug-23	77,893	73,732	2,445	3,923	154,070
Sep-23	64,582	63,841	2,054	3,455	130,477
Oct-23	57,028	59,208	1,952	3,221	118,188
Nov-23	41,977	45,337	1,449	2,327	88,763
Dec-23	41,523	47,048	1,438	2,357	90,009

Number of customers with ongoing payment plans					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	99,331	105,785	2,554	5,635	207,670
Feb-23	115,628	127,804	3,214	6,506	246,646
Mar-23	106,398	104,029	2,750	5,088	213,177
Apr-23	89,376	88,200	2,391	4,560	179,967
May-23	88,304	87,146	2,414	4,261	177,864
Jun-23	95,903	85,731	2,437	4,456	184,071
Jul-23	86,769	74,378	2,263	3,874	163,410
Aug-23	74,145	66,343	2,006	3,507	142,494
Sep-23	75,144	68,920	1,850	3,938	145,914
Oct-23	68,252	58,056	1,810	3,651	128,118
Nov-23	67,520	59,631	1,900	3,921	129,051
Dec-23	60,847	53,278	1,789	3,566	115,914

Number of customers receiving payment extension of <30 days					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	7,742	7,111	220	477	15,073
Feb-23	6,583	5,061	154	360	11,798
Mar-23	6,509	4,913	127	350	11,549
Apr-23	5,499	4,545	132	346	10,176
May-23	7,105	6,223	192	415	13,520
Jun-23	7,273	6,534	157	458	13,964
Jul-23	7,171	6,841	208	441	14,220
Aug-23	11,256	10,254	333	757	21,843
Sep-23	9,887	9,037	251	624	19,175
Oct-23	7,272	7,102	225	528	14,599
Nov-23	4,807	5,178	132	396	10,117
Dec-23	5,622	6,438	183	449	12,243

Number of customers with 3 month payment arrangements					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	8,132	8,242	217	387	16,591
Feb-23	7,366	7,354	175	354	14,895
Mar-23	7,771	7,074	171	341	15,016
Apr-23	6,549	6,113	139	286	12,801
May-23	6,733	6,581	157	338	13,471
Jun-23	7,640	7,218	195	373	15,053
Jul-23	7,511	7,822	162	351	15,495
Aug-23	9,224	9,780	218	497	19,222
Sep-23	9,363	10,166	243	463	19,772
Oct-23	9,731	10,626	265	494	20,622
Nov-23	7,100	7,710	179	375	14,989
Dec-23	6,382	7,255	140	377	13,777

Number of customers with 3 month+ payment arrangements					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	31,060	32,799	1,044	1,541	64,903
Feb-23	26,153	23,752	796	1,066	50,701
Mar-23	38,817	30,516	1,094	1,078	70,427
Apr-23	49,109	40,802	1,410	1,005	91,321
May-23	60,906	43,686	1,482	1,687	106,074
Jun-23	61,036	47,320	1,722	1,765	110,078
Jul-23	54,110	45,041	1,612	1,706	100,763
Aug-23	57,413	53,698	1,894	2,669	113,005
Sep-23	45,332	44,638	1,560	2,368	91,530
Oct-23	40,025	41,480	1,462	2,199	82,967
Nov-23	30,070	32,449	1,138	1,556	63,657
Dec-23	29,519	33,355	1,115	1,531	63,989

Number of customers who were connected with outside bill payment assistance from organizations (IOU/Local Service Provider)					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	1,601	2,730	5	221	4,336
Feb-23	859	1,559	4	148	2,422
Mar-23	1,418	2,183	1	165	3,602
Apr-23	1,549	2,425	9	150	3,983
May-23	1,346	2,300	6	167	3,652
Jun-23	1,345	2,132	9	174	3,486
Jul-23	926	1,745	5	127	2,676
Aug-23	1,013	2,490	3	225	3,506
Sep-23	759	2,572	8	183	3,339
Oct-23	845	2,845	14	196	3,704
Nov-23	600	2,182	9	165	2,791
Dec-23	404	1,839	7	169	2,250

Number of customers who received outside bill payment assistance from organizations (IOU/Local Service Provider) ***					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	844	2,286	5	186	3,135
Feb-23	324	848	6	64	1,178
Mar-23	2,164	5,465	7	477	7,636
Apr-23	1,916	4,482	6	377	6,404
May-23	-	5	-	1	5
Jun-23	2,593	6,108	17	490	8,718
Jul-23	346	826	4	65	1,176
Aug-23	1,614	5,608	13	456	7,235
Sep-23	610	2,360	3	175	2,973
Oct-23	616	2,760	8	213	3,384
Nov-23	507	3,243	9	265	3,759
Dec-23	531	3,047	3	216	3,581

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.
**This number reflects number of customer accounts receiving payment plans.
*** Number of customers who received outside bill payment assistance from organizations is defined as customers that received assistance from the Low-Income Home Energy Assistance Program (LIHEAP).

Section 2 - Broken Payment Arrangements

Number of customers with late or broken 3 month payment arrangements					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	5,260	4,155	102	190	9,517
Feb-23	5,118	4,127	99	171	9,344
Mar-23	6,575	4,409	115	214	11,099
Apr-23	5,889	4,198	106	182	10,193
May-23	5,158	3,871	100	211	9,129
Jun-23	5,914	4,806	106	225	10,826
Jul-23	6,093	5,546	102	243	11,741
Aug-23	6,127	6,643	119	271	12,889
Sep-23	6,431	6,599	130	300	13,160
Oct-23	8,329	8,149	192	367	16,670
Nov-23	6,475	6,382	149	291	13,006
Dec-23	5,562	6,616	127	319	12,305

Number of customers with late or broken 3 month+ payment arrangements					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	16,372	10,901	341	529	27,614
Feb-23	15,504	10,701	355	487	26,560
Mar-23	19,821	11,965	411	539	32,197
Apr-23	36,167	21,609	698	776	58,474
May-23	28,144	19,436	603	731	48,183
Jun-23	33,407	23,054	736	762	57,197
Jul-23	37,457	27,238	903	1,008	65,598
Aug-23	38,099	29,316	952	1,107	68,367
Sep-23	33,092	25,330	838	1,060	59,260
Oct-23	33,747	31,675	947	1,329	66,369
Nov-23	26,159	23,503	814	1,032	50,476
Dec-23	24,249	24,539	811	1,110	49,599

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 3 - Arrearages***

Number of customers** in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	552,375	290,288	6,725	13,010	849,388
Feb-23	550,639	286,734	6,596	12,559	843,969
Mar-23	508,265	260,812	6,302	12,084	775,379
Apr-23	495,650	255,173	6,236	12,360	757,059
May-23	505,050	273,036	6,568	12,549	784,654
Jun-23	505,951	291,933	6,985	12,880	804,869
Jul-23	565,418	325,117	7,738	14,410	898,273
Aug-23	517,828	321,143	7,886	14,436	846,857
Sep-23	552,979	362,898	9,069	16,643	924,946
Oct-23	523,722	366,058	9,479	17,043	899,259
Nov-23	513,611	353,294	9,216	16,507	876,121
Dec-23	543,100	369,897	9,409	16,811	922,406

Number of customers** 31-60 days in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	136,632	65,297	1,337	3,209	203,266
Feb-23	135,103	61,849	1,247	2,995	198,199
Mar-23	119,372	46,029	1,101	2,733	166,502
Apr-23	111,869	40,705	1,061	2,693	153,635
May-23	138,651	62,022	1,355	3,064	202,028
Jun-23	148,427	65,542	1,519	3,359	215,488
Jul-23	199,559	85,999	2,018	4,457	287,576
Aug-23	160,496	82,104	2,007	4,424	244,607
Sep-23	183,725	107,714	2,570	5,654	294,009
Oct-23	143,180	80,257	2,033	4,313	225,470
Nov-23	124,638	51,760	1,389	3,302	177,787
Dec-23	163,467	78,436	1,846	4,072	243,749

Number of customers** 61-90 days in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	60,906	28,589	653	1,343	90,148
Feb-23	61,421	32,624	671	1,478	94,716
Mar-23	51,870	27,131	564	1,224	79,565
Apr-23	59,715	26,406	589	1,385	86,710
May-23	50,526	20,199	507	1,099	71,232
Jun-23	63,249	31,020	641	1,292	94,910
Jul-23	69,669	34,424	747	1,568	104,840
Aug-23	69,179	36,227	879	1,638	106,285
Sep-23	75,774	46,854	1,207	2,320	123,835
Oct-23	90,021	63,824	1,646	3,158	155,491
Nov-23	71,653	48,851	1,174	2,310	121,678
Dec-23	57,689	30,051	778	1,613	88,518

Number of customers** 91-120 days in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	35,507	19,175	474	1,027	55,156
Feb-23	36,453	18,526	421	868	55,400
Mar-23	38,188	22,293	480	1,067	60,961
Apr-23	34,478	20,618	416	944	55,512
May-23	36,732	18,926	427	963	56,085
Jun-23	30,745	14,603	393	790	45,741
Jul-23	43,519	22,990	489	959	66,998
Aug-23	39,258	22,378	543	1,045	62,179
Sep-23	43,878	26,591	736	1,208	71,205
Oct-23	49,139	38,455	1,037	1,969	88,631
Nov-23	62,668	52,150	1,428	2,529	116,246
Dec-23	43,896	35,363	833	1,531	80,092

Number of customers** 121+ days in arrears					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	319,330	177,227	4,261	7,431	500,818
Feb-23	317,662	173,735	4,257	7,218	495,654
Mar-23	298,835	165,359	4,157	7,060	468,351
Apr-23	289,588	167,444	4,170	7,338	461,202
May-23	279,141	171,889	4,279	7,423	455,309
Jun-23	263,530	180,768	4,432	7,439	448,730
Jul-23	252,671	181,704	4,484	7,426	438,859
Aug-23	248,895	180,434	4,457	7,329	433,786
Sep-23	249,602	181,739	4,556	7,461	435,897
Oct-23	241,382	183,522	4,763	7,603	429,667
Nov-23	254,652	200,533	5,225	8,366	460,410
Dec-23	278,048	226,047	5,952	9,595	510,047

Number of accounts paid 100% within 30 days from statement date					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	2,576,715	788,459	18,057	73,666	3,383,231
Feb-23	2,150,993	638,806	15,047	61,252	2,804,846
Mar-23	2,360,390	652,034	16,471	67,062	3,028,895
Apr-23	1,737,262	436,629	13,212	56,482	2,187,103
May-23	2,604,408	749,499	19,475	77,295	3,373,382
Jun-23	2,151,150	677,286	16,140	64,706	2,844,576
Jul-23	2,165,808	702,994	16,638	66,719	2,885,440
Aug-23	2,566,728	797,109	19,179	76,615	3,383,016
Sep-23	2,087,932	647,370	15,638	63,051	2,750,940
Oct-23	2,400,951	745,286	18,992	76,028	3,165,229
Nov-23	1,876,353	566,374	16,313	63,903	2,459,040
Dec-23	1,947,069	632,147	16,322	62,439	2,595,538

Number of accounts paid 50-99% within 30 days from statement date					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	33,299	23,418	504	1,285	57,221
Feb-23	45,816	39,784	854	1,844	86,454
Mar-23	53,493	41,898	818	1,921	96,209
Apr-23	27,341	16,726	374	954	44,441
May-23	38,128	27,498	451	1,281	66,077
Jun-23	26,232	18,952	387	1,013	45,571
Jul-23	27,457	18,581	380	1,114	46,418
Aug-23	43,268	31,670	835	1,995	75,773
Sep-23	32,450	23,954	618	1,513	57,022
Oct-23	95,198	94,196	1,550	3,459	190,944
Nov-23	73,704	57,447	907	1,814	132,058
Dec-23	26,552	21,344	354	1,040	48,250

Number of accounts paid <50% within 30 days from statement date					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	664,373	327,289	6,674	13,398	998,336
Feb-23	490,890	209,552	4,454	8,926	704,896
Mar-23	543,176	215,014	4,949	9,769	763,139
Apr-23	461,175	196,862	4,635	9,610	662,672
May-23	636,671	315,267	6,719	13,802	958,657
Jun-23	535,321	287,282	6,119	11,908	828,722
Jul-23	560,224	312,437	6,694	13,018	879,355
Aug-23	675,262	396,956	8,752	17,593	1,080,970
Sep-23	567,379	347,952	7,962	15,213	923,293
Oct-23	574,748	326,099	8,595	16,400	909,442
Nov-23	524,843	307,670	7,867	15,446	840,380
Dec-23	505,693	329,096	7,488	13,850	842,277

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.
**This number reflects number of unique customer accounts.
*** Active Residential 31+ Days.

Section 3 - Arrearages By Number of Days**

Total Dollar amount of Residential accounts in arrears - Jan 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 65,241,402	8%
31-60 days	$ 120,047,410	15%
61-90 days	$ 79,891,640	10%
91-120 days	$ 83,304,964	10%
121-150 days	$ 114,011,564	14%
151-179 days	$ 96,526,864	12%
180+ days	$ 241,982,563	30%
Total	$ 801,006,407	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Jan 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 48,340,589	8%
31-60 days	$ 85,800,253	15%
61-90 days	$ 56,957,682	10%
91-120 days	$ 59,114,976	10%
121-150 days	$ 79,206,528	14%
151-179 days	$ 68,213,934	12%
180+ days	$ 182,073,074	31%
Total	$ 579,707,036	100%

Total Dollar amount of CARE accounts in arrears - Jan 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 16,432,950	8%
31-60 days	$ 33,259,874	15%
61-90 days	$ 22,208,057	10%
91-120 days	$ 23,380,885	11%
121-150 days	$ 33,723,401	16%
151-179 days	$ 27,428,426	13%
180+ days	$ 58,199,113	27%
Total	$ 214,632,707	100%

Total Dollar amount of FERA accounts in arrears - Jan 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 467,863	7%
31-60 days	$ 987,283	15%
61-90 days	$ 725,901	11%
91-120 days	$ 809,102	12%
121-150 days	$ 1,081,635	16%
151-179 days	$ 884,505	13%
180+ days	$ 1,710,377	26%
Total	$ 6,666,664	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Jan 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,611,978	12%
31-60 days	$ 2,226,327	16%
61-90 days	$ 1,514,146	11%
91-120 days	$ 1,658,690	12%
121-150 days	$ 2,033,817	15%
151-179 days	$ 1,668,717	12%
180+ days	$ 3,196,780	23%
Total	$ 13,910,456	100%

Total Dollar amount of Residential accounts in arrears - Feb 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 54,950,534	7%
31-60 days	$ 119,388,002	15%
61-90 days	$ 95,927,910	12%
91-120 days	$ 68,548,360	8%
121-150 days	$ 70,286,161	9%
151-179 days	$ 108,924,743	13%
180+ days	$ 304,211,870	37%
Total	$ 822,237,580	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Feb 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 43,122,718	7%
31-60 days	$ 86,646,409	14%
61-90 days	$ 68,180,762	11%
91-120 days	$ 48,884,816	8%
121-150 days	$ 49,787,834	8%
151-179 days	$ 76,002,987	13%
180+ days	$ 227,582,635	38%
Total	$ 600,208,161	100%

Total Dollar amount of CARE accounts in arrears - Feb 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 11,438,000	5%
31-60 days	$ 31,795,886	15%
61-90 days	$ 26,939,114	13%
91-120 days	$ 19,022,280	9%
121-150 days	$ 19,816,054	9%
151-179 days	$ 31,899,119	15%
180+ days	$ 74,372,417	35%
Total	$ 215,282,871	100%

Total Dollar amount of FERA accounts in arrears - Feb 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 389,816	6%
31-60 days	$ 945,706	14%
61-90 days	$ 808,034	12%
91-120 days	$ 641,263	10%
121-150 days	$ 682,273	10%
151-179 days	$ 1,022,638	15%
180+ days	$ 2,256,818	33%
Total	$ 6,746,548	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Feb 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,551,536	11%
31-60 days	$ 2,201,430	16%
61-90 days	$ 1,658,772	12%
91-120 days	$ 1,241,139	9%
121-150 days	$ 1,325,115	10%
151-179 days	$ 1,887,776	14%
180+ days	$ 3,969,166	29%
Total	$ 13,834,934	100%

Total Dollar amount of Residential accounts in arrears - March 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 47,211,449	6%
31-60 days	$ 115,253,728	14%
61-90 days	$ 83,741,320	10%
91-120 days	$ 80,142,276	10%
121-150 days	$ 59,410,691	7%
151-179 days	$ 63,310,477	8%
180+ days	$ 356,181,300	44%
Total	$ 805,251,241	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - March 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 36,431,893	6%
31-60 days	$ 87,018,385	15%
61-90 days	$ 59,149,350	10%
91-120 days	$ 56,226,459	10%
121-150 days	$ 41,766,795	7%
151-179 days	$ 44,353,794	8%
180+ days	$ 262,047,055	45%
Total	$ 586,993,733	100%

Total Dollar amount of CARE accounts in arrears - March 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 10,400,235	5%
31-60 days	$ 27,380,069	13%
61-90 days	$ 23,895,902	11%
91-120 days	$ 23,226,507	11%
121-150 days	$ 17,087,064	8%
151-179 days	$ 18,328,668	9%
180+ days	$ 91,315,073	43%
Total	$ 211,633,518	100%

Total Dollar amount of FERA accounts in arrears - March 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 379,321	6%
31-60 days	$ 855,273	13%
61-90 days	$ 696,067	11%
91-120 days	$ 689,310	10%
121-150 days	$ 556,833	8%
151-179 days	$ 628,015	9%
180+ days	$ 2,819,172	43%
Total	$ 6,623,990	100%

Total Dollar amount of Medical Baseline* accounts in arrears - March 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,457,207	10%
31-60 days	$ 2,195,431	16%
61-90 days	$ 1,536,661	11%
91-120 days	$ 1,431,895	10%
121-150 days	$ 1,130,752	8%
151-179 days	$ 1,227,825	9%
180+ days	$ 5,046,676	36%
Total	$ 14,026,446	100%

Total Dollar amount of Residential accounts in arrears - April 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$37,504,029	5%
31-60 days	$85,644,471	11%
61-90 days	$85,747,224	11%
91-120 days	$69,283,385	9%
121-150 days	$68,912,957	9%
151-179 days	$49,754,564	7%
180+ days	$368,493,958	48%
Total	$ 765,340,589	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - April 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$27,799,227	5%
31-60 days	$63,826,711	12%
61-90 days	$62,528,588	11%
91-120 days	$47,886,984	9%
121-150 days	$47,661,277	9%
151-179 days	$34,596,384	6%
180+ days	$269,235,917	49%
Total	$553,535,089	100%

Total Dollar amount of CARE accounts in arrears - April 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$9,423,958	5%
31-60 days	$21,080,939	10%
61-90 days	$22,523,688	11%
91-120 days	$20,788,162	10%
121-150 days	$20,620,434	10%
151-179 days	$14,687,964	7%
180+ days	$96,285,953	47%
Total	$205,411,098	100%

Total Dollar amount of FERA accounts in arrears - April 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$280,845	4%
31-60 days	$736,821	12%
61-90 days	$694,948	11%
91-120 days	$608,239	10%
121-150 days	$631,246	10%
151-179 days	$470,216	7%
180+ days	$2,972,088	46%
Total	$6,394,402	100%

Total Dollar amount of Medical Baseline* accounts in arrears - April 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$833,403	6%
31-60 days	$2,166,921	15%
61-90 days	$1,744,443	12%
91-120 days	$1,364,150	10%
121-150 days	$1,303,868	9%
151-179 days	$1,000,011	7%
180+ days	$5,695,020	40%
Total	$14,107,816	100%

Section 3 - Arrearages By Number of Days**

Total Dollar amount of Residential accounts in arrears - May 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$55,091,100	7%
31-60 days	$95,565,184	13%
61-90 days	$63,022,110	8%
91-120 days	$71,163,609	9%
121-150 days	$62,725,265	8%
151-179 days	$56,210,442	7%
180+ days	$359,765,109	47%
Total	$763,542,821	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - May 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 40,427,032	8%
31-60 days	$ 68,386,555	13%
61-90 days	$ 44,437,903	8%
91-120 days	$ 49,775,501	9%
121-150 days	$ 42,079,088	8%
151-179 days	$ 37,679,788	7%
180+ days	$ 250,873,749	47%
Total	$ 533,659,617	100%

Total Dollar amount of CARE accounts in arrears - May 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 14,183,067	6%
31-60 days	$ 26,356,626	12%
61-90 days	$ 17,965,284	8%
91-120 days	$ 20,718,716	9%
121-150 days	$ 20,038,472	9%
151-179 days	$ 17,977,418	8%
180+ days	$ 105,614,468	47%
Total	$ 222,854,051	100%

Total Dollar amount of FERA accounts in arrears - May 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 481,002	7%
31-60 days	$ 822,003	12%
61-90 days	$ 618,923	9%
91-120 days	$ 669,392	10%
121-150 days	$ 607,705	9%
151-179 days	$ 553,236	8%
180+ days	$ 3,276,892	47%
Total	$ 7,029,153	100%

Total Dollar amount of Medical Baseline* accounts in arrears - May 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,314,841	9%
31-60 days	$ 1,950,781	13%
61-90 days	$ 1,555,142	11%
91-120 days	$ 1,487,069	10%
121-150 days	$ 1,274,874	9%
151-179 days	$ 1,115,821	8%
180+ days	$ 5,965,402	41%
Total	$ 14,663,929	100%

Total Dollar amount of Residential accounts in arrears - June 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 60,398,214	8%
31-60 days	$ 93,750,551	13%
61-90 days	$ 70,161,849	10%
91-120 days	$ 52,426,311	7%
121-150 days	$ 61,311,210	8%
151-179 days	$ 54,460,322	7%
180+ days	$ 342,560,267	47%
Total	$ 735,068,724	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - June 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 42,741,086	9%
31-60 days	$ 64,566,821	13%
61-90 days	$ 46,729,588	10%
91-120 days	$ 34,566,511	7%
121-150 days	$ 40,536,201	8%
151-179 days	$ 34,444,762	7%
180+ days	$ 221,117,557	46%
Total	$ 484,702,527	100%

Total Dollar amount of CARE accounts in arrears - June 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 17,121,725	7%
31-60 days	$ 28,264,307	12%
61-90 days	$ 22,739,547	9%
91-120 days	$ 17,279,123	7%
121-150 days	$ 20,146,532	8%
151-179 days	$ 19,440,460	8%
180+ days	$ 117,957,873	49%
Total	$ 242,949,567	100%

Total Dollar amount of FERA accounts in arrears - June 2023		
Number of Days	All Balances	Total Dollar amount of FERA accounts in arrears - June 2023
21-30 days	$ 535,403	7%
31-60 days	$ 919,422	12%
61-90 days	$ 692,714	9%
91-120 days	$ 580,676	8%
121-150 days	$ 628,477	8%
151-179 days	$ 575,100	8%
180+ days	$ 3,484,837	47%
Total	$ 7,416,630	100%

Total Dollar amount of Medical Baseline* accounts in arrears - June 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,447,677	10%
31-60 days	$ 2,015,809	14%
61-90 days	$ 1,474,992	10%
91-120 days	$ 1,324,534	9%
121-150 days	$ 1,324,598	9%
151-179 days	$ 1,155,471	8%
180+ days	$ 6,079,429	41%
Total	$ 14,822,511	100%

Total Dollar amount of Residential accounts in arrears - July 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 40,518,982	5%
31-60 days	$ 122,612,332	17%
61-90 days	$ 70,624,344	10%
91-120 days	$ 61,794,419	8%
121-150 days	$ 43,254,212	6%
151-179 days	$ 52,738,355	7%
180+ days	$ 351,069,637	47%
Total	$ 742,612,281	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - July 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 28,495,957	6%
31-60 days	$ 83,296,462	17%
61-90 days	$ 46,135,528	10%
91-120 days	$ 39,622,333	8%
121-150 days	$ 27,486,190	6%
151-179 days	$ 33,908,289	7%
180+ days	$ 219,770,484	46%
Total	$ 478,715,244	100%

Total Dollar amount of CARE accounts in arrears - July 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 11,622,115	5%
31-60 days	$ 38,144,296	15%
61-90 days	$ 23,717,726	9%
91-120 days	$ 21,507,778	8%
121-150 days	$ 15,260,215	6%
151-179 days	$ 18,262,031	7%
180+ days	$ 127,572,426	50%
Total	$ 256,086,587	100%

Total Dollar amount of FERA accounts in arrears - July 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 400,910	5%
31-60 days	$ 1,171,573	15%
61-90 days	$ 771,090	10%
91-120 days	$ 664,308	9%
121-150 days	$ 507,807	7%
151-179 days	$ 568,035	7%
180+ days	$ 3,726,727	48%
Total	$ 7,810,451	100%

Total Dollar amount of Medical Baseline* accounts in arrears - July 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,371,076	9%
31-60 days	$ 2,701,637	17%
61-90 days	$ 1,613,890	10%
91-120 days	$ 1,346,127	8%
121-150 days	$ 1,028,821	6%
151-179 days	$ 1,117,815	7%
180+ days	$ 6,753,944	42%
Total	$ 15,933,309	100%

Total Dollar amount of Residential accounts in arrears - Aug 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 119,769,105	14%
31-60 days	$ 143,527,006	17%
61-90 days	$ 80,433,946	10%
91-120 days	$ 56,966,037	7%
121-150 days	$ 54,279,819	7%
151-179 days	$ 35,823,774	4%
180+ days	$ 342,318,059	41%
Total	$ 833,117,746	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Aug 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 80,540,368	15%
31-60 days	$ 93,525,771	18%
61-90 days	$ 51,000,592	10%
91-120 days	$ 35,972,332	7%
121-150 days	$ 34,064,973	6%
151-179 days	$ 22,369,638	4%
180+ days	$ 214,352,510	40%
Total	$ 531,826,184	100%

Total Dollar amount of CARE accounts in arrears - Aug 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 37,939,000	13%
31-60 days	$ 48,462,460	17%
61-90 days	$ 28,542,870	10%
91-120 days	$ 20,337,130	7%
121-150 days	$ 19,606,994	7%
151-179 days	$ 13,008,222	4%
180+ days	$ 124,322,027	43%
Total	$ 292,218,701	100%

Total Dollar amount of FERA accounts in arrears - Aug 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,289,737	14%
31-60 days	$ 1,538,775	17%
61-90 days	$ 890,485	10%
91-120 days	$ 656,575	7%
121-150 days	$ 607,853	7%
151-179 days	$ 445,914	5%
180+ days	$ 3,643,521	40%
Total	$ 9,072,860	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Aug 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 3,558,120	19%
31-60 days	$ 3,566,307	19%
61-90 days	$ 1,749,710	9%
91-120 days	$ 1,345,743	7%
121-150 days	$ 1,235,743	6%
151-179 days	$ 865,281	5%
180+ days	$ 6,895,671	36%
Total	$ 19,216,575	100%

Section 3 - Arrearages By Number of Days**

Total Dollar amount of Residential accounts in arrears - Sept 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 88,906,266	10%
31-60 days	$ 219,890,194	24%
61-90 days	$ 105,753,434	12%
91-120 days	$ 67,846,962	7%
121-150 days	$ 49,952,367	5%
151-179 days	$ 46,061,791	5%
180+ days	$ 334,940,660	37%
Total	$ 913,351,673	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Sept 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 59,930,377	10%
31-60 days	$ 140,127,008	24%
61-90 days	$ 65,540,024	11%
91-120 days	$ 41,718,129	7%
121-150 days	$ 30,915,512	5%
151-179 days	$ 28,384,552	5%
180+ days	$ 206,737,986	36%
Total	$ 573,353,589	100%

Total Dollar amount of CARE accounts in arrears - Sept 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 28,028,270	9%
31-60 days	$ 77,211,459	23%
61-90 days	$ 38,957,210	12%
91-120 days	$ 25,314,034	8%
121-150 days	$ 18,435,630	6%
151-179 days	$ 17,147,126	5%
180+ days	$ 124,531,214	38%
Total	$ 329,624,943	100%

Total Dollar amount of FERA accounts in arrears - Sept 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 947,619	9%
31-60 days	$ 2,551,727	25%
61-90 days	$ 1,256,200	12%
91-120 days	$ 814,799	8%
121-150 days	$ 601,225	6%
151-179 days	$ 530,113	5%
180+ days	$ 3,671,460	35%
Total	$ 10,373,142	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Sept 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 2,443,045	11%
31-60 days	$ 5,299,337	25%
61-90 days	$ 2,672,003	13%
91-120 days	$ 1,538,567	7%
121-150 days	$ 1,193,856	6%
151-179 days	$ 1,068,555	5%
180+ days	$ 7,031,563	33%
Total	$ 21,246,924	100%

Total Dollar amount of Residential accounts in arrears - Oct 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 65,781,973	7%
31-60 days	$ 188,886,439	20%
61-90 days	$ 163,699,291	17%
91-120 days	$ 93,224,477	10%
121-150 days	$ 55,629,523	6%
151-179 days	$ 41,586,541	4%
180+ days	$ 331,351,921	35%
Total	$ 940,160,166	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Oct 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 44,671,226	8%
31-60 days	$ 118,788,162	21%
61-90 days	$ 97,920,337	17%
91-120 days	$ 55,168,299	10%
121-150 days	$ 33,142,267	6%
151-179 days	$ 24,883,808	4%
180+ days	$ 199,203,411	35%
Total	$ 573,777,508	100%

Total Dollar amount of CARE accounts in arrears - Oct 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 20,408,199	6%
31-60 days	$ 67,838,346	19%
61-90 days	$ 63,670,636	18%
91-120 days	$ 36,864,747	10%
121-150 days	$ 21,800,326	6%
151-179 days	$ 16,198,303	5%
180+ days	$ 128,452,707	36%
Total	$ 355,233,265	100%

Total Dollar amount of FERA accounts in arrears - Oct 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 702,548	6%
31-60 days	$ 2,259,931	20%
61-90 days	$ 2,108,318	19%
91-120 days	$ 1,191,431	11%
121-150 days	$ 686,931	6%
151-179 days	$ 504,430	5%
180+ days	$ 3,695,803	33%
Total	$ 11,149,393	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Oct 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,933,174	9%
31-60 days	$ 4,402,979	20%
61-90 days	$ 3,950,777	18%
91-120 days	$ 2,483,306	11%
121-150 days	$ 1,361,371	6%
151-179 days	$ 1,029,645	5%
180+ days	$ 7,345,585	33%
Total	$ 22,506,836	100%

Total Dollar amount of Residential accounts in arrears - Nov 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 75,912,843	8%
31-60 days	$ 117,384,069	12%
61-90 days	$ 146,845,473	16%
91-120 days	$ 139,547,601	15%
121-150 days	$ 81,309,168	9%
151-179 days	$ 49,327,977	5%
180+ days	$ 329,018,836	35%
Total	$ 939,345,966	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Nov 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 50,841,576	9%
31-60 days	$ 75,710,864	13%
61-90 days	$ 87,562,447	15%
91-120 days	$ 80,867,730	14%
121-150 days	$ 47,148,576	8%
151-179 days	$ 28,959,555	5%
180+ days	$ 195,433,921	34%
Total	$ 566,524,669	100%

Total Dollar amount of CARE accounts in arrears - Nov 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 24,288,603	7%
31-60 days	$ 40,285,466	11%
61-90 days	$ 57,379,593	16%
91-120 days	$ 56,822,052	16%
121-150 days	$ 33,104,979	9%
151-179 days	$ 19,747,464	5%
180+ days	$ 129,929,882	36%
Total	$ 361,558,040	100%

Total Dollar amount of FERA accounts in arrears - Nov 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 782,665	7%
31-60 days	$ 1,387,740	12%
61-90 days	$ 1,903,432	17%
91-120 days	$ 1,857,818	16%
121-150 days	$ 1,055,613	9%
151-179 days	$ 620,958	6%
180+ days	$ 3,655,033	32%
Total	$ 11,263,258	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Nov 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 2,098,903	9%
31-60 days	$ 3,116,271	14%
61-90 days	$ 3,338,596	15%
91-120 days	$ 3,427,738	15%
121-150 days	$ 2,167,080	9%
151-179 days	$ 1,238,180	5%
180+ days	$ 7,498,922	33%
Total	$ 22,885,691	100%

Total Dollar amount of Residential accounts in arrears - Dec 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 53,207,796	6%
31-60 days	$ 123,940,399	14%
61-90 days	$ 96,371,622	11%
91-120 days	$ 118,565,080	13%
121-150 days	$ 121,183,907	13%
151-179 days	$ 71,690,426	8%
180+ days	$ 330,301,714	36%
Total	$ 915,260,945	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Dec 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 35,586,606	6%
31-60 days	$ 78,824,082	14%
61-90 days	$ 58,842,766	11%
91-120 days	$ 68,959,423	13%
121-150 days	$ 69,438,917	13%
151-179 days	$ 41,253,214	8%
180+ days	$ 196,029,579	36%
Total	$ 548,934,587	100%

Total Dollar amount of CARE accounts in arrears - Dec 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 17,082,961	5%
31-60 days	$ 43,733,773	12%
61-90 days	$ 36,292,566	10%
91-120 days	$ 48,046,262	14%
121-150 days	$ 50,130,913	14%
151-179 days	$ 29,514,803	8%
180+ days	$ 130,671,797	37%
Total	$ 355,473,075	100%

Total Dollar amount of FERA accounts in arrears - Dec 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 538,230	5%
31-60 days	$ 1,382,544	13%
61-90 days	$ 1,236,290	11%
91-120 days	$ 1,559,396	14%
121-150 days	$ 1,614,077	15%
151-179 days	$ 922,409	8%
180+ days	$ 3,600,338	33%
Total	$ 10,853,283	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Dec 2023		
Number of Days	All Balances	% of total outstanding
21-30 days	$ 1,375,425	6%
31-60 days	$ 3,219,219	14%
61-90 days	$ 2,593,341	12%
91-120 days	$ 2,680,950	12%
121-150 days	$ 3,016,753	13%
151-179 days	$ 1,900,925	8%
180+ days	$ 7,717,766	34%
Total	$ 22,504,378	100%

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.
** Active Residential Customers 21+ days.

Section 3 - Arrearages by Amount Owed***

Total Dollar amount of Residential accounts in arrears - Jan 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 80,984,864	11%
$1000 - $500	$ 110,990,430	15%
$2000-1000	$ 194,873,779	26%
>$2000	$ 348,915,932	47%
Total	$ 735,765,005	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Jan 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 49,347,766	9%
$1000 - $500	$ 68,417,752	13%
$2000-1000	$ 127,863,549	24%
>$2000	$ 285,737,381	54%
Total	$ 531,366,447	100%

Total Dollar amount of CARE accounts in arrears - Jan 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 30,990,637	16%
$1000 - $500	$ 41,536,073	21%
$2000-1000	$ 65,198,070	33%
>$2000	$ 60,474,976	31%
Total	$ 198,199,756	100%

Total Dollar amount of FERA accounts in arrears - Jan 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 646,461	10%
$1000 - $500	$ 1,036,605	17%
$2000-1000	$ 1,812,160	29%
>$2000	$ 2,703,575	44%
Total	$ 6,198,802	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Jan 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 1,339,182	11%
$1000 - $500	$ 1,726,433	14%
$2000-1000	$ 3,033,062	25%
>$2000	$ 6,199,800	50%
Total	$ 12,298,478	100%

Total number of accounts** in arrears by amount owed - Jan 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	186,204	98,853	1,745	3,822	286,802
$500 - $200	106,241	66,588	1,458	2,978	174,287
$1000 - $500	94,159	57,607	1,427	2,388	153,193
$2000 - $1000	89,575	46,380	1,279	2,141	137,234
>$2000	76,196	20,860	816	1,681	97,872

Total Dollar amount of Residential accounts in arrears - Feb 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 80,191,188	10%
$1000 - $500	$ 109,178,127	14%
$2000-1000	$ 195,224,216	25%
>$2000	$ 382,693,515	50%
Total	$ 767,287,046	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Feb 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 49,454,839	9%
$1000 - $500	$ 67,437,944	12%
$2000-1000	$ 127,582,196	23%
>$2000	$ 312,610,464	56%
Total	$ 557,085,443	100%

Total Dollar amount of CARE accounts in arrears - Feb 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 30,095,162	15%
$1000 - $500	$ 40,721,556	20%
$2000-1000	$ 65,892,591	32%
>$2000	$ 67,135,563	33%
Total	$ 203,844,871	100%

Total Dollar amount of FERA accounts in arrears - Feb 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 641,187	10%
$1000 - $500	$ 1,018,627	16%
$2000-1000	$ 1,749,430	28%
>$2000	$ 2,947,488	46%
Total	$ 6,356,732	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Feb 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 1,279,511	10%
$1000 - $500	$ 1,687,183	14%
$2000-1000	$ 2,895,295	24%
>$2000	$ 6,421,410	52%
Total	$ 12,283,398	100%

Total number of accounts** in arrears by amount owed - Feb 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	179,971	95,986	1,623	3,578	277,580
$500 - $200	106,684	64,786	1,462	2,883	172,932
$1000 - $500	92,834	56,398	1,401	2,343	150,633
$2000 - $1000	89,260	46,702	1,235	2,041	137,197
>$2000	81,890	22,862	875	1,714	105,627

Total Dollar amount of Residential accounts in arrears - March 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 73,547,395	10%
$1000 - $500	$ 103,626,966	14%
$2000-1000	$ 182,506,207	24%
>$2000	$ 398,359,222	53%
Total	$ 758,039,791	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - March 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 45,996,613	8%
$1000 - $500	$ 64,484,719	12%
$2000-1000	$ 118,203,563	21%
>$2000	$ 321,876,944	58%
Total	$ 550,561,839	100%

Total Dollar amount of CARE accounts in arrears - March 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 26,963,811	13%
$1000 - $500	$ 38,153,247	19%
$2000-1000	$ 62,610,472	31%
>$2000	$ 73,505,753	37%
Total	$ 201,233,283	100%

Total Dollar amount of FERA accounts in arrears - March 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 586,971	9%
$1000 - $500	$ 989,001	16%
$2000-1000	$ 1,692,172	27%
>$2000	$ 2,976,526	48%
Total	$ 6,244,669	100%

Total Dollar amount of Medical Baseline* accounts in arrears - March 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$ 1,211,572	10%
$1000 - $500	$ 1,620,207	13%
$2000-1000	$ 2,780,777	22%
>$2000	$ 6,956,683	55%
Total	$ 12,569,239	100%

Total number of accounts** in arrears by amount owed - March 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	154,786	80,574	1,546	3,413	236,906
$500 - $200	100,583	59,077	1,329	2,721	160,989
$1000 - $500	88,549	52,648	1,357	2,252	142,554
$2000 - $1000	82,658	44,237	1187	1,945	128,082
>$2000	81,689	24,276	883	1,753	106,848

Total Dollar amount of Residential accounts in arrears - April 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$69,995,769	10%
$1000 - $500	$93,594,373	13%
$2000-1000	$165,957,866	23%
>$2000	$398,288,551	55%
Total	$727,836,559	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - April 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$43,504,019	8%
$1000 - $500	$56,997,221	11%
$2000-1000	$105,796,663	20%
>$2000	$319,437,959	61%
Total	$525,735,862	100%

Total Dollar amount of CARE accounts in arrears - April 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$25,902,034	13%
$1000 - $500	$35,641,185	18%
$2000-1000	$58,581,502	30%
>$2000	$75,862,420	39%
Total	$195,987,141	100%

Total Dollar amount of FERA accounts in arrears - April 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$589,716	10%
$1000 - $500	$955,967	16%
$2000-1000	$1,579,701	26%
>$2000	$2,988,172	49%
Total	$6,113,557	100%

Total Dollar amount of Medical Baseline* accounts in arrears - April 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,210,251	9%
$1000 - $500	$1,598,504	12%
$2000-1000	$2,696,965	20%
>$2000	$7,768,693	59%
Total	$13,274,413	100%

Total number of accounts** in arrears by amount owed - April 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	169,661	83,265	1,621	3,762	254,547
$500 - $200	94,769	56,768	1,328	2,694	152,865
$1000 - $500	78,460	49,270	1,307	2,205	129,037
$2000 - $1000	73,862	41,413	1,111	1,885	116,386
>$2000	78,898	24,457	869	1,814	104,224

Total Dollar amount of Residential accounts in arrears - May 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$74,190,256	10%
$1000 - $500	$91,558,116	13%
$2000-1000	$157,740,929	22%
>$2000	$384,962,419	54%
Total	$708,451,720	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - May 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$46,292,205	9%
$1000 - $500	$55,736,733	11%
$2000-1000	$98,000,001	20%
>$2000	$293,203,647	59%
Total	$493,232,585	100%

Total Dollar amount of CARE accounts in arrears - May 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$27,287,683	13%
$1000 - $500	$34,914,379	17%
$2000-1000	$58,143,738	28%
>$2000	$88,325,184	42%
Total	$208,670,984	100%

Total Dollar amount of FERA accounts in arrears - May 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$610,368	9%
$1000 - $500	$907,004	14%
$2000-1000	$1,597,191	24%
>$2000	$3,433,589	52%
Total	$6,548,151	100%

Total Dollar amount of Medical Baseline* accounts in arrears - May 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,230,069	9%
$1000 - $500	$1,611,282	12%
$2000-1000	$2,619,829	20%
>$2000	$7,887,909	59%
Total	$13,349,089	100%

Total number of accounts** in arrears by amount owed - May 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	190,291	99,281	1,902	3,948	291,474
$500 - $200	97,566	57,217	1,317	2,681	156,100
$1000 - $500	76,962	48,284	1,249	2,228	126,495
$2000 - $1000	68,655	41,059	1,127	1,836	110,841
>$2000	71,576	27,195	973	1,856	99,744

Total Dollar amount of Residential accounts in arrears - June 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$77,480,167	11%
$1000 - $500	$93,394,496	14%
$2000-1000	$150,418,391	22%
>$2000	$353,377,456	52%
Total	$674,670,510	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - June 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$47,510,121	11%
$1000 - $500	$55,760,597	13%
$2000-1000	$89,380,935	20%
>$2000	$249,309,788	56%
Total	$441,961,441	100%

Total Dollar amount of CARE accounts in arrears - June 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$29,316,074	13%
$1000 - $500	$36,724,598	16%
$2000-1000	$59,395,318	26%
>$2000	$100,391,852	44%
Total	$225,827,843	100%

Total Dollar amount of FERA accounts in arrears - June 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$653,972	10%
$1000 - $500	$909,301	13%
$2000-1000	$1,642,139	24%
>$2000	$3,675,816	53%
Total	$6,881,227	100%

Total Dollar amount of Medical Baseline* accounts in arrears - June 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,283,068	10%
$1000 - $500	$1,601,954	12%
$2000-1000	$2,588,157	19%
>$2000	$7,901,655	59%
Total	$13,374,834	100%

Total number of accounts** in arrears by amount owed - June 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	205,666	108,434	2,046	4,193	316,146
$500 - $200	99,188	60,917	1,446	2,819	161,551
$1000 - $500	77,011	50,725	1,260	2,223	128,996
$2000 - $1000	63,314	42,105	1,180	1,832	106,599
>$2000	60,772	29,752	1,053	1,813	91,577

Section 3 - Arrearages by Amount Owed***

Total Dollar amount of Residential accounts in arrears - July 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$89,011,791	13%
$1000 - $500	$98,884,006	14%
$2000-1000	$153,943,835	22%
>$2000	$360,253,668	51%
Total	$702,093,300	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - July 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$54,971,452	12%
$1000 - $500	$58,640,280	13%
$2000-1000	$89,489,439	20%
>$2000	$247,118,116	55%
Total	$450,219,287	100%

Total Dollar amount of CARE accounts in arrears - July 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$33,300,166	14%
$1000 - $500	$39,248,237	16%
$2000-1000	$62,761,548	26%
>$2000	$109,154,521	45%
Total	$244,464,472	100%

Total Dollar amount of FERA accounts in arrears - July 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$740,172	10%
$1000 - $500	$995,489	13%
$2000-1000	$1,692,849	23%
>$2000	$3,981,030	54%
Total	$7,409,541	100%

Total Dollar amount of Medical Baseline* accounts in arrears - July 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,458,675	10%
$1000 - $500	$1,703,397	12%
$2000-1000	$2,812,211	19%
>$2000	$8,587,950	59%
Total	$14,562,234	100%

Total number of accounts** in arrears by amount owed - July 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	248,983	126,590	2,456	4,980	378,029
$500 - $200	112,667	67,881	1,595	3,164	182,143
$1000 - $500	80,933	54,152	1,363	2,361	136,448
$2000 - $1000	63,719	44,707	1,211	1,982	109,637
>$2000	59,116	31,787	1,113	1,923	92,016

Total Dollar amount of Residential accounts in arrears - Aug 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$87,272,959	12%
$1000 - $500	$107,711,460	15%
$2000-1000	$157,953,123	22%
>$2000	$360,411,097	51%
Total	$713,348,641	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Aug 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$50,884,720	11%
$1000 - $500	$63,486,915	14%
$2000-1000	$92,265,014	20%
>$2000	$244,649,167	54%
Total	$451,285,816	100%

Total Dollar amount of CARE accounts in arrears - Aug 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$35,604,232	14%
$1000 - $500	$43,075,942	17%
$2000-1000	$63,890,912	25%
>$2000	$111,708,617	44%
Total	$254,279,702	100%

Total Dollar amount of FERA accounts in arrears - Aug 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$784,008	10%
$1000 - $500	$1,148,604	15%
$2000-1000	$1,797,198	23%
>$2000	$4,053,314	52%
Total	$7,783,123	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Aug 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,518,290	10%
$1000 - $500	$1,902,597	12%
$2000-1000	$2,947,475	19%
>$2000	$9,290,093	59%
Total	$15,658,455	100%

Total number of accounts** in arrears by amount owed - Aug 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	192,967	105,418	2,075	4,120	300,460
$500 - $200	112,660	78,073	1,826	3,510	192,559
$1000 - $500	88,108	59,699	1,577	2,661	149,384
$2000 - $1000	66,034	45,734	1,288	2,084	113,056
>$2000	58,059	32,219	1,120	2,061	91,398

Total Dollar amount of Residential accounts in arrears - Sept 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$97,952,083	12%
$1000 - $500	$128,433,804	16%
$2000-1000	$190,667,947	23%
>$2000	$407,391,573	49%
Total	$824,445,407	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Sept 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$55,825,483	11%
$1000 - $500	$75,049,045	15%
$2000-1000	$112,336,503	22%
>$2000	$270,212,180	53%
Total	$513,423,211	100%

Total Dollar amount of CARE accounts in arrears - Sept 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$41,196,488	14%
$1000 - $500	$51,952,490	17%
$2000-1000	$76,080,166	25%
>$2000	$132,367,529	44%
Total	$301,596,673	100%

Total Dollar amount of FERA accounts in arrears - Sept 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$930,112	10%
$1000 - $500	$1,432,269	15%
$2000-1000	$2,251,277	24%
>$2000	$4,811,864	51%
Total	$9,425,523	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Sept 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,763,724	9%
$1000 - $500	$2,462,196	13%
$2000-1000	$3,576,468	19%
>$2000	$11,001,492	59%
Total	$18,803,879	100%

Total number of accounts** in arrears by amount owed - Sept 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	176,934	104,817	1,923	4,090	283,674
$500 - $200	126,603	93,571	2,221	4,153	222,395
$1000 - $500	104,329	72,353	1,987	3,457	178,669
$2000 - $1000	80,305	54,506	1,613	2,532	136,424
>$2000	64,808	37,651	1,325	2,411	103,784

Total Dollar amount of Residential accounts in arrears - Oct 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$91,323,229	10%
$1000 - $500	$129,133,838	15%
$2000-1000	$206,807,403	24%
>$2000	$447,113,723	51%
Total	$874,378,193	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Oct 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$51,484,242	10%
$1000 - $500	$72,602,223	14%
$2000-1000	$119,520,161	23%
>$2000	$285,499,655	54%
Total	$529,106,282	100%

Total Dollar amount of CARE accounts in arrears - Oct 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$38,928,341	12%
$1000 - $500	$55,027,284	16%
$2000-1000	$84,716,699	25%
>$2000	$156,152,742	47%
Total	$334,825,066	100%

Total Dollar amount of FERA accounts in arrears - Oct 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$910,646	9%
$1000 - $500	$1,504,331	14%
$2000-1000	$2,570,543	25%
>$2000	$5,461,326	52%
Total	$10,446,845	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Oct 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,708,196	8%
$1000 - $500	$2,573,928	13%
$2000-1000	$3,936,220	19%
>$2000	$12,355,318	60%
Total	$20,573,663	100%

Total number of accounts** in arrears by amount owed - Oct 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	150,630	97,095	1,873	3,889	249,598
$500 - $200	118,234	88,490	2,199	4,068	208,923
$1000 - $500	100,511	76,270	2,088	3,571	178,869
$2000 - $1000	84,895	60,420	1,822	2,773	147,137
>$2000	69,452	43,783	1,497	2,742	114,732

Total Dollar amount of Residential accounts in arrears - Nov 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$80,047,100	9%
$1000 - $500	$120,280,169	14%
$2000-1000	$204,196,256	24%
>$2000	$458,909,598	53%
Total	$863,433,123	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Nov 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$44,718,863	9%
$1000 - $500	$66,338,325	13%
$2000-1000	$116,776,872	23%
>$2000	$287,849,033	56%
Total	$515,683,093	100%

Total Dollar amount of CARE accounts in arrears - Nov 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$34,517,343	10%
$1000 - $500	$52,469,084	16%
$2000-1000	$84,912,773	25%
>$2000	$165,370,236	49%
Total	$337,269,437	100%

Total Dollar amount of FERA accounts in arrears - Nov 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$810,894	8%
$1000 - $500	$1,472,760	14%
$2000-1000	$2,506,610	24%
>$2000	$5,690,329	54%
Total	$10,480,593	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Nov 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,522,297	7%
$1000 - $500	$2,359,133	11%
$2000-1000	$3,870,959	19%
>$2000	$13,034,399	63%
Total	$20,786,787	100%

Total number of accounts** in arrears by amount owed - Nov 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	170,259	97,359	2,006	4,217	269,624
$500 - $200	99,237	77,291	1,873	3,476	178,401
$1000 - $500	91,424	72,600	2,031	3,272	166,055
$2000 - $1000	82,480	60,293	1,752	2,722	144,525
>$2000	70,211	45,751	1,554	2,820	117,516

Total Dollar amount of Residential accounts in arrears - Dec 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$84,036,671	10%
$1000 - $500	$115,490,281	13%
$2000-1000	$202,497,460	23%
>$2000	$460,028,737	53%
Total	$862,053,149	100%

Total Dollar amount of non-CARE/FERA accounts in arrears - Dec 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$47,349,971	9%
$1000 - $500	$63,390,193	12%
$2000-1000	$115,659,692	23%
>$2000	$286,948,125	56%
Total	$513,347,981	100%

Total Dollar amount of CARE accounts in arrears - Dec 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$35,856,289	11%
$1000 - $500	$50,701,840	15%
$2000-1000	$84,425,064	25%
>$2000	$167,406,921	49%
Total	$338,390,114	100%

Total Dollar amount of FERA accounts in arrears - Dec 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$830,411	8%
$1000 - $500	$1,398,248	14%
$2000-1000	$2,412,704	23%
>$2000	$5,673,691	55%
Total	$10,315,054	100%

Total Dollar amount of Medical Baseline* accounts in arrears - Dec 2023		
Amount Owed	All Balances	% of total outstanding
$500 >	$1,577,396	7%
$1000 - $500	$2,194,198	10%
$2000-1000	$3,686,424	17%
>$2000	$13,670,935	65%
Total	$21,128,953	100%

Total number of accounts** in arrears by amount owed - Dec 2023					
Amount Owed	Non CARE/Non FERA	CARE	FERA	Medical Baseline*	Total
$200 >	202,633	117,242	2,340	4,790	322,215
$500 - $200	100,909	76,560	1,874	3,535	179,343
$1000 - $500	87,341	70,032	1,925	3,039	159,298
$2000 - $1000	81,475	59,691	1,696	2,595	142,862
>$2000	70,742	46,372	1,574	2,852	118,688

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.
**This number reflects number of unique customer accounts.
*** Active Residential Customers 31+ days.

Section 4 - Disconnection/Termination

Number of customers sent disconnection notices					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	2,970	738	13	-	3,721
Feb-23	9,401	3,010	62	-	12,473
Mar-23	32,764	12,912	368	34	46,044
Apr-23	60,121	26,368	723	273	87,212
May-23	82,450	24,838	661	780	107,949
Jun-23	63,269	21,915	576	664	85,760
Jul-23	58,250	22,470	571	504	81,291
Aug-23	20,188	7,751	216	222	28,155
Sep-23	12,761	4,310	143	142	17,214
Oct-23	14,105	4,990	170	84	19,265
Nov-23	11,471	5,506	127	67	17,104
Dec-23	16,048	7,835	261	118	24,144

Number of customers experiencing disconnection for non-payment					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	201	52	-	-	253
Feb-23	1,139	371	5	-	1,515
Mar-23	3,585	1,209	21	-	4,816
Apr-23	7,735	3,098	82	-	10,915
May-23	7,268	2,870	51	-	10,189
Jun-23	918	185	12	-	1,115
Jul-23	-	-	-	-	-
Aug-23	26	1	-	-	27
Sep-23	162	58	1	-	221
Oct-23	302	84	1	-	387
Nov-23	319	101	2	-	422
Dec-23	256	79	1	-	336

Out of those disconnected in the month please show those for whom it is their 2nd or more disconnection that year					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	-	-	-	-	-
Feb-23	-	-	-	-	-
Mar-23	1	1	-	-	2
Apr-23	296	46	1	-	343
May-23	524	88	3	-	615
Jun-23	7	3	-	-	10
Jul-23	-	-	-	-	-
Aug-23	-	-	-	-	-
Sep-23	9	2	-	-	11
Oct-23	24	-	-	-	24
Nov-23	10	-	-	-	10
Dec-23	16	1	-	-	17

Number of customers reconnected within 24 hours					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	145	44	-	-	189
Feb-23	862	304	5	-	1,171
Mar-23	2,762	1,009	18	-	3,789
Apr-23	5,626	2,550	64	-	8,240
May-23	5,223	2,323	48	-	7,594
Jun-23	865	176	11	-	1,052
Jul-23	-	-	-	-	-
Aug-23	1	-	-	-	1
Sep-23	30	17	1	-	48
Oct-23	120	45	-	-	165
Nov-23	103	42	1	-	146
Dec-23	95	44	1	-	140

Number of customers reconnected within 48 hours					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	7	2	-	-	9
Feb-23	32	8	-	-	40
Mar-23	152	31	2	-	185
Apr-23	394	91	7	-	492
May-23	291	85	3	-	379
Jun-23	124	18	-	-	142
Jul-23	-	-	-	-	-
Aug-23	-	-	-	-	-
Sep-23	-	1	-	-	1
Oct-23	6	1	-	-	7
Nov-23	2	2	-	-	4
Dec-23	3	1	-	-	4

Number of customers reconnected within 72 hours					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	4	1	-	-	5
Feb-23	29	8	-	-	37
Mar-23	78	18	-	-	96
Apr-23	218	66	1	-	285
May-23	155	37	-	-	192
Jun-23	13	3	-	-	16
Jul-23	-	-	-	-	-
Aug-23	-	-	-	-	-
Sep-23	1	1	-	-	2
Oct-23	1	3	-	-	4
Nov-23	1	-	-	-	1
Dec-23	6	1	-	-	7

Number of customers reconnected within 72+ hours					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	16	2	-	-	18
Feb-23	90	18	-	-	108
Mar-23	342	87	1	-	430
Apr-23	811	182	3	-	996
May-23	1,108	191	4	-	1,303
Jun-23	735	129	1	-	865
Jul-23	108	17	-	-	125
Aug-23	14	11	-	-	25
Sep-23	6	2	-	-	8
Oct-23	28	5	1	-	34
Nov-23	31	15	-	-	46
Dec-23	28	10	-	-	38

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.
** Number of customers that were reconnected during this reporting period and can include reconnections due to a new customer moving into a location with a prior disconnection for non-payment. Customer may have been disconnected in a prior reporting period.
***Due to system synching issues, the disconnections and reconnections numbers include some customers whose disconnections were either canceled or never processed and reconnections where disconnections did not take place. SCE is evaluating potential system changes to address these issues.

Section 5 - Security Deposits

Number of customers with security deposits					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	162,013	69,912	1,665	2,572	233,590
Feb-23	160,910	67,662	1,646	2,442	230,218
Mar-23	157,857	66,402	1,621	2,471	225,880
Apr-23	154,448	65,723	1,614	2,502	221,785
May-23	146,157	67,728	1,720	2,491	215,605
Jun-23	135,331	71,631	1,798	2,478	208,760
Jul-23	127,639	74,355	1,853	2,500	203,847
Aug-23	122,740	73,608	1,852	2,544	198,200
Sep-23	119,386	73,435	1,790	2,574	194,611
Oct-23	114,811	73,911	1,804	2,601	190,526
Nov-23	111,973	72,684	1,767	2,561	186,424
Dec-23	109,270	71,626	1,761	2,499	182,657

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

Section 6 - Notices

Number of customers who received an initial disconnection notice (15 day or similar)**					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	221,208	72,904	2,204	5,992	296,316
Feb-23	238,896	84,276	2,474	6,105	325,646
Mar-23	222,344	68,453	2,085	5,405	292,882
Apr-23	271,615	86,684	2,430	5,550	360,729
May-23	254,732	79,341	2,564	6,854	336,637
Jun-23	282,890	98,636	3,094	7,296	384,620
Jul-23	282,694	111,683	3,327	7,716	397,704
Aug-23	421,541	208,889	5,630	11,822	636,060
Sep-23	416,921	210,564	5,462	12,069	632,947
Oct-23	416,650	219,408	5,819	12,647	641,877
Nov-23	280,686	128,838	3,975	9,316	413,499
Dec-23	306,743	146,034	4,271	10,061	457,048

Number of customers who received a secondary disconnection notice (48 hour or similar)					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	2,970	738	13	-	3,721
Feb-23	9,401	3,010	62	-	12,473
Mar-23	32,764	12,912	368	34	46,044
Apr-23	60,121	26,368	723	273	87,212
May-23	82,450	24,838	661	780	107,949
Jun-23	63,269	21,915	576	664	85,760
Jul-23	58,250	22,470	571	504	81,291
Aug-23	20,188	7,751	216	222	28,155
Sep-23	12,761	4,310	143	142	17,214
Oct-23	14,105	4,990	170	84	19,265
Nov-23	11,471	5,506	127	67	17,104
Dec-23	16,048	7,835	261	118	24,144

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.

** Customers who have received a past due notice and are at risk of disconnection for nonpayment, as defined by SCE's internal business rules.

Section 7 - Basic Information

Number of active customer accounts in IOU territory**					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	3,409,471	1,134,867	26,027	92,822	4,570,365
Feb-23	3,421,082	1,125,569	25,946	93,087	4,572,597
Mar-23	3,422,425	1,127,896	26,086	94,925	4,576,407
Apr-23	3,420,534	1,131,238	26,245	96,191	4,578,017
May-23	3,417,292	1,140,318	26,701	96,881	4,584,311
Jun-23	3,381,552	1,176,701	27,228	97,803	4,585,481
Jul-23	3,359,454	1,203,009	27,927	98,525	4,590,390
Aug-23	3,346,077	1,214,688	28,686	100,034	4,589,451
Sep-23	3,336,280	1,225,895	29,306	101,146	4,591,481
Oct-23	3,324,936	1,241,330	29,788	102,658	4,596,054
Nov-23	3,317,931	1,250,813	30,092	103,146	4,598,836
Dec-23	3,305,447	1,265,007	30,310	103,250	4,600,764

Number of customers involuntarily returned to utility service from CCA					
Month	Non CARE/Non FERA	CARE	FERA	Medical Baseline *	Total
Jan-23	-	-	-	-	-
Feb-23	-	-	-	-	-
Mar-23	-	-	-	-	-
Apr-23	-	-	-	-	-
May-23	-	-	-	-	-
Jun-23	-	-	-	-	-
Jul-23	-	-	-	-	-
Aug-23	-	-	-	-	-
Sep-23	-	-	-	-	-
Oct-23	-	-	-	-	-
Nov-23	-	-	-	-	-
Dec-23	-	-	-	-	-

* Medical Baseline Accounts are also included in the Non CARE/Non FERA, CARE, and FERA accounts.
** Customer accounts do not include submetered accounts.

Section 7 - Zip Code Segmented Information

• A list of zip codes within the IOU territory by disconnection rate for that month, descending, Excel format

• A list of zip codes within the IOU territory by total number of disconnections for that month, descending, Excel format

Jan-23	
ZIP CODE	RATE
92241	0.11%
93202	0.08%
93223	0.07%
90212	0.07%
93256	0.07%
90044	0.05%
92372	0.05%
93265	0.05%
92585	0.05%
93247	0.04%
92567	0.04%
91340	0.03%
92325	0.03%
92359	0.03%
90056	0.03%
92394	0.03%
93555	0.03%
90043	0.03%
92234	0.03%
91767	0.03%
92371	0.03%
92311	0.03%
92878	0.02%
92553	0.02%
90250	0.02%
91711	0.02%
92677	0.02%
92354	0.02%
92701	0.02%
90606	0.02%
92313	0.02%
90701	0.02%
92881	0.02%
90063	0.02%
92841	0.02%
92706	0.02%
92335	0.02%
91024	0.02%
91786	0.02%
90401	0.02%
93221	0.02%
93015	0.02%
91321	0.02%
92582	0.02%
92376	0.02%
90502	0.02%
93021	0.02%
90270	0.02%
92344	0.02%
92703	0.02%
92503	0.02%
92407	0.02%
92587	0.02%
90640	0.02%
93561	0.02%
92410	0.01%
93036	0.01%
92225	0.01%
92555	0.01%
91384	0.01%
90405	0.01%
92551	0.01%
91732	0.01%
91360	0.01%
92630	0.01%
92660	0.01%
93536	0.01%
90265	0.01%
90745	0.01%
92557	0.01%
91016	0.01%
93257	0.01%
91745	0.01%
90660	0.01%
90022	0.01%
92705	0.01%
91010	0.01%
91764	0.01%
90249	0.01%
90746	0.01%
91740	0.01%
90602	0.01%
90255	0.01%
90680	0.01%
92399	0.01%
91792	0.01%
92404	0.01%
90810	0.01%
92405	0.01%
92337	0.01%
91761	0.01%
91302	0.01%
91351	0.01%
92626	0.01%
92584	0.01%
92301	0.01%
90001	0.01%
91763	0.01%
92223	0.01%
92596	0.01%
90712	0.01%

Jan-23	
ZIP CODE	TOTAL DISCONNECTIONS
90250	7
92234	7
92335	5
92553	5
90044	4
90212	4
91767	4
91786	4
92376	4
92585	4
93555	4
90640	3
91711	3
92311	3
92394	3
92407	3
92630	3
92701	3
93257	3
93536	3
90022	2
90063	2
90201	2
90255	2
90405	2
90606	2
90660	2
90745	2
91016	2
91321	2
91340	2
91360	2
91709	2
91710	2
91732	2
91745	2
91761	2
91764	2
92223	2
92241	2
92325	2
92345	2
92354	2
92371	2
92399	2
92404	2
92410	2
92557	2
92563	2
92584	2
92626	2
92660	2
92703	2
92705	2
92706	2
92841	2
92881	2
93021	2
93036	2
93223	2
93247	2
93561	2
90001	1
90043	1
90056	1
90220	1
90241	1
90249	1
90262	1
90265	1
90270	1
90277	1
90280	1
90301	1
90401	1
90502	1
90602	1
90604	1
90621	1
90630	1
90680	1
90701	1
90706	1
90712	1
90746	1
90802	1
90805	1
90807	1
90810	1
91010	1
91024	1
91302	1
91320	1
91351	1
91354	1
91384	1
91387	1
91701	1
91706	1
91730	1
91740	1

91354	0.01%
90621	0.01%
92563	0.01%
90201	0.01%
91754	0.01%
92692	0.01%
91780	0.01%
91710	0.01%
90604	0.01%
90807	0.01%
90301	0.01%
91709	0.01%
92395	0.01%
90220	0.01%
91789	0.01%
91701	0.01%
91748	0.01%
92543	0.01%
92345	0.01%
92879	0.01%
92840	0.01%
90241	0.01%
92374	0.01%
93030	0.01%
90262	0.01%
91387	0.01%
92570	0.01%
92264	0.01%
91320	0.01%
92544	0.01%
92833	0.01%
92545	0.01%
90630	0.01%
91770	0.01%
90277	0.01%
91706	0.01%
91744	0.01%
92346	0.01%
92530	0.01%
92262	0.01%
91766	0.01%
91801	0.00%
92392	0.00%
92260	0.00%
92627	0.00%
90802	0.00%
90706	0.00%
90280	0.00%
91730	0.00%
90805	0.00%
92592	0.00%

91744	1
91748	1
91754	1
91763	1
91766	1
91770	1
91780	1
91789	1
91792	1
91801	1
92225	1
92260	1
92262	1
92264	1
92301	1
92313	1
92337	1
92344	1
92346	1
92359	1
92372	1
92374	1
92392	1
92395	1
92405	1
92503	1
92530	1
92543	1
92544	1
92545	1
92551	1
92555	1
92567	1
92570	1
92582	1
92587	1
92592	1
92596	1
92627	1
92677	1
92692	1
92833	1
92840	1
92878	1
92879	1
93015	1
93030	1
93202	1
93221	1
93256	1
93265	1

Feb-23	
ZIP CODE	RATE
92378	0.46%
92347	0.37%
93207	0.30%
93208	0.27%
93562	0.24%
92506	0.23%
93227	0.22%
93523	0.20%
93219	0.19%
92401	0.17%
92311	0.15%
92301	0.14%
93534	0.13%
92359	0.13%
93535	0.12%
91723	0.12%
93516	0.12%
93247	0.11%
93272	0.11%
92590	0.11%
90059	0.11%
91762	0.11%
92411	0.11%
93250	0.10%
92553	0.10%
90063	0.10%
92407	0.10%
90270	0.10%
92410	0.10%
90301	0.10%
92405	0.10%
91763	0.10%
92313	0.09%
91731	0.09%
91764	0.09%
90221	0.09%
90066	0.09%
90044	0.09%
92395	0.09%
92316	0.08%
91767	0.08%
90201	0.08%
93033	0.08%
90262	0.08%
90813	0.08%
90255	0.08%
90715	0.08%
90680	0.08%
92504	0.08%
92394	0.08%
93215	0.08%
91786	0.08%
92408	0.08%
90061	0.07%
90404	0.07%

Feb-23	
ZIP CODE	TOTAL DISCONNECTIONS
93535	27
91762	21
93534	20
92553	20
92345	20
92407	19
90201	19
92311	18
92335	17
90280	16
91764	15
91786	15
93274	15
92301	14
90813	14
90255	14
90631	14
92376	14
93536	14
92410	13
93033	13
93230	13
90301	12
91767	12
90262	12
90022	12
92530	12
91766	12
92404	12
92234	12
91710	12
92395	11
91387	11
93277	11
92392	11
90805	11
91763	10
90221	10
92879	10
92557	10
92262	10
90640	10
90706	10
90063	9
92405	9
93215	9
93555	9
90241	9
92307	9
92780	9
92704	9
92882	9
90650	9
90250	9
91723	8

92345	0.07%	92394	8
90022	0.07%	90404	8
92225	0.07%	92240	8
92567	0.07%	93030	8
91387	0.07%	92570	8
90069	0.07%	92346	8
92879	0.07%	93257	8
92335	0.07%	92336	8
90212	0.07%	92411	7
92866	0.07%	91731	7
90303	0.07%	90044	7
93286	0.07%	90680	7
93560	0.07%	90069	7
93256	0.07%	92707	7
93225	0.07%	91732	7
90280	0.07%	92683	7
90222	0.07%	90804	6
92377	0.07%	90270	6
92530	0.07%	91792	6
91766	0.06%	90001	6
91792	0.06%	90247	6
92404	0.06%	92701	6
93555	0.06%	91790	6
92557	0.06%	91748	6
90241	0.06%	92374	6
90717	0.06%	93247	7
90631	0.06%	91016	6
93274	0.06%	90660	6
92307	0.06%	92870	6
92376	0.06%	93063	6
90002	0.06%	92260	6
91381	0.06%	92223	6
93536	0.06%	92562	6
90249	0.06%	90802	6
93505	0.06%	91730	6
90001	0.06%	92316	5
90670	0.06%	90715	5
92252	0.06%	92225	5
92240	0.06%	90303	5
93230	0.06%	93560	5
93277	0.06%	90222	5
92551	0.06%	90717	5
92241	0.06%	91381	5
92234	0.05%	90249	5
91107	0.05%	91302	5
92262	0.05%	92583	5
93030	0.05%	91733	5
90048	0.05%	92843	5
92582	0.05%	92782	5
92570	0.05%	90504	5
92780	0.05%	90806	5
92392	0.05%	90220	5
92707	0.05%	90723	5
91302	0.05%	92264	5
92583	0.05%	92821	5
92508	0.05%	92308	5
90640	0.05%	90745	5
90232	0.05%	91744	5
91710	0.05%	92399	5
91733	0.05%	93291	5
93501	0.05%	93219	4
92320	0.05%	92359	4
91732	0.05%	90059	4
92704	0.05%	92313	4
91724	0.05%	90212	4
90247	0.05%	92866	4
92701	0.05%	92377	4
93022	0.05%	92551	4
91740	0.05%	91724	4
90606	0.05%	91740	4
92587	0.05%	90606	4
92843	0.04%	91755	4
91755	0.04%	90810	4
91790	0.04%	92706	4
91748	0.04%	91722	4
92346	0.04%	93004	4
92882	0.04%	92663	4
92661	0.04%	90302	4
90603	0.04%	92284	4
92782	0.04%	90242	4
90805	0.04%	91776	4
90810	0.04%	91739	4
90504	0.04%	91001	4
90706	0.04%	92840	4
92706	0.04%	92373	4
92374	0.04%	93292	4
91024	0.04%	91320	4
93510	0.04%	91765	4
92679	0.04%	92544	4
90804	0.04%	91770	4
91722	0.04%	93003	4
92548	0.04%	92627	4
90806	0.04%	92563	4
91020	0.04%	93065	4
90220	0.04%	91709	4
93004	0.04%	92408	3
92356	0.04%	93505	3
92663	0.04%	90670	3
90723	0.04%	92252	3
91016	0.04%	92582	3
90660	0.04%	90232	3
93015	0.04%	92587	3
90302	0.04%	90603	3
93223	0.04%	92679	3
90210	0.04%	91768	3
91768	0.04%	90602	3
90602	0.03%	90501	3
90501	0.03%	92277	3
92870	0.03%	92337	3
92397	0.03%	93546	3

92284	0.03%	91803	3
91340	0.03%	91791	3
90650	0.03%	91321	3
90242	0.03%	90046	3
93257	0.03%	92883	3
92264	0.03%	91750	3
92821	0.03%	92692	3
92342	0.03%	91754	3
92277	0.03%	91780	3
91776	0.03%	91007	3
91739	0.03%	92869	3
92308	0.03%	91789	3
93063	0.03%	92867	3
90745	0.03%	93036	3
91001	0.03%	91350	3
90250	0.03%	91360	3
90716	0.03%	90703	3
92337	0.03%	91745	3
93546	0.03%	90278	3
92503	0.03%	90630	3
92507	0.03%	92886	3
92865	0.03%	92626	3
92555	0.03%	92618	3
91803	0.03%	93562	2
92260	0.03%	92590	2
92223	0.03%	90066	2
92840	0.03%	92504	2
92887	0.03%	90061	2
92683	0.03%	92567	2
91744	0.03%	93286	2
92373	0.03%	93225	2
91791	0.03%	90002	2
92399	0.03%	91107	2
90211	0.03%	92320	2
91321	0.03%	91024	2
92336	0.03%	93015	2
92371	0.03%	90210	2
92562	0.03%	91340	2
90802	0.03%	92503	2
90046	0.03%	92865	2
93292	0.03%	92555	2
92883	0.03%	92887	2
93041	0.03%	92371	2
91750	0.03%	93041	2
93543	0.03%	90240	2
91320	0.03%	92354	2
92692	0.03%	92585	2
91754	0.03%	92881	2
90240	0.03%	90814	2
91780	0.03%	93060	2
93291	0.03%	90260	2
91007	0.03%	93552	2
91765	0.03%	90712	2
92544	0.03%	90601	2
92869	0.03%	91006	2
92804	0.02%	91354	2
92878	0.02%	91773	2
91730	0.02%	93035	2
92354	0.02%	90604	2
91770	0.02%	92703	2
91789	0.02%	92691	2
92585	0.02%	93561	2
92867	0.02%	91701	2
93036	0.02%	92543	2
92881	0.02%	91362	2
90814	0.02%	92270	2
93003	0.02%	90403	2
91350	0.02%	92688	2
93060	0.02%	92211	2
93514	0.02%	90638	2
91360	0.02%	92660	2
90260	0.02%	93010	2
90401	0.02%	92705	2
91214	0.02%	90503	2
93552	0.02%	90803	2
90623	0.02%	92656	2
93221	0.02%	91761	2
90703	0.02%	92584	2
92657	0.02%	92592	2
91745	0.02%	92378	1
92627	0.02%	92347	1
90278	0.02%	93207	1
90712	0.02%	93208	1
90630	0.02%	92506	1
90601	0.02%	93227	1
91006	0.02%	93523	1
91354	0.02%	92401	1
91708	0.02%	93516	1
92886	0.02%	93272	1
91773	0.02%	93250	1
92563	0.02%	93256	1
92845	0.02%	92241	1
93035	0.02%	90048	1
92325	0.02%	92508	1
90604	0.02%	93501	1
90304	0.02%	93022	1
91390	0.02%	92661	1
92703	0.02%	93510	1
93065	0.02%	92548	1
91709	0.02%	91020	1
92625	0.02%	92356	1
92691	0.02%	93223	1
93561	0.02%	92397	1
90292	0.02%	92342	1
91701	0.02%	90716	1
91746	0.01%	92507	1
92626	0.01%	90211	1
92543	0.01%	93543	1
91362	0.01%	92804	1
92270	0.01%	92878	1

90403	0.01%
92688	0.01%
91384	0.01%
92211	0.01%
90638	0.01%
92660	0.01%
90265	0.01%
91010	0.01%
93010	0.01%
91775	0.01%
91737	0.01%
92705	0.01%
90503	0.01%
92352	0.01%
90803	0.01%
91361	0.01%
90230	0.01%
92656	0.01%
92868	0.01%
92618	0.01%
91741	0.01%
91761	0.01%
91351	0.01%
92586	0.01%
91784	0.01%
92584	0.01%
92595	0.01%
92651	0.01%
90605	0.01%
91030	0.01%
92596	0.01%
92602	0.01%
93021	0.01%
92614	0.01%
92592	0.01%
91355	0.01%
92831	0.01%
93001	0.01%
90740	0.01%
90505	0.01%
90266	0.01%
93012	0.01%
90815	0.01%
92591	0.01%
92880	0.01%
92833	0.01%
92545	0.01%
90275	0.01%
90277	0.01%
93551	0.01%
91706	0.01%
92648	0.00%
91801	0.00%

93514	1
90401	1
91214	1
90623	1
93221	1
92657	1
91708	1
92845	1
92325	1
90304	1
91390	1
92625	1
90292	1
91746	1
91384	1
90265	1
91010	1
91775	1
91737	1
92352	1
91361	1
90230	1
92868	1
91741	1
91351	1
92586	1
91784	1
92595	1
92651	1
90605	1
91030	1
92596	1
92602	1
93021	1
92614	1
91355	1
92831	1
93001	1
90740	1
90505	1
90266	1
93012	1
90815	1
92591	1
92880	1
92833	1
92545	1
90275	1
90277	1
93551	1
91706	1
92648	1
91801	1

Mar-23	
ZIP CODE	RATE
92581	2.27%
91042	2.08%
92258	1.30%
90038	1.15%
92327	0.97%
91364	0.72%
92282	0.71%
92368	0.60%
93518	0.57%
92385	0.46%
92230	0.45%
93505	0.44%
93227	0.44%
93534	0.44%
90732	0.41%
92410	0.40%
93523	0.40%
93501	0.39%
92347	0.38%
92240	0.36%
92311	0.36%
93283	0.35%
93535	0.34%
92344	0.34%
92220	0.33%
93255	0.33%
92301	0.33%
92404	0.32%
92553	0.31%
92356	0.30%
92532	0.30%
92405	0.30%
93066	0.30%
93553	0.30%
92587	0.29%
93257	0.29%
93247	0.29%
92395	0.28%
92313	0.28%
93532	0.27%
92411	0.27%
93221	0.27%
92225	0.26%
92394	0.26%
93277	0.26%
92363	0.26%
92567	0.26%
92557	0.25%
91764	0.25%
92358	0.25%
93560	0.25%
90002	0.25%

Mar-23	
ZIP CODE	TOTAL DISCONNECTIONS
93535	75
93257	70
93534	65
92553	63
92404	59
93274	57
92345	55
92410	54
92376	51
93277	50
92240	49
93230	44
92335	43
91764	42
92311	42
92392	41
93536	41
92557	40
92234	39
92407	38
90805	36
92395	36
91387	35
92262	35
92544	35
92562	35
90201	34
93291	34
92301	33
92336	33
92570	32
91730	31
92260	31
92530	31
91732	30
91761	30
93292	29
90221	28
92405	28
90650	27
92307	27
92394	27
92308	26
92346	26
90280	25
90813	25
91762	25
92374	25
90022	24
90631	24
90706	24
91786	24

90221	0.25%
90045	0.25%
93510	0.24%
90044	0.24%
93202	0.24%
93562	0.24%
93205	0.24%
92501	0.24%
93543	0.24%
93516	0.24%
93274	0.24%
93267	0.23%
91387	0.23%
92324	0.23%
91008	0.23%
93235	0.23%
92376	0.22%
93544	0.22%
92544	0.22%
91342	0.22%
92590	0.22%
92570	0.21%
91768	0.21%
91732	0.20%
93256	0.20%
92345	0.20%
92277	0.20%
93240	0.20%
93230	0.20%
92252	0.20%
92392	0.19%
92407	0.19%
93292	0.19%
92372	0.19%
92371	0.19%
92262	0.19%
92307	0.19%
92583	0.18%
90292	0.18%
92585	0.18%
92365	0.18%
92335	0.18%
92234	0.18%
93215	0.18%
90023	0.18%
93536	0.18%
91302	0.17%
93286	0.17%
92401	0.17%
91702	0.17%
93291	0.17%
92374	0.17%
90047	0.17%
92503	0.17%
92530	0.17%
92308	0.17%
92337	0.17%
90043	0.17%
91737	0.17%
92342	0.17%
91351	0.16%
92548	0.16%
92883	0.16%
92536	0.16%
92562	0.16%
92398	0.16%
91010	0.16%
92707	0.16%
91761	0.15%
92543	0.15%
90302	0.15%
92284	0.15%
91792	0.15%
93555	0.15%
90262	0.15%
92878	0.15%
92260	0.15%
90201	0.15%
90022	0.15%
90305	0.15%
93591	0.15%
92339	0.15%
93219	0.15%
91390	0.14%
92346	0.14%
90813	0.14%
91763	0.14%
91731	0.14%
93030	0.14%
90805	0.14%
90063	0.14%
92653	0.14%
91739	0.14%
91767	0.14%
93225	0.14%
91790	0.13%
92354	0.13%
91723	0.13%
90059	0.13%
92316	0.13%
90066	0.13%
92285	0.13%
90304	0.13%
91724	0.13%
90605	0.13%
90301	0.13%
91730	0.13%
92551	0.13%
90241	0.13%
90303	0.13%

92532	24
90802	23
91709	23
92509	23
90262	22
91710	22
91766	22
92592	22
93065	22
93505	22
92344	21
92543	21
92707	21
93030	21
93215	21
93555	21
90044	20
91744	20
91767	20
92563	20
92584	19
92587	19
90241	18
91768	18
91770	18
91790	18
92223	18
92225	18
92277	18
92284	18
92411	18
92583	18
92705	18
92882	18
92883	18
93560	18
90302	17
90640	17
91302	17
91739	17
92780	17
93033	17
90220	16
90255	16
90301	16
90723	16
91351	16
92337	16
92399	16
92585	16
92630	16
92821	16
92879	16
93551	16
90806	15
91763	15
92211	15
92591	15
92656	15
92880	15
93247	15
90250	14
90604	14
90605	14
91737	14
91748	14
91792	14
91801	14
92371	14
92571	14
92683	14
92704	14
92840	14
93221	14
93550	14
90046	13
90063	13
90660	13
91010	13
91016	13
91776	13
92626	13
92870	13
90242	12
90292	12
90745	12
91780	12
92313	12
92586	12
92627	12
92701	12
93010	12
90601	11
90804	11
91355	11
91724	11
91731	11
92264	11
92354	11
92373	11
92503	11
93063	11
90680	10
90810	10
91007	10
91321	10
91741	10
91745	10
91765	10
91791	10

91762	0.13%
90056	0.12%
90220	0.12%
91708	0.12%
93270	0.12%
91786	0.12%
90723	0.12%
90401	0.12%
92586	0.12%
91766	0.12%
90806	0.12%
91340	0.12%
92555	0.12%
90046	0.12%
92377	0.12%
92504	0.12%
90604	0.11%
93272	0.11%
92879	0.11%
92655	0.11%
92844	0.11%
92509	0.11%
90680	0.11%
92336	0.11%
90061	0.11%
92241	0.11%
91744	0.11%
92881	0.11%
90810	0.11%
93033	0.11%
91770	0.11%
92211	0.11%
92705	0.11%
90631	0.11%
91776	0.11%
92821	0.11%
90280	0.11%
91740	0.10%
90602	0.10%
91741	0.10%
91748	0.10%
90265	0.10%
93250	0.10%
90802	0.10%
90706	0.10%
91780	0.10%
91307	0.10%
92571	0.10%
92408	0.10%
90650	0.10%
93527	0.10%
90242	0.10%
90601	0.10%
92780	0.10%
92840	0.10%
92591	0.10%
92868	0.10%
92706	0.10%
92701	0.09%
90222	0.09%
92880	0.09%
92584	0.09%
93265	0.09%
90069	0.09%
91791	0.09%
90040	0.09%
92507	0.09%
91710	0.09%
90255	0.09%
90701	0.09%
91321	0.09%
93551	0.09%
91709	0.09%
92596	0.09%
90240	0.09%
91733	0.09%
92582	0.09%
90210	0.09%
92882	0.09%
90755	0.09%
93065	0.09%
92399	0.09%
92563	0.09%
93552	0.09%
90640	0.09%
92610	0.09%
92592	0.09%
91355	0.08%
92223	0.08%
91007	0.08%
91775	0.08%
92656	0.08%
91016	0.08%
90270	0.08%
90660	0.08%
92703	0.08%
91354	0.08%
91722	0.08%
90715	0.08%
91752	0.08%
90745	0.08%
92691	0.08%
91754	0.08%
92373	0.08%
92595	0.08%
92804	0.07%
92870	0.07%
92704	0.07%
93015	0.07%
90804	0.07%

92252	10
92545	10
92596	10
92660	10
92691	10
92703	10
92881	10
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93552	9
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92377	7
92567	7
92651	7
93036	7
93561	7
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91030	6
91301	6
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90210	5
90260	5
90270	5
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90715	5
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92582	5
92648	5
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92860	5
93021	5
93060	5
93286	5
90056	4

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92264	0.07%
92320	0.07%
91384	0.07%
90249	0.07%
93223	0.07%
93010	0.07%
90247	0.07%
92860	0.07%
92630	0.07%
92831	0.07%
91801	0.07%
91803	0.07%
91755	0.07%
92651	0.07%
92660	0.06%
91301	0.06%
92626	0.06%
91765	0.06%
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93546	0.06%
92210	0.06%
91745	0.06%
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91789	0.06%
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90638	0.06%
91381	0.06%
91214	0.06%
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92867	0.06%
93001	0.06%
93063	0.06%
93222	0.06%
92886	0.06%
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93004	0.06%
92887	0.06%
92683	0.06%
92627	0.06%
91030	0.06%
90211	0.05%
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92841	0.05%
90048	0.05%
93561	0.05%
91701	0.05%
90212	0.05%
92823	0.05%
91773	0.05%
92549	0.05%
91320	0.05%
90815	0.05%
91362	0.05%
93036	0.05%
93023	0.05%
93060	0.05%
92508	0.05%
92382	0.05%
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90260	0.05%
92869	0.05%
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90703	0.05%
90250	0.05%
92861	0.05%
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90278	0.05%
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93013	0.05%
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90503	0.05%
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93003	0.05%
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91361	0.05%
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91750	0.04%
90603	0.04%
93285	0.04%
92688	0.04%
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91104	0.04%
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91001	0.04%
93041	0.04%
91706	0.04%
91020	0.04%
90623	0.04%
92663	0.04%
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92325	0.03%
92359	0.03%
90716	0.03%
90713	0.03%

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90701	4
90712	4
90717	4
90746	4
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90061	3
90066	3
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92679	3
92804	3
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93013	3
93041	3
93066	3
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93202	3
93205	3
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93256	3
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93532	3
93591	3
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90245	2
90254	2
90274	2
90606	2
90621	2
90623	2
90720	2
90803	2
91107	2
91108	2
92241	2
92258	2
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92365	2
92368	2
92382	2
92549	2
92606	2
92649	2
92677	2
92692	2
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92865	2
92866	2
93035	2
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93227	2
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93270	2
93516	2
93523	2
93553	2
93562	2
90045	1
90048	1
90502	1
90504	1

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91784	0.03%
90620	0.03%
90277	0.03%
90245	0.03%
90404	0.03%
92612	0.03%
92648	0.02%
90720	0.02%
92614	0.02%
92606	0.02%
92352	0.02%
90606	0.02%
90403	0.02%
90740	0.02%
90254	0.02%
92618	0.02%
90266	0.02%
90274	0.02%
93117	0.02%
90670	0.02%
92833	0.02%
92657	0.02%
92647	0.02%
90275	0.02%
90630	0.02%
93110	0.02%
92620	0.02%
90621	0.02%
93035	0.02%
92692	0.02%
90502	0.02%
92625	0.02%
92649	0.01%
90803	0.01%
90814	0.01%
90504	0.01%
93012	0.01%

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90716	1
90732	1
90814	1
91008	1
91020	1
91042	1
91104	1
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93012	1
93110	1
93222	1
93250	1
93255	1
93271	1
93272	1
93285	1
93527	1
93544	1

Apr-23	
ZIP CODE	RATE
92401	1.56%
92318	1.47%
93518	1.28%
93531	1.23%
93562	1.22%
92309	1.20%
92561	1.15%
93243	1.14%
93227	1.09%
92365	1.00%
92398	0.94%
92230	0.91%
93553	0.89%
93512	0.88%
92311	0.87%
93270	0.85%
92301	0.83%
93523	0.80%
92356	0.80%
93534	0.77%
93535	0.76%
90038	0.76%
92543	0.76%
93267	0.76%
92347	0.75%
92404	0.74%
93501	0.73%
92405	0.71%
93218	0.70%
93505	0.68%
92395	0.67%
92410	0.67%
92220	0.67%
91342	0.66%
93235	0.60%
92368	0.60%
90008	0.60%
92553	0.59%
93223	0.57%
92371	0.57%
93205	0.56%
92225	0.56%
92240	0.55%
90044	0.55%
92544	0.55%
93591	0.54%
93283	0.53%
92282	0.53%
92411	0.53%
93550	0.52%
93285	0.52%
92548	0.51%
92551	0.51%
93552	0.51%
93257	0.50%
93541	0.50%
93261	0.49%
92327	0.49%
92345	0.48%
92307	0.48%
92501	0.48%
92346	0.47%
93560	0.47%
93274	0.46%
93240	0.46%
91764	0.46%
93247	0.46%

Apr-23	
ZIP CODE	TOTAL DISCONNECTIONS
93535	167
92404	138
92345	130
93257	121
92553	118
93550	118
93534	115
93274	112
92311	103
92543	103
93536	100
92376	98
92335	95
92410	90
93230	88
93291	88
92395	87
92407	87
92544	87
92346	85
92301	84
90805	83
91730	77
90201	76
91764	76
91786	76
92240	76
92392	76
93551	75
92570	73
92557	71
92307	69
92336	68
93277	68
92405	67
91762	66
92509	66
92530	65
90280	62
92571	62
93555	62
90802	61
91710	60
92308	60
91766	59
92234	59
92545	58
90650	57
90250	55
90706	55
92262	55
93292	55
92260	54
90640	53
93552	53
90813	52
92223	52
93215	52
91767	51
92562	51
91706	50
91387	49
90301	48
91732	48
92707	48
92394	47
92399	47

92285	0.46%
92408	0.45%
92557	0.45%
92394	0.45%
92583	0.45%
93543	0.45%
93291	0.45%
92407	0.45%
92571	0.44%
93555	0.44%
93215	0.44%
92376	0.43%
93536	0.43%
93551	0.42%
93225	0.41%
90302	0.40%
91340	0.40%
90221	0.40%
91731	0.40%
93527	0.40%
92335	0.40%
93230	0.39%
92359	0.39%
90043	0.39%
92308	0.39%
90301	0.39%
91786	0.38%
92587	0.38%
91708	0.38%
92277	0.38%
92372	0.38%
92239	0.38%
90047	0.38%
92324	0.38%
92570	0.38%
92582	0.37%
92252	0.37%
93292	0.36%
91768	0.36%
93532	0.36%
92392	0.36%
92545	0.36%
92707	0.36%
92530	0.36%
92284	0.35%
93516	0.35%
92354	0.35%
91767	0.35%
93277	0.35%
90220	0.35%
90001	0.35%
93272	0.34%
90059	0.34%
93256	0.34%
93219	0.34%
90002	0.34%
91762	0.33%
93255	0.33%
92325	0.33%
92316	0.33%
90201	0.33%
91732	0.33%
91790	0.33%
90805	0.33%
93510	0.33%
91387	0.32%
92590	0.32%
92509	0.32%
93265	0.32%
93202	0.32%
92256	0.32%
92536	0.32%
91766	0.32%
91730	0.32%
92532	0.31%
93250	0.31%
92879	0.31%
92504	0.31%
92555	0.31%
92585	0.31%
90806	0.31%
90040	0.31%
92508	0.31%
92595	0.30%
93207	0.30%
90210	0.30%
90813	0.30%
92262	0.30%
92868	0.30%
92342	0.30%
90222	0.29%
91752	0.29%
90292	0.29%
91722	0.29%
93238	0.29%
93221	0.28%
92881	0.28%
90710	0.28%
92374	0.28%
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93041	0.28%
93286	0.28%
90802	0.27%
92322	0.27%
92234	0.27%
90640	0.27%
90723	0.27%
92860	0.27%
92880	0.27%
93514	0.26%

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92683	47
90221	46
91761	46
90044	45
90220	45
90255	45
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92583	44
92592	44
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92880	43
92284	42
92371	42
92374	41
92584	41
92647	41
90022	40
90806	39
92780	39
92225	38
92591	37
90723	36
92551	36
92705	36
90001	35
92277	35
92411	35
92704	35
91748	34
92211	34
93505	34
93560	34
90241	33
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90262	32
90660	32
90804	32
91709	32
91745	32
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90631	31
91731	31
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91770	27
92585	27
92840	27
90745	26
91791	26
92373	26
92656	26
92881	26
91321	25
91739	25
92532	25
92587	25
92701	25
92708	25
90604	24
91001	24
91340	24
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92620	24
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93247	24
90247	23
90605	23
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90222	22
90242	22
91351	22
91708	22
92841	22
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93561	22
90602	21
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92337	21
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92555	21
92582	21
93030	21
93036	21
93041	21
93063	21
90063	20
90601	20
90815	20
91362	20
91789	20

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92399	0.26%
92260	0.26%
90255	0.26%
92653	0.26%
92567	0.25%
90023	0.25%
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92268	0.25%
91710	0.25%
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92861	0.25%
90022	0.24%
90602	0.24%
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92223	0.24%
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92703	0.24%
92591	0.24%
92317	0.24%
93015	0.24%
91791	0.24%
91733	0.24%
91723	0.24%
91761	0.24%
92841	0.24%
93222	0.23%
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90241	0.23%
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92336	0.23%
92506	0.23%
91321	0.23%
92780	0.23%
92344	0.23%
92804	0.22%
91351	0.22%
90061	0.22%
93544	0.22%
92882	0.22%
92337	0.22%
90056	0.22%
90063	0.22%
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92705	0.21%
90804	0.21%
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90605	0.21%
90650	0.21%
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92701	0.20%
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92878	0.20%
91740	0.20%
91745	0.20%
90604	0.20%
90670	0.20%
90660	0.20%
90305	0.20%
90250	0.19%
92305	0.19%
91001	0.19%
92647	0.19%
92655	0.19%
91381	0.19%
91737	0.19%
92840	0.19%
92586	0.19%
92683	0.19%
91302	0.19%
92844	0.18%
92549	0.18%
92704	0.18%
90242	0.18%
90247	0.18%
90601	0.18%
92377	0.18%
90680	0.18%
92373	0.18%
93065	0.18%
91746	0.18%
90240	0.18%
93067	0.18%
90715	0.17%
91384	0.17%
91792	0.17%
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91744	0.17%
92592	0.17%
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91750	0.17%
91775	0.17%
92241	0.17%
90745	0.17%
92602	0.17%

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93001	20
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90292	19
90803	19
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90717	11
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91741	11
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92377	11

92870	0.17%	92653	11
91803	0.17%	92692	11
90211	0.16%	92886	11
90713	0.16%	93035	11
92867	0.16%	93101	11
90606	0.16%	93591	11
91770	0.16%	90023	10
91390	0.16%	90040	10
90048	0.16%	90249	10
91701	0.16%	90670	10
92706	0.16%	91010	10
90716	0.16%	91361	10
92626	0.16%	91390	10
91776	0.16%	91755	10
93036	0.15%	92382	10
93060	0.15%	92651	10
91789	0.15%	92833	10
90046	0.15%	93021	10
92264	0.15%	93117	10
93033	0.15%	93562	10
93004	0.15%	90254	9
91007	0.15%	90502	9
92614	0.15%	90746	9
90502	0.15%	92342	9
91773	0.15%	92352	9
91784	0.15%	92401	9
93001	0.15%	92503	9
91362	0.15%	92782	9
91355	0.15%	92804	9
92339	0.15%	93518	9
91801	0.15%	90230	8
93271	0.15%	90266	8
92831	0.15%	90304	8
91754	0.14%	91780	8
92656	0.14%	92230	8
93030	0.14%	92372	8
90265	0.14%	92504	8
93022	0.14%	92606	8
92835	0.14%	92649	8
90501	0.14%	92878	8
92503	0.14%	93012	8
90717	0.14%	93103	8
90631	0.14%	93235	8
91107	0.14%	93286	8
92630	0.14%	93510	8
91108	0.13%	90056	7
90621	0.13%	90212	7
90755	0.13%	90245	7
92708	0.13%	90720	7
90066	0.13%	91301	7
90290	0.13%	92285	7
90304	0.13%	92507	7
90807	0.13%	92549	7
90815	0.13%	92567	7
92610	0.13%	92688	7
92676	0.13%	93023	7
91104	0.13%	93105	7
90814	0.13%	93205	7
93529	0.13%	93219	7
93003	0.13%	93265	7
92596	0.13%	90061	6
91709	0.13%	90211	6
92821	0.13%	90274	6
91320	0.12%	90404	6
91350	0.12%	90603	6
92883	0.12%	90755	6
90212	0.12%	91108	6
90069	0.12%	92220	6
92604	0.12%	92256	6
91010	0.12%	92397	6
92637	0.12%	92398	6
92320	0.12%	92508	6
90249	0.12%	92590	6
90712	0.12%	92610	6
91361	0.12%	92625	6
90275	0.12%	92679	6
90620	0.12%	92865	6
92618	0.12%	92866	6
91711	0.11%	93283	6
91741	0.11%	93553	6
90701	0.11%	90401	5
91765	0.11%	90402	5
93063	0.11%	90623	5
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90402	0.11%	90716	5
92627	0.11%	91030	5
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92341	0.09%	91011	3

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92606	0.09%
92692	0.09%
91360	0.09%
91016	0.09%
93101	0.09%
90638	0.09%
92625	0.09%
92651	0.09%
90505	0.09%
90277	0.09%
92691	0.09%
92865	0.09%
90230	0.09%
93023	0.09%
93010	0.09%
92661	0.09%
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90405	0.09%
90720	0.08%
93021	0.08%
92679	0.08%
93111	0.08%
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92646	0.08%
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91301	0.08%
91311	0.07%
92677	0.07%
93110	0.07%
92887	0.07%
93105	0.07%
91702	0.07%
91780	0.07%
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93117	0.07%
92886	0.06%
92833	0.06%
91024	0.06%
90248	0.06%
90274	0.06%
91377	0.06%
90266	0.06%
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92662	0.06%
92649	0.06%
90404	0.06%
93012	0.06%
92823	0.05%
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93546	0.05%
92688	0.05%
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91011	0.04%
93108	0.04%
91214	0.04%
91020	0.04%
92603	0.04%
90232	0.03%
93013	0.03%
90740	0.03%
90704	0.02%
92210	0.02%
Not Valid*	0.00%

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91104	3
91342	3
91377	3
92241	3
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93531	3
90038	2
90232	2
91214	2
91702	2
92309	2
92322	2
92347	2
92368	2
92501	2
92536	2
92661	2
93013	2
93108	2
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93067	1
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93255	1
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93529	1
93541	1
93544	1
93634	1

May-23	
ZIP CODE	RATE
92312	50.00%
93212	50.00%
93558	2.04%
93244	1.73%
92318	1.47%
93255	1.32%
92401	1.22%
93523	1.21%
92561	1.15%
93261	1.15%
93287	1.12%
92378	0.93%
92365	0.91%
92368	0.90%
93202	0.88%
93550	0.86%
92230	0.79%
93543	0.79%
93501	0.78%
93267	0.76%
93040	0.74%
93591	0.73%
92411	0.72%
91364	0.72%
92389	0.70%
92590	0.70%
93535	0.68%
93256	0.68%
93544	0.66%
92570	0.66%
93534	0.65%
93247	0.65%
92587	0.64%
92410	0.64%
92311	0.63%
92301	0.62%
92324	0.61%
93562	0.61%
90008	0.60%
93553	0.59%

May-23	
ZIP CODE	TOTAL DISCONNECTIONS
93550	194
93535	150
90805	110
92345	109
93274	106
92404	105
92553	104
92570	100
93257	100
93534	97
92392	91
92376	90
92407	88
92410	86
92335	83
92544	80
92346	78
93230	78
92543	77
90280	74
92311	74
92557	71
93536	70
90813	68
92395	68
92336	67
90640	65
90201	64
90262	64
92530	64
90802	63
91762	63
91764	63
92301	63
93292	63
90650	62
91730	61
92509	60
93277	60
93291	59

91759	0.59%
93272	0.57%
92404	0.57%
92543	0.56%
92551	0.56%
91768	0.56%
93205	0.56%
93240	0.56%
92220	0.55%
93223	0.54%
91340	0.54%
92256	0.53%
92395	0.53%
92553	0.52%
93250	0.51%
92544	0.50%
92405	0.50%
93527	0.50%
92358	0.50%
90222	0.49%
92327	0.48%
92391	0.48%
93516	0.47%
93552	0.46%
93505	0.46%
92356	0.45%
92407	0.45%
92557	0.45%
92583	0.44%
93227	0.44%
93274	0.44%
92371	0.43%
90805	0.43%
90262	0.43%
92392	0.43%
92346	0.43%
90221	0.43%
90002	0.43%
92342	0.43%
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93270	0.42%
93518	0.42%
93260	0.42%
93215	0.42%
90302	0.42%
93292	0.42%
90220	0.42%
93286	0.42%
93257	0.41%
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92372	0.38%
92239	0.38%
92305	0.38%
91764	0.38%
90731	0.38%
93221	0.38%
92347	0.38%
93235	0.38%
93218	0.35%
91387	0.35%
92408	0.35%
92530	0.35%
93230	0.35%
92335	0.35%
90047	0.34%
92308	0.33%
91792	0.33%
92507	0.33%
92571	0.33%
90640	0.33%
93022	0.33%
91763	0.32%
90255	0.32%
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90723	0.32%
92284	0.32%
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90302	47
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92562	47
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92840	23
93060	23
93063	23
93505	23
90605	22
90620	22

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92223	0.26%
92307	0.26%
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93060	0.24%
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92549	0.21%
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90048	0.11%

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92866	9
93105	9
93546	9
90059	8
90210	8
90401	8
90404	8
90603	8
90670	8
90712	8
90720	8
91107	8
92324	8
92352	8
92359	8
92372	8
92549	8
92603	8
92860	8
92869	8
90043	7
90304	7
90502	7
90701	7
90740	7
90755	7
91030	7
91750	7
92230	7
92397	7
92401	7
92688	7
92886	7
93003	7
93015	7
93022	7
93103	7
93109	7
93205	7
93225	7
93261	7
93270	7
93285	7
90040	6
90056	6
90245	6
90254	6
90266	6
90505	6
90814	6
91020	6
91702	6
92285	6
92382	6
92391	6
92679	6
92692	6
93523	6
90066	5
90211	5
90230	5
90232	5
91746	5
92220	5
92504	5
92602	5

91354	0.11%
92606	0.11%
93035	0.10%
92870	0.10%
91801	0.10%
92603	0.10%
93108	0.10%
91355	0.10%
92708	0.10%
90703	0.10%
92656	0.10%
90803	0.10%
92677	0.10%
90720	0.10%
93103	0.10%
90710	0.09%
93004	0.09%
92341	0.09%
91709	0.09%
91780	0.09%
92651	0.09%
93546	0.09%
92352	0.09%
90277	0.09%
92691	0.09%
91108	0.09%
91006	0.09%
93105	0.09%
90402	0.09%
91362	0.09%
91745	0.09%
92610	0.09%
91016	0.09%
92821	0.09%
93117	0.08%
90630	0.08%
90245	0.08%
90232	0.08%
90808	0.08%
92679	0.08%
92618	0.08%
93013	0.08%
92646	0.08%
91214	0.08%
90405	0.08%
92782	0.08%
91746	0.07%
90404	0.07%
91711	0.07%
90712	0.07%
92320	0.07%
93010	0.07%
92660	0.07%
90815	0.07%
90212	0.07%
91350	0.07%
90704	0.07%
91360	0.07%
92869	0.07%
91030	0.06%
90254	0.06%
90814	0.06%
90716	0.06%
92625	0.06%
91750	0.06%
90275	0.06%
90278	0.06%
90230	0.06%
93664	0.05%
92692	0.05%
92508	0.05%
92688	0.05%
90740	0.05%
92620	0.05%
92602	0.04%
90505	0.04%
91011	0.04%
90266	0.04%
92886	0.04%
92637	0.04%
90274	0.04%
92657	0.04%
93003	0.04%
93111	0.03%
90713	0.03%
92270	0.03%
91024	0.02%
91377	0.02%

92637	5
92804	5
92878	5
93013	5
93040	5
93108	5
93235	5
93250	5
93265	5
93272	5
93527	5
93562	5
90008	4
90212	4
90248	4
90274	4
90402	4
91108	4
91214	4
91311	4
92241	4
92270	4
92610	4
92625	4
92655	4
92661	4
92677	4
93244	4
93255	4
93516	4
93553	4
90061	3
90290	3
90704	3
90713	3
91011	3
91104	3
92320	3
92368	3
93219	3
93222	3
93283	3
93518	3
93544	3
90048	2
90716	2
90731	2
91759	2
92305	2
92339	2
92358	2
92378	2
92398	2
92536	2
92657	2
93066	2
93111	2
93227	2
93238	2
93260	2
93271	2
93532	2
90045	1
90710	1
91008	1
91024	1
91364	1
91377	1
92239	1
92268	1
92282	1
92312	1
92317	1
92318	1
92322	1
92327	1
92341	1
92347	1
92389	1
92508	1
92561	1
93067	1
93212	1
93218	1
93287	1
93529	1
93558	1
93664	1

Jun-23	
ZIP CODE	RATE
92347	1.13%
92368	0.89%
93512	0.88%
93562	0.73%
93226	0.54%
93227	0.44%
92239	0.39%
93222	0.35%
93218	0.35%
93255	0.33%
92266	0.30%
93553	0.30%
93518	0.28%
92371	0.26%
93552	0.22%
93238	0.19%
92305	0.19%

Jun-23	
ZIP CODE	TOTAL DISCONNECTIONS
93257	30
92234	27
92404	25
93552	23
93536	23
92371	19
92553	18
93534	17
93230	17
92301	15
92346	15
92335	15
93291	14
93292	13
91766	13
92583	11
93551	11

92372	0.19%
93543	0.18%
92282	0.18%
92408	0.17%
92241	0.17%
92342	0.16%
92324	0.15%
92804	0.15%
92301	0.15%
92325	0.15%
93223	0.14%
92404	0.13%
92363	0.13%
92234	0.12%
93257	0.12%
91340	0.12%
92548	0.12%
93272	0.11%
93534	0.11%
92583	0.11%
92225	0.10%
93536	0.10%
90040	0.09%
92553	0.09%
93283	0.09%
92277	0.09%
93292	0.09%
92346	0.08%
93560	0.08%
93202	0.08%
91754	0.08%
92311	0.08%
93230	0.08%
91311	0.07%
92677	0.07%
90210	0.07%
93291	0.07%
91766	0.07%
93286	0.07%
91708	0.07%
92313	0.07%
92585	0.07%
92284	0.07%
92285	0.06%
90240	0.06%
92335	0.06%
93551	0.06%
91745	0.06%
90248	0.06%
90713	0.06%
92586	0.06%
93505	0.06%
93215	0.06%
92707	0.06%
93267	0.06%
92240	0.06%
92374	0.05%
90712	0.05%
90302	0.05%
90212	0.05%
92596	0.05%
93664	0.05%
90815	0.05%
92508	0.05%
93555	0.05%
92878	0.05%
93591	0.05%
90305	0.05%
93063	0.05%
92392	0.05%
92395	0.05%
92410	0.04%
91790	0.04%
93550	0.04%
92555	0.04%
92705	0.04%
92337	0.04%
93535	0.04%
91020	0.04%
92655	0.04%
92394	0.04%
92399	0.04%
93247	0.04%
92356	0.04%
93274	0.04%
91321	0.04%
92571	0.04%
90746	0.04%
92307	0.03%
90808	0.03%
93225	0.03%
90262	0.03%
91710	0.03%
91739	0.03%
92262	0.03%
90270	0.03%
90745	0.03%
92706	0.03%
90715	0.03%
92544	0.03%
92833	0.03%
90056	0.03%
92587	0.03%
92503	0.03%
91351	0.03%
92563	0.03%
91746	0.03%
90723	0.03%
91722	0.03%
92867	0.03%

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92392	10
93550	10
92325	9
91754	9
92311	9
93063	9
93535	9
93274	9
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92408	7
91340	7
92225	7
93215	7
93555	7
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92563	7
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92804	6
93560	6
92585	6
90713	6
92586	6
90712	6
90302	6
92596	6
92395	6
92410	6
91790	6
92262	6
92584	6
90802	6
90706	6
92342	5
90240	5
92571	5
92307	5
90808	5
90262	5
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91761	4
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90631	4
92630	4
93065	4
92683	4
92336	4
92347	3
92368	3
92241	3
92548	3
90040	3
92677	3
92313	3
93505	3
90212	3
90305	3
92555	3
90746	3
92706	3
91351	3
91722	3
91752	3
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91362	3
92543	3
90241	3
91387	3
92570	3
91764	3
92656	3

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91752	0.03%
92584	0.03%
90603	0.03%
92870	0.03%
92860	0.03%
92551	0.03%
90043	0.03%
91767	0.03%
90802	0.03%
91360	0.03%
90638	0.03%
93041	0.03%
90059	0.03%
90621	0.03%
92704	0.03%
91773	0.03%
93023	0.03%
90706	0.03%
92557	0.03%
92382	0.03%
92545	0.02%
90604	0.02%
92701	0.02%
93561	0.02%
90402	0.02%
91362	0.02%
90755	0.02%
92543	0.02%
92530	0.02%
90063	0.02%
92832	0.02%
90810	0.02%
92405	0.02%
90241	0.02%
91024	0.02%
91761	0.02%
91730	0.02%
93514	0.02%
91786	0.02%
93108	0.02%
91387	0.02%
92570	0.02%
91214	0.02%
90670	0.02%
92882	0.02%
92509	0.02%
92260	0.02%
90623	0.02%
92657	0.02%
92223	0.02%
90404	0.02%
93015	0.02%
91764	0.02%
91006	0.02%
90631	0.02%
92582	0.02%
91750	0.02%
92845	0.02%
93035	0.02%
92630	0.02%
92869	0.02%
92656	0.02%
91711	0.02%
90807	0.02%
92344	0.02%
90301	0.02%
92703	0.02%
93065	0.02%
92683	0.02%
90806	0.02%
90220	0.02%
92691	0.02%
90292	0.02%
91701	0.02%
91762	0.02%
92411	0.02%
92626	0.01%
91748	0.01%
93036	0.01%
90403	0.01%
92879	0.01%
92844	0.01%
90266	0.01%
92840	0.01%
92647	0.01%
90303	0.01%
91732	0.01%
92562	0.01%
92336	0.01%
92264	0.01%
92660	0.01%
91731	0.01%
90201	0.01%
91765	0.01%
92880	0.01%
92532	0.01%
90275	0.01%
90278	0.01%
90044	0.01%
92354	0.01%
90630	0.01%
91010	0.01%
91737	0.01%
91770	0.01%
91724	0.01%
91768	0.01%
92886	0.01%
92592	0.01%
90602	0.01%

91762	3
92626	3
92647	3
92562	3
90201	3
92592	3
90650	3
90250	3
93227	2
93553	2
93518	2
93238	2
92324	2
93286	2
92878	2
93247	2
90270	2
90715	2
92587	2
92503	2
91746	2
90603	2
92860	2
92551	2
93041	2
93023	2
90063	2
92832	2
90810	2
92405	2
90404	2
91006	2
91750	2
93035	2
92869	2
91711	2
90807	2
90301	2
92703	2
90806	2
90220	2
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92840	2
91732	2
92264	2
92660	2
91765	2
92880	2
90275	2
90278	2
90630	2
91770	2
92886	2
90277	2
90813	2
90255	2
91744	2
92407	2
93277	2
92627	2
92620	2
92376	2
90805	2
91709	2
93512	1
93226	1
92239	1
93218	1
93255	1
92266	1
92305	1
92282	1
92363	1
93272	1
93283	1
93202	1
91311	1
92285	1
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93267	1
93664	1
92508	1
93591	1
91020	1
92655	1
92356	1
93225	1
90056	1
90043	1
90059	1
92382	1
90402	1
90755	1
91024	1
93514	1
93108	1
91214	1
90670	1
90623	1
92657	1
93015	1
92582	1
92845	1
92344	1

90277	0.01%
90813	0.01%
90255	0.01%
90230	0.01%
90680	0.01%
91755	0.01%
90650	0.01%
91744	0.01%
91301	0.01%
92841	0.01%
90250	0.01%
93546	0.01%
91302	0.01%
93060	0.01%
92407	0.01%
93277	0.01%
90260	0.01%
90274	0.01%
91733	0.01%
91784	0.01%
90001	0.01%
92595	0.01%
92627	0.01%
91791	0.01%
90601	0.01%
92843	0.01%
92620	0.01%
91354	0.01%
90221	0.01%
92376	0.01%
93101	0.01%
91780	0.01%
91007	0.01%
90242	0.01%
91776	0.01%
90805	0.01%
91709	0.01%
91355	0.01%
92831	0.01%
90620	0.01%
90505	0.01%
92373	0.01%
93030	0.01%
90804	0.01%
92821	0.01%
91320	0.01%
92308	0.01%
90703	0.01%
90660	0.01%
92780	0.01%
91706	0.01%
92708	0.01%
90640	0.01%
91801	0.00%
90280	0.00%
92618	0.00%

90292	1
92411	1
92844	1
90303	1
91731	1
92532	1
90044	1
92354	1
91010	1
91737	1
91724	1
91768	1
90602	1
90230	1
90680	1
91755	1
91301	1
92841	1
93546	1
91302	1
93060	1
90260	1
90274	1
91733	1
91784	1
90001	1
92595	1
91791	1
90601	1
92843	1
91354	1
90221	1
93101	1
91780	1
91007	1
90242	1
91776	1
91355	1
92831	1
90620	1
90505	1
92373	1
93030	1
90804	1
92821	1
91320	1
92308	1
90703	1
90660	1
92780	1
91706	1
92708	1
90640	1
91801	1
90280	1
92618	1

Jul-23	
ZIP CODE	RATE
-	-

Jul-23	
ZIP CODE	TOTAL DISCONNECTIONS
-	-

Aug-23	
ZIP CODE	RATE
91307	0.10%
90047	0.02%
90304	0.02%
92840	0.01%
91732	0.01%
91768	0.01%
93060	0.01%
91752	0.01%
92663	0.01%
92869	0.01%
90242	0.01%
92395	0.01%
90405	0.01%
90241	0.01%
90262	0.01%
91360	0.01%
91765	0.01%
92705	0.01%
92509	0.00%
92392	0.00%
93550	0.00%
92630	0.00%
93536	0.00%
93274	0.00%
92345	0.00%

8/1/2023 **	
ZIP CODE	TOTAL DISCONNECTIONS
92840	2
91732	2
91307	1
90047	1
90304	1
91768	1
93060	1
91752	1
92663	1
92869	1
90242	1
92395	1
90405	1
90241	1
90262	1
91360	1
91765	1
92705	1
92509	1
92392	1
93550	1
92630	1
93536	1
93274	1
92345	1

Sep-23	
ZIP CODE	RATE
93285	0.13%
92676	0.13%
91307	0.10%
90710	0.09%
93267	0.06%
93501	0.05%
92344	0.05%
92377	0.05%
93265	0.05%
90047	0.04%
92337	0.04%
92371	0.04%
93510	0.04%
90222	0.04%

9/1/2023 **	
ZIP CODE	TOTAL DISCONNECTIONS
92392	6
93535	6
93274	6
93550	5
92337	4
92543	4
91764	4
93285	3
92344	3
92377	3
92371	3
90222	3
92395	3
92374	3

93505	0.04%
92504	0.04%
90270	0.03%
92543	0.03%
92392	0.03%
93535	0.03%
93543	0.03%
93274	0.02%
92395	0.02%
91764	0.02%
93550	0.02%
92881	0.02%
92841	0.02%
92610	0.02%
90814	0.02%
92374	0.02%
92570	0.02%
91752	0.02%
93247	0.02%
93552	0.02%
92544	0.02%
90210	0.02%
92886	0.02%
93551	0.02%
91340	0.02%
91390	0.02%
90301	0.02%
92703	0.02%
90715	0.02%
92587	0.02%
92407	0.02%
93277	0.02%
90292	0.02%
92707	0.01%
90603	0.01%
92571	0.01%
90245	0.01%
92307	0.01%
91767	0.01%
92679	0.01%
92376	0.01%
93536	0.01%
90240	0.01%
92557	0.01%
91710	0.01%
92532	0.01%
90044	0.01%
93010	0.01%
91010	0.01%
91770	0.01%
91361	0.01%
90680	0.01%
92345	0.01%
92530	0.01%
92399	0.01%
92832	0.01%
92405	0.01%
92706	0.01%
93546	0.01%
91302	0.01%
93060	0.01%
92583	0.01%
90640	0.01%
92336	0.01%
93291	0.01%
91762	0.01%
92553	0.01%
91722	0.01%
92882	0.01%
92562	0.01%
91006	0.01%
90631	0.01%
91773	0.01%
93035	0.01%
91007	0.01%
93257	0.01%
90604	0.01%
91739	0.01%
93065	0.01%
90805	0.01%
90220	0.01%
90723	0.01%
91790	0.01%
90650	0.01%
91748	0.01%
92867	0.01%
93555	0.01%
90241	0.01%
92649	0.01%
90804	0.01%
92660	0.01%
92880	0.01%
90703	0.01%
91745	0.01%
91016	0.01%
90022	0.01%
92545	0.01%
90630	0.01%
92780	0.01%
92346	0.01%
91766	0.01%
92404	0.01%
93063	0.01%
93003	0.01%
92509	0.00%
91801	0.00%
92260	0.00%
92223	0.00%
92335	0.00%
91730	0.00%

92570	3
92544	3
92886	3
93551	3
92407	3
93277	3
92376	3
93536	3
91710	3
92345	3
92336	3
90047	2
93505	2
90270	2
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92841	2
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91752	2
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90301	2
92703	2
92707	2
92571	2
92307	2
91767	2
92557	2
93010	2
91770	2
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91762	2
92553	2
92882	2
92562	2
90631	2
93257	2
93065	2
90805	2
90650	2
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90710	1
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93501	1
93265	1
93510	1
92504	1
93543	1
92610	1
93247	1
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90715	1
92587	1
90292	1
90603	1
90245	1
92679	1
90240	1
92532	1
90044	1
91010	1
91361	1
90680	1
92832	1
92405	1
92706	1
93546	1
91302	1
93060	1
92583	1
91722	1
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91739	1
90220	1
90723	1
91790	1
91748	1
92867	1
93555	1
90241	1
92649	1
90804	1
92660	1
92880	1
90703	1
91745	1
91016	1
90022	1
92545	1
90630	1
92780	1
92346	1
91766	1
92404	1
93063	1
93003	1
92509	1
91801	1
92260	1
92223	1
92335	1
91730	1

92683	0.00%
90250	0.00%
Not Valid*	0.00%

92683	1
90250	1
Not Valid*	1

Oct-23	
ZIP CODE	RATE
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92368	0.30%
93205	0.24%
92398	0.16%
93272	0.11%
92341	0.09%
92365	0.09%
93535	0.09%
92570	0.08%
92880	0.06%
92256	0.05%
92405	0.05%
92410	0.05%
92590	0.05%
93591	0.05%
93501	0.05%
90715	0.05%
93022	0.05%
92277	0.04%
93285	0.04%
90303	0.04%
93505	0.04%
92567	0.04%
92835	0.03%
92307	0.03%
92509	0.03%
92308	0.03%
91390	0.03%
92557	0.03%
92704	0.03%
91302	0.03%
92545	0.03%
91723	0.03%
91722	0.03%
92543	0.03%
93274	0.03%
91107	0.03%
90059	0.03%
92549	0.03%
93292	0.03%
90221	0.03%
92407	0.03%
90240	0.03%
92804	0.02%
92320	0.02%
92260	0.02%
90602	0.02%
90501	0.02%
90813	0.02%
93561	0.02%
93551	0.02%
91706	0.02%
90802	0.02%
92867	0.02%
93230	0.02%
90755	0.02%
92881	0.02%
92530	0.02%
91766	0.02%
92832	0.02%
93555	0.02%
91741	0.02%
91767	0.02%
92604	0.02%
93514	0.02%
91784	0.02%
91752	0.02%
92252	0.02%
90745	0.02%
92544	0.02%
90703	0.02%
92657	0.02%
90404	0.02%
92223	0.02%
90601	0.02%
92843	0.02%
91006	0.02%
91754	0.02%
90242	0.02%
91708	0.02%
92262	0.02%
90305	0.02%
92404	0.02%
92377	0.02%
91001	0.02%
92683	0.02%
92614	0.02%
92701	0.02%
93277	0.02%
92865	0.02%
90292	0.02%
92411	0.02%
90723	0.01%
93036	0.01%
91384	0.01%
92392	0.01%
90250	0.01%
92371	0.01%
93534	0.01%
90222	0.01%
90638	0.01%
93550	0.01%

10/1/2023**	
ZIP CODE	TOTAL DISCONNECTIONS
93535	19
92570	12
92880	9
92410	7
92509	7
93274	7
92704	6
92405	5
92307	5
92308	5
92557	5
92545	5
92407	5
92260	5
90802	5
93230	5
92277	4
92543	4
93292	4
90813	4
93551	4
91706	4
92530	4
91766	4
92223	4
92683	4
90250	4
93205	3
90715	3
90303	3
92835	3
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91723	2
90240	2
90602	2
90501	2
92881	2
92832	2
91741	2
92604	2
91784	2
91752	2
90404	2
90601	2
92843	2
91006	2
91754	2
90242	2
91001	2
92614	2
92701	2
90723	2
93036	2
93534	2
90638	2
90275	2
90022	2
91770	2
90255	2
92346	2
92553	2
92584	2
92627	2
92562	2
92630	2
90805	2
92561	1
92368	1
92398	1
93272	1
92341	1
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93591	1
93501	1
93022	1
93285	1
92567	1
91107	1
90059	1

91731	0.01%
93023	0.01%
93536	0.01%
93257	0.01%
90275	0.01%
90044	0.01%
90022	0.01%
91775	0.01%
91770	0.01%
92592	0.01%
91768	0.01%
90606	0.01%
90255	0.01%
91755	0.01%
92346	0.01%
92345	0.01%
92841	0.01%
92336	0.01%
92553	0.01%
90001	0.01%
92584	0.01%
92394	0.01%
93552	0.01%
92595	0.01%
90605	0.01%
92627	0.01%
91791	0.01%
92562	0.01%
90046	0.01%
91773	0.01%
92602	0.01%
92630	0.01%
91711	0.01%
91739	0.01%
92637	0.01%
90805	0.01%
90220	0.01%
91790	0.01%
91748	0.01%
92707	0.01%
90620	0.01%
92571	0.01%
92373	0.01%
92374	0.01%
90262	0.01%
90804	0.01%
91387	0.01%
92264	0.01%
91765	0.01%
91745	0.01%
90660	0.01%
90278	0.01%
92705	0.01%
90503	0.01%
92886	0.01%
92780	0.01%
90803	0.01%
91744	0.01%
91761	0.01%
91786	0.01%
90640	0.01%
93291	0.01%
92648	0.00%
92626	0.00%
92647	0.00%
92376	0.00%
92563	0.00%
90706	0.00%
91710	0.00%
91730	0.00%
90650	0.00%
92618	0.00%

92549	1
92804	1
92320	1
90755	1
93514	1
92252	1
92657	1
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92865	1
90292	1
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91739	1
92637	1
90220	1
91790	1
91748	1
92707	1
90620	1
92571	1
92373	1
92374	1
90262	1
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91387	1
92264	1
91765	1
91745	1
90660	1
90278	1
92705	1
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90706	1
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91730	1
90650	1
92618	1

Nov-23	
ZIP CODE	RATE
93518	0.28%
93285	0.09%
92371	0.08%
93510	0.08%
93205	0.08%
92570	0.08%
92324	0.08%
92285	0.06%
90040	0.06%
93505	0.06%
93267	0.06%
93247	0.06%
90211	0.05%
92405	0.05%
92549	0.05%
92823	0.05%
93664	0.05%
92861	0.05%
93591	0.05%
92320	0.05%
92372	0.05%
91768	0.05%
90220	0.05%
92557	0.04%
92661	0.04%
91104	0.04%
91020	0.04%
92394	0.04%
92410	0.04%
92548	0.04%
92543	0.04%
92582	0.03%
92307	0.03%

11/1/2023**	
ZIP CODE	TOTAL DISCONNECTIONS
92570	12
92557	7
92392	7
93550	7
92371	6
90220	6
92404	6
92376	6
93536	6
93257	6
92405	5
92410	5
92543	5
92307	5
93292	5
91744	5
92530	5
91768	4
92394	4
91767	4
93534	4
92264	4
92308	4
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93535	4
93230	4
91730	4
93505	3
93247	3
91792	3
92337	3

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91702	0.03%
92392	0.03%
93292	0.03%
92359	0.03%
90305	0.03%
91792	0.03%
92404	0.03%
92344	0.03%
92377	0.03%
93550	0.03%
90056	0.03%
92337	0.03%
90603	0.03%
91763	0.03%
91744	0.03%
92530	0.03%
91767	0.03%
93534	0.03%
92264	0.03%
92376	0.03%
93543	0.03%
92308	0.03%
93536	0.03%
92311	0.03%
90023	0.03%
92382	0.03%
92596	0.03%
90242	0.02%
92532	0.02%
93257	0.02%
90044	0.02%
91739	0.02%
90606	0.02%
91108	0.02%
92585	0.02%
90755	0.02%
90620	0.02%
90047	0.02%
92706	0.02%
92571	0.02%
92373	0.02%
93277	0.02%
90713	0.02%
91214	0.02%
90001	0.02%
92882	0.02%
92612	0.02%
92584	0.02%
93221	0.02%
92544	0.02%
92880	0.02%
90022	0.02%
90302	0.02%
93535	0.02%
90210	0.02%
93230	0.02%
90212	0.02%
92845	0.02%
93551	0.02%
91007	0.02%
91730	0.02%
92325	0.02%
91711	0.02%
91390	0.02%
90715	0.02%
91708	0.02%
92625	0.02%
91355	0.02%
92395	0.02%
92587	0.02%
92407	0.02%
90292	0.02%
93561	0.02%
91790	0.01%
92225	0.01%
92707	0.01%
92555	0.01%
92509	0.01%
93555	0.01%
91011	0.01%
92551	0.01%
92840	0.01%
90241	0.01%
93103	0.01%
92562	0.01%
90222	0.01%
91387	0.01%
92821	0.01%
92603	0.01%
91765	0.01%
92335	0.01%
93274	0.01%
91724	0.01%
91709	0.01%
90746	0.01%
90813	0.01%
91755	0.01%
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92346	0.01%
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92277	0.01%
92262	0.01%
92832	0.01%
93063	0.01%
93546	0.01%
93060	0.01%
91351	0.01%
91786	0.01%
92336	0.01%

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92311	3
92596	3
90242	3
91739	3
90620	3
92571	3
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92509	3
92562	3
92335	3
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92336	3
93518	2
93285	2
93510	2
90040	2
90211	2
92549	2
92320	2
92582	2
90305	2
92344	2
92377	2
90603	2
92532	2
90044	2
90606	2
92585	2
92706	2
90713	2
90001	2
90302	2
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91387	2
92821	2
91765	2
90813	2
92346	2
92262	2
93063	2
91786	2
92553	2
91762	2
92646	2
92563	2
90706	2
92345	2
93205	1
92324	1
92285	1
93267	1
92823	1
93664	1
92861	1
93591	1
92372	1
92661	1
91104	1
91020	1
92548	1
93286	1
91702	1
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90056	1
93543	1
90023	1
92382	1
91108	1
90755	1
90047	1
91214	1
93221	1
90210	1
90212	1
92845	1
92325	1
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92551	1
93103	1
90222	1
92603	1
91724	1
90746	1
91755	1

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91762	0.01%
91733	0.01%
91752	0.01%
93552	0.01%
92646	0.01%
92595	0.01%
91321	0.01%
92843	0.01%
91006	0.01%
90621	0.01%
90221	0.01%
92563	0.01%
91754	0.01%
90706	0.01%
92284	0.01%
93021	0.01%
90604	0.01%
91776	0.01%
92703	0.01%
92701	0.01%
91789	0.01%
91748	0.01%
91362	0.01%
92345	0.01%
93036	0.01%
93001	0.01%
90505	0.01%
91732	0.01%
92374	0.01%
90262	0.01%
90804	0.01%
90815	0.01%
92591	0.01%
91745	0.01%
90660	0.01%
92545	0.01%
92705	0.01%
90277	0.01%
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91764	0.01%
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91766	0.01%
92704	0.01%
92708	0.01%
93003	0.01%
91761	0.01%
93291	0.01%
92648	0.00%
92626	0.00%
92260	0.00%
92647	0.00%
92223	0.00%
90631	0.00%
92620	0.00%
90802	0.00%
90201	0.00%
91710	0.00%
93065	0.00%
92683	0.00%
90805	0.00%
92618	0.00%

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92277	1
92832	1
93546	1
93060	1
91351	1
91733	1
91752	1
93552	1
92595	1
91321	1
92843	1
91006	1
90621	1
90221	1
91754	1
92284	1
93021	1
90604	1
91776	1
92703	1
92701	1
91789	1
91748	1
91362	1
93036	1
93001	1
90505	1
91732	1
92374	1
90262	1
90804	1
90815	1
92591	1
91745	1
90660	1
92545	1
92705	1
90277	1
90803	1
91764	1
92399	1
91766	1
92704	1
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93003	1
91761	1
93291	1
92648	1
92626	1
92260	1
92647	1
92223	1
90631	1
92620	1
90802	1
90201	1
91710	1
93065	1
92683	1
90805	1
92618	1

Dec-23	
ZIP CODE	RATE
92401	0.35%
92368	0.30%
92358	0.25%
93227	0.22%
92536	0.16%
92230	0.11%
93250	0.10%
93066	0.09%
93285	0.09%
90248	0.06%
92404	0.06%
92256	0.05%
92405	0.05%
92408	0.05%
93501	0.05%
93265	0.05%
92411	0.04%
92557	0.04%
90066	0.04%
91351	0.04%
93510	0.04%
92570	0.04%
90240	0.04%
92410	0.04%
92548	0.04%
90249	0.04%
90813	0.03%
92342	0.03%
93274	0.03%
92359	0.03%
90270	0.03%
90715	0.03%
90056	0.03%
93535	0.03%
93291	0.03%
91723	0.03%
92555	0.03%
93552	0.03%
93560	0.03%
92843	0.03%
92549	0.03%
93543	0.03%
91731	0.03%
92284	0.03%

12/1/2023**	
ZIP CODE	TOTAL DISCONNECTIONS
92404	11
93274	8
92557	7
93535	7
92570	6
90813	6
93291	6
90280	6
92405	5
92410	5
92630	5
93536	5
91351	4
91706	4
92399	4
91786	4
93257	4
92411	3
90240	3
90249	3
93552	3
92843	3
92284	3
90242	3
92707	3
92543	3
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92544	3
91744	3
92376	3
93230	3
92335	3
92401	2
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92555	2
93560	2
91731	2
91010	2
92832	2
92337	2

90280	0.03%
90242	0.02%
91010	0.02%
92653	0.02%
90701	0.02%
91706	0.02%
90402	0.02%
92707	0.02%
92543	0.02%
92630	0.02%
92399	0.02%
92832	0.02%
93536	0.02%
92337	0.02%
92706	0.02%
92840	0.02%
91786	0.02%
90401	0.02%
93505	0.02%
92252	0.02%
93221	0.02%
92544	0.02%
92657	0.02%
92595	0.02%
93110	0.02%
91006	0.02%
92582	0.02%
93101	0.02%
91744	0.02%
93257	0.02%
92377	0.02%
92701	0.02%
91746	0.01%
91790	0.01%
92867	0.01%
92844	0.01%
92571	0.01%
90241	0.01%
93012	0.01%
93103	0.01%
92371	0.01%
91767	0.01%
93030	0.01%
90804	0.01%
92376	0.01%
93230	0.01%
93292	0.01%
90265	0.01%
92603	0.01%
92335	0.01%
90044	0.01%
91775	0.01%
91724	0.01%
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90606	0.01%
90680	0.01%
92585	0.01%
92346	0.01%
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91302	0.01%
92407	0.01%
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90046	0.01%
90631	0.01%
93550	0.01%
90802	0.01%
90621	0.01%
90221	0.01%
90201	0.01%
92883	0.01%
91007	0.01%
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92596	0.01%
91776	0.01%
90807	0.01%
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92345	0.01%
92240	0.01%
90740	0.01%
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92211	0.01%
92307	0.01%
91732	0.01%
92374	0.01%
93534	0.01%

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92595	2
91006	2
93101	2
92701	2
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92867	2
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91762	2
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90740	1
93555	1
92211	1
92307	1
91732	1
92374	1
93534	1

91387	0.01%
92612	0.01%
92308	0.01%
90745	0.01%
91765	0.01%
90660	0.01%
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90630	0.01%
91770	0.01%
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92705	0.01%
92780	0.01%
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93551	0.01%
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93277	1
90640	1
92648	1
92392	1
92223	1
92563	1
93065	1
92683	1
90805	1
92592	1
90250	1
92618	1

*Due to system constraints, ZIP Code data was not attached to these disconnections. SCE is working on system improvements to remedy this issue.

**Due to system synching issues, the disconnections and reconnections numbers include some customers whose disconnections were either canceled or never processed and reconnections where disconnections did not take place. SCE is evaluating potential system changes to address these issues.

Section 8 - Interim Measures Information

Total Disconnections / Month

Month	Total Residential Accounts* (a)	Total Residential Disconnections (b)	Annual Target Rate (c)	Residential Disconnection Cap Annual Target (d) = (a) from prior month x (c)	Residential Disconnections in Past 11 Months (e) sum of (b) from prior 11 months	Residential Disconnections Allowed for Current Month (d) - (e)
Jan-21	4,580,636	-	7%	320,644	49,134	271,510
Feb-21	4,578,893	-	7%	320,522	16,315	304,207
Mar-21	4,577,057	-	7%	320,393	-	320,393
Apr-21	4,580,418	-	7%	320,629	-	320,629
May-21	4,456,734	-	7%	311,971	-	311,971
Jun-21	4,465,054	-	7%	312,553	-	312,553
Jul-21	4,463,117	-	7%	312,418	-	312,418
Aug-21	4,468,023	-	7%	312,761	-	312,761
Sep-21	4,469,650	-	7%	312,875	-	312,875
Oct-21	4,475,058	-	7%	313,254	-	313,254
Jan-21	4,482,476	-	7%	313,773	-	313,773
Dec-21	4,479,396	-	7%	313,557	-	313,557
Jan-22	4,491,053	-	6%	269,463	-	269,463
Feb-22	4,570,365	-	6%	274,221	-	274,221
Mar-22	4,531,142	-	6%	271,868	-	271,868
Apr-22	4,529,894	-	6%	271,793	-	271,793
May-22	4,530,678	-	6%	271,840	-	271,840
Jun-22	4,538,203	-	6%	272,292	-	272,292
Jul-22	4,544,477	-	6%	272,668	-	272,668
Aug-22	4,548,361	-	6%	272,901	-	272,901
Sep-22	4,553,547	-	6%	273,212	-	273,212
Oct-22	4,513,097	-	6%	270,785	-	270,785
Nov-22	4,559,108	24	6%	273,546	24	273,522
Dec-22	4,561,560	115	6%	273,693	139	273,554
Jan-23	4,565,101	253	5%	228,255	392	227,863
Feb-23	4,570,365	1,515	5%	228,518	1,907	226,611
Mar-23	4,572,597	4,816	5%	228,629	6,723	221,906
Apr-23	4,576,407	10,915	5%	228,820	17,638	211,182
May-23	4,578,017	10,189	5%	228,900	27,827	201,073
Jun-23	4,584,311	1,115	5%	229,215	28,942	200,273
Jul-23	4,585,481	-	5%	229,274	28,942	200,332
Aug-23	4,590,390	27	5%	229,519	28,969	200,550
Sep-23	4,589,451	221	5%	229,472	29,190	200,282
Oct-23	4,591,481	387	5%	229,574	29,553	200,021
Nov-23	4,596,054	422	5%	229,802	29,860	199,942
Dec-23	4,598,836	336	5%	229,941	29,943	199,998
Jan-24			4%			
Feb-24			4%			
Mar-24			4%			
Apr-24			4%			
May-24			4%			
Jun-24			4%			
Jul-24			4%			
Aug-24			4%			
Sep-24			4%			
Oct-24			4%			
Jan-24			4%			
Dec-24			4%			

*This is the number of total residential accounts as of the last day of the previous month.

**Residential customers shall not be disconnected when temperatures above 100 degrees or below 32 degrees are forecasted based on a 72-hour look-ahead period.

On the following dates, SCE invoked temperature related limits on disconnections in one or more cities:**

Month	Days
Jan-23	2, 3, 4, 5, 6, 9, 10, 11, 12, 13, 16, 17, 18, 19, 20, 23, 24, 25, 26, 27, 30, 31
Feb-23	1, 2, 3, 6, 7, 8, 9, 10, 13, 14, 15, 16, 17, 21, 22, 23, 24, 27, 28
Mar-23	1, 2, 3, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 20, 21, 22, 23, 24, 27, 28, 29, 30, 31
Apr-23	3, 4, 5, 6, 7, 10, 11, 12, 13, 14, 17, 18, 19, 20, 21, 24, 25, 27, 28
May-23	1, 2, 3, 4, 5, 8, 9, 10, 11, 12, 15, 16, 17, 18, 19, 22, 23, 24, 25, 26, 29, 30, 31
Jun-23	1, 2, 5, 6, 7, 8, 9, 13, 14, 15, 16, 19, 20, 21, 22, 23, 26, 27, 28, 29, 30
Jul-23	3, 4, 5, 6, 7, 10, 11, 12, 13, 14, 17, 18, 19, 20, 21, 24, 25, 26, 27, 28, 31
Aug-23	1, 2, 4, 7, 8, 9, 10, 11, 14, 15, 16, 17, 18, 22, 23, 24, 25, 28, 29, 30, 31
Sep-23	1, 5, 6, 7, 8, 11, 12, 13, 14, 15, 18, 19, 20, 21, 25, 26, 27,28, 29
Oct-23	2, 3, 4, 5, 6, 12, 13, 16, 17, 18, 19, 20, 23, 24, 25, 26, 27, 30, 31
Nov-23	1, 2, 3, 6, 7, 8, 9, 10, 13, 14, 15, 16, 17, 20, 21, 22, 23, 24, 27, 28, 29, 30
Dec-23	1, 4, 5, 6, 7, 8, 12, 13, 14, 15, 18, 19, 20, 21, 22

Average amount owed of customers who were disconnected

Month	Average Amount
Jan-23	$ 1,496
Feb-23	$ 1,360
Mar-23	$ 2,495
Apr-23	$ 2,266
May-23	$ 2,789
Jun-23	$ 6,660
Jul-23	$ -
Aug-23	$ 7,650
Sep-23	$ 6,647
Oct-23	$ 8,068
Nov-23	$ 9,091
Dec-23	$ 6,384

MBL Household Counts

MBL Household Counts - 2023*															
Month	**New Households Enrolled**				**Removed Households****				**Certifications*****				**Total Households**		
	MBL Only Households	**CARE and MBL Households**	**FERA and MBL Households**	**Total MBL Households**	**MBL Only Households**	**CARE and MBL Households**	**FERA and MBL Households**	**Total MBL Households**	**MBL Only Households**	**CARE and MBL Households**	**FERA and MBL Households**	**Total MBL Households**	**MBL Only Households**	**CARE and MBL Households**	**FERA and MBL Households**
January	1,962	1,411	31	3,404	2,166	1,303	20	3,489	2,615	1,556	35	4,206	55,450	36,672	700
February	2,309	1,476	32	3,817	1,784	1,032	19	2,835	1,195	809	18	2,022	55,824	36,562	701
March	1,846	1,166	20	3,032	204	154	4	362	418	227	7	652	57,179	37,042	704
April	1,272	921	12	2,205	220	154	1	375	478	253	4	735	57,976	37,441	713
May	1,062	939	14	2,015	344	214	7	565	503	291	14	808	58,281	37,744	721
June	1,308	1106	19	2,433	334	281	6	621	497	375	9	881	58,278	38,705	729
July	1,065	1,000	22	2,087	218	195	3	416	700	456	6	1,162	58,351	39,431	743
August	1,369	1,248	22	2,639	229	167	5	401	832	488	8	1,328	58,955	40,302	777
September	1,374	1,217	38	2,629	420	329	12	761	717	469	9	1,195	59,333	41,006	807
October	1,602	1,416	25	3,043	444	311	6	761	765	510	14	1,289	59,750	42,081	827
November	908	988	11	1,907	416	301	9	726	292	181	7	480	59,666	42,648	832
December	823	876	16	1,715	482	296	6	784	139	85	1	225	59,320	43,098	832

* Household status changes that include both a new MBL enrollment and a MBL removal, and that occur within the same calendar month will not be included in the 'New Households Enrolled' or 'Removed Households' tables.

** Household(s) removed from Medical Baseline due to failure to recertify eligibility. Does not include households removed for other reasons.

*** Households that recertify by self-certification or by certification from a medical practitioner.

Total MBL Households
92,822
93,087
94,925
96,130
96,746
97,712
98,525
100,034
101,146
102,658
103,146
103,250



UTILITY COSTS AND AFFORDABILITY OF THE GRID OF THE FUTURE:

An Evaluation of Electric Costs, Rates, and Equity Issues Pursuant to P.U. Code Section 913.1

MAY 2021

California Public Utilities Commission

UTILITY COSTS AND AFFORDABILITY OF THE GRID OF THE FUTURE

AN EVALUATION OF ELECTRIC COSTS, RATES AND EQUITY ISSUES
PURSUANT TO P.U. CODE SECTION 913.1

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UTILITY COSTS AND AFFORDABILITY OF THE GRID OF THE FUTURE

I. EXECUTIVE SUMMARY

Senate Bill (SB) 695 (Kehoe, 2009) requires the CPUC to prepare an annual report addressing electric and gas cost and rate trends as well as actions to limit or reduce utility costs.[1] For 2021, the CPUC is taking a different approach to this report in order to provide a longer-term rate forecast and to leverage a wider array of subject matter expertise from within the CPUC as well as externally in academia and the energy industry. The goal is to evaluate longer term system costs and policy risks. The draft of this report (the SB 695 Report or White Paper) laid the foundation for an "En Banc Meeting on Cost and Rate Trends" held on February 24, 2021, which provided a venue for discussing potential options for addressing the trends and impacts identified herein.

The CPUC faces multiple intersecting policy mandates that require a delicate balance to avoid unintended consequences. If handled incorrectly, California's policy goals could result in rate and bill increases that would make other policy goals more difficult to achieve and could result in overall energy bills becoming unaffordable for some Californians. Electrification goals and wildfire mitigation planning are among the near-term needs, for example, that place upward pressure on rates and bills.

Another regulatory risk that has been identified in prior SB 695 reports and is further detailed in this white paper is a continuing increase in capital investments that are recovered in rate base by the investor-owned utilities (IOUs). While capital investments by IOUs will be necessary to meet California's energy and climate policy goals, they can result in higher bills for customers. Evaluating the reasonableness of these investments in a cleaner, more efficient grid raises affordability and equity implications that merit further investigation.

While this white paper does not explore a comprehensive, detailed breakout of all essential cost categories and their incremental impacts on IOU rates, it evaluates select areas of projected costs of specific programs and policy priorities, including transportation electrification (TE) and wildfire mitigation plan (WMP) implementation. The decision to highlight these specific areas of cost is informed by recent findings of staff analysis and the desire to bring their relative impacts on overall rate forecasts into sharper focus within the broader operations and revenue requirements of California's IOUs. The figures below provide the

[1] Public Utilities Code Section 913.1(b) states, "In preparing the report required by subdivision (a), the commission shall require electrical corporations with 1,000,000 or more retail customers in California, and gas corporations with 500,000 or more retail customers in California, to study and report on measures the corporation recommends be undertaken to limit costs and rate increases."

illustrative impacts of projected wildfire spending relative to the other major bundled[2] residential rate components from 2021 through 2030.[3]

Figure ES-1: PG&E Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate

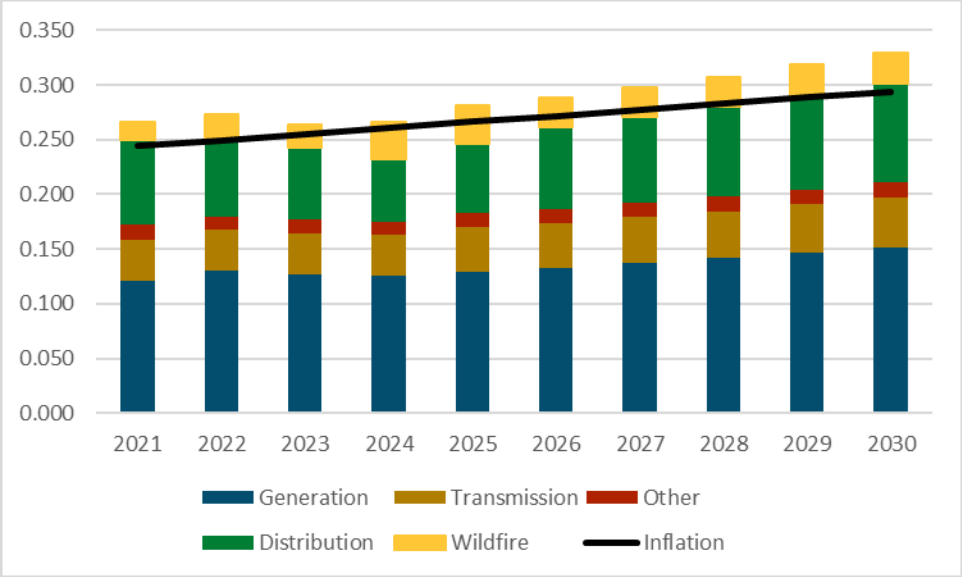
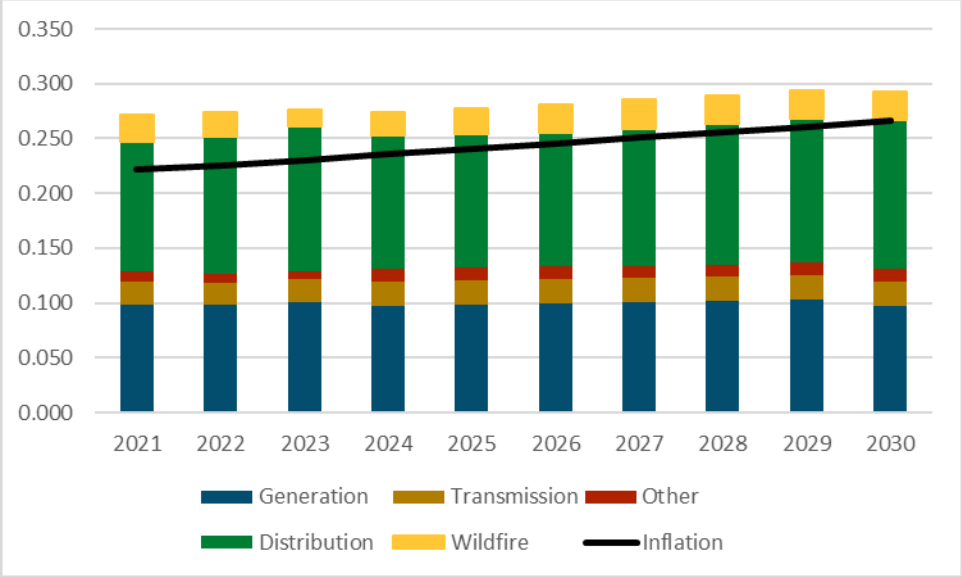


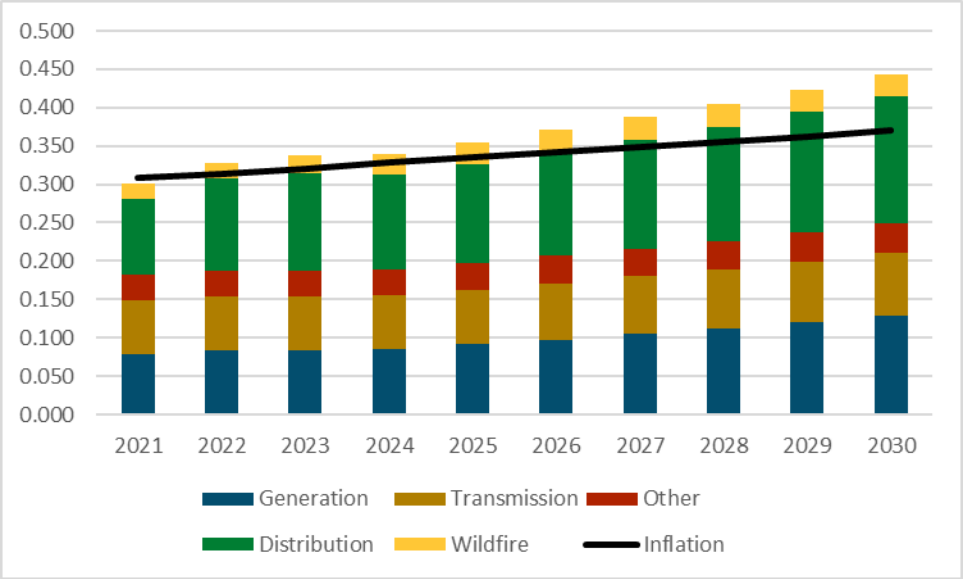
Figure ES-2: SCE Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



[2] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

[3] The inflation-adjusted forecasted rate line is based on 2020 actual rates. The rates in Figures ES-1 through ES-3 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

Figure ES-3: SDG&E Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



The rate forecasts developed as part of this white paper, in conjunction with estimates of natural gas rates and gasoline prices, were used to project total energy bills for a representative high energy usage household located in a hot climate zone based on rates for each of the major IOUs, as presented in the figures below. These projections show that, for energy price sensitive households, bills are expected to outpace inflation over the coming decade. The implication is that, if household incomes are expected to generally increase at the rate of inflation, energy bills will become less affordable over time.

Figure ES-4: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on PG&E Rates

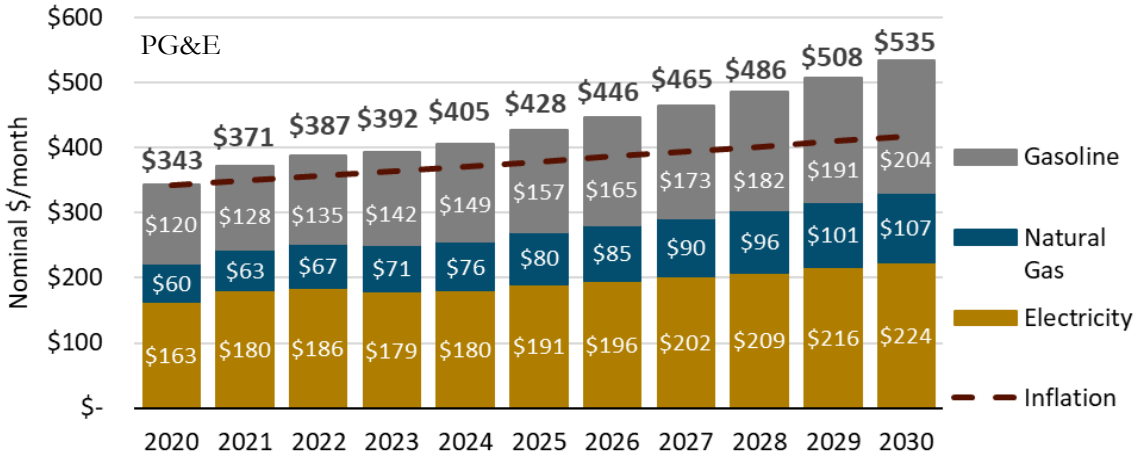


Figure ES-5: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SCE/SoCalGas Rates

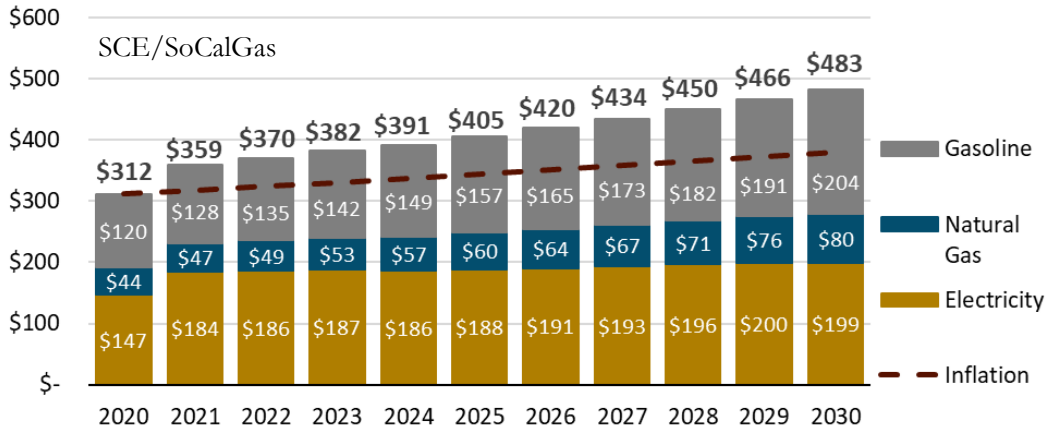
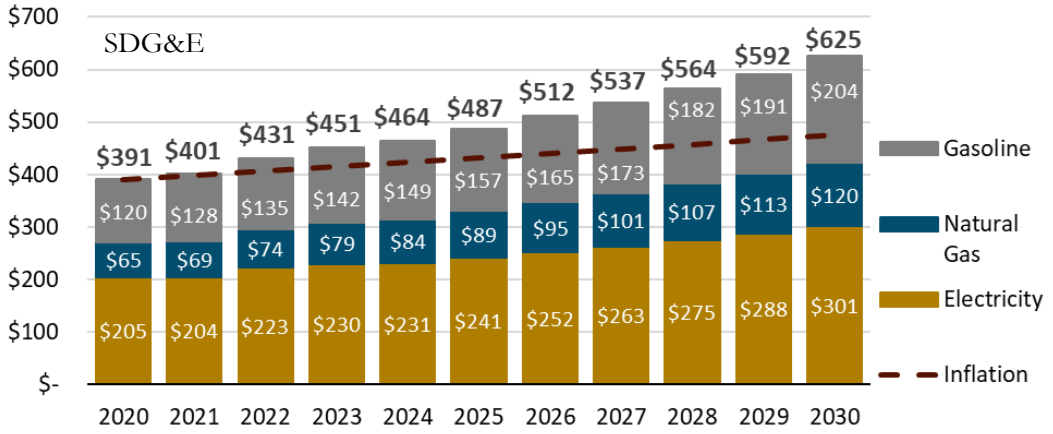


Figure ES-6: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SDG&E Rates



The policy goals and regulatory requirements that create upward cost pressures appear manageable over a longer time horizon, but if not managed correctly, they could trigger equity and affordability concerns for vulnerable customer populations over the short- to mid-term horizon. There is the potential for a growing divide in the cost of service between customers participating in behind-the-meter (BTM) or distributed energy resources (DER) and those who are less likely to do so. Moderate- to higher-income customers are more likely to invest in DERs such as solar photovoltaic (PV) systems, electric vehicles (EV), and storage technologies, and the advanced rate offerings that support them. This enables them to shift load and take advantage of potential structural billing benefits, which often results in a cost shift onto lower-income and otherwise vulnerable customers. Without the prudent management of IOU revenue requirements, rate base,

rate structures, and DER incentives, California's continued progress toward the optimized grid of the future may widen this chasm between participants and non-participants of DER opportunities.

There are three critical and overlapping regulatory fronts that must be actively managed to address this fundamental equity risk for vulnerable customers:

1. The costs and timing of fulfilling clean energy and electrification mandates;
2. The relatively rapid pace of rate base growth; and,
3. Revenue shifts to lower-income non-participants from Net Energy Metering (NEM) and other DER incentives.

Problem Statement

The need to improve the safety and reliability of the electric system while meeting California's climate goals and various statutory mandates will require careful management of rate and bill impacts to ensure that electric services remain affordable. As California continues transitioning to a more robust distributed energy resources marketplace with greater deployment of electric vehicles, it will be essential to employ aggressive actions to minimize growth in utility rate base and to protect lower-income ratepayers from cost shifts and bill impacts. This white paper explores the affordability of the grid of the future and is intended to stimulate discussion of potential solutions that will be necessary to ease this transition, particularly for California's most vulnerable customers.

Key Findings

Across all three IOUs since 2013, rates have increased by 37% for PG&E, 6% for SCE, and 48% for SDG&E.[4] The growth in rates can be largely attributed to increases in capital additions driven by rising investments in transmission by PG&E and distribution by SCE and SDG&E. While the utilities have made major financial commitments to wildfire mitigation and transportation electrification, these costs have not been fully reflected in rates so far. This paper finds that transportation electrification investments are not expected to contribute to significant rate growth in the near term, but that wildfire mitigation efforts will. Furthermore, higher than national average returns on equity (ROE) are a more modest but not insignificant factor that has amplified the three IOUs' revenue growth in recent years.

While tracking rates is important, customers care more about their bills than rates. California bills have typically been lower than most of the country in recent years, but those trends are changing. In 2019, SDG&E's bundled residential average monthly bill ranked 142nd highest out of about 200 IOUs, even though its rate was among the top 20 highest. PG&E, however, is showing a 2018 and 2019 monthly bill ranking of 94th highest and 70th highest, respectively, meaning PG&E's bills are higher than most of the IOUs being ranked. Further, SCE's bills, while still lower than the median (#100 ranking), moved up in the rankings from 136th highest to 122nd highest between 2018 and 2019.

[4] Bundled system average rate. Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU. These increases on an average annual basis from 2013 to 2020 are about: PG&E 5.3 percent; SCE 0.8 percent; SDG&E 6.8 percent.

Looking forward, the paper's 10-year baseline forecast shows steady growth in customer rates (nominal $/kWh) between 2020 and 2030 for the three IOUs:

- PG&E: $0.240 to $0.329, or about an annual average increase of 3.7 percent
- SCE: $0.217 to $0.293, or about an annual average increase of 3.5 percent
- SDG&E: $0.302 to $0.443, or about an annual average increase of 4.7 percent

By 2030, bundled residential rates are forecasted to be approximately 12 percent, 10 percent, and 20 percent higher, respectively, than they would have been if 2020 actual rates for each IOU had grown at the rate of inflation.[5] However, when the analysis focuses on households in the hotter regions of the state, household bills (electric, natural gas, and gasoline) are forecasted to rise at an annual rate of 4.5 percent, as compared to a 1.9% inflation rate.

While the cost to further reduce GHG emissions in the electric sector to 38 million metric tons (MMT) compared to a target of 46 MMT would increase bills by $4 to $9 a month, a well-managed effort to move customers to all electric homes and electric vehicles could result in over a $100 a month reduction in overall energy bills. This means that, in order to avoid large increases in energy bills, customers will need to adopt technologies that require large up-front investments. In the absence of subsidies and low-cost financing options, this could create equity concerns for low- to moderate-income households and exacerbate existing disparities in electricity affordability.

ORGANIZATION

The remainder of this white paper is organized as follows:

- **Section II**: A foundational review of *historical* trends in costs, rates, and bills with a focus on longer-term, capital-related costs and impacts on bills from clean energy programs, and statutory mandates that have historically resulted in additional ratepayer costs are presented.

- **Section III**: An evaluation of cost and rate *projections* with a particular focus on two areas: transportation electrification and wildfire mitigation costs. In addition, this section highlights affordability concerns and distributional equity in low to moderate income households.

- **Section IV:** Information provided by the IOUs to fulfill the requirements of Public Utilities Code Section 913.1(b).

- **Section V:** Conclusion.

- **Addenda:** Critical addenda are included on natural gas cost and rate trends as well as summaries of En Banc panelist discussions and stakeholder comments on this white paper.

[5] 2020 rates are actual rates in effect at yearend 2020; if 2020 rates were to increase at the rate of inflation (approximately 1.9% per year), rates in 2030 would be: PG&E 0.294; SCE 0.266; SDG&E 0.370. Inflation is approximately 1.9% per year.

II. Historical Cost and Rate Trends

2.1 Section Summary

In past years, the SB 695 Report has provided a historical review of IOU revenue requirements at the functional area of utility operations[6] level to illustrate the major drivers of electric cost and rate growth. This functional-level revenue requirement review, generally presented as a percentage change in the generation revenue requirement, distribution revenue requirement, etc., is a high-level view of overall trends; the review does not quantitatively analyze underlying cost data that may categorically[7] form part of historical General Rate Case (GRC) costs or stand-alone[8] program costs.

For the 2021 SB 695 Report embodied in this white paper, transportation electrification and wildfire-related costs are highlighted as potential cost drivers.[9] Both of these cost categories involve capital costs i.e., investment in IOU infrastructure, prompting a discussion of the IOUs' continually increasing capital investments. While IOU capital investments (generally known as "rate base") will be necessary to meet California's policy goals, balancing major investments in a cleaner, more efficient grid while sustaining affordable rates is more challenging as IOU rate base grows.

In keeping with past SB 695 Reports, rates and bills for the bundled[10] residential customer class are highlighted in this white paper. Compared to IOUs in the rest of the country, California IOUs Pacific Gas & Electric (PG&E), Southern California Edison (SCE), and San Diego Gas & Electric (SDG&E) bundled residential rates are higher than most while bills are lower than most. For 2018 and 2019,[11] bundled residential electric rates for PG&E and SDG&E customers increased faster than the rate of inflation. SDG&E's residential rates in particular have seen increases in recent years due to departing load as a result of high rates of solar adoption. Further, bundled residential and small business customers generally have higher average rates than the bundled system average and bundled large industrial and agricultural customers generally have lower average rates.[12]

Across all three IOUs, rate base is increasing, meaning that net capital additions have been outpacing depreciation of existing assets. The growth in rate base has been driven by rising transmission investments for PG&E and distribution investments for SCE and SDG&E. This rise in rate base has been coupled with a growth of solar adoption, which in turn has led to residential costs being shifted from customers who have

[6] Functional areas of utility operations include generation, distribution, etc.

[7] Some of these categories could broadly fall under Safety, Affordability (reasonable rates), Reliability, and Clean Energy, with potentially other subcategories of analytical interest, such as Wildfire Mitigation (i.e. Safety) and Transportation Electrification (i.e. Clean Energy).

[8] Stand-alone here means not included in a GRC or Energy Resource Recovery Account (ERRA) proceeding. Stand-alone costs can include legislative policy program costs such as those in the "Legislative Policy Program Costs" sub-section.

[9] A functional area of utility operations revenue requirement review was not performed, but rather, specific cost categories were selected for further examination; Electrification goals and wildfire mitigation planning are among the near-term needs may that place upward pressure on rates and bills.

[10] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

[11] 2019 is the most recent year for which national-level data is available.

[12] All other things being equal, a class average rate is generally higher than the system average rate when the class in question contributes a higher proportion of revenue requirement relative to the system average and to other classes.

installed rooftop solar to customers who have not.[13] The result is that growing electric rates have been offset to some extent for NEM customers, who are disproportionately older homeowners in high-income areas, while non-NEM customers have shouldered some of the cost of maintaining the grid. In addition, continued adoption of other distributed energy resources (storage, EVs, etc.) and advanced rate offerings that promote improved load management may add to costs shifted to non-participating customers. However, this requires a deeper examination of the long-term savings and benefits to the system of a more efficient grid with greater penetration of behind-the-meter (BTM) resources.

This section also considers the impact that transportation electrification (TE) programs, wildfire mitigation-related costs, and Federal Energy Regulatory Commission (FERC) transmission costs have had on electric rates. The analysis found:

- TE programs have had little impact on bundled residential rates, and the TE portion of forecasted bundled residential rates is not expected to grow significantly in the near-term.

- Historical experience with wildfire mitigation-related costs is largely based on SDG&E, since SDG&E's experience with wildfire spending precedes that of the other two IOUs; despite a decade of spending on wildfire mitigation, SDG&E's wildfire costs have continued to increase, which may indicate what is in store for PG&E and SCE.

- FERC transmission revenue requirements have increased significantly over the past few years in a number of categories.[14]

California Utilities Compared to the Rest of the U.S.

California leadership in advancing clean energy policy in the United States must be considered in any discussion of both past and future rates and bill trends:

- The state's per capita energy consumption is the fourth lowest in the nation, due in part to California's mild climate but more importantly due to a commitment to energy efficiency.[15]

- California ranks first in the nation as a producer of electricity from solar, geothermal, and biomass resources and fourth in the nation in conventional hydroelectric power generation.[16]

- California has the most operating utility-scale battery storage capacity in the nation at over 200 MW, about twice as much as the installed capacity of the state with the next largest amount.[17]

[13] The cost shift results in shifts in revenue requirements among different customer groups.

[14] Transmission revenue requirements have risen a total of 38.1 percent over the period from 2016 to 2021 across the three IOUs.

[15] *See* U.S. Energy Information Administration (EIA), California State Profile and Energy Estimates https://www.eia.gov/state/print.php?sid=CA (last updated January 16, 2020, accessed January 5, 2021).

[16] *Id.*

[17] *See* EIA bar graph, "U.S. operating utility-scale battery storage by state (top 10, March 2019)" https://www.eia.gov/todayinenergy/detail.php?id=40072 (accessed January 5, 2021).

- About one-fourth of the nation's electric vehicle charging stations are in California.[18]

- California leads the nation in installed flexible distributed energy resource capacity of 4.7 GW, or one tenth of statewide grid demand, and may have up to 13.5 GW by 2025.[19]

Many of these efforts have resulted in a cleaner electricity portfolio but have also led to declines in electricity sales due to energy efficiency, energy conservation, and customer generation of electricity. Declines in electricity sales have had the effect of raising electric rates as fixed costs are spread over a smaller usage base.

Historically, the bundled Residential Average Rates (RAR) of the California IOUs have been higher than those of most United States IOUs.[20] Table 1 shows for 2018 and 2019[21] the simple volumetric bundled residential average rate for PG&E, SCE, and SDG&E, compared to approximately 200 total IOUs nationally, ranked from highest rates (#1 ranking) to lowest rates (#200 ranking). For example, in 2019 SDG&E's bundled residential average rate ranked 17th highest out of about 200 IOUs.

However, while rates are an important measure of the cost of providing electricity, looking at actual bills provides a clearer picture of affordability. California IOU bundled residential customer bills have generally been lower than about half of all U.S. IOUs, as shown by the rankings. For example, in 2019 SDG&E's bundled residential average monthly bill ranked 142nd highest out of about 200 IOUs, even though its rate was among the top 20 highest. PG&E, however, is showing a 2018 and 2019 monthly bill ranking of 94th highest and 70th highest, respectively, meaning PG&E's bills are higher than most of the IOUs being ranked. Further, SCE's bills, while still lower than the median (#100 ranking), moved up in the rankings from 136th highest to 122nd highest between 2018 and 2019.

Table 1: U.S. IOU Ranking of PG&E, SCE, and SDG&E, Bundled Residential Average Rates and Monthly Bills (2018, 2019)

U.S. IOU Ranking – Highest to Lowest (out of approximately 200 IOUs)				
	Bundled Residential Average Rate		Bundled Residential Average Monthly Bill	
	2018	**2019**	**2018**	**2019**
PG&E	15	24	94	70
SCE	31	42	136	122
SDG&E	9	17	108	142

[18] *See* U.S. Energy Information Administration (EIA), California State Profile and Energy Estimates.

[19] *See* "Unlocking California's Gigawatt-Scale Distributed Energy Potential", Greentech Media, September 22, 2020. Available at: https://www.greentechmedia.com/articles/read/unlocking-californias-gigawatt-scale-distributed-energy-potential

[20] "Higher than most" is the same as "higher than the median," or "higher than half of the items being ranked." In other words, because the ranking is from highest to lowest, the lower the ranking number, the higher the rate or bill.

[21] 2019 is the most recent year for which national-level data is available. *See* U.S. Energy Information Administration (U.S. EIA) https://www.eia.gov/electricity/sales_revenue_price/, Table 6.

2.2 Historical Trends in Electric Rates and Bills

Electric rates measure price per kilowatt hour paid by electric customers, and historical rate trends allow comparison of how an IOU's rates track another metric, inflation, over time. The reason inflation is typically used as a benchmark for electric rate growth is because it has traditionally been assumed that household incomes rise at about the rate of inflation, thus if electric rates increase at the same rate then the affordability of electric service should remain unchanged for the average household.[22]

Bundled System Average Rate

Rates may be viewed at system level for all customer classes or at customer class level, such as residential class level. **Bundled System Average Rate (SAR)** is a high-level measure of an IOU's authorized bundled[23] customer revenue requirement expected to be recouped through authorized forecasted sales to bundled customers.

$$Bundled\ SAR = \frac{Bundled\ customers\ authorized\ revenue\ requirement\ (\$)}{Bundled\ authorized\ forecasted\ sales\ (kWh)}$$

Figure 1 through Figure 3 show each IOU's nominal rates in the color-shaded portion of the figure, with the IOU's inflation-adjusted rates shown by the black line. Nominal rates trending below the black line indicate that the IOU's bundled SARs are tracking favorably to inflation-adjusted rates. Nominal rates trending above the black line indicate that the IOUs' bundled SARs are increasing higher than the rate of inflation.

[22] Rates are tracked from the base year 2012 by applying the Consumer Price Index (CPI) to the previous year's bundled SAR to show inflation-adjusted bundled SAR. CPI reported by the U.S. Department of Labor, Bureau of Labor Statistics, West Region, All Items, All Urban Consumers (not seasonally adjusted). 2020 CPI data reflects 11 months of data.

[23] Bundled IOU customers receive all services — generation, transmission, and distribution services — from the IOU.

Figure 1: PG&E Bundled System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1

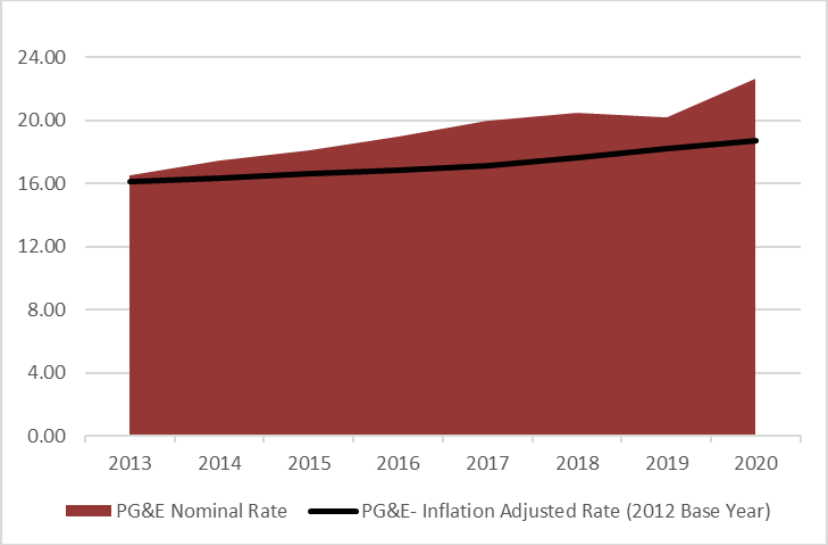


Figure 2: SCE Bundled System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1

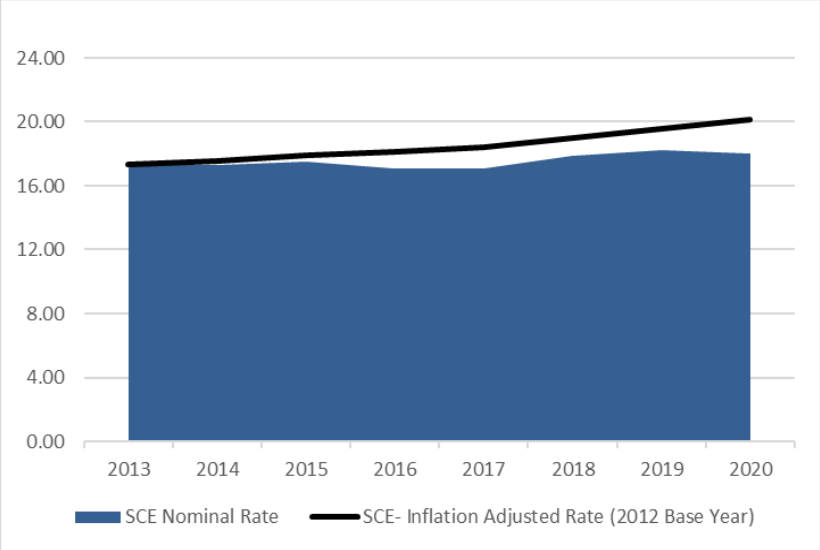
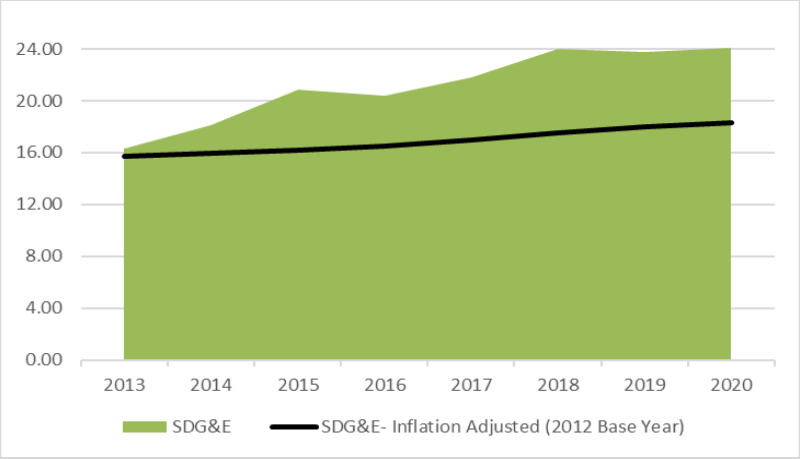


Figure 3: SDG&E Bundled System Average Rate (¢/kWh), Nominal and Inflation-Adjusted, Rates in Effect January 1



The variance in Figure 3 between SDG&E's inflation-adjusted SAR and its nominal SAR may be due to the effect of diminishing kWh sales. SDG&E has a larger share of customers investing in rooftop solar compared to PG&E and SCE. This high rate of photo-voltaic (PV) adoption affects the denominator (kWh sales) of SDG&E's bundled SAR, as customers are purchasing less electricity from the utility, although they may still be consuming the same amount from their PV system. While the decreased demand from the utility allows it to avoid some costs of procuring generation, a utility still has fixed costs that cannot be fully eliminated. As a result, declining utility sales result in larger rate increases as utility fixed costs are now spread across fewer units of usage.

Bundled System Average Rate by Customer Class

A breakdown of the bundled system average rate by customer class is shown for each IOU in Figure 4 through

Figure 6. Each class shows the same upward trend as the system average rate over this period, with the residential and small business customers generally having higher average rates than the system average and the large industrial and agricultural customers generally having lower average rates.

Figure 4: PG&E Bundled System Average Rate (¢/kWh) By Class, Nominal Rates in Effect January 1

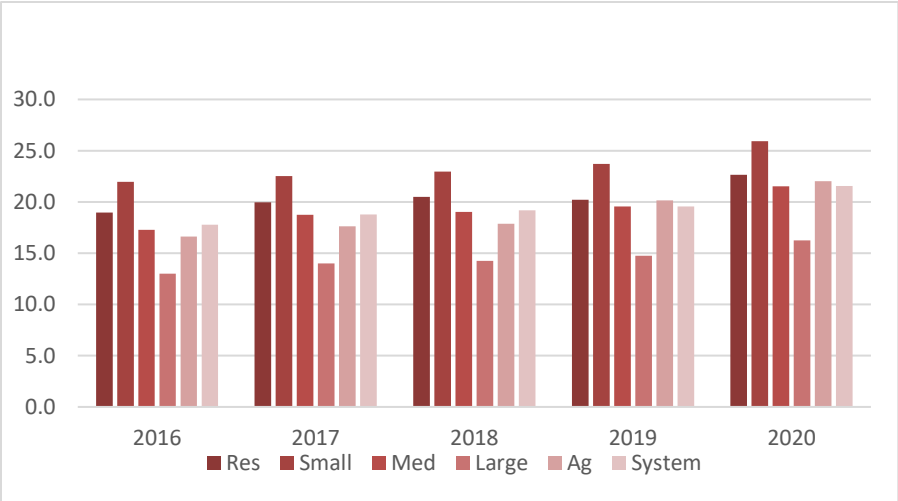


Figure 5: SCE Bundled System Average Rate (¢/kWh) By Class, Nominal Rates in Effect January 1

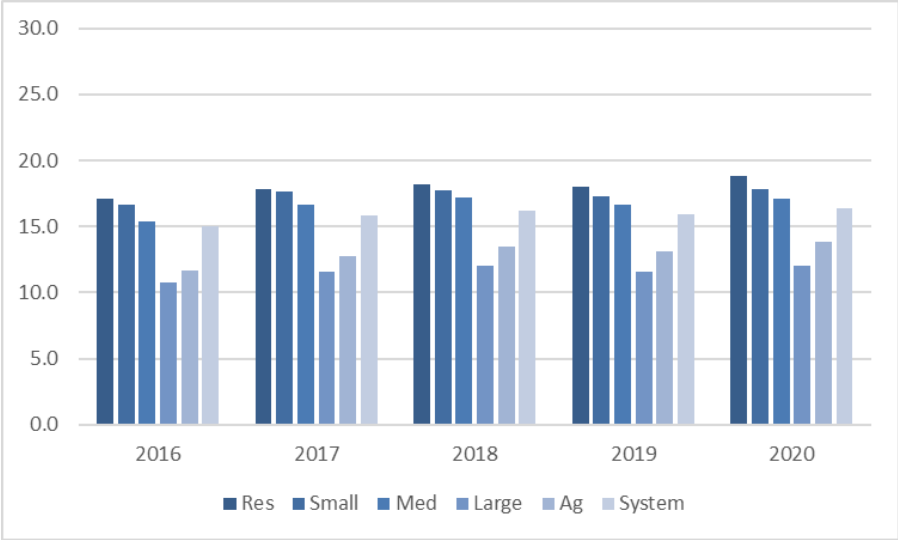
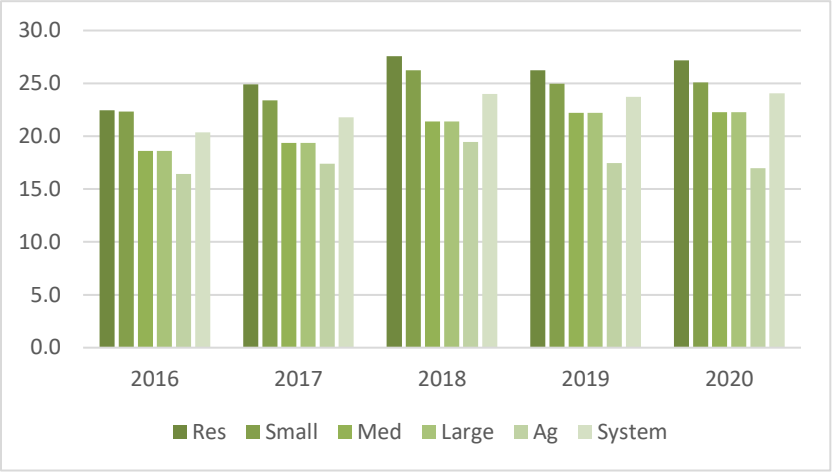


Figure 6: SDG&E Bundled System Average Rate (¢/kWh) By Class, Nominal Rates in Effect January 1



Residential and Select Small Commercial Bundled Average Monthly Bills

The major determinant in calculating bills is electricity **usage**.[24] Residential usage tends to cluster around typical usage profiles, which vary by climate zone.[25] However, typical load profiles for non-residential customers can vary substantially, depending on their usage patterns in the commercial, industrial, or agricultural customer class.[26] Nevertheless, small business customers may be grouped by commercial customer group using standard industry codes such as the North American Industry Classification System (NAICS) in order to get a sense of typical usage for customers with the same industry code.[27] Figure 7 through Figure 9 show for each IOU typical bundled average monthly bills for residential customers[28] as well as for commercial customers representing Food Services and Drinking Places (NAICS 722), Ambulatory Health Care Services (NAICS 621), and Real Estate (Property Management, NAICS 531).[29] Bundled small business customers with industry subsector code Food Services (NAICS 722) show typical average monthly bills in the mid- to high triple-digits.[30]

[24] Usage (in kWh) multiplied by a rate factor equals the volume of electricity billed. Other bill elements such as fixed charges and taxes are outside the scope of this analysis.

[25] For residential, usage includes electricity consumption (kWh). For this analysis, average monthly usage for each IOU is based on average monthly usage reported for bill impacts presented in bill inserts.

[26] For non-residential, usage may include electricity consumption (kWh) or demand (kW). Demand usage is outside the scope of this analysis.

[27] Grouping by industry code does not definitively determine typical usage profiles as several other factors such as climate zone, size of establishment, age of establishment, and energy efficiency of equipment may significantly affect usage.

[28] Residential customers not enrolled in the California Alternate Rates for Energy CARE (Non-CARE). Lower-income residential customers enrolled in the CARE program receive up to a 35 percent discount on bills.

[29] *See* U.S. Bureau of Labor Statistics for more information about NAICS subsector codes. These NAICS subsector codes were selected by the IOUs as being representative of small commercial customers and are not exhaustive for the customer class.

[30] Typical average monthly bills are for illustrative purposes only.

Figure 7: PG&E Typical Bundled Average Monthly Bills ($/Month), Residential and Select Small Commercial, Nominal Rates in Effect January 1

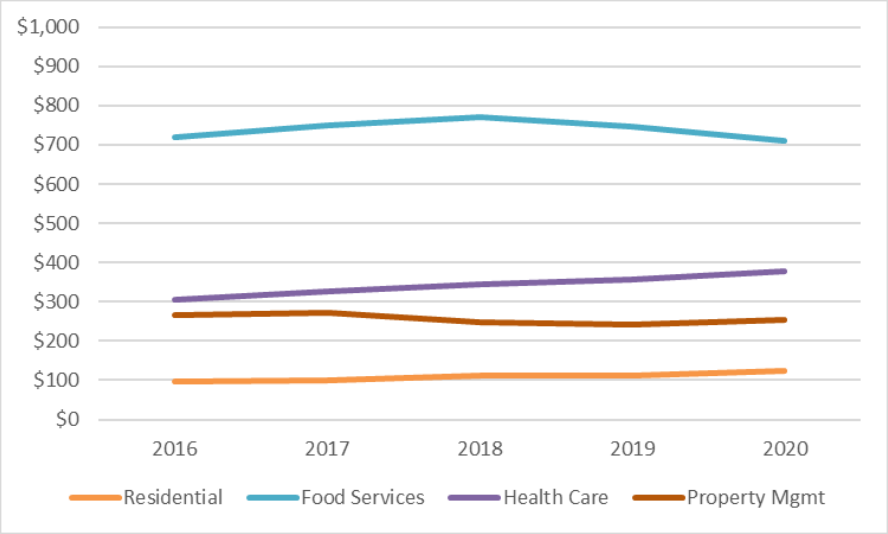


Figure 8: SCE Typical Bundled Average Monthly Bills ($/Month), Residential and Select Small Commercial, Nominal Rates in Effect January 1

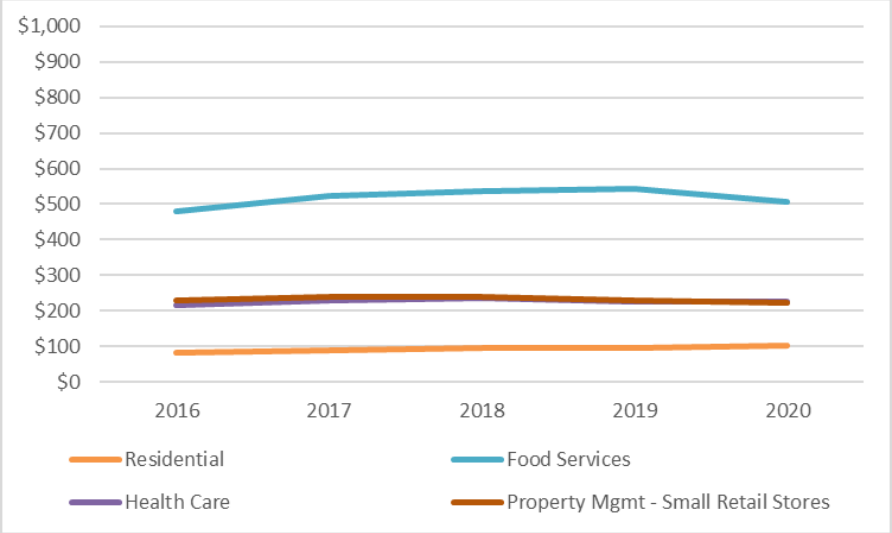
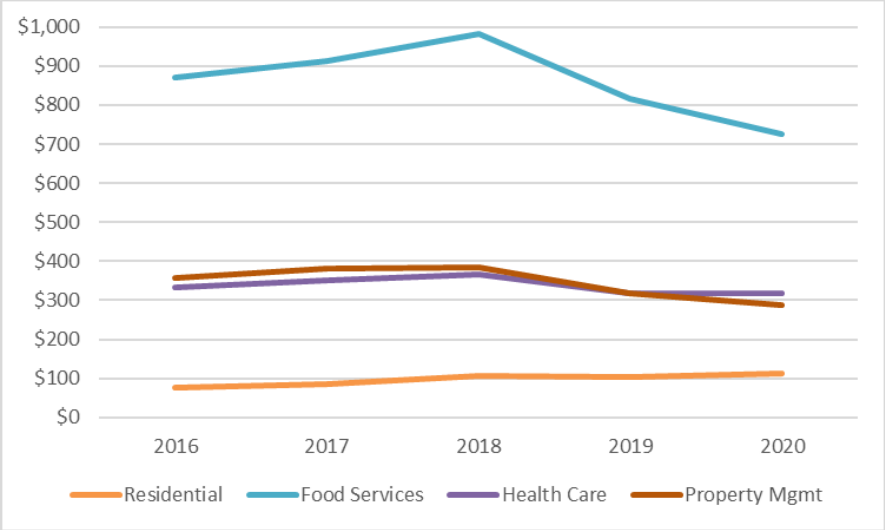


Figure 9: SDG&E Typical Bundled Average Monthly Bills ($/Month), Residential and Select Small Commercial, Nominal Rates in Effect January 1



2.3 Historical Utility Costs and Transparency

Capital Costs and Capital-Related Revenue Requirements

The CPUC annually issues the *California Electric and Gas Utility Cost Report*, also known as the Assembly Bill (AB) 67 Report, which publishes the costs to ratepayers of all utility programs and activities currently recovered in retail rates.[31] These costs are presented at the **authorized** revenue requirement level, which is the level at which costs go into rates. Recorded costs authorized for recovery during ratesetting proceedings include both **capital expenditures** and **operations and maintenance** (O&M) expenses, both of which must be converted to revenue requirement as part of rates implementation.

Operations & Maintenance Expenses

O&M expenses are generally passed-through to ratepayers without profit markup and are recovered from ratepayers on a dollar-for-dollar basis with no amortized cost recovery over time, meaning the utility earns no profit on O&M expenses and recovers those costs in the same year they were incurred. These expenses include all labor and non-labor expenses for a utility's operation and maintenance of its generation plants and distribution and transmission systems. O&M expenses also include general and administrative expenses such as personnel costs and purchased materials and services.

[31] The 2019 AB 67 Report is available at: https://www.cpuc.ca.gov/General.aspx?id=6442460031 . The most recently available year of this report is 2019.

Capital Expenditures

The utility earns profits on capital expenditures, and capital expenditures are recovered over a long period of time as the related asset depreciates. Because of the multi-year recovery timeframe for capital investments, the revenue requirement in any given year is a fraction of the total **capital-related revenue requirement**. This fractional approach makes conversion of capital expenditures into annual capital-related revenue requirement a complicated process, and limits the transparency of the full costs that ratepayers will pay over time for capital expenditures. For example, if the utility were to spend $1 billion in one year on wildfire mitigation costs that include both capital expenditures (e.g. undergrounding electric lines) and O&M costs (e.g. vegetation management) the rate impact in that first year would be far less than $1 billion since only the O&M cost would be recovered in the first year, but the capital costs will be included in rates for many years and will ultimately be higher than $1 billion since the capital investment is recovered over time and includes the utility's profits.

To understand how capital-related revenue requirement is calculated, one must first understand the concept of **rate base** which is essentially the book value of the utility's assets taking accumulated depreciation into account. Depreciation spreads the cost to ratepayers of the capital investment over the assets' useful life. The IOU's rate base is the value of the company's undepreciated assets at a specific point in time and provides a basis for computing rates of return. The measurement of rate base is dependent on two main components, net capital additions and accumulated depreciation.

Rate Base = Net capital additions – Accumulated depreciation

Thus, rate base is the amount that remains after accumulated depreciation[32] is subtracted from net capital additions. When net capital additions exceed accumulated depreciation, which has generally been the case for PG&E, SCE, and SDG&E, rate base and the related capital revenue requirements increase:

Net capital additions > Accumulated depreciation = Increase in rate base

Capital-Related Revenue Requirement

Capital-related revenue requirements are comprised of **depreciation expense revenue requirement** (including related tax effects) and **return on rate base revenue requirement**:

Capital-related revenue requirement = Depreciation expense (including related tax effects) revenue requirement + Return on rate base revenue requirement

Return on rate base represents the cost to the utility of financing the capital investment, including the cost of the authorized profit, known as return on equity.[33] Depreciation expense is calculated according to the IOU's depreciation rate schedules. Return on rate base is calculated by multiplying the IOU's authorized rate of return by **rate base**:

Return on rate base revenue requirement = Authorized rate of return (a percentage) x Rate base

[32] Related tax effects are grouped with accumulated depreciation.

[33] Other costs included in return on rate base are interest on debt, which represents the cost of borrowing from a bond investor.

California IOUs' Authorized Return on Equity Has Been Above the National Average

The CPUC establishes capital structure for each utility by setting the percentages of common stock, long-term debt, and preferred stock to total capital that the utility should hold. Within each utility's capital structure, the CPUC also sets the cost of each capital component, which results in an overall cost of capital (also known as rate of return) as shown in Table 2: SCE, PG&E, SDG&E, SoCalGas Cost of Capital

Utility	Cost of Common Stock (ROE)	Cost of Long-term Debt	Cost of Preferred Stock	Overall Cost of Capital (ROR)
SCE	10.30%	4.74%	5.70%	7.68%
PG&E	10.25%	5.16%	5.52%	7.81%
SDG&E	10.20%	4.59%	6.22%	7.55%
SoCalGas	10.05%	4.23%	6.00%	7.30%

.[34]

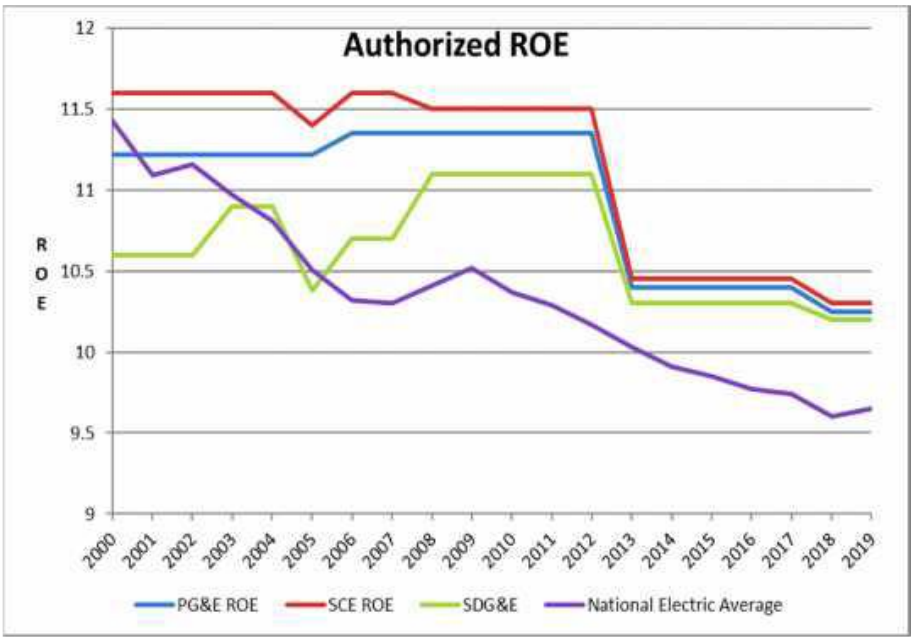
Table 2: SCE, PG&E, SDG&E, SoCalGas Cost of Capital

Utility	Cost of Common Stock (ROE)	Cost of Long-term Debt	Cost of Preferred Stock	Overall Cost of Capital (ROR)
SCE	10.30%	4.74%	5.70%	7.68%
PG&E	10.25%	5.16%	5.52%	7.81%
SDG&E	10.20%	4.59%	6.22%	7.55%
SoCalGas	10.05%	4.23%	6.00%	7.30%

The cost of common stock or return on equity (ROE) is a large component of the overall cost of capital. The CPUC sets ROE by estimating expected return on alternative investments of comparable risk in capital markets using financial models. Figure 10 shows that even though the authorized ROE for each utility declined in 2013 from previous years, the ROEs remain higher than national average ROE.

Figure 10: PG&E, SCE, and SDG&E Authorized Return on Equity, Compared to National Electric Average Return on Equity (2000 – 2019)

[34] Each capital component is weighted by its percentage of total capital in arriving at the overall cost of capital.



Rate Base is Increasing

Figure 11 through Figure 13[35] show the total annual rate base for each of the IOUs from 2016 through 2020.[36] Net capital additions are greater than accumulated depreciation in all figures, with corresponding increases in rate base. Increases in rate base over time result in higher depreciation expense revenue requirement and return on rate base revenue requirement as depreciation and return on rate base are now being calculated over an increasing base amount. Rate base has been increasing on average by approximately 5 percent per year for PG&E, 8 percent per year for SCE, and 7 percent per year for SDG&E since 2016, despite relatively flat load growth.[37]

[35] SDG&E rate base data is from AB 67 Report data responses and does not include a breakout of net capital additions and accumulated depreciation. PG&E and SCE data are from Energy Division data responses.

[36] "Other" rate base (working capital, other non-fixed asset adjustments) not material and not included.

[37] Percentages in nominal terms. Real terms would be slightly lower to account for inflation.

Figure 11: PG&E, Total Electric Rate Base ($000), Nominal and Inflation-Adjusted, January 1

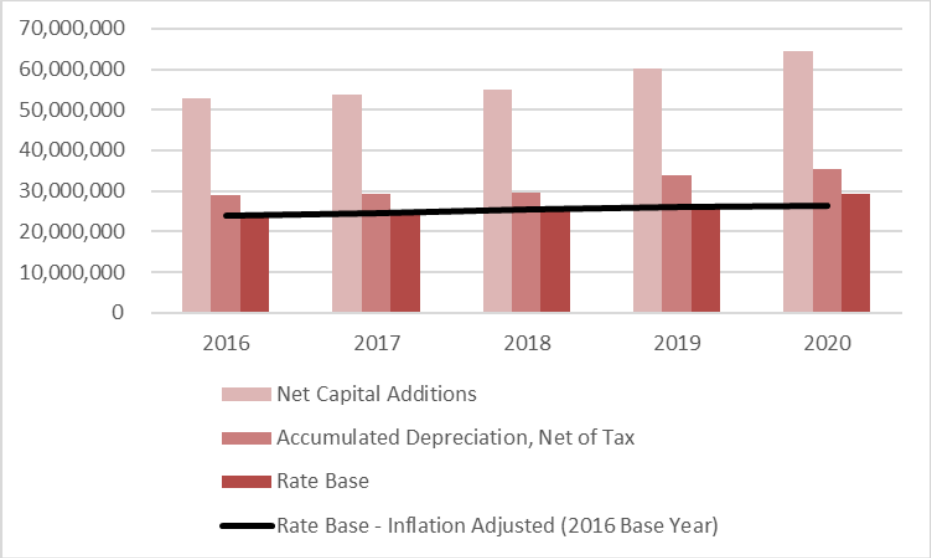


Figure 12: SCE, Total Electric Rate Base ($000), Nominal and Inflation-Adjusted, January 1

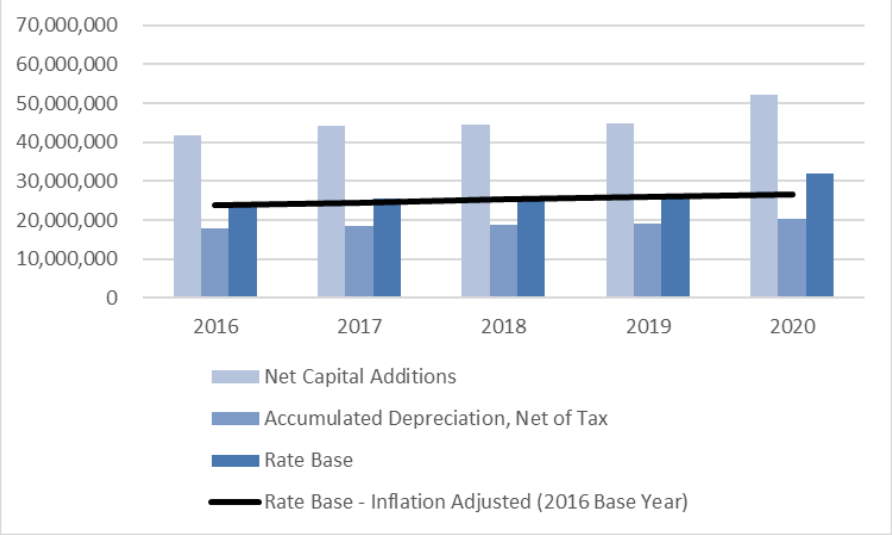
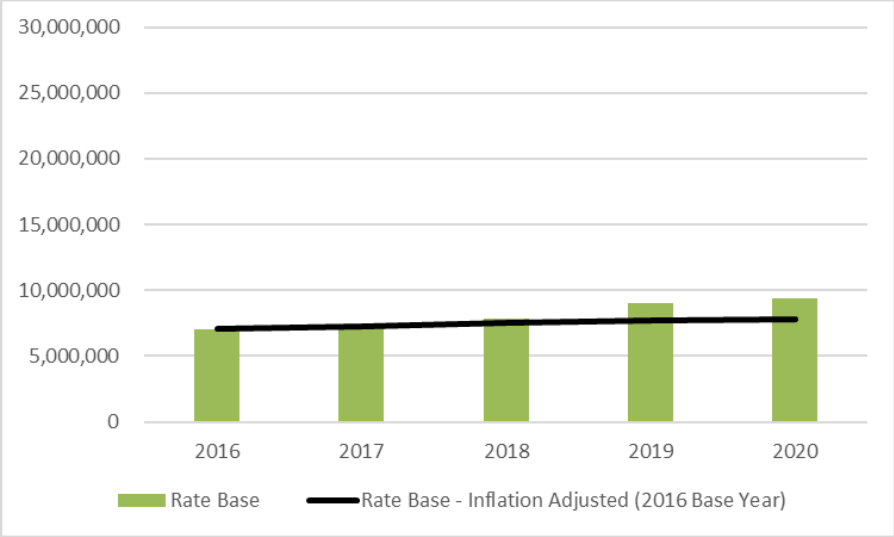


Figure 13: SDG&E, Total Electric Rate Base ($000), Nominal and Inflation-Adjusted, January 1



A Comparison of California Utilities' and Select U.S. Utilities' Electric Net Utility Plant

Electric net utility plant data may be examined to compare PG&E, SCE and SDG&E electric rate base growth to that of other U.S. IOUs. Data obtained from the Federal Energy Regulatory Commission (FERC) Form 1 presents **net utility plant** data, which is plant-in-service[38] data net of accumulated depreciation.[39] The net utility plant data is not directly comparable with the IOU rate base data presented above.[40] However, using net utility plant data for comparison illustrates the California IOUs' net utility plant investments relative to that of other IOUs with similar bundled revenues.

Figure 14 shows 2016 - 2019[41] net utility plant data for PG&E and SCE compared with five other U.S. IOUs grouped by the U.S. Energy Information Administration (EIA) 2019 bundled revenue rankings.[42] In other words, Florida Power & Light had the highest bundled retail revenue and is ranked #1, with SCE at #2. Figure 15 similarly shows 2016 – 2019 net utility plant data for SDG&E compared with three other U.S. IOUs in the U.S. EIA 2019 bundled revenue rankings. For example, Entergy Louisiana comes in at #16 ranking and SDG&E at #17.

[38] Plant-in-service includes certain capital lease data as well as construction work-in-process data, among other line items.

[39] Accumulated amortization and depletion is reported along with accumulated depreciation.

[40] It is unknown what methodology the IOUs use for reporting plant-in-service and accumulated depreciation data to FERC.

[41] FERC Form 1 data is reported at quarter and yearend. Data presented for 2016 – 2019 is as of yearend (2020 yearend data not yet available).

[42] Bundled revenue ($000) = Sales (MWh) x Rate (cents/kWh). Revenue data from U.S. Energy Information Administration (U.S. EIA). *See* https://www.eia.gov/electricity/sales_revenue_price/, Table 10 for bundled revenue data. Note: the #18 ranked utility is not an IOU and is not included in this analysis.

Figure 14: Net Electric Utility Plant, PG&E, SCE, and Five Other U.S. IOUs ($000), Ranked by Bundled Revenue (Highest to Lowest) (2016 – 2019)

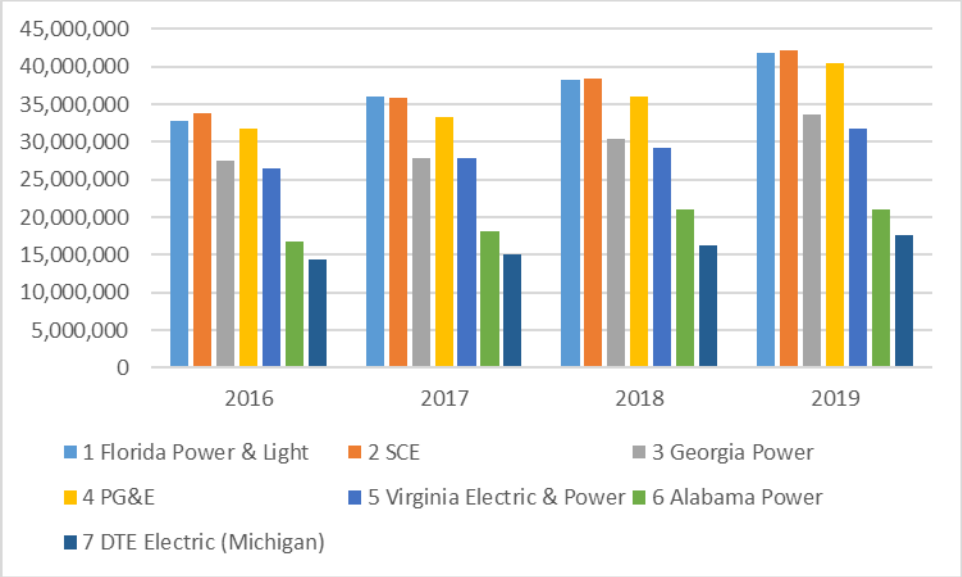
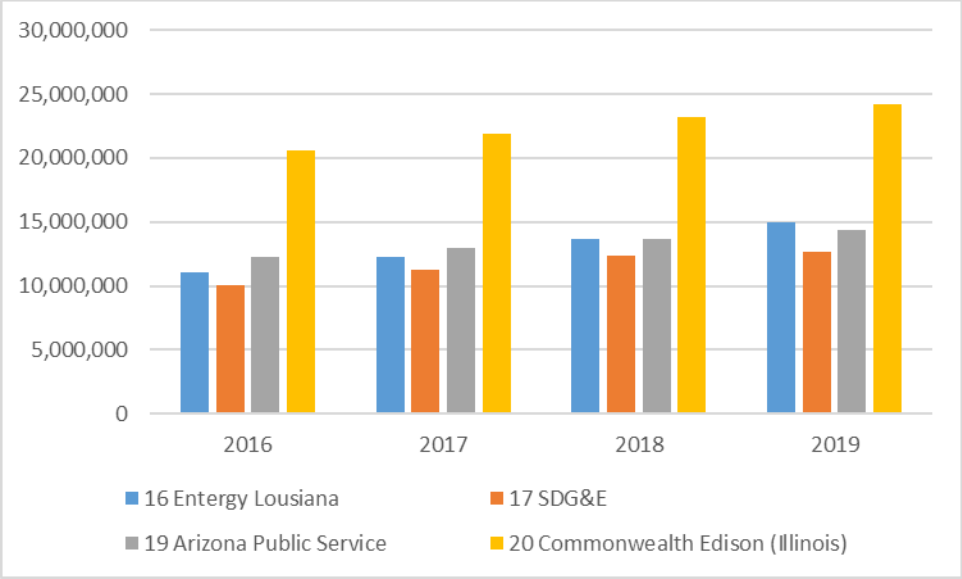


Figure 15: Net Electric Utility Plant, SDG&E and Three Other U.S. IOUs ($000), Ranked by Bundled Revenue (Highest to Lowest) (2016 – 2019)



For the utility grouping with PG&E and SCE, all IOUs show an increase in net utility plant from 2016 to 2019. Average annual increases over this period (from highest to lowest) are: Florida Power & Light 8.5 percent; PG&E 8.4 percent; Alabama Power 8.2 percent; SCE 7.6 percent; DTE Electric 7.1 percent; Georgia Power 7.1 percent; and Virginia Electric & Power 6.4 percent. Even though SCE shows the highest

overall net utility plant over this period, its average annual increases are less than those of PG&E and two other IOUs.

The SDG&E utility grouping similarly shows an increase in net utility plant from 2016 to 2019 across all IOUs. Average annual increases over this period (from highest to lowest) are: Entergy Louisiana 10.5 percent; SDG&E 8.0 percent; Commonwealth Edison 5.6 percent; and Arizona Public Service 5.4 percent. SDG&E shows the lowest overall net utility plant over this period, however its average annual increase is the second highest compared to the three other IOUs.

Return on Rate Base Revenue Requirement is Increasing

As previously shown,[43] rate base has a direct relationship with the return on rate base revenue requirement that is recovered from ratepayers. The return on rate base revenue requirement reflects the opportunity for the IOU to earn a profit.[44] Return on rate base may represent a return to shareholders paid by ratepayers; however, having a set[45] rate of return ensures that IOUs are able to raise sufficient capital to make improvements to infrastructure and provide safe and reliable service to all customers. On the flip side, by having a set rate of return, IOUs are inherently incentivized to make investments to drive an increase in their rate base and therefore, their profitability.[46]

Figure 16 through Figure 18[47] show for each IOU the return on rate base revenue requirement by functional category. The return on rate base revenue requirement for distribution is showing an increasing trend for SCE and SDG&E. PG&E's distribution return on rate base revenue requirement has been fairly constant, while its transmission return on rate base revenue requirement spiked in 2020, having roughly doubled since 2016.[48] Total annual return on rate base revenue requirement since 2016 grew by approximately 5 percent per year for PG&E, 7 percent per year for SCE, and 5 percent per year for SDG&E.

[43] *See Return on Rate Base Revenue Requirement* equation under "Capital-Related Revenue Requirement" heading.

[44] Profit is earned after the service of debt acquired to finance capital additions.

[45] Return on equity is set by the CPUC; debt-service return is determined by the bond market.

[46] This is known as the **Averch-Johnson effect:** the perception that the rate of return is higher than what the utility actually needs to ensure that shareholders continue to provide capital for investment, and the utility increases its returns to shareholders by making investments beyond the need threshold.

[47] SDG&E return on rate base data 2016 - 2018 is from AB 67 Report data responses; data for 2019 – 2020 is extrapolated from 2016 – 2018 data. PG&E and SCE data are from Energy Division data responses.

[48] This increase of about 50 percent in 2020 over 2019 is due to the implementation of Transmission Owner (TO) 20 formula rate as of January 2020.

Figure 16: PG&E, Return on Electric Rate Base Revenue Requirement ($000), Nominal Rates in Effect January 1

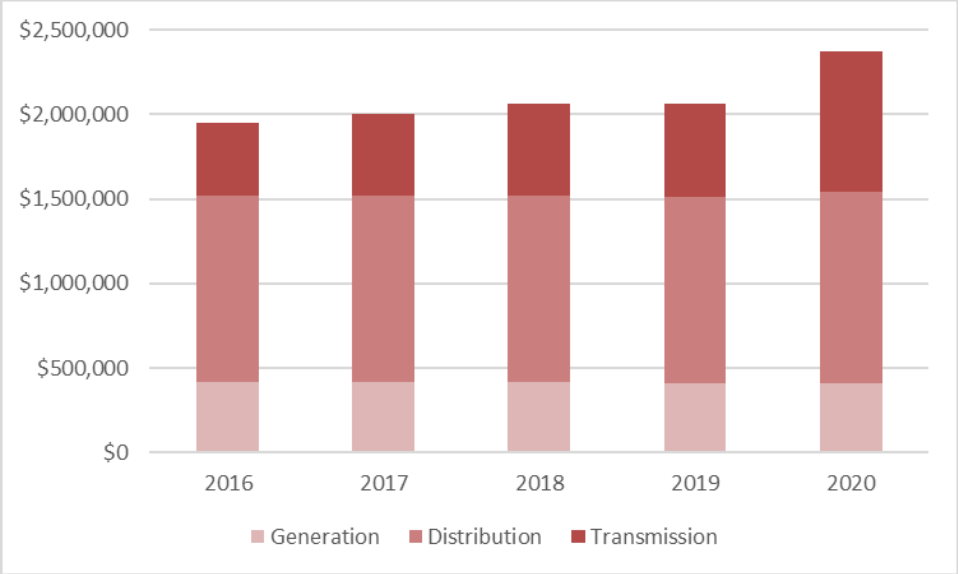


Figure 17: SCE, Return on Rate Electric Base Revenue Requirement ($000), Nominal Rates in Effect January 1

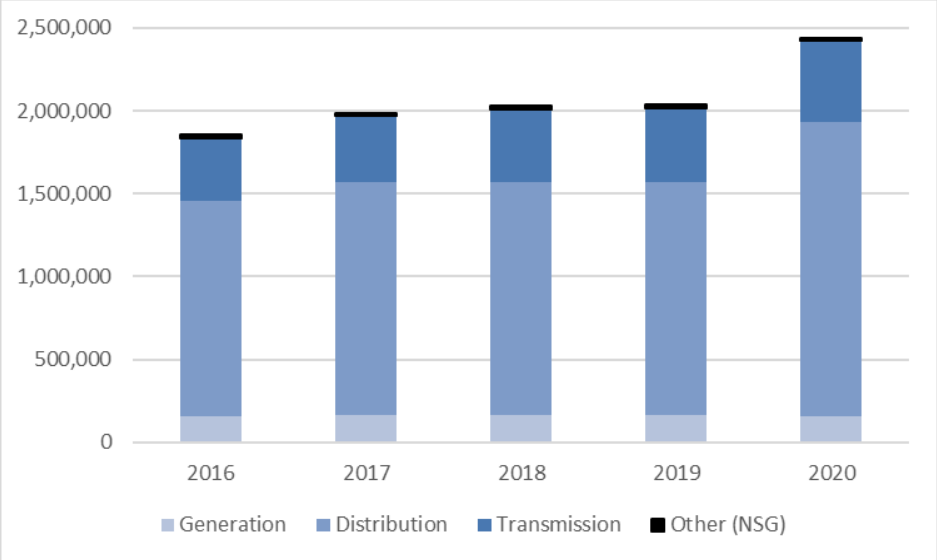
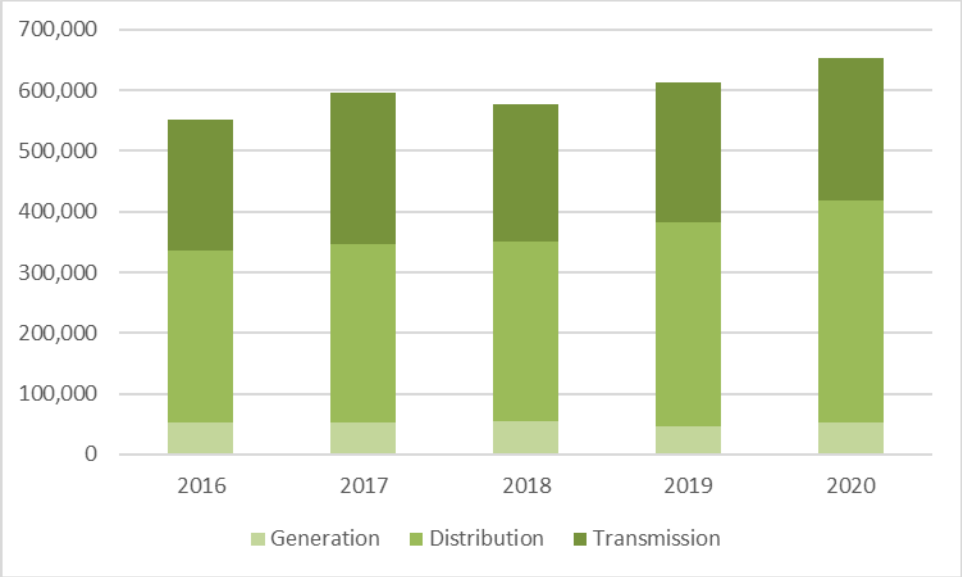


Figure 18: SDG&E, Return on Electric Rate Base Revenue Requirement ($000), Nominal Rates in Effect January 1



IOU net capital additions, accumulated depreciation, rate base, depreciation expense (including related tax effects) revenue requirement, and return on rate base revenue requirement are reviewed in Phase I of each General Rate Case (GRC) cycle,[49] except for transmission capital additions, which are reviewed in FERC rate cases. Currently, there are no known projected rate base schedules with corresponding projected depreciation expense and return on rate base revenue requirements for periods extending beyond the *current* GRC cycle. Better transparency into the full costs that ratepayers will pay over time for capital expenditures may facilitate analysis of the effects of projected capital-related revenue requirement escalation on projected utility rates.

Transparency into program areas with large capital investments such as Transportation Electrification (TE) is important for the CPUC and stakeholders to have a clear understanding of how an IOU's proposed capital spending will impact revenue requirements beyond the initial years of the program. SCE and SDG&E maintain projected capital cost and capital-related revenue requirements data for certain TE stand-alone programs beyond the year the program terminates.[50] After program termination, the ongoing capital-related revenue requirements will become part of GRC filings.[51] It is unknown at this time if these ongoing capital-related revenue requirements will be tracked separately in GRC filings.

[49] The IOUs are in the process of switching over to a four-year cycle from a three-year cycle. PG&E will file its next GRC in 2023, SCE is expected to file a petition requesting the filing of its next GRC in 2025, and SDG&E has filed a petition requesting the filing of its next GRC in 2024.

[50] SCE and SDG&E provided to Energy Division by data request TE program costs beyond the years the programs terminate out to the year 2030.

[51] TE programs generally have lengths of about five years. Programs initiated as early as 2017 may be terminating, for which the capital-related revenue requirements will roll into the subsequent GRC cycle.

2.4 Net Energy Metering Costs and Benefits

California's net energy metering (NEM) program started in 1997, prompted by Senate Bill 656 (1995, Alquist). It allows customers who install eligible renewable electrical generation facilities to serve onsite energy needs and receive credits on their electric bills for surplus energy sent to the electric grid. Most customer-sited, grid-connected solar in California is interconnected through NEM tariffs. California's first NEM program, now colloquially known as "NEM 1.0," was revised in 2016 via Decision (D).16-01-044[52] per Assembly Bill (AB) 327 (2013, Perea). Customers on the "NEM successor tariff," or "NEM 2.0," pay for their cost to connect to the grid; take service on a "time-of-use" rate plan; and pay "non-bypassable" charges that cannot be offset with surplus energy credits, in order to contribute their fair share toward public purpose programs and other initiatives.

To achieve the mandates of AB 327, the CPUC opened a new proceeding in August 2020 (Rulemaking (R).20-08-020) to revisit the NEM 2.0 tariff.[53] The proceeding will be guided by the statutory mandates of AB 327 to ensure the sustainable growth of distributed renewable energy, with benefits approximately equal to costs.

NEM 2.0 Costs and Benefits Study

An independent research firm, Verdant Associates, recently completed an evaluation study of the costs and benefits of NEM 2.0 on behalf of the CPUC.[54] The CPUC directed this study to gather information in preparation for its planned revisit of the tariff.[55] The study found that, over time, NEM 2.0 customers usually save more money on their electric bills than they pay for their generation facilities (e.g. a rooftop solar system).

The study also found that the cost to the electric utilities—and their customers—of providing these extra electric bill savings is greater than the energy's value, i.e. the utility pays more to NEM customers than it would pay elsewhere for the same amount of energy and other electric grid benefits. This is illustrated by the CPUC's total resource cost (TRC) test, which compares an energy resource's benefits and costs to both participants and utilities. Using a model representing the NEM 2.0 population, the study found a statewide weighted average TRC ratio of 0.84, meaning the total benefits, $7.96 billion, are about one-sixth lower than the total costs, $9.46 billion. A related test, the CPUC's ratepayer impact measure (RIM) test, calculates effects of an energy resource on customer bills. The model had a NEM 2.0 weighted average RIM ratio of 0.37, with total benefits of $7.58 billion and total costs of $20.58 billion. A RIM ratio below 1.0 means that NEM 2.0 increases non-participant bills. Non-NEM customers' bills rise most, not being offset by onsite

[52] D.16-01-044 can be accessed at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M158/K181/158181678.pdf.

[53] Documents in R.20-08-020 can be accessed at: https://apps.cpuc.ca.gov/apex/f?p=401:56:0::NO:RP,57,RIR:P5_PROCEEDING_SELECT:R2008020.

[54] Verdant was previously part of Itron, Inc., the firm that won the competitive solicitation to conduct the NEM 2.0 evaluation study. The study can be accessed at: https://www.cpuc.ca.gov/General.aspx?id=6442463430.

[55] D.18-09-044 can be accessed at: https://docs.cpuc.ca.gov/PublishedDocs/Published/G000/M230/K892/230892616.pdf.

energy generation. Table 3 shows the TRC and RIM weighted average benefit-cost ratios for the residential customer sector and all sectors.

Table 3: Weighted Average Benefit-Cost Ratios

	Residential		All Sectors (Including Residential)	
	TRC Ratio	RIM Ratio	TRC Ratio	RIM Ratio
PG&E	0.69	0.31	0.80	0.33
SCE	0.80	0.43	0.91	0.49
SDG&E	0.76	0.29	0.84	0.31

The evaluation study found that, as compared to the general California population, NEM customers are disproportionately older, located in high-income areas, likely to own their home, and less likely to live in a disadvantaged community. Consequently, the costs of NEM are disproportionately paid by younger, less wealthy, and more disadvantaged ratepayers, many of whom are renters. To address these concerns, the CPUC is considering modifying the structure of the NEM 2.0 tariff to achieve California's social and environmental goals for distributed renewable energy while allocating its costs and benefits in a more equitable manner.

NEM Cost Shift Equity Considerations

All residential non-NEM or non-participating customers, including California Alternate Rates for Energy (CARE) customers, shoulder an additional rate burden as a result of the cost shift from NEM customers.[56] Potential equity concerns related to the NEM cost shift include the following:[57]

- As of November 2020, PG&E had approximately 519,000 residential NEM customers and 1.3 million CARE customers. Of these CARE customers, only about 5 percent are NEM participants, meaning approximately 95 percent of CARE customers did not participate and therefore bear the cost responsibility of compensating NEM customers.

- SCE had, as of December 2020, approximately 361,000 residential NEM customers and 1.5 million CARE customers. Of these CARE customers, only 4 percent participate in NEM, meaning over 1.4 million CARE customers, or about 96 percent, shoulder the additional cost burden from all NEM customers.

[56] NEM cost shift reflects the cost shift created by residential NEM customers that non-NEM customers (also referred to as "non-participating" customers) may be paying in higher rates. NEM Cost Shift = NEM Customer Bill Savings – Avoided Costs where "Bill Savings" is the yearly dollar amount that NEM customer avoid paying because of their self-generation and netting (compensation) and "Avoided Costs" are fixed and variable costs of service that the utility should avoid incurring as a result of distributed generation.

[57] This information was gleaned from IOU data responses submitted to Energy Division.

- As of November 2020, SDG&E had approximately 199,000 residential NEM customers and 320,000 CARE customers. Of these CARE customers, only 8 percent are NEM participants. CARE customers are currently seeing bills that are 13 percent higher as a result of the NEM cost shift.

2.5 Historical Distribution Costs

Distribution costs include O&M and capital-related costs associated with distribution infrastructure. This reflects the costs to distribute power to customers and includes power lines, poles, transformers, repair crews and emergency services, as well as certain wildfire mitigation costs related to grid reliability and safety. In addition, the CPUC has authorized the IOUs to recover funding related to specific public policy objectives such as transportation electrification and demand response through the distribution rate component. Here we focus on distribution costs associated with transportation electrification and wildfire mitigation.

Historical Transportation Electrification Costs

Legislative Background

The CPUC is responding to several legislative mandates and gubernatorial directives to support and accelerate widespread transportation electrification (TE).[58] SB 350 directed the CPUC to require the investor-owned utilities (IOUs) to submit applications for programs that leverage ratepayer funding to support electric vehicle (EV) adoption.[59] To date, the CPUC has authorized the IOUs to implement many TE programs to help meet California's zero-emission vehicle (ZEV) targets of five million ZEVs on the road by 2030 and 250,000 installed publicly available EV charging stations and 200 publicly available hydrogen fueling stations in the state by 2025.[60]

In September 2020, Governor Newsom pushed these state goals further by issuing Executive Order N-79-20 to require all in-state sales of new passenger vehicles be zero-emission by 2035. The Executive Order also set a further goal that 100 percent of medium- and heavy-duty vehicles in the state be zero-emission by 2045 for all operations where feasible and by 2035 for drayage trucks. Further, it sets a state goal to transition to 100 percent zero-emission off-road vehicles and equipment by 2035 where feasible.

Additionally, AB 841 (Ting, 2020) was signed into law in September 2020. The bill directs the establishment of new electric rules or tariffs that authorize each IOU to design and deploy all utility-side electrical distribution infrastructure for customers installing separately metered EV charging. This changes the CPUC practice of authorizing utility-side, electrical distribution infrastructure needed to charge EVs[61] on a case-by-

[58] SB 350 defined TE as any vehicle fueled by electricity generated outside of the vehicle, including light-duty vehicles, medium- and heavy-duty vehicles, off-road vehicles, and shipping vessels.

[59] Such as multi-unit dwellings, workplaces, destination centers, disadvantaged communities, and low/medium income residential communities.

[60] Executive Order (E.O.) B-48-18.

[61] Section 740.19(b) defines "electrical distribution infrastructure" as including poles, vaults, service, drops, transformers, mounting pads, trenching, conduit, wire, cable, meters, other equipment as necessary, and associated engineering and civil construction work.

case basis through individual program applications, to authorization of that infrastructure and associated design, engineering, and construction costs on an ongoing basis in an IOU's general rate case (GRC). The bill also makes permanent the exemption to CPUC Electric Rules 15 and 16, which allows service facility upgrade costs resulting from residential EV charging to be treated as a common cost paid for by all ratepayers.

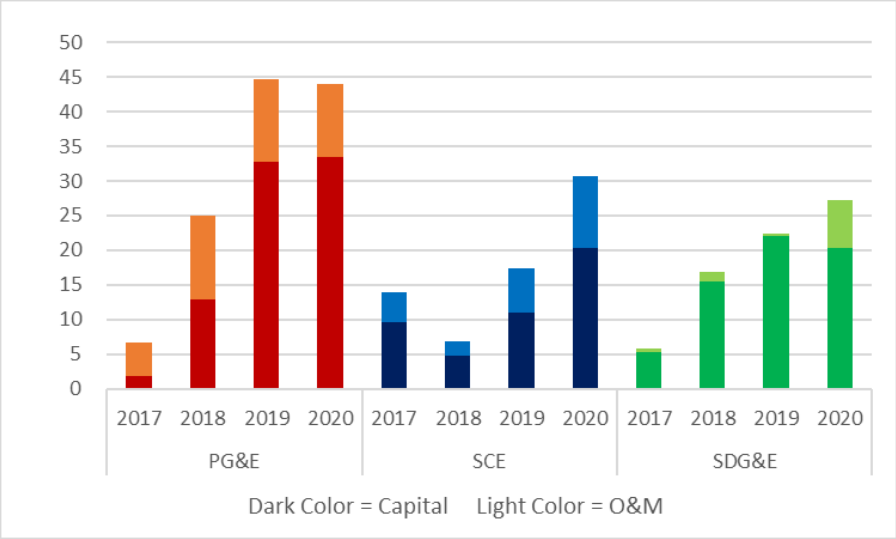
Costs in Rates

As of fourth quarter 2020, the CPUC has authorized the IOUs to spend approximately $1.6 billion on EV charging infrastructure to support the state's TE goals and is considering another application from SDG&E for approximately $44 million in TE funding.[62]

- Out of the authorized IOU funding to date, $238 million has been spent.
- Another $1.29 billion is still available for TE investment.

Figure 19 shows each IOU's transportation electrification program spending by O&M and capital cost classification and by the year implemented in rates.

Figure 19: PGE, SCE, and SDG&E Transportation Electrification Program Costs in Rates ($ million) (2017 -2020)



[62] *See* "Transportation Electrification Investments" on CPUC website: https://www.cpuc.ca.gov/zev/ .

Table 4 shows the rate attributable to transportation electrification costs embedded in the bundled average residential rate for the period 2017 to 2020.[63]

Table 4: Transportation Electrification Rate Embedded in Bundled Residential Average Rate (nominal $/kWh) (2017 – 2020)

	Transportation Electrification Rate Embedded in Bundled Residential Average Rate (nominal $/kWh)				Bundled Residential Average Rate (nominal $/kWh)			
	2017	2018	2019	2020	2017	2018	2019	2020
PG&E	0.00004	0.00027	0.00049	0.00033	0.204	0.205	0.220	0.230
SCE	0.00010	0.00005	0.00019	0.00025	0.177	0.181	0.183	0.209
SDG&E	0.00017	0.00043	0.00057	0.00139	0.249	0.276	0.263	0.271

With California's aggressive goals for transportation electrification over the next decade, significant upgrades to the distribution grid may be necessary to accommodate charging demand. While there is an ongoing policy discussion regarding the extent of ratepayer responsibility for TE costs, there is the potential for these costs to drive rate increases.

Historical Wildfire-Related Costs

Wildfire-related costs fall into several categories. First, the IOUs incur costs to implement wildfire mitigation activities. The costs associated with wildfire mitigation activities are recovered by the IOUs in General Rate Cases or through separate applications.

The CPUC also allows the IOUs to recover certain wildfire-related costs for liabilities, including insurance premiums. These costs are tracked through a mechanism called a Wildfire Expense Memorandum Account (WEMA). WEMAs track wildfire related liability costs, and no other category. WEMAs are designed to allow the utility the ability to track its costs incurred for claims made against the company as a result of property losses, in addition to other incremental liability costs including (but not limited to) higher-than-forecasted insurance premiums and legal fees.

In 2019, the Legislature also established a Wildfire Fund for excess liabilities. This is discussed in more detail below in the section on legislative background.

Legislative Background

[63] Year-end effective rates. Transportation Electrification rates expanded to five decimal places as the three decimal place convention in this paper produces 0.000 and 0.001 rates. To get an estimate of the portion of the monthly bill to which the transportation electrification rate corresponds, multiply the rate by 500 kWh, the monthly usage data that is used in legal bill inserts for PG&E's 2020 GRC Phase II, SCE's 2021 GRC Phase II, and SDG&E's 2019 GRC Phase II applications.

SB 901 (Dodd, 2018) and AB 1054 (Holden, 2019) require electric utilities to prepare and submit wildfire mitigation plans (WMP), which describe the level of wildfire risk in their service territories and how they intend to address those risks.[64] The WMPs cover a three-year period with new comprehensive plans to be filed at least once every three years and annual updates to the plans in between.

AB 1054 Wildfire Fund and Securitization

AB 1054 created a $21 billion Wildfire Fund to be funded equally by ratepayers and utilities. Utility shareholders will contribute approximately $10.5 billion to the Wildfire Fund through annual payments until 2030. Ratepayer funding amounts to an additional $10.5 billion which will be funded through a new non-bypassable charge (NBC). D.20-09-023 adopted a charge of $0.0058 per kWh from October 1, 2020-December 31, 2020 to support the Wildfire Fund and D.20-12-024 adopted the same charge for calendar year 2021. This amounts to approximately $3 per month for an average residential customer using 500 kwh per month.[65]

The Wildfire Fund is designed to act as an insurance fund for the utilities and can be used to pay costs resulting from utility caused wildfires provided that certain conditions are meet by the utility. While the fund represents an ongoing surcharge to rate payers it could reduce costs to ratepayer over time by creating more certainty for utility investors and thus reducing utility operating and borrowing costs.

AB 1054 Securitization and Rate Payer Savings

In addition, AB 1054 contains two separate benefits for ratepayers related to Wildfire Mitigation Plan (WMP) capital spending. AB 1054 requires the first $5 billion of WMP capital spending be excluded from earning a Return on Equity (ROE). This reduces rates directly by eliminating the shareholder profit portion of the return on rate base on the $5 billion WMP capital spending. Of the $5 billion in capital expenditures total, PG&E's share is $3.21 billion, SCE's share is $1.575 billion, and SDG&E's share is $215 million.

AB 1054 also allows for this $5 billion capital spending to be securitized through a CPUC financing order rather than being financed through the more traditional unsecured bond offerings. This securitization benefits ratepayers by allowing the utility to obtain a lower interest rate than would otherwise be available to finance WMP capital expenditures. On July 8, 2020, SCE filed A.20-07-008 with the CPUC, becoming the first utility to file for this securitization provision of AB 1054. In D.20-11-007, the CPUC granted forming the Financing Order allowing the securitization, subject to certain conditions.

Costs in Rates

SB 901 and AB 1054 permitted the IOUs to open accounts in 2019 to track spending to implement their WMPs. The IOUs are allowed to seek recovery of this spending in their General Rate Cases or through a

[64] *See* each IOU's WMP at https://www.cpuc.ca.gov/2019wmp/ .

[65] CARE and Medical Baseline customers are exempt from paying the non-bypassable charge.

separate application, after the conclusion of the time period covered by the plan. Therefore, there is lag between when spending takes place and when it is reflected in rates.

Table 5 shows spending related to the WMPs that is reflected in 2019 and 2020 rates is minimal compared to increases expected in future years for PG&E and SCE. SDG&E's spending is higher relative to their revenue requirement as a result of programs adopted in response to fires in their service territory in 2007.[66]

Table 5: Wildfire Mitigation Plan Costs in Rates (2019 - 2020)

	2019		2020	
	O&M Costs in Rates	Capital Costs in Rates	O&M Costs in Rates	Capital Costs in Rates
PG&E	-	$13.7 million	$20.3 million	$15.8 million
SCE	$33.9 million	$3.0 million	$173.1 million	$82.4 million
SDG&E	$25.8 million	-	$28.3 million	-

After destructive fires in SDG&E's service territory in 2007, the CPUC approved SDG&E cost recovery applications for a total of about $1.7 billion dollars over the period 2007 – 2018 for grid hardening, situational awareness, and vegetation management to better address the risk of wildfires. Figure 20 and Figure 21 show O&M and capital costs incurred[67] for wildfire prevention over the period 2007 – 2018 relative to all other non-wildfire costs, with wildfire prevention distribution spending directly representing over half of the total wildfire prevention costs.[68]

[66] FERC-related costs are not included in SDG&E's filed WMPs.

[67] Costs may be implemented in rates in a different year than year incurred.

[68] Other wildfire prevention costs represented include FERC-jurisdictional and mixed CPUC GRC and FERC Common costs.

Figure 20: SDG&E Wildfire Prevention O&M Costs Relative to All Other O&M Costs (Non-Wildfire), ($ million)

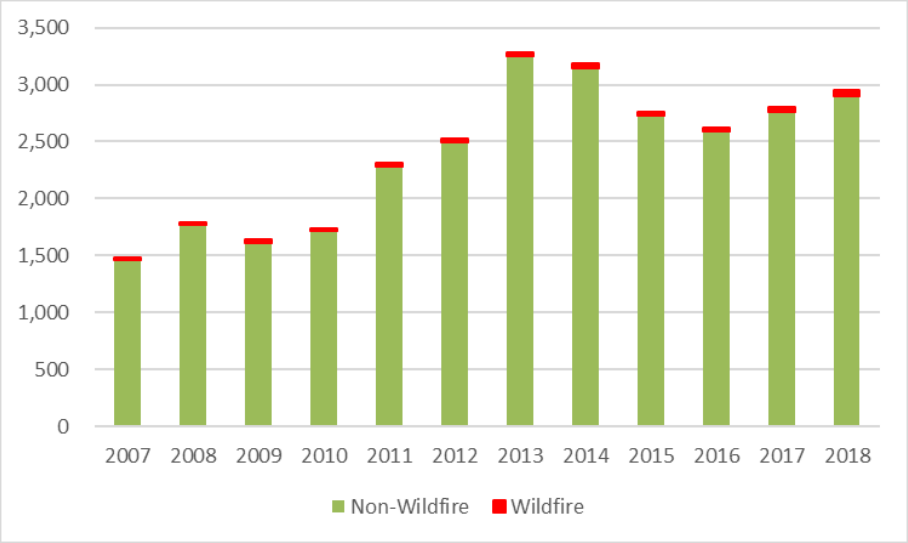


Figure 21: SDG&E Wildfire Prevention Capital Costs Relative to All Other Capital Costs (Non-Wildfire), ($ million)

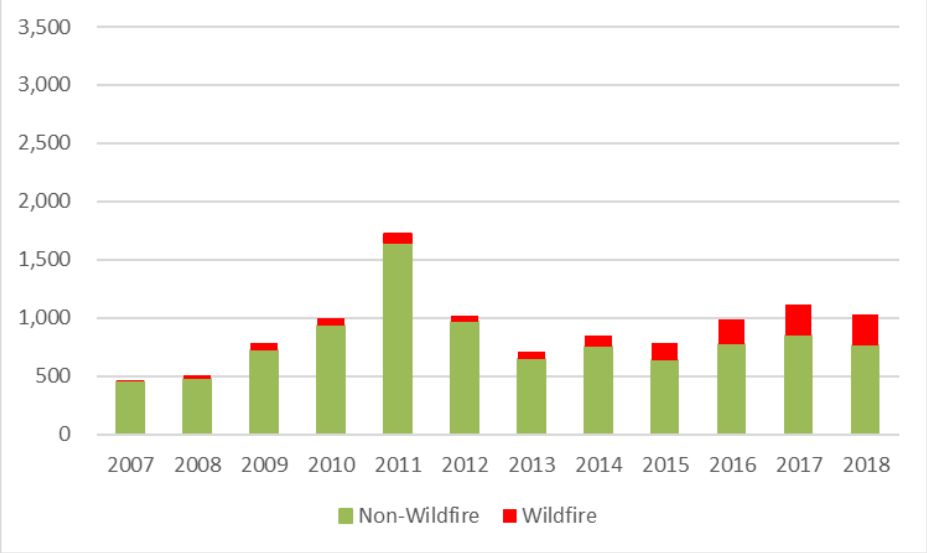


Figure 21 shows SDG&E's wildfire prevention capital expenditures increasing over time, particularly after 2013. Table 6 shows this wildfire prevention capital spend by SDG&E-designated cost categories for the years 2016 to 2018.

Table 6: SDG&E Wildfire Prevention Capital Expenditures by Cost Category ($ million) (2016 – 2018)

Cost Category ($ million)	2016	2017	2018
Wood-to-Steel (WTS) Pole Replacement Program	46.5	42.3	45.5
Cleveland National Forest (CNF) Projects	84.8	125.8	120.5
Fire Risk Mitigation (FiRM) Program	86.2	89.6	94.3
IntelliRupters	0.2	0.3	0.2
Emergency Communications/Trailers	0.1	0.4	0
Weather Modeling & Analytics	1.4	3.4	0.4
Pole Risk Mitigation Engineering (PRiME) Program	0	0	5
Total	219.2	261.8	265.9

The spending trends in Figure 20 and Figure 21 reflect SDG&E's increased focus in the last decade on hardening its electric system in high fire threat areas. These programs have expanded in recent years in response to the catastrophic wildfires of 2017-19. SDG&E wildfire mitigation costs since its destructive 2007 fires have not declined; in fact, they have continued to increase. This trend of wildfire spending by SDG&E may be informative of future spending by PG&E and SCE as these utilities ramp up their wildfire mitigation programs and harden their systems.

2.6 Historical Transmission Costs

Transmission revenue requirements (TRR) have been on the rise in recent years, driven largely by Capital Additions, Operations & Maintenance (O&M) costs, and Administrative & General (A&G) expenses. Collectively, the three big IOUs' annual spending has increased by approximately 60 percent on capital additions, 80 percent on O&M, and nearly 30 percent on A&G. The resulting Transmission Access Charge (TAC) that is paid by all ratepayers has been increasing while the total annual gross load has been declining in the California Independent System Operator (CAISO) control area.

Background

Transmission costs are set by the Federal Energy Regulatory Commission (FERC) and not by the CPUC, and Transmission Owners (TO) in the CAISO control area file at FERC to recover costs through transmission rates. At FERC, the CPUC represents California ratepayers as an advocate for just and reasonable rates. In the Transmission Owner rate cases, FERC approves revenue requirements recovered from both wholesale and retail transmission customers of larger IOUs such as PG&E, SCE, and SDG&E, as well as smaller merchant TOs. As explained in the CPUC's 2020 *California Electric and Gas Utility Cost*

Report (AB 67 Report), the proportion of a retail customer's' cost per kilowatt hour attributed to transmission in 2019 was 16.6 percent for PG&E, 9.1 percent for SCE, and 15.1 percent for SDG&E.[69]

Transmission Revenue Requirements Are Increasing Rapidly

In recent years, the sum of the three IOUs' transmission revenue requirements (TRR) has increased 38.1 percent, from $3.14 billion in 2016 to $4.34 billion in 2021 as forecasted in the three IOUs' rate filings at FERC on December 1, 2020. While this is a total increase of 38.1 percent, PG&E's TRR has increased over 66 percent during that time and SDG&E's by nearly 45 percent. After a dip during this period, SCE's TRR is at the same level it was in 2016. Further, the TRR and resulting electric transmission rates are driven by Operations & Maintenance costs and Administrative & General expenses. While the sum of operations and maintenance (O&M) costs for the three IOUs was $375.5 million in 2016, O&M costs have increased to a forecasted $674.6 million in 2021 – a nearly 80 percent increase. A&G also increase by almost 30 percent across the three IOUs. Table 7 through Table 10 show this data.

Table 7 shows the differences in transmission revenue requirements between 2016 and the 2021 forecast in total and for the individual utilities, reflecting increasing revenue requirements with the exception of SCE.

Table 7: Transmission Revenue Requirements in Settled TO Rate Cases at FERC

Utility	2016	2021	Percentage Change
SDG&E	$ 716 million	$ 1.036 billion	44.7%
SCE	$ 1.092 billion	$ 1.087 billion	-0.5%
PG&E	$ 1.331 billion	$ 2.214 billion	66.3%
Total	**$ 3.139 billion**	**$ 4.336 billion**	**38.1%**

Each IOUs' rate base, meaning the transmission capital investment on which the utility receives an approved rate of return, has significantly increased over the same period, as shown in Table 8.

Table 8: Transmission Rate Base

Utility	2016	2021	Percentage Change
SDG&E	$ 2.896 billion	$ 4.342 billion	49.9%
SCE	$ 5.171 billion	$ 6.428 billion	24.3%
PG&E	$ 5.846 billion	$ 8.476 billion	45.0%
Total	**$ 13.914 billion**	**$ 19.246 billion**	**38.3%**

Table 9 shows the overall increase of nearly 80 percent in annual O&M costs since 2016, with PG&E's rate base increasing a staggering 118 percent. O&M costs are also impacted by the substantial increases in rate base, but the primary driver of these costs is wildfire mitigation work, including enhanced inspections and vegetation management efforts.

[69] CPUC's 2020 *California Electric and Gas Utility Cost Report: AB 67 Report to the Governor and Legislature, p.10 (April 2020).*

Table 9: Operations & Maintenance Expenses

Utility	2016	2021	Percentage Change
SDG&E	$ 62.5 million	$ 85.6 million	37.0%
SCE	$ 93.5 million	$ 110.9 million	18.6%
PG&E	$ 219.5 million	$ 478.1 million	117.8%
Total	**$ 375.5 million**	**$ 674.6 million**	**79.7%**

The most variable transmission cost category is Administrative & General (A&G) expenses, which have fluctuated substantially from year-to-year. As these expenses have been influenced by injuries and damages related to wildfires for SCE and PG&E in recent years, SDG&E's A&G costs have declined as more time has passed since it experienced major wildfire impacts, as shown in Table 10.

Table 10: Administrative & General Expenses

Utility	2016	2021	Percentage Change
SDG&E	$ 79.9 million	$ 70.0 million	-12.4%
SCE	$ 49.7 million	$ 81.8 million	64.5%
PG&E	$ 73.6 million	$ 111.1 million	50.9%
Total	**$ 203.2 million**	**$ 262.8 million**	**29.3%**

Growth in Transmission Capital Additions

As described above, FERC reviews and approves transmission owner rate cases, which allow recovery of costs of service for the network transmission system under the CAISO's operative control. A critical driver of these overall transmission increases has been a continual rise in annual capital investment by the utilities, also referred to as "capital additions," from $2.14 billion in 2016 to a forecasted capital addition of $2.59 billion in 2021, an approximately 21 percent increase.

The rate of return (ROR) on capital additions allows utility shareholders to earn profits for shareholders' benefit. Utilities have an incentive to seek FERC approval for the highest possible ROR. The more capital additions that go into operation, the more profit the IOUs can attain. Conservative assumptions indicate that every dollar put into transmission rate base costs ratepayers in excess of $3.50 over the life of a transmission asset. For example, the $2.75 billion in capital additions for the three IOUs in 2020 alone can be expected to cost ratepayers at least $9.7 billion over the lives of the assets, using a conservative asset life estimate of 36 years.[70]

Utilities do not start collecting revenue for capital investments in transmission projects until the projects are completed and put into service. This means that ratepayers can see a large increase in the transmission portion of their bill when expensive projects are complete. Table 11 shows the in-service date of the largest transmission projects over the past 10 years. For two of the three projects in Table 11, the final total costs

[70] Transmission asset lives typically range between 30 to 50 years, and 36 years is chosen as a conservative mid-range estimate.

that were approved by FERC exceeded the original total cost estimates provided to the CAISO and the CPUC as part of the planning process.

Table 11: Large CAISO-approved Transmission Projects

Project	Original Est. Cost	Cost	In Service Date	IOU Territory
Sunrise Powerlink	$1.9 billion	$1.9 billion	2012	SDG&E
Devers-Colorado River	$545 million	$775 million	2013	SCE
Tehachapi Renewable Transmission Project	$1.7 billion	$3.062 billion	2016	SCE

Another factor that can accentuate the impacts of capital projects on ratepayers was the issuance of FERC Order No. 679 in 2006,[71] which provided incentives pursuant to Section 219 of the Federal Power Act[72] to promote necessary transmission development in the wake of the August 2003 Northeast-Midwest blackout. These incentives enable a utility to collect certain costs before it normally would, or ensure the ability to collect the costs on a project that needs to be abandoned through no fault of the utility. In addition, incentives boost the utility's ROE, either across the entire rate base or for specific projects. Over the last decade, these incentives have cost California ratepayers hundreds of millions of dollars.

An example of a utility ROE incentive is the adder FERC has awarded to transmission owners for participation in the CAISO. This incentive was meant to encourage utilities to join Independent System Operators and Regional Transmission Organizations. Despite the fact that the California IOUs' participation in CAISO is required under California law, FERC still grants a 50-basis point (0.5 percent) ROE adder to each IOU as an "incentive" for its membership in the CAISO. The CPUC is litigating the reasonableness of awarding an incentive to the IOUs for remaining a member of the CAISO. Currently, this incentive costs California ratepayers over $70 million annually.

An example of a project-specific ROE incentive is the 125-basis point (1.25 percent) adder granted to SCE in 2007 for the Tehachapi Renewable Transmission Project. The FERC declaratory order granted this incentive for the entire $1.7 billion project.[73] However, at this time, the cost of the project has nearly doubled, with over $3.06 billion placed into rate base.[74] It appears that SCE will seek the incentive ROE on the total project cost of $3.06 billion.

Increase in Utility Self-Approved Projects

[71] *Promoting Transmission Investment Through Pricing Reform*, Order No. 679, 116 FERC ¶ 61,057 (2006)

[72] 16 U.S. Code § 824s - Transmission infrastructure investment

[73] Order Granting Petition for Declaratory Order, EL07-62, 121 FERC ¶ 61,168, P135 (November 16, 2007).

[74] Southern California Edison Company's Formula Transmission Rate Annual Update Filing in Docket No. ER19-1553 (TO2021), Attachment 2 to Appendix IX: Formula Rate Spreadsheet, 14-IncentivePlant, line 66 (November 20, 2020).

Projects that expand the capacity of the transmission grid are included in CAISO's annual Transmission Planning Process (TPP), pursuant to requirements of FERC Order No. 890 ("Order 890"), which requires transparent transmission planning. However, a majority of the California IOUs' spending on capital additions is not related to grid capacity expansion and therefore receives no review by the CAISO through the TPP. FERC has determined that Order 890 does not apply to projects that do not expand the capacity of the transmission grid. These projects that are outside of the scope of the TPP are referred to as "self-approved." A TO rate case at FERC includes no review of specific utility self-approved projects. The end result is that there is no state or federal review on either the need or costs for these projects.

In data reported by the IOUs to the CPUC in July 2020, capital additions between 2016 and 2019 for all three IOUs totaled over $7.5 billion. Approximately $4.5 billion (60 percent) of these capital additions were utility self-approved, while $3 billion were CAISO-approved. The annual average for all capital additions for 2016 to 2019 was $1.875 billion. In comparison, in 2010, the capital additions for the IOUs totaled less than $950 million, with the share of self-approved projects in 2010 at 50.6 percent and CAISO-approved projects was 49.4 percent. The annual capital additions projected for just 2020 and 2021 total $5.3 billion, with approximately 60 percent being self-approved projects across all three IOUs, with PG&E exceeding 80 percent self-approved.

As the previous table shows, the largest CAISO-approved projects occurred in SDG&E's and SCE's territories. Table 12 shows the proportion of CAISO-approved and utility self-approved projects between 2010 and 2019. While over 80 percent of SCE's and SDG&E's project costs during that time were CAISO-approved, primarily because of the large projects in Table 11 only 31 percent of PG&E's capital additions were CAISO approved. PG&E's overall capital project costs far exceed those of either SCE or SDG&E and a large majority of those costs were self-approved.

Table 12: CAISO-approved and Utility Self-approved Projects 2010-2019 ($000)

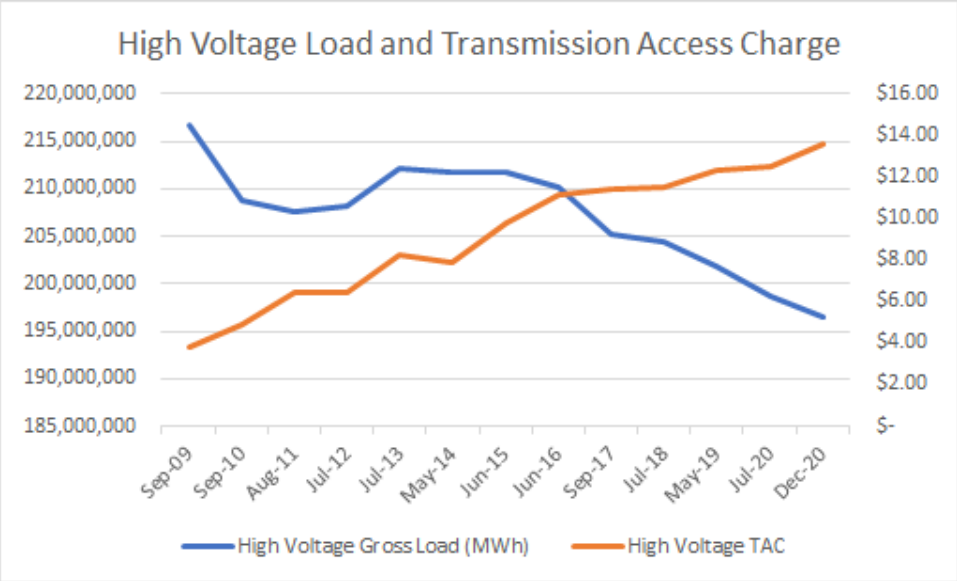
Utility	Self-approved Projects	CAISO-approved Projects	Total Capital Additions	Percentage Self-approved	Percentage CAISO-approved
SDG&E	$ 0.81 million	$ 3.99 million	$ 4.80 million	16.9%	83.1%
SCE	$ 1.18 million	$ 5.08 million	$ 6.26 million	18.9%	81.1%
PG&E	$ 6.16 million	$ 2.77 million	$ 8.93 million	69.0%	31.0%
Total	**$ 8.15 million**	**$11.84 million**	**$19.99 million**	**40.8%**	**59.2%**

Declining Loads and Increasing Rates

For more than a decade, the total annual gross load, which is a measure of all energy delivered for the supply of end-use customer loads, has been declining in the CAISO control area. However, over that same period, CAISO's High Voltage Transmission Access Charge (TAC), which is a primary component of transmission charges on customers' bills, has increased substantially. In 2009, the annual load in the CAISO

was 216.7 million megawatt hours (MWh).[75] Figure 22 shows as of December 2, 2020, the load forecast for 2021 was down to 196.5 million MWh, a decline of 9.3 percent. Meanwhile, as of December 2020 the forecast for the 2021 high voltage TAC was $13.60 per MWh, a 255 percent increase from $3.83 per MWh in 2009.[76]

Figure 22: High Voltage Load and Transmission Access Charge



2.7 Legislative Policy Program Costs

Clean energy and other legislative mandates for the 5-year period 2016 – 2020 are shown in Table 13, listed from the highest to lowest total cost (or cost reduction) in total electric revenue requirement equivalent. Programs classified as primarily related to clean energy are highlighted in blue-green, with those that are primarily not related to clean energy highlighted in light-purple.[77] This table shows program costs but does not calculate possible savings to the utility ratepayers; the CPUC details these costs and benefits in other reports. For example, while the Renewable Portfolio Standard (RPS) creates added costs there is also a savings from avoided procurement of other generation, with savings increasing over time as renewables become less and less expensive.[78]

[75] High Voltage Load and TAC data for 2009 through July 2020 derived from: California ISO September 01, 2009 TAC Rates, California ISO September 01, 2010 TAC Rates, California ISO August 01, 2011 TAC Rates, California ISO July 03, 2012 TAC Rates, California ISO July 01, 2013 TAC Rates, California ISO May 01, 2014 TAC Rates, California ISO June 01, 2015 TAC Rates, California ISO June 01, 2016 TAC Rates, California ISO September 15, 2017 TAC Rates, California ISO July 01, 2018 TAC Rates, California ISO May 01, 2019 TAC Rates, and California ISO July 01, 2020 TAC Rates.

[76] Pacific Gas and Electric Company Transmission Owner Tariff Transmission Access Charge Balancing Account Filing, Exhibit PGE-003, p. 2 of 12, FERC Docket No. ER21-657 (December 15, 2020).

[77] The list of legislatively mandated programs does not capture programs that result in a cost shift or cross-subsidy between various customers groups. This includes, but is not limited to, programs such as Net Energy Metering (AB 920), California Alternate Rates for Energy (AB 3), the FERA Program (Federal Emergency Relief Act of 1993), and the Medical Baseline Program (PUC Code 739).

[78] *See Costs and Cost Savings for the RPS Program* (Padilla Repot) at: https://www.cpuc.ca.gov/General.aspx?id=6442463728 .

Table 13: Programs Mandated by California Statute, Electric Revenue Requirement in Rates, Five Year Total (2016 – 2020)

		2016 – 2020 Five-Year Total ($ million)			
Legislation	Program Name	PG&E	SCE	SDG&E	Total
SB 1078, SB 350, SB 100	Renewable Portfolio Standard[79]	$10,710	$11,039	$3,413	$25,162
AB 1X	Department of Water Resources Bond	$2,028	$2,023	$450	$4,501
AB 32	Greenhouse Gas Revenue Return	$(1,896)	$(1,800)	$(403)	$(4,099)
SB 350, AB 1330, AB 802, AB 32, AB 1890	Energy Efficiency	$1,467	$1,205	$497	$3,169
AB 32	Greenhouse Gas Cost	$386	$1,530	$158	2,074
Public Utilities Code § 2790, § 382; AB 327, AB 2857, SB 580, AB 2140	Energy Savings Assistance Program and California Alternate Rates for Energy Program Administrative Expense	$729	$364	$609	$1,702
Public Utilities Code § 399.8; AB 1890	Electric Program Investment Charge	$463	$366	$78	$907
SB 1414, AB 793	Demand Response[80]	$212	$306	$81	$599
AB 970, SB 700, AB 1144	Self-Generation Incentive Program	$240	$227	$72	$539
AB 1X	Total Rate Adjustment Component	$0	$0	$533	$533
Public Utilities Code § 431-432	CPUC Fee	$187	$195	$46	$428
AB 693	Solar on Multifamily Affordable Housing	$146	$161	$32	$339
SB 1, AB 217, AB 2723	California Solar Initiative - Multifamily Affordable Solar Housing/Single-Family Affordable Solar Homes	$40	$121	$11	$172

[79] RPS revenue requirements do not distinguish the above-market portion.

[80] Demand Response includes DR Auction Mechanism and IDSM, as applicable.

2016 – 2020 Five-Year Total ($ million)					
Legislation	Program Name	PG&E	SCE	SDG&E	Total
SB 859	Tree Mortality Non-Bypassable Charge	$100	$50	$21	$171
AB X1 6	Hazardous Substance Memorandum Account	$147	$14	$2	$163
Public Utilities Code § 2791-2799	Mobile Home Park Program	$55	$72	$15	$142
SB 350, AB 1082, AB 1083, AB 628	Transportation Electrification Programs[81]	$76	$33	$22	$131
SB 1, AB X1 15	New Solar Homes Partnership Program	$57	$46	$10	$113
Other	Other[82]	$156	$140	$13	$309
Five-Year Total[83]		**$15,303**	**$16,092**	**$5,660**	**37,055**
One-Year Average Total[84]		**$3,061**	**$3,218**	**$1,132**	**$7,411**

[81] Transportation Electrification includes pilots, as applicable.

[82] Other includes: AB 793 Statewide Marketing Program; AB 32, SB 17, Smart Grid; SB 43 Green Tariff Shared Renewables; SB 96 California Energy Systems for 21st Century; AB 2514 Aliso Canyon Energy Storage; AB 2672 San Joaquin Valley Disadvantaged Communities Pilot and Data Gathering; AB 327 Disadvantaged Communities - Single-Family Affordable Solar Homes, Green-Tariff, Community Solar Green Tariff; SB 987, SB 1135 Family Electric Rate Assistance (administrative expense); AB 1070 Net Energy Metering (solar system contracts and disclosures); SB 901 Officer Compensation.

[83] Not all programs have five years of data; for example, programs may have started within the five-year period for which less than five years data will be shown.

[84] *Ibid.*

III. Modeling Assumptions and Frameworks for Evaluating Forecasted Utility Costs

3.1 Section Summary

Public Utilities Code Section 913.1(a) requires the CPUC's to make recommendations for actions that can be undertaken during the succeeding 12 months[85] to limit utility cost and rate increases, consistent with the state's energy and environmental goals, including goals for reducing emissions of greenhouse gases. For the 2021 SB 695 Report contained within this white paper, the CPUC is presenting a 10-year bundled[86] residential rates forecast as a backdrop for discussion related to the white paper.

This section describes the process by which the 10-year forecast was developed, starting with a description of the cost and rate tracking tools used to project IOU rates in the near-term (1 to 3 years) followed by a summary of the methodology used to extend the forecast out to 2030. The baseline forecast shows steady growth in bundled rates (nominal $/kWh) between 2020 and 2030 for the three IOUs:

- PG&E: $0.240 to $0.329, or about an annual average increase of 3.7 percent
- SCE: $0.217 to $0.293, or about an annual average increase of 3.5 percent
- SDG&E: $0.302 to $0.443, or about an annual average increase of 4.7 percent

By 2030, bundled residential rates are forecasted to be approximately 12 percent, 10 percent, and 20 percent higher, respectively, than they would have been if 2020 actual rates for each IOU had grown at the rate of inflation.[87]

This section also describes how costs were projected for two specific components of the rates forecast: wildfire management and transportation electrification. Component contribution to the forecasted bundled residential rates is also presented. These costs are of particular interest because there is a great deal of uncertainty around their growth in the coming decade. The portion of the baseline forecasted bundled residential rates that corresponds to wildfire management and transportation electrification rates in 2021 and 2030 is shown in Table 14.

[85] The succeeding 12 months refers to the 12-month period after the report is submitted by May 1 of each year.

[86] Bundled IOU customers receive all services from the IOU: generation, transmission, and distribution services.

[87] 2020 rates are actual rates in effect at yearend 2020; if 2020 rates were to increase at the rate of inflation (approximately 1.9% per year), rates in 2030 would be: PG&E 0.294; SCE 0.266; SDG&E 0.370. Inflation is approximately 1.9% per year.

Table 14: Wildfire Management and Transportation Electrification Embedded Rates as a Portion of Forecasted Bundled Residential Rate (nominal $/month)

	2021					2030				
	Embedded Wildfire Rate ($/kWh)	Embedded TE Rate ($/kWh)	Forecasted Bundled Residential Rate ($/kWh)	Wildfire Portion %	TE Portion %	Embedded Wildfire Rate ($/kWh)	Embedded TE Rate ($/kWh)	Forecasted Bundled Residential Rate ($/kWh)	Wildfire Portion %	TE Portion %
PG&E	0.016	0.001	0.266	6.0%	0.4%	0.028	0.001	0.329	8.5%	0.3%
SCE	0.024	<0.001	0.272	8.8%	<0.4%	0.025	0.003	0.293	8.5%	1.0%
SDG&E	0.019	0.002	0.300	6.3%	0.7%	0.029	0.006	0.443	6.5%	1.4%

Table 15 shows the wildfire management and transportation electrification portion of monthly forecasted bundled residential customer bills in 2021 and 2030.[88]

Table 15: Wildfire Management and Transportation Electrification Portion of Monthly Forecasted Bill, Bundled Residential Customers (nominal $/month)

	2021					2030				
	Wildfire Portion ($/month)	TE Portion ($/month)	Total Bill ($/month)	Wildfire Portion %	TE Portion %	Wildfire Portion ($/month)	TE Portion ($/month)	Total Bill ($/month)	Wildfire Portion %	TE Portion %
PG&E	8.00	0.50	133.00	6.0%	0.4%	14.00	0.50	164.50	8.5%	0.3%
SCE	12.00	<0.50	136.00	8.8%	<0.4%	12.50	1.50	162.00	7.7%	0.9%
SDG&E	9.50	1.00	150.00	6.3%	0.7%	14.50	3.00	221.50	6.5%	1.4%

The results of the rate forecasting exercise were then used as an input to a consultant-developed Residential Energy Cost Calculator (RECC) tool, along with projections of natural gas and gasoline prices. The tool was used to estimate changes in total energy bills for an example household with greater-than-average energy usage[89] to demonstrate the cost implications for Californians who are most sensitive to energy price shocks.

This analysis shows that energy bills for this greater-than-average energy usage household are forecasted to rise **at an annual rate of 4.5 percent**, implying that households' energy burdens will increase if household incomes track the assumed inflation rate of 1.9 percent.

This analysis implies that, in order for Californians to avoid forecasted increases in energy bills, large up-front investments may be needed. From an equity perspective, this will pose a significant challenge in an environment where affordability disparities are already evident. A recent analysis using CPUC-developed

[88] Bills are for illustrative purposes only.

[89] Greater than average usage in the consultant-developed tool is approximately 680 kWh/month.

metrics indicates that there are significant disparities across the state in terms of low-income households' ability to pay for utility services. The analysis found that there are specific geographic areas within the state where affordability concerns are most acute, including Oakland, Stockton, Fresno, Modesto, Tulare County, Bakersfield, San Bernardino, and many parts of Los Angeles.

These observed disparities may be exacerbated in the coming years as the impacts of the COVID-19 pandemic and accompanying economic recession unfold. Preliminary economic data indicates that prior disparities have likely worsened over the past year. Furthermore, experience from the last recession of 2008 indicates that disadvantaged households take a longer time to recover from economic downturns, and there is no reason to believe this recession will be any different.

3.2 Cost and Rate Tracking Tools (CRT)

Background

In an ongoing proceeding to better assess affordability of utility bills in California, the CPUC ordered PG&E, SCE, and SDG&E to each submit a quarterly cost and rate tracking tool (CRT) to the CPUC's Energy Division for evaluating the inputs of the affordability metrics developed as part of the OIR and for other ongoing support of the CPUC's work.[90] In addition to producing rates for the affordability metrics, each IOU's CRT is used to produce a short- to medium term comprehensive[91] rate forecast to show overall rate trends as requested by CPUC Commissioners or other parties. This tool will also be used to provide Commissioners and the public a clear understanding of the bill impacts of individual decisions made by the CPUC. The CRT can produce estimated bills for bundled residential customers at the IOU service territory or climate zone level.

The CRT models comprehensive forecasted revenue requirement[92] and forecasted sales information, as provided by the large electric IOUs,[93] to produce rates. While the CRT will help inform CPUC decisions, the tool may still have limitations based on the completeness and classification of data provided by the utilities. For example, certain wildfire mitigation plan cost recovery applications have not yet been filed, and the IOUs may not have filed estimates of the cost recovery in the CRTs. Further, it may be difficult to break out wildfire mitigation costs that form part of a proceeding, such as a GRC, to combine the costs with stand-alone application requests, such as recovery of wildfire mitigation memorandum accounts. A comprehensive wildfire mitigation cost tracking system, including conversion of wildfire mitigation costs to revenue requirements, could serve as a cost classification basis in future versions of the CRT.

[90] D.20-07-032, Ordering Paragraph (OP) 1, p. 99.

[91] The forecasts produce cumulative rate and bill impacts, assuming recovery of all pending rate requests, for the current year and three additional years.

[92] Forecasted incremental revenue requirement information is updated in the CRT for the duration of each cost recovery proceeding, in order to reflect the most-recently available requested revenue requirement data.

[93] CRTs for the large natural gas IOUs are in development.

Bundled Rate Transparency Considerations

As rates and bills produced by the CRT are occasionally shared with parties outside of the CPUC,[94] there have been inquiries into the revenue requirements and sales forecasts that comprise the rates.[95] Forecasted incremental revenue requirements modeled in the CRT are based on publicly available information; there are no transparency issues related to the availability[96] of forecasted revenue requirement data at system level. However, certain sales forecast data provided by the IOUs in their respective CRTs[97] are not available to parties outside the CPUC.

Bundled sales forecast data are available in the public domain for PG&E[98] and are not publicly-available for SCE and SDG&E.[99] Due to the confidentiality of SCE and SDG&E bundled residential sales, for interested parties without access to the CRTs, there is a lack of transparency into the revenue requirement and sales forecast that comprise an authorized bundled residential rate. This is because if the bundled residential revenue requirement is known, one can calculate the bundled residential sales forecast by solving for x in the equation:

$$Rate = Authorized\ Revenue\ Requirement\ /\ X; \quad X = Authorized\ Revenue\ Requirement\ /\ Rate$$

While not a transparency concern for the CPUC due to the CRT, transparency for stakeholders[100] with respect to the bundled revenue requirement and bundled sales forecast in authorized rates[101] should be weighed against the business reasons the IOUs may have for not providing access to this data. Transparency into PG&E's bundled residential rate is clear as both the revenue requirement and sales forecast can be accessed in PG&E's rates implementation advice letters. However, there is a lack of transparency with respect to bundled sales forecast data in SCE's and SDG&E's rates implementation advice letters.

Sales forecast confidentiality treatment in each IOU's CRT, for both authorized and projected bundled sales forecasts, as well as in each IOU's rates implementation advice letters, is shown in Table 16.

[94] Parties could be members of the legislature, other state agencies, or institutions of higher learning.

[95] Rate = Revenue Requirement / Forecasted Sales.

[96] Forecasted system-level revenue requirement data is available in the rates implementation advice letters the IOUs file before a rate change.

[97] Sales forecast data in the CRT may vary from year to year.

[98] Authorized bundled sales forecasts are generally available in PG&E's rates implementation advice letters. In the CRT, PG&E's forecasting methodology for years beyond the authorized bundled sales forecast uses a projection trend of authorized bundled sales forecasts; the results do not necessarily represent PG&E's view of the sales forecast in future years.

[99] SCE's methodology uses current authorized bundled sales and internally-developed projected bundled sales forecasts, neither of which are publicly available. SDG&E's methodology uses current authorized bundled sales forecast for all years, which is not publicly available.

[100] Stakeholders may wish to know the amounts of the authorized bundled revenue requirement and authorized bundled forecasted sales components for various reasons, including using the authorized rate as a benchmark from which to make projections.

[101] Authorized rates currently in effect. Prior authorized rates may not have these transparency issues.

Table 16: Bundled Sales Forecast Treatment in IOU Cost and Rate Tracking Tools

IOU	Confidentiality Labeling – Authorized Sales Forecasts	Confidentiality Labeling – Projected Sales Forecasts	Other Observations
PG&E	No confidentiality labeling	No confidentiality labeling; PG&E disclaims forecasts do not necessarily represent PG&E's view	PG&E additionally provides full authorized sales forecast data i.e., bundled and unbundled, in each advice letter implementing rate changes.
SCE	All sales forecasts and resulting bundled residential revenue allocations labeled **Confidential** per D. 16-08-024 and D. 17-09-023	All sales forecasts and resulting bundled residential revenue allocations labeled **Confidential** per D. 16-08-024 and D. 17-09-023	SCE's Confidentiality Declaration states that bundled customer sales forecast data is confidential and proprietary as it represents load and energy forecasts that are market sensitive under Section V of the R.05-06-040 Matrix of Allowed Confidential Treatment – IOU Data; Advice letters implementing rate changes similarly contain no bundled sales data.
SDG&E	All bundled sales forecasts and related bundled data labeled **Confidential** per D.06-06-066	N/A (No projected sales forecasts in CRT)	Advice letters implementing rate changes do not have bundled sales data.

While PG&E has experienced a high level of departed load, it nevertheless has maintained its transparent position about the availability of all authorized bundled sales forecast data. Presumably, PG&E has not been negatively impacted by the transparent position it has taken, as it continues to provide bundled sales data in the public domain. Accessible data is important for interested parties without access to the CRTs who may seek to understand current and projected rate trends,[102] and the CPUC may want to look more closely at the possibility of requiring transparency of all authorized sales forecast data, including bundled data, for all IOUs at the rates implementation advice letter level. Advice letter bundled sales forecast consistency among the IOUs may be a first step in addressing this issue.

3.3 En Banc Bundled Residential Customer Rates Forecast

Background

[102] "Interested parties" could include those in higher-learning institutions as well as in other California state agencies.

The Cost and Rate En Banc rates forecast discussed below is based on bundled residential rates in keeping with CRT capability of calculating rates and bills for bundled customers.[103] Costs and rates for non-residential customer classes are not modeled in the CRTs, as usage for a typical non-residential customer needed to show bill impact is difficult to define.[104]

Methodology and Assumptions

PG&E's, SCE's, and SDG&E's current CRT[105] were used as the foundation for a special-purpose 10-year rates forecast solely for use in this white paper (En Banc Bundled Residential Rates Forecast). Projected rate impacts in the En Banc Bundled Residential Rates Forecast are forecasts, including assumptions related to those forecasts, and are for illustrative purposes only. Further, forecasts are based on forward-looking estimates that are not historical facts.

Forecasts were developed for bundled residential rates for 2021 – 2030.[106] The forecasted rates are simple volumetric rates based on forecasted bundled residential revenue requirements and bundled residential sales forecasts. The En Banc Bundled Residential Rates Forecast methodological considerations include:

- Rates for 2021 – 2023 are based on CRT-produced rates from CRT revenue requirements[107] and sales forecasts.[108]
- Rates for 2024 – 2030 are largely based on 2023 CRT revenue requirements, with escalation factors used by the California Energy Commission (CEC) in CEC rates forecasts.[109]
- Rates for 2030 use a preliminary CEC bundled residential sales forecast developed for use in preparing the rate forecast for the *California Energy Demand Forecast Update, 2020 – 2030* (Demand

[103] The CRTs are not capable of calculating rate or bill impacts for unbundled customers.

[104] *See* Section II, sub-section, "Historical Trends in Electric Rates and Bills," sub-heading *Residential and Select Small Commercial Bundled Average Monthly Bills.*

[105] PG&E and SCE's current CRTs are Fourth Quarter 2020 (Q4-2020) and SDG&E's current CRT is Third Quarter 2020 (Q3-2020).

[106] Actual rates at yearend 2020 are included as a reference.

[107] Forecasted incremental revenue requirement information is updated in the CRT for the duration of each cost recovery proceeding, in order to reflect the most-recently available requested revenue requirement data.

[108] CRT-produced bundled residential sales forecasts are confidential for SCE and SDG&E as indicated in the previous sub-section "Bundled Rate Transparency Considerations."

[109] The CEC produces IOU service area residential rate forecasts (the weighted average of bundled, CCA, and direct access rates) as part of constructing planning area rates, which group revenue requirements in four categories: Generation, Distribution, Transmission and Other. The CEC also internally produces illustrative bundled residential rate forecasts for the three large electric IOUs. Escalation factors (presented here as multipliers) used for 2020 illustrative bundled residential rate forecasts for these categories are 1.045 percent, 1.045 percent, 1.025 percent (1.045 PG&E), and roughly 1.02 percent (i.e., inflation), respectively. PG&E transmission escalation factor 1.025 used in this analysis.

Forecast 2020), Mid-Demand Case.[110] Bundled residential sales forecasts from 2024 – 2029 are then interpolated between 2023 sales forecasts and 2030 sales forecasts.

- Bundled residential sales forecasts from 2024 – 2030 do not include IOU-departed load expansions not known at the time the CEC rate forecast was prepared.
- Rates exclude the California Climate Credit, also known as the Greenhouse Gas (GHG) Allowance Return. The GHG Allowance Return functions as revenue requirement reduction.[111]
- Rates include an estimate for the Power Charge Indifference Adjustment (PCIA), benchmarked to 2020 PCIA amounts. The PCIA functions as a revenue requirement reduction.

Baseline Scenario

The En Banc Bundled Residential Rates Forecast baseline scenario is shown in Table 17.[112]

Table 17: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates (nominal $/kWh), Baseline Scenario

	Baseline Bundled Residential Electric Rate (nominal $/kWh)										
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	$ 0.240	$ 0.266	$ 0.273	$ 0.264	$ 0.266	$ 0.281	$ 0.289	$ 0.298	$ 0.307	$ 0.318	$ 0.329
SCE	$ 0.217	$ 0.272	$ 0.274	$ 0.276	$ 0.273	$ 0.277	$ 0.281	$ 0.285	$ 0.289	$ 0.294	$ 0.293
SDG&E	$ 0.302	$ 0.300	$ 0.328	$ 0.338	$ 0.340	$ 0.355	$ 0.371	$ 0.388	$ 0.405	$ 0.424	$ 0.443

The percentage change in forecasted 2030 bundled residential rates over 2020 rates for each IOU are:

- PG&E: 37 percent over 10 years or an annual average of 3.7 percent over this time period
- SCE: 35 percent over 10 years or an annual average of 3.5 percent over this time period
- SDG&E: 47 percent over 10 years or an annual average of 4.7 percent over this time period

[110] The Demand Forecast Update 2020 - 2030 provides 10-year forecasts for electricity demand in California and for major utility planning areas within the state. *See* https://www.energy.ca.gov/data-reports/reports/integrated-energy-policy-report/2020-integrated-energy-policy-report-update-0 . For IOU service area residential sector rate forecasts, *see* 20-IEPR-03 docket, "CEDU 2020 Electricity Rate Scenarios" (January 20, 2021) at: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03 . The CEC also internally produces service area residential sales forecasts for the three large electric IOUs. Preliminary bundled residential sales forecasts are derived from these preliminary service area sales forecasts.

[111] This is similar to forecasted rates produced by the CEC, which also exclude the California Climate Credit.

[112] 2020 actual rate presented for reference. The rates in Table 17 and Figure 23 through Figure 27 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

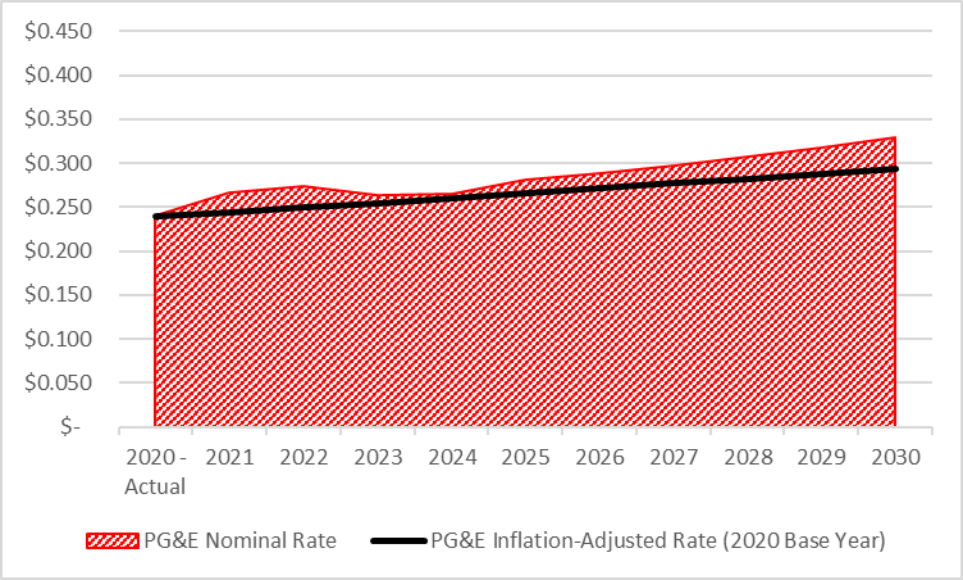
The percentage change in forecasted bundled residential rate for PG&E[113] of 37 percent over 10 years is broken down by the forecasted bundled residential revenue requirement and bundled residential sales forecast changes as shown in Table 18:[114]

Table 18: PG&E 2020 Actual and 2030 Forecasted Bundled Residential Revenue Requirement and Sales Forecast, Baseline Scenario

PG&E						
2020 Actual Bundled Residential Revenue Requirement ($ million)	2030 Forecasted Bundled Residential Revenue Requirement ($ million)	2020 -3030 Forecasted Bundled Residential Revenue Requirement Change (%)	2020 Actual Bundled Residential Sales Forecast (GWh)	3030 Forecasted Bundled Residential Sales Forecast (GWh)	2020 -3030 Forecasted Bundled Residential Sales Change (%)	2020 -3030 Forecasted Bundled Residential Rate Change (%)
3,329	4,512	36%	13,888	13,704	(1%)	37%

Inflation-adjusted rates for each IOU, based on 2020 actual rate as the base rate, show how the bundled residential rate forecast comports with forecasted inflation.[115] The En Banc Bundled Residential Rates Forecast baseline scenario with 2020 actual inflation-adjusted forecasted rates are shown in Figure 23 through Figure 25.

Figure 23: PG&E Forecasted Bundled Residential Rate (¢/kWh), Nominal and Inflation-Adjusted, Baseline Scenario



[113] Authorized bundled residential revenue requirement and authorized bundled residential sales forecast corresponding to SCE and SDG&E 2020 actual rates are labeled confidential and not available for presentation.

[114] 2020 actual rates at year-end.

[115] Gross Domestic Product (GDP) inflator used for CEC Planning Area $2019 average rates (Moody's, July 2020).

Figure 24: SCE Forecasted Bundled Residential Rate (¢/kWh), Nominal and Inflation-Adjusted, Baseline Scenario

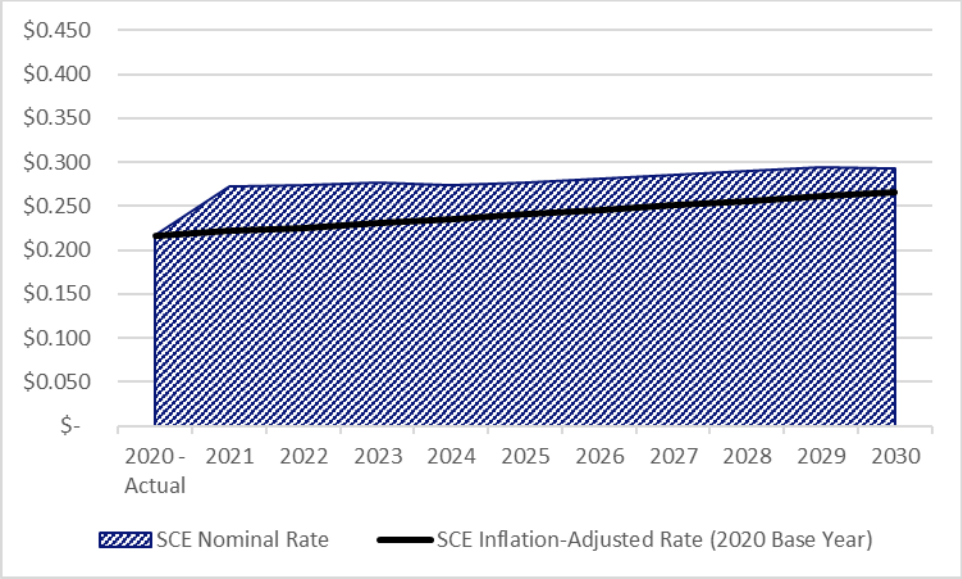
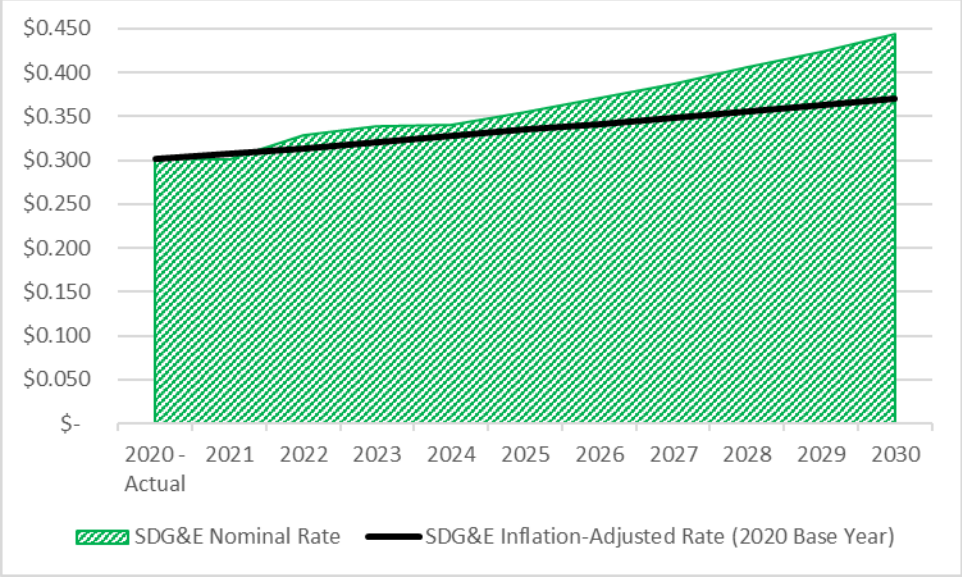


Figure 25: SDG&E Forecasted Bundled Residential Rate (¢/kWh), Nominal and Inflation-Adjusted, Baseline Scenario



The En Banc Bundled Residential Rates Forecast is shown in nominal dollars per kWh in Figure 26 and deflated to 2019 dollars per kWh i.e., 2019 real dollars,[116] per kWh in Figure 27.

Figure 26: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates (nominal $/kWh), Baseline Scenario

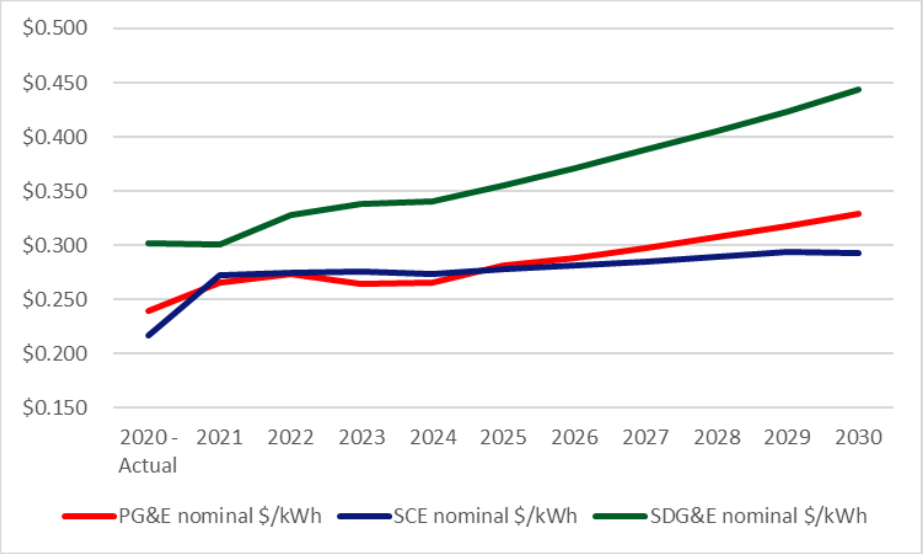
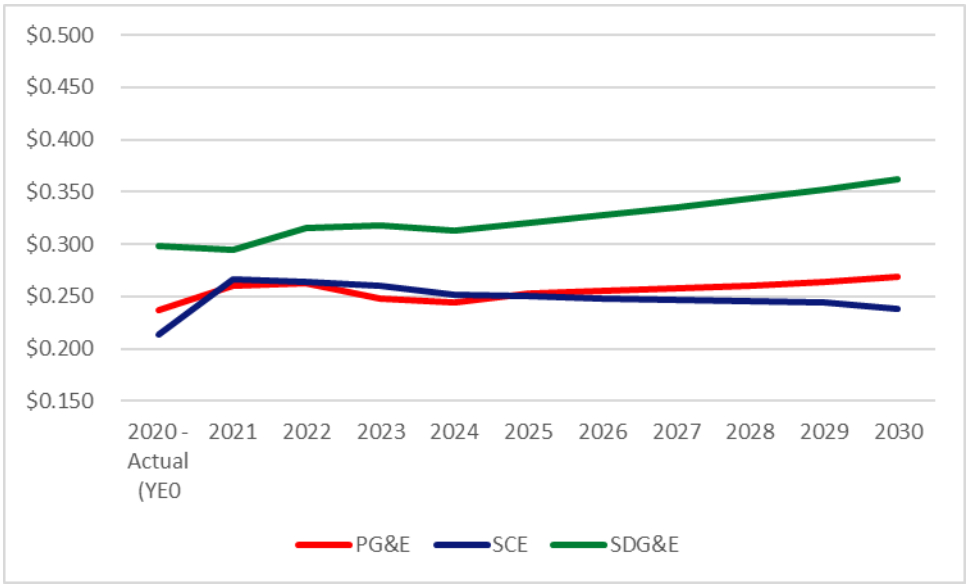


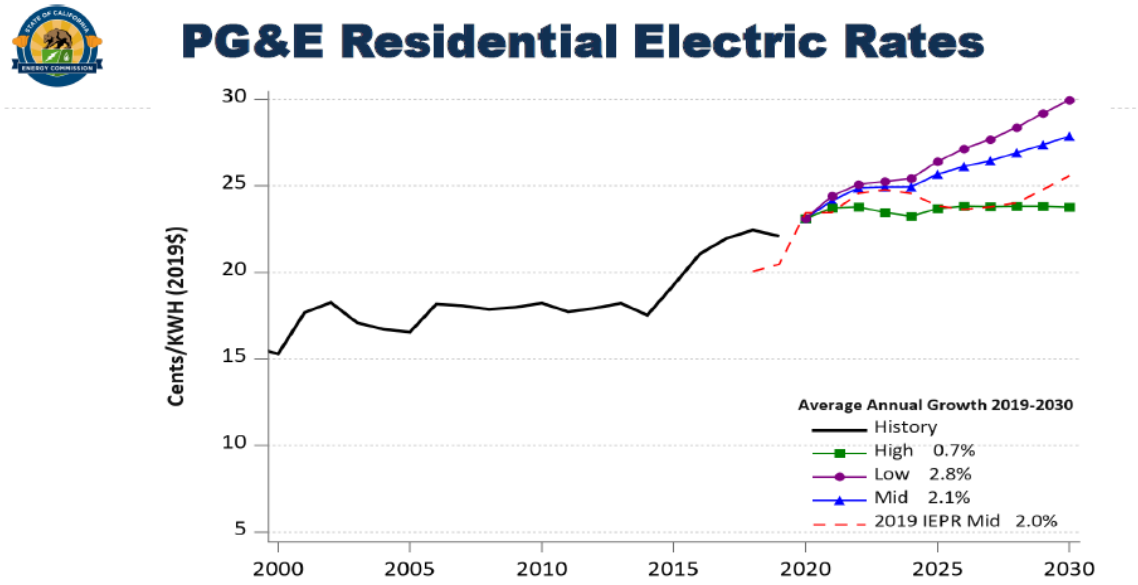
Figure 27: PG&E, SCE, and SDG&E Forecasted Bundled Residential Rates ($2019/kWh), Baseline Scenario



CEC 2020 IEPR Planning Area Residential Average Rate Scenarios

Residential average rates for PG&E, SCE, and SDG&E **planning areas** were filed by the California Energy Commission (CEC) in the 2020 Integrated Energy Policy Report (IEPR) docket.[117] Planning area rates are the weighted average for all utilities in the planning area, e.g., IOUs and Publicly-Owned Utilities (POU).[118] Figure 28 through Figure 30 show these residential rates in 2019 dollars.[119] The blue line shows the mid-demand case.

Figure 28: CEC 2020 IEPR Planning Area Residential Rates Scenarios, PG&E



[116] $2019 dollars uses Gross Domestic Product (GDP) deflator used for CEC Planning Area $2019 average rates (Moody's, July 2020).

[117] *See* 20-IEPR-03 docket, "Electric Rate Scenarios" (August 25, 2020) at:
https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=20-IEPR-03 .

[118] Planning area rates are not directly comparable with IOU service area rates due to the inclusion of revenue requirement of the POUs.

[119] Adjusted to nominal dollars, the planning area mid-demand case residential rates (kWh) for PG&E, SCE, and SDG&E in 2030 are: PG&E $0.342; SCE $0.242; SDG&E $0.348.

Figure 29: CEC 2020 IEPR Planning Area Residential Rates Scenarios, SCE

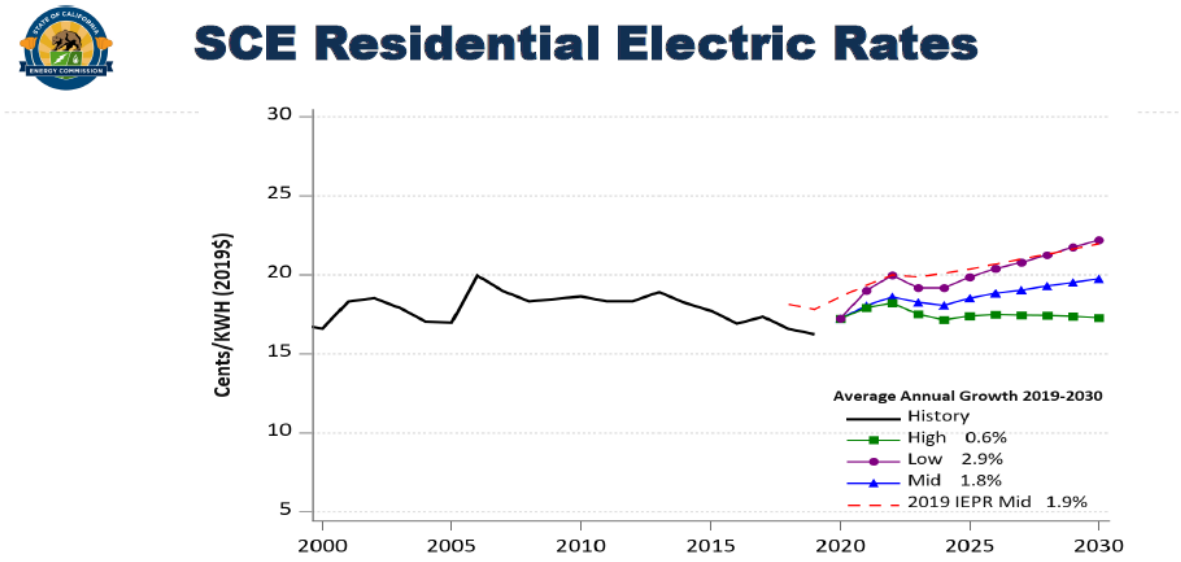
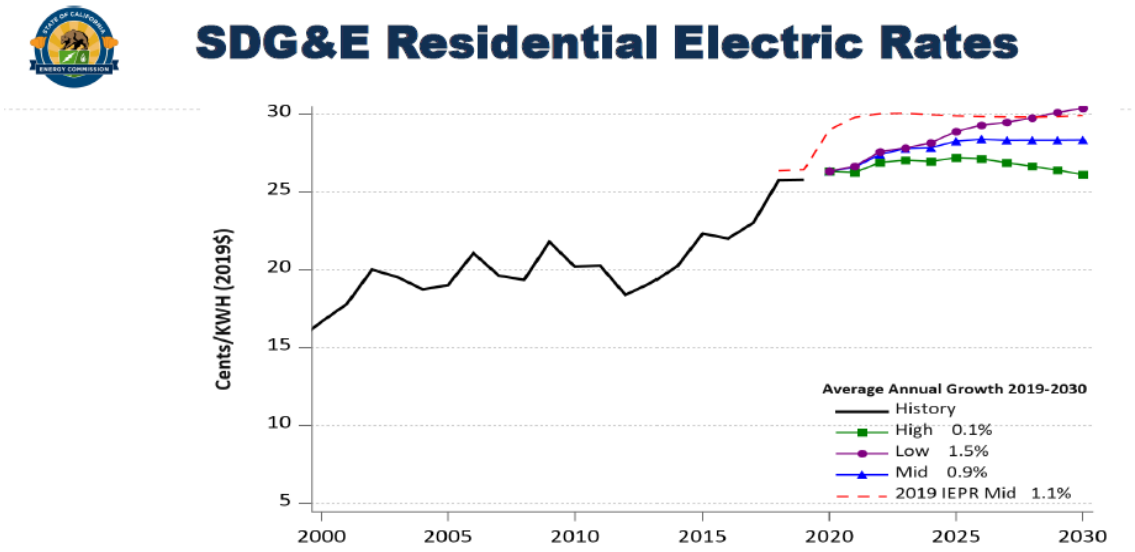


Figure 30: CEC 2020 IEPR Planning Area Residential Rates Scenarios, SDG&E



The CEC 2020 IPER residential rates planning area forecast uses IOU revenue requirement as originally filed with the CEC for the 2019 IEPR[120] updated with CPUC Energy Division CRT data as a base, with adjustments, and a 4.5 percent escalator for the mid-demand case distribution revenue requirement for years 2025 – 2030. This 2020 escalator assumption is higher than that used in the 2019 IEPR to reflect increased spending for wildfire mitigation, grid modernization, and electrification.[121]

[120] The IOUs file these revenue requirements on CEC Form 8.1.

[121] Generation is updated using wholesale electricity prices from 2019 IEPR PLEXOS results.

CEC 2020 IEPR Service Area Residential Average Rate Scenarios and CPUC Forecasted Bundled Residential Rates

Before comparing CEC preliminary bundled residential rates with CPUC forecasted bundled residential rates, adjustments must be made to account for the PCIA. The PCIA is the mechanism used to ensure that the creation of Community Choice Aggregators (CCA) does not result in cost increases for bundled customers. While the PCIA has no impact on system average rates (which includes both CCA and bundled customers), it has the impact of lowering overall rates for bundled customers. As previously indicated, CPUC forecasted bundled residential rates include an estimate for the PCIA, which lowers the revenue requirement for which the bundled residential class is responsible. However, CEC planning area forecasted residential rates don't consider PCIA as an input, as CEC forecast models run at the service area level and reflect a system average rate.

To account for this difference and also to facilitate a more direct comparison, it is better to compare the CEC preliminary bundled residential rates with the CPUC forecasted bundled residential rates. The CEC produces IOU service area residential rate forecasts (the weighted average of bundled, CCA, and direct access rates) as part of constructing IEPR planning area rates. Further, service area residential rate forecasts can be used to produce illustrative bundled residential rate forecasts for the three large electric IOUs.[122] Table 19 compares the CEC preliminary forecasted bundled residential rate, adjusted for the PCIA revenue reduction, with the CPUC forecasted bundled residential rate in 2030 for each of the IOUs.[123]

[122] The CEC also internally produces illustrative bundled residential rate forecasts for the three large electric IOUs.

[123] The rates in the CPUC Forecasted Bundled Residential Rate column match the 2030 rates in Table 17.

Table 19: CEC Preliminary and CPUC Forecasted Bundled Residential Rate Comparison (2030)

	CEC Preliminary Bundled Residential Rate, Unadjusted ($/kWh) 2030	CEC Preliminary Bundled Residential Rate, Adjusted for PCIA revenue reduction ($/kWh) 2030	CPUC Forecasted Bundled Residential Rate ($/kWh) 2030
PG&E	0.347	0.314	0.329
SCE	0.244	0.213	0.293
SDG&E	0.341	0.314	0.443

The 2030 rate comparison shows similar CPUC forecasted rates to the CEC preliminary rates for PG&E. However, SCE and SDG&E 2030 CPUC forecasted rates are not similar to the preliminary forecasted rates. The difference in both cases is due to a higher revenue requirement in the CPUC forecasted bundled residential rate. The level-setting of the revenue requirement in 2024 to 2023 CRT revenue requirement, per the previously indicated methodology, is the primary reason that the CPUC forecasted bundled residential rate revenue requirement is higher. The CPUC forecasted system-level revenue requirement and bundled residential revenue requirement in 2030 for each of the IOUs is shown in Table 20.

Table 20: CPUC Forecasted Bundled Residential Rate Comparison (2030)

	Forecasted System-Level Revenue Requirement 2030	Forecasted Bundled Residential Revenue Requirement 2030
PG&E	$21.5 billion	$4.5 billion
SCE	$20.3 billion	$6.4 billion
SDG&E	$5.1 billion	$2.3 billion

Key to 2030 forecasted bundled residential rates is the projected sales forecast underlying the bundled residential rates. The CPUC forecasted bundled residential rates reflect an estimate based on a preliminary CEC bundled residential sales forecast.[124] It must be emphasized that forecast reliability decreases the further out the time horizon, with accuracy of 2030 forecasted rates necessarily less than that of 2021.

The En Banc Rates Forecast baseline scenario sets the baseline rates from which further rate analysis in this white paper will be based. The baseline scenario and the wildfire high-cost scenario used in a later section of this paper are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

3.4 Wildfire Mitigation Plan Projected Costs

The IOUs provide the CPUC with their anticipated wildfire mitigation spending in various proceedings, including Wildfire Mitigation Plans, General Rate Cases (GRC) and the Risk Assessment Mitigation Phase (RAMP) of the GRC, among others. The IOUs file GRC applications on a staggered schedule, therefore the

most recent data available for most of the IOUs is their latest WMP. The most recently filed WMPs at the time of the preparation of this paper were prepared as part of the 2020 WMP filings in February 2020 and included spending estimates for calendar years 2020-2022. In order to develop estimates for this paper, the IOUs were asked to provide wildfire mitigation spending estimates through 2030. All the IOUs responded that they were unable to provide reliable data beyond what had been publicly shared to date. The IOUs asserted that wildfire mitigation is not a predictable effort at this time, as they operate with the intention of letting lessons learned each year determine next year's effort. In some instances, the IOUs provided considerations that are expected to have an impact on their long-term planning but declined to provide detailed forecasts.

In the absence of detailed information from the IOUs, the forecasts generally incorporate known program changes and assume a small escalation factor for remaining activities. For the purposes of this exercise, the forecast also assumes pending applications related to wildfire are approved at the level of recovery requested and excludes wildfire-related transmission costs, which would overlap with the transmission costs discussed separately in this paper. In developing the forecast, Energy Division staff also consulted with Wildfire Safety Division Staff for input on expected trends in wildfire mitigation activities. Details on the forecast assumptions for each IOU are described below. The assumptions detailed below are not intended to reflect precise anticipated spending or predetermine what the CPUC may grant for recovery.

Baseline Scenario Assumptions of Wildfire Mitigation Plan Costs

PG&E

PG&E's forecast is based on a data request response that projects wildfire spending to 2026 consistent with data in its most recent RAMP filing. PG&E aggregates its mitigations into large generic programs such as "System Hardening" and reports data at that program level. This presents challenges to adjusting the forecast in the out years for individual programs. Therefore, for years beyond 2026, the forecast assumes a two percent annual increase in revenue requirement for wildfire spending.

SCE

SCE's forecast uses as its basis estimates from the 2020 WMP filing and 2023 request from the Test Year 2021 GRC filing. To estimate years 2024 through 2026, the forecast uses a five-year average of a combination of recorded and forecast data for 2019-2023.[125] The CPUC commonly uses a five-year average to forecast costs in GRC proceedings. While the five-year average methodology typically uses all recorded data, many of the IOUs wildfire mitigation programs were adopted in response to SB 901 (Dodd, 2018), AB 1054 (Holden, 2019), and the WMP process, and therefore data before 2018-2019 are unlikely to be

[124] As part of this process, CEC service area sales are estimated by benchmarking to 2019 actual service area sales, using a planning area sales forecast growth escalation. The CEC also internally produces illustrative bundled residential rate forecasts for the three large electric IOUs.

[125] As Energy Division does not have a tool to convert SCE's capital costs to revenue requirement equivalent, estimates were used for this conversion. Capital cost conversions may include ongoing capital-related revenue requirements from previous capital expenditures.

predictive of future spending. Consistent with PG&E's estimates, the forecast assumes a two percent annual increase each year between 2027 and 2030.

The forecast includes exceptions to the five-year average and escalation methodology for SCE's most expensive activity, the Wildfire Covered Conductor Program.[126] SCE's 2020 WMP indicates plans to significantly ramp-up covered conductor installation in its High Fire Risk Areas (HFRA) over the first half of the decade, at which time SCE anticipates having addressed 70 percent of the overhead wire originally in scope as part of its 2018 Grid Safety & Resiliency Plan. In consultation with the CPUC's Wildfire Safety Division, the forecast assumes increases above the 2022 projection of an average seven percent per year through 2025, then remaining steady over the following five years as technology and installation becomes more standardized and SCE replaces remaining high-risk circuits in its HFRA. The overall total would also likely be capped by overhead line miles in High Fire Threat District (HFTD) areas.[127] SCE has about 14,500 overhead miles in HFTD areas. The forecast estimates approximately two-thirds of those lines being replaced by covered conductor (i.e., insulated power lines).

SCE's covered conductor program is likely to impact its distribution pole replacement estimates, as installation of covered conductors often requires concurrent replacement of poles, and crossarms due to increased weight from insulation. Accordingly, as SCE ramps up its covered conductor installation, the forecast assumes distribution pole replacement costs to equally increase and then plateau in line with the covered conductor installations.

As with all other programs, the Wildfire Covered Conductor Program estimates are subject to change as more data become available regarding effectiveness.

SDG&E

The basis for SDG&E's wildfire mitigation costs is the 2020 WMP estimates for 2020-2022. The forecast for 2023-2030 is based on SDG&E 2022 amounts as filed in the 2020 WMP, with adjustments to the capital system hardening program estimates.[128]

SDG&E allocates a significant portion of the spending in its 2020 WMP toward undergrounding. In consultation with the Wildfire Safety Division, the forecast for undergrounding significantly ramps up over the next WMP plan period (2023-2025) and then slowly tapers off as the majority of riskier circuits that may justify the need for undergrounding are replaced and there is less remaining circuitry that qualifies.

The forecast for overhead hardening and pole replacement in 2023-2030 utilizes a five-year average of combined recorded and estimated costs for 2019-2022. There are also two adjustments to reflect the

[126] Covered conductor is aluminum or copper wire covered by three layers of insulation designed to withstand incidental contact from foreign objects, such as vegetation, other debris, and the ground in wire down events.

[127] "High Fire Threat Districts" are designated by CPUC in R.15-05-006. "High Fire Risk Areas" are an internal SCE designation based on a combination of its historical map boundaries (based on past fire management and response experiences), CAL FIRE's Fire Hazard Severity Zone (FHSZ) maps, and most recently, the CPUC's HFTD maps released in January 2018. SCE has since considered Zone 1, Tier 2 and Tier 3 (collectively, the HFTD), and non-CPUC historical high fire risk areas, to collectively be "HFRA." See SCE's 2020 WMP for more information.

[128] As Energy Division does not have a tool to convert SDG&E's capital costs to revenue requirement equivalent, estimates were used for this conversion. Capital cost conversions may include ongoing capital-related revenue requirements from previous capital expenditures.

completion of work on two projects, namely beginning in 2022 for the system hardening project in the Cleveland National Forest and beginning in 2023 and for expulsion fuse replacement, as specified in the 2020 WMP.

Baseline Scenario Assumptions of Wildfire Insurance and Catastrophic Event Costs

The CPUC allows the IOUs to recover certain wildfire-related costs that are external to the activities described in the WMP, including for wildfire insurance premiums and catastrophic events. Wildfire insurance costs that are incremental to the insurance costs authorized in the GRCs may be tracked for recovery through the Wildfire Expense Memorandum Account (WEMA) for PG&E and SCE, and the Liability Insurance Premiums Balancing Account (LIPBA) for SDG&E. The IOUs also track eligible costs to respond to catastrophic events, including wildfire, in their Catastrophic Event Memorandum Accounts (CEMA).

To estimate future costs for wildfire insurance and catastrophic events, the baseline scenario includes the average costs requested in applications over the last three years, 2018-2020. The last three years were used to reflect the period of time since SB 901 was enacted.

For PG&E and SCE, the forecast for wildfire insurance and catastrophic events costs is based on the average requested cost recovery between 2018-2020 for CEMA and WEMA applications.[129] The forecast assumes the IOUs will request these amounts for recovery in applications filed annually beginning in 2021, which would begin to impact rates in 2023 through 2030. Given the magnitude of these costs, the forecast assumes a two-year recovery period for each application.

SDG&E does not have any CEMA cost recovery applications during this time period but requested recovery of the 2020 under-collection in its LIPBA beginning in 2021. The forecast assumes the 2020 under-collection of $59.8 million will be an annual recurring cost from 2021 to 2030. The forecast does not assume additional liability claims costs beyond those included in the wildfire insurance premiums forecast in the WEMA and the AB 1054 Wildfire Fund, discussed in the previous section of this paper on historic wildfire costs. If wildfire claims exceed the amounts covered by insurance and the Wildfire Fund, PG&E and SCE may track incremental liability claims in their WEMAs. The amount that would ultimately be approved for rate recovery depends on the CPUC's reasonableness determination and is unknown at this time.

It is possible that these costs could decrease over time as a result of system hardening activities and efforts by the Legislature to support a pooled insurance fund. On the other hand, the recent trend of increasingly catastrophic wildfires could result in costs that exceed the historical average. The assumptions in the forecast assume the costs requested in recent years continue at a similar level, however these assumptions are not intended to reflect exact anticipated spending, given the uncertainties.

[129] SCE's estimate also includes incremental wildfire insurance premium costs requested in Advice Letter 3768-E in 2018.

Wildfire High-Cost Scenario Assumptions

As previously discussed, there is significant uncertainty surrounding the actual level of IOU spending on wildfire mitigation over the next 10 years. The last full year of wildfire mitigation spending data available during the preparation of this paper was for calendar year 2019. In comparing planned 2019 to actual 2019 spending, each IOU recorded significantly higher costs than estimated. PG&E planned to spend $2.5 billion and recorded $3 billion (19 percent higher). SCE planned to spend $671 million and recorded $1.6 billion (132 percent higher). SDG&E planned to spend $219.9 million and recorded $306.7 million (40 percent higher). These figures suggest actual spending may be higher than forecast in future years.

Further, the CPUC has acknowledged the difficulty in developing accurate forecasts for wildfire spending by allowing balancing account treatment that permits recovery of additional amounts above the authorized budget. For example, in PG&E's recent GRC Decision (D.) 20-12-005, the CPUC allows PG&E to recover up to 115 percent of the authorized budget tracked in the Wildfire Mitigation Balancing Account and 120 percent of the budget tracked in the Vegetation Management Balancing Account. Similarly, the CPUC approved SCE's Grid Safety & Resiliency Program in proceeding D.20-04-013, which adopted a settlement agreement that includes an allowance for recovery of up to 115 percent for the covered conductor program budget.

To develop a high-cost scenario for wildfire mitigation costs in this paper, the forecast assumes a 20 percent adder starting in 2023 for wildfire mitigation estimates to account for uncertainties such as increased spending and cost overruns. The 20 percent adder is applied to wildfire insurance and catastrophic events costs as well. Together, wildfire mitigation and wildfire insurance (and catastrophic events) are referred to as "wildfire costs." These assumptions are not intended to suggest an expected outcome but are developed for the purposes of showing the potential impact of such spending on customer rates and bills.

2020-2030 Estimated Wildfire Costs

Baseline Scenario

Baseline total incremental revenue requirement resulting from wildfire costs between 2021 and 2030 for each of the IOUs are estimated as follows:

- PG&E: $20.2 billion
- SCE: $14.8 billion
- SDG&E: $ 3.9 billion

Forecasted revenue requirements in 2030 for estimated wildfire costs at system-level and for bundled residential are show in Table 21.

Table 21: Forecasted Wildfire Revenue Requirements, System-Level and Bundled Residential (2030)

	Forecasted Wildfire Revenue Requirement: System Level 2030	Forecasted Wildfire Revenue Requirement: Residential Level (Bundled) 2030
PG&E	$2.2 billion	$380 million
SCE	$1.7 billion	$385 million
SDG&E	$418 million	$145 million

The forecasted wildfire bundled residential revenue requirement produces the forecasted wildfire rate embedded in the forecasted baseline bundled residential rate as shown in the lower portion of Table 22. For convenience, the forecasted baseline bundled residential rate is shown in the upper portion of the figure.[130]

Table 22: Forecasted Wildfire Rate Embedded in Baseline Bundled Residential Rate Forecast (nominal $/kWh)

Baseline Bundled Residential Electric Rate (nominal $/kWh)											
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	$ 0.240	$ 0.266	$ 0.273	$ 0.264	$ 0.266	$ 0.281	$ 0.289	$ 0.298	$ 0.307	$ 0.318	$ 0.329
SCE	$ 0.217	$ 0.272	$ 0.274	$ 0.276	$ 0.273	$ 0.277	$ 0.281	$ 0.285	$ 0.289	$ 0.294	$ 0.293
SDG&E	$ 0.302	$ 0.300	$ 0.328	$ 0.338	$ 0.340	$ 0.355	$ 0.371	$ 0.388	$ 0.405	$ 0.424	$ 0.443

Wildfire Rate Embedded in Baseline Bundled Residential Electric Rate (nominal $/kWh)											
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	$ 0.004	$ 0.016	$ 0.021	$ 0.021	$ 0.034	$ 0.035	$ 0.027	$ 0.027	$ 0.027	$ 0.028	$ 0.028
SCE	$ 0.007	$ 0.024	$ 0.022	$ 0.015	$ 0.021	$ 0.023	$ 0.026	$ 0.026	$ 0.026	$ 0.025	$ 0.025
SDG&E	$ 0.010	$ 0.019	$ 0.021	$ 0.024	$ 0.027	$ 0.028	$ 0.029	$ 0.030	$ 0.030	$ 0.030	$ 0.029

To get an idea of the portion of the monthly bill that corresponds to wildfire costs, a comparison is made between the wildfire portion of the forecasted monthly bills in 2021 and 2030 for each IOU, along with a total bill comparison, as shown in Table 23. The forecasted rates are multiplied by the usage amounts that the IOUs use in their legal bill inserts – 500 kWh per month for PG&E, SCE, and SDG&E.[131]

[130] The rates in the upper portion of Table 22 match the rates in Table 17. Similar to Table 17, the rates in Table 22 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

[131] In compliance with Rule 3.2 (d) of the CPUC's Rules of Practice and Procedure, the IOUs are to provide notice of, among other things, proposed residential rate changes addressed in a utility's application. Bill impacts for a typical residential customer usually accompany these rate changes in a bill insert sent to customers known as the "legal bill insert." Usage data here is that used in legal bill inserts for PG&E's 2020 GRC Phase II, SCE's 2021 GRC Phase II, and SDG&E's 2019 GRC Phase II applications. Bills are for illustrative purposes only.

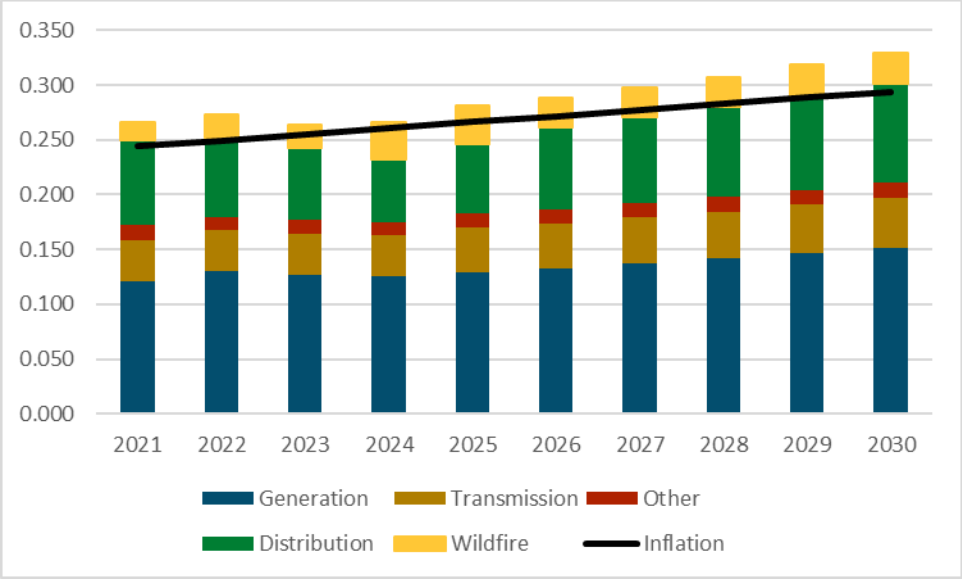
Table 23: Wildfire Portion of Monthly Bill and Total Monthly Bill, Bundled Residential Customers (nominal $/month)

	2021			2030		
	Wildfire Portion ($/month)	Total Bill ($/month)	Wildfire Portion (%)	Wildfire Portion ($/month)	Total Bill ($/month)	Wildfire Portion (%)
PG&E	8.00	133.00	6.0%	14.00	164.50	8.5%
SCE	12.00	136.00	8.8%	12.50	162.00	7.7%
SDG&E	9.50	150.00	6.3%	14.50	221.50	6.5%

For all of the IOUs, the wildfire mitigation programs estimated to contribute most significantly to cost increases in 2030 are vegetation management and system hardening, including undergrounding and replacing bare overhead conductors with covered conductors.

The rate attributable to wildfire costs is embedded in the baseline bundled residential rate;[132] however, it can be viewed separately from the non-wildfire portion of the rate[133] as shown in Figure 31 through Figure 33.[134] The inflation-adjusted forecasted rate line is based on 2020 actual rates. For all embedded rate components by $/kWh, see Appendix B.

Figure 31: PG&E Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



[132] The wildfire rate is included as a component of the distribution rate.

Figure 32: SCE Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate

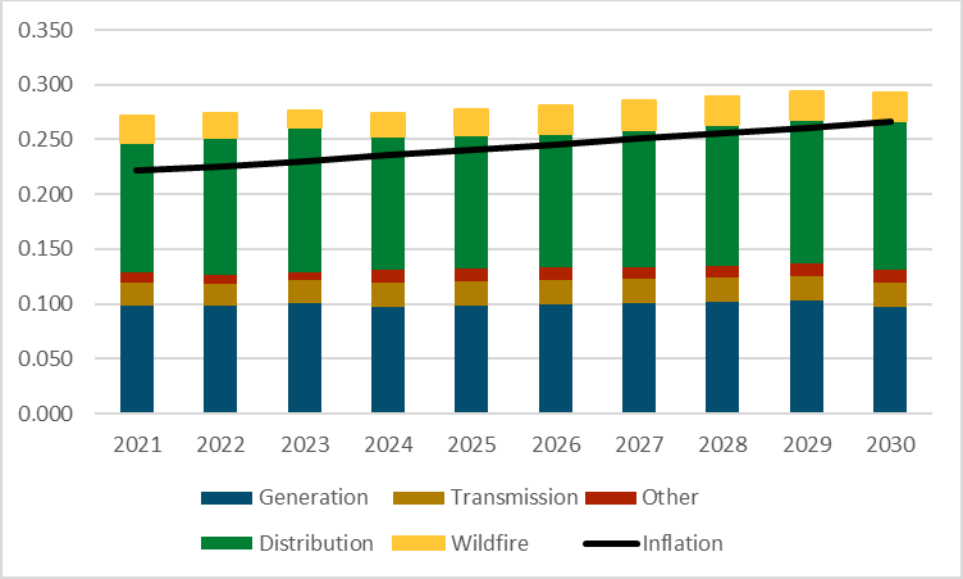
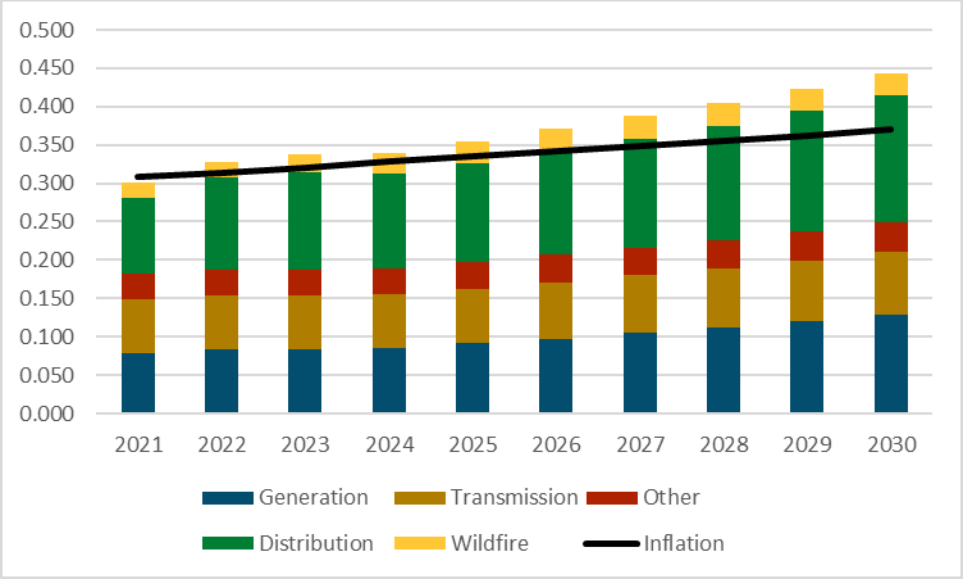


Figure 33: SDG&E Forecasted Bundled Residential Rates ($ nominal/kWh), Wildfire Rate Relative to All-Other (Non-Wildfire) Rate



Wildfire High-Cost Scenario

[133] The rates in Figure 31 through Figure 33 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

[134] From a theoretical standpoint, the non-wildfire rate portion could be called a counterfactual wildfire rate i.e., the rate if no wildfire costs were included.

Estimated total incremental revenue requirement, including the high-cost wildfire adder, between 2021 and 2030 for each of the IOUs are:

- PG&E: $23.7 billion
- SCE: $17.2 billion
- SDG&E: $ 4.6 billion

Unlike wildfire costs in the baseline scenario which are embedded in the rates forecast, the wildfire high-cost scenario uses a 20 percent adder which boosts the overall revenue requirement compared to that in the baseline scenario.[135] Forecasted revenue requirements in 2030 for estimated wildfire costs at system-level and for bundled residential are show in Table 24.

Table 24: Forecasted High-Cost Wildfire Revenue Requirements, System-Level and Bundled Residential (2030)

	Forecasted High-Cost Wildfire Revenue Requirement: System Level 2030	Forecasted High-Cost Wildfire Revenue Requirement: Residential Level (Bundled) 2030
PG&E	$2.6 billion	$456 million
SCE	$2.1 billion	$462 million
SDG&E	$502 million	$174 million

The forecasted high-cost wildfire bundled residential revenue requirement is reflected in the forecasted rates shown in Table 25.[136]

Table 25: Forecasted Bundled Residential Electric Rate with High-Cost Wildfire Adder (nominal $/kWh)

	Bundled Residential Electric Rate with High-Cost Wildfire Adder (nominal $/kWh)									
	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	0.266	0.273	0.268	0.272	0.288	0.294	0.303	0.313	0.324	0.335
SCE	0.272	0.274	0.279	0.278	0.282	0.286	0.290	0.294	0.299	0.298
SDG&E	0.300	0.328	0.343	0.346	0.361	0.377	0.394	0.411	0.430	0.449

The tables above offer insight into the rate impacts associated with increasing levels of wildfire mitigation spending. However, many questions remain regarding what constitutes a sufficient level of spending on wildfire mitigation. The actual wildfire risk reduction and performance of many of the utility proposed programs are currently unknown.

As part of the annual Wildfire Mitigation Plan review process, the CPUC and Wildfire Safety Division continue to refine the evaluation of IOU wildfire mitigation activities. The WMP review process requires the IOUs to submit specific details and supporting information to evaluate the efficacy of individual initiatives.

[135] The 20 percent adder applies to the distribution rate only.

[136] The rates in Table 25 are intended solely to facilitate discussion related to white paper and are not to be used for any other purpose.

More data on risk reduction capabilities and performance of wildfire mitigation measures will inform CPUC decision-making regarding the costs and levels of deployment of various wildfire mitigation measures, consistent with just and reasonable rates.

Future decisions related to the timeline and method, such as securitization of wildfire-related cost recovery, will affect how the wildfire mitigation costs ultimately impact customer bills. In coming years, we can expect more predictable levels of spending as initial programs are completed and the risk reduction potential of various programs are validated.

3.5 Transportation Electrification Programs Projected Cost

Background

While the number of EVs on the road has increased significantly in recent years, rapid growth in sales is expected over the next decade. As battery and vehicle costs decline, EV adoption will expand beyond early adopters to the broader population of vehicle owners, as well as other sectors of vehicles such as buses, delivery fleets, and off-road vehicles such as farm equipment, to meet California's ambitious climate and TE goals.

To further this transition, CPUC staff issued a draft Transportation Electrification Framework (TEF) in 2020.[137] In 2021, the CPUC may adopt recommendations from the TEF, which would, among other things:

- Require the IOUs to undertake a TE planning and prioritization process to ensure that electric infrastructure will be able to support a large influx of new EVs.
- Resolve policy issues previously raised on a case-by-case basis, including issues pertaining to cost recovery.
- Allow for more streamlined pilot and program review.
- Provide a signal to third-party market participants about the IOUs' role in meeting the state's goals and managing the electric grid.

Adopting the TEF as currently proposed would set the stage for the IOUs to propose future programs to support TE goals. At this juncture, the scale and cost of any such programs are unknown and will be subject to review in the context of the IOUs' long-term Transportation Electrification Plans envisioned by the TEF, as well as other planning endeavors, such as the Integrated Resource Planning process to ensure that the proper generation resources are available to support increased electricity demand from EVs.

More broadly, California will be undertaking a tremendous effort to accelerate TE infrastructure deployment in the coming years to meet the state's TE goals. The scale of the challenge is highlighted in the recently issued CEC Staff report *Assembly Bill (AB) 2127 Electric Vehicle Charging Infrastructure Assessment*, which notes that 1.5 million chargers will be needed by 2030 to support Governor Newsom's goals for light-duty

[137] *See* "Transportation Electrification Framework – Energy Division Staff Proposal" Issued via Ruling, February 3, 2020. Weblink can be accessed at: https://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=326172086

vehicles. Considering that the state had 188,000 public chargers installed or planned as of September 30, 2020, there is a substantial gap in public charging infrastructure that will need to be funded through a combination of ratepayer, private, and public (e.g., state/federal grant) funding.[138] While the report urges continued public financing of chargers and infrastructure in the near-term, it also highlights the importance of devising innovative financing mechanisms that can reduce the burden of these investments on ratepayers and the public, and for finding ways to utilize charging infrastructure to benefit the grid, and thus potentially reduce infrastructure upgrade costs elsewhere. Examples of public funding include:

- **CEC California Electric Vehicle Infrastructure Project (CALeVIP)**: an incentive program that provides funds for EV charger installations across the state. CALeVIP is currently funded for $124.9 million through CEC funding, with $32 million in co-funding partner contributions.[139]

- **IOU Charging Infrastructure Programs:** much of the ratepayer (i.e., public) funding allocated for IOU-led TE activities is being used to support the construction of shared or public charging infrastructure.

- **Innovative Public Financing**: Governor Newsom's proposed budget for 2021-2022 includes a proposal to securitize $1 billion in future revenue / vehicle registration fees, a portion of which would be used for loans to leverage private sector capital towards the construction of charging infrastructure.[140]

- **Low Carbon Fuel Standard (LCFS):** credit revenue generated from the use of EVs is used in many cases to support additional charging infrastructure.

Baseline Scenario Assumptions of Transportation Electrification Program Costs

IOU TE programs and infrastructure upgrades are primarily recovered through rates. As the CPUC is actively deliberating the magnitude of potential investments in TE and the degree of responsibility for IOU ratepayers to cover those costs over the next decade, we refrain from detailed speculation regarding future investments by IOUs. Rather, this analysis presents cost estimates based on existing IOU spending on TE. This approach allows for an examination of the impact of current programs on rates, and a simple doubling of program spending in the latter half of the decade.[141]

[138] Crisostomo, Noel, Wendell Krell, Jeffrey Lu, and Raja Ramesh. January 2021. Assembly Bill 2127 Electric Vehicle Charging Infrastructure Assessment: Analyzing Charging Needs to Support Zero-Emission Vehicles in 2030. California Energy Commission. Publication Number: CEC-600-2021-001.

[139] https://calevip.org/about-calevip

[140] http://www.ebudget.ca.gov/budget/2021-22/#/BudgetSummary

[141] This approach may not reflect the outcome of forthcoming IOU planning endeavors for TE that result from the TEF.

2020-2030 Estimated Transportation Electrification Costs

The baseline forecast assumes an incremental revenue requirement resulting from TE programs between 2021 to 2030 of $2.8 billion across SCE, SDG&E, and PG&E. This forecast is based on the following inputs and assumptions:

- Existing CPUC-approved TE programs.[142]
- SDG&E's pending application for Power Your Drive 2.[143]
- Projected 2030 incremental revenue requirements for TE – this includes ongoing capital-related revenue requirement for existing programs, plus rough estimates for incremental program revenue requirements.
    - The rough estimates were obtained by doubling the 2023 forecasted incremental revenue requirement, based on a near-doubling of electrification load that would correspond to a doubling in annualized costs for electrification program/infrastructure, as shown in the 2019 IEPR.[144]
- Growth formula – interpolation of the forecasted incremental revenue requirement is used to determine the revenue requirement between the years 2023 and 2030. A simple percentage growth formula is used to accomplish this.[145]

Forecasted revenue requirements in 2030 for estimated transportation costs at system-level and for bundled residential are show in Table 26.

Table 26: Forecasted Transportation Electrification Revenue Requirements, System-Level and Bundled Residential (2030)

	Forecasted Transportation Electrification Revenue Requirement: System Level 2030	Forecasted Transportation Electrification Revenue Requirement: Residential Level (Bundled) 2030
PG&E	$115 million	$20 million
SCE	$224 million	$50 million
SDG&E	$81 million	$28 million

[142] IOUs provided forecasted incremental revenue requirements through 2023 via data request.

[143] *Id.*

[144] The CEC's 2019 IEPR forecasts CAISO-wide electric sales due to electrification growing from 7.8 TWh in 2023 to 14.6 TWh in 2030. This projected CAISO-wide growth is largely a result of TE, with approximately 90 percent associated with TE and 10 percent associated with "other electrification."

[145] The simple percentage growth methodology assumes equal revenue requirement for each year between 2023 and 2030. This results in smaller percentage changes each year as the interval revenue requirement is calculated over an increasingly larger base. First year percentage growth is about 14 percent.

To calculate a baseline bundled residential rate forecast, we used the forecasted revenue requirement in 2030 and a CEC-driven electricity sales forecast, shown in the upper portion of Table 27.[146] The baseline TE rate embedded in these total rates is broken out in the lower portion of the Table 27.

Table 27: Transportation Rate Embedded in Baseline Bundled Residential Rate Forecast (nominal $/kWh)

Baseline Bundled Residential Electric Rate (nominal $/kWh)											
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	$ 0.240	$ 0.266	$ 0.273	$ 0.264	$ 0.266	$ 0.281	$ 0.289	$ 0.298	$ 0.307	$ 0.318	$ 0.329
SCE	$ 0.217	$ 0.272	$ 0.274	$ 0.276	$ 0.273	$ 0.277	$ 0.281	$ 0.285	$ 0.289	$ 0.294	$ 0.293
SDG&E	$ 0.302	$ 0.300	$ 0.328	$ 0.338	$ 0.340	$ 0.355	$ 0.371	$ 0.388	$ 0.405	$ 0.424	$ 0.443

TE Rate Embedded in Baseline Bundled Residential Electric Rate (nominal $/kWh)											
	2020 - Act	2021	2022	2023	2024	2025	2026	2027	2028	2029	2030
PG&E	$ 0.000	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001	$ 0.001
SCE	$ 0.000	$ 0.000	$ 0.001	$ 0.002	$ 0.002	$ 0.002	$ 0.003	$ 0.003	$ 0.003	$ 0.003	$ 0.003
SDG&E	$ 0.001	$ 0.002	$ 0.002	$ 0.003	$ 0.003	$ 0.004	$ 0.004	$ 0.004	$ 0.005	$ 0.005	$ 0.006

To get a rough idea of the portion of the monthly bill that corresponds to TE costs, we multiply the 2023 forecasted rates by the usage amounts that the IOUs use in their legal bill inserts[147] – 500 kWh per month for PG&E, SCE, and SDG&E. Through this process we see that in the near-term the portion of the bill that results from TE remains relatively low. For example, SDG&E's 2023 estimated monthly bill portion that corresponds to TE is $1.50/month out of a total bill of approximately $169.00.[148] Using the same methodology to estimate costs further into the decade when accounting for the estimated increases in TE program spending, the bill impact from TE program spending remains low relative to the overall bill.

Caveats

While the foregoing estimates indicate a relatively low impact to customer bills, it is important to consider that IOU TE spending could, in fact, exceed our estimates in this white paper given the magnitude of investment needed to support state climate goals. However, that responsibility for IOU spending has not yet been established and the topic will be a matter of ongoing deliberation for the CPUC and the California Legislature in the coming years, with affordability being a central consideration.

[146] The rates in Table 27 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

[147] In compliance with Rule 3.2 (d) of the CPUC's Rules of Practice and Procedure, the IOUs are to provide notice of, among other things, proposed residential rate changes addressed in a utility's application. Bill impacts for a typical residential customer usually accompany these rate changes in a bill insert sent to customers known as the "legal bill insert." Usage data here is that used in legal bill inserts for PG&E's 2020 GRC Phase II, SCE's 2021 GRC Phase II, and SDG&E's 2019 GRC Phase II applications.

[148] $0.003/kWh x 500 kWh = $1.50/month. Rates are at class level i.e., not broken out by Non-CARE and CARE, so the monthly bill impacts presented here are for general illustrative purposes only.

Downward Pressure on Rates from TE

One consideration when assessing the affordability of EVs in the context of greater IOU spending is the notion that IOU investments in TE may have the eventual effect of placing downward pressure on rates, therefore making it even more affordable to operate an EV, in addition to lowering rates for customers not utilizing EVs.

Although some experts believe this effect will be substantial, it is unclear if it will be a significant counteracting factor considering a potential increase in spending on infrastructure needed to support TE. However, it is worthy of careful consideration. Increased electricity sales might only place a slight downward pressure on rates, but it could be sufficient to both offset TE expenditures and cause some additional decrease in rates. This can only be confirmed through future analysis. To that end, the Energy Division's Transportation Electrification Framework notes that staff may seek to establish tracking mechanisms to evaluate what pressure on rates is occurring now or in the future, as this could help better account for not only the costs, but also for the affordability benefits of greater investment in TE.

3.6 Residential Energy Cost Calculator

Background

To better understand how different long-term planning scenarios would affect customer energy bills, consultants to the CPUC (Energy and Environmental Economics, or E3) developed a Residential Energy Cost Calculator (RECC) that estimates energy bills (electricity, natural gas, and gasoline) for a set of example households.

This chapter uses the RECC to forecast customer energy bills under a baseline rate scenario and to consider the impacts of vehicle and building electrification on customer energy bills and on electric rates. The chapter is broken into two sections. The first describes the electric, natural gas, and gasoline price forecasts used in this analysis, as well as estimates of household energy bills for a representative household. It also considers the impact of a stricter electric-sector GHG target on household energy bills for households with different levels of electrification adoption. The second section is focused on the customer cost-effectiveness of vehicle and home electrification, as well as the impact of a *High Electrification* scenario on residential electric rates.

Customer Energy Rates and Bills

Background on the Residential Energy Cost Calculator

To complement existing tools used in California's integrated resource planning (IRP) process, the RECC was developed to provide a 10-year forecast of energy bills for representative households. It enables comparison among different customers under a given system portfolio, illustrating how variations in climate zone, building type, electrification status, and other factors may affect residential energy bills. The RECC

also enables comparison among different electric sector portfolios, revealing how a change in planning targets or modeling assumptions would affect bills for a given household.

IRP modeling does not explicitly consider how the costs of new generation resources are borne by individual utilities. As a result, the RECC was not designed to produce different electric rate forecasts for each IOU. For this analysis, residential electric rate forecasts for each IOU come from modeling done by the CPUC Rates team and are not based on the RESOLVE electric system planning model used in IRP. In this analysis, the RESOLVE model is only used to consider incremental generation costs associated with a particular scenario such as a more stringent GHG target or a *High Electrification* sensitivity.

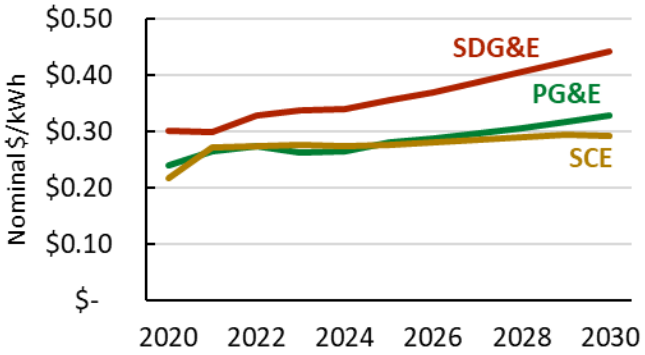
Before presenting the energy bill estimates for a representative household, the underlying forecasts for electric rates, natural gas rates, and gasoline prices are discussed below. These forecasts serve as inputs to the RECC.

Electric and Gas rates and Gasoline Prices

Electric Rates

Figure 34 shows the three large IOU bundled residential average electric rate forecasts prepared by the CPUC Rates team, as described previously.[149]

Figure 34: IOU Bundled Residential Average Electric Rate Forecast



Natural Gas Rates

Figure 35 shows the residential gas rate forecasts developed for the three large gas IOUs: PG&E, SoCalGas, and SDG&E. Residential gas rates are generally expressed as the sum of two components: the commodity rate (the cost of natural gas itself) and the delivery (or transportation) rate, which is the regulated rate for the cost of transporting the gas to customers. For this analysis, these two components have been forecasted independently.

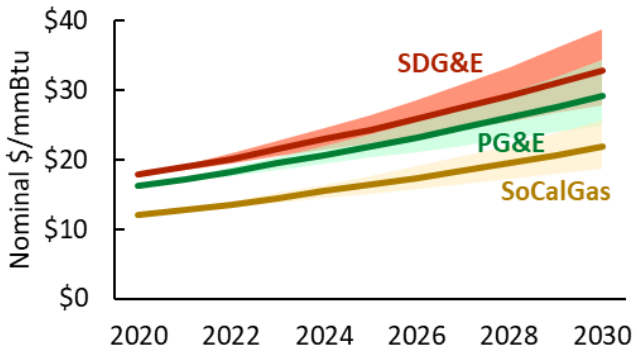
[149] As described in the *3.3 En Banc Bundled Residential Customer Rates Forecast*.

The commodity rate was based on gas commodity price forecasts developed by the gas IOUs and shared in the 2020 California Gas Report.[150] The IOUs provide these forecasts at two hubs: PG&E Citygate (PG&E) and SoCal Border (SoCalGas, SDG&E). To convert from real 2019 dollars to nominal dollars, a 2 percent annual inflation rate was assumed.

The starting point for the residential delivery rate forecast was the 2020 delivery rates for the three IOUs based on their residential tariffs. These tariffs have two tiers: a lower price for "baseline" usage and a higher price for "excess" usage. Baseline rates apply to about 70 percent of average household winter usage.[151] A weighted average was used by applying 70 percent of the baseline rate and 30 percent of the excess rate to generate a single volumetric gas delivery rate for each IOU. Finally, the charge for public purpose programs (PPP) was added for each of the IOUs based on their PPP tariffs as of December 2020.

To consider how delivery rates may grow in the future, 11 years of historical data for California residential gas customers (2009-2019) were examined. The Energy Information Administration (EIA) provides historical residential gas rates[152] and a historical average CA citygate gas price[153]; the difference is assumed to be the average residential delivery rate. Taken over the period 2009-2019, the historical delivery rate shows a compound annual growth rate of 6.5 percent/year (nominal). To forecast the delivery rate for each IOU over the next 10 years, a nominal escalation rate of 6.5 percent/year was assumed for a Mid case, along with 4.5 percent/year for a Low case and 8.5 percent/year for a High case.

Figure 35: Residential Natural Gas Rate Forecast



To confirm that this is a reasonable forecast for the gas delivery rate, regulatory filings by PG&E and SoCalGas were also used for comparison. PG&E's 2020 GRC Phase I Settlement Agreement includes 11 percent growth in the gas distribution revenue requirement from 2020 to 2022[154] (gas transmission costs are included in a separate filing). Combined with PG&E's forecast of a decline in core gas sales of 1.3

[150] 2020 California Gas Report, Figure 2: "Natural Gas Price Chart." Weblink can be accessed at: https://www.pge.com/pipeline_resources/pdf/library/regulatory/downloads/cgr20.pdf

[151] See e.g.: https://www.cpuc.ca.gov/uploadedFiles/CPUC_Public_Website/Content/News_Room/News_and_Updates/CPUC%20Rates%20Fact%20Sheet%20SCG.pdf

[152] EIA Sourcekey N3010CA3, https://www.eia.gov/dnav/ng/hist/n3010ca3a.htm

[153] EIA Sourcekey N3050CA3, http://www.eia.gov/dnav/ng/hist/n3050ca3a.htm

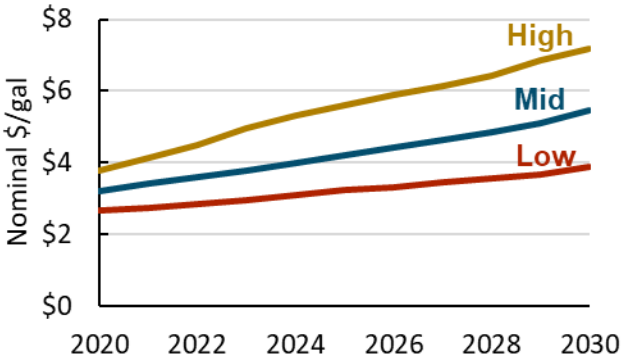
[154] PG&E GRC Phase 1 Settlement, Appendix C.

percent/year[155] and assuming a fixed revenue requirement allocation to the residential class, this results in an estimated 6.7 percent annual growth in the residential gas delivery rate (for distribution costs). The numbers are similar for SoCalGas: the 2019 GRC Phase 1 includes 19 percent revenue requirement growth from 2019 through 2022[156] (gas distribution, transmission, and storage); combined with residential demand falling by 1.1 percent/year[157], this translates to 7.1 percent annual growth in the gas delivery rate. Overall, it appears reasonable to assume the 6.5 percent historical growth in CA gas delivery rates will continue in the near-term.

It is worth noting that, while the electric rate forecast excludes the California Climate Credit, this gas rate forecast includes the Credit. Specifically, the gas rate forecast assumes that residential gas rates are indifferent to costs associated with California's Cap-and-Trade program. Due to the much more carbon-intensive nature of natural gas as compared to California's electric generation portfolio (which includes substantial renewable resources and is decarbonizing further every year), the impact of excluding the California Climate Credit would be larger for natural gas rates compared to electric rates.

Gasoline Prices

Figure 36: Gasoline Price Forecast



To provide a more complete picture of household energy expenditures, this analysis also includes gasoline costs for residential households. Figure 36 shows Low, Mid, and High gasoline price forecasts that were developed for this analysis. These forecasts are based on three components: a base price, an adder for California's Cap-and-Trade program, and an adder for the state's Low Carbon Fuel Standard (LCFS).

The base component of the gasoline price forecasts was taken from the EIA's 2020 Annual Energy Outlook.[158] The base gasoline prices reflect the Pacific region forecast of gasoline prices with the "Energy Tax/Allowance Fee" component removed. For the Mid case, the Reference forecast was used. For the Low and High cases, the Low Oil Prices and High Oil Prices forecasts were used, respectively.

[155] 2020 California Gas Report, Table 20: "PG&E Core Throughput."

[156] SoCalGas GRC Phase 1 Proposed Decision, Attachment D.

[157] 2020 California Gas Report, p99.

[158] EIA 2020 AEO, https://www.eia.gov/outlooks/aeo/

The Cap-and-Trade adder is based on the 2019 IEPR GHG Allowance Price forecast.[159] For the Mid and High cases, the "Mid" IEPR GHG Allowance Price forecast was used. For the Low case, the "Low" IEPR GHG Allowance Price forecast (which corresponds to the Cap-and-Trade price floor) was used.

For the LCFS adder, forecasts were developed by assuming $0.10/gal in 2020 followed by a linear trend to a 2030 price. For the Mid and High cases, it was assumed that LCFS credits reach the price ceiling, corresponding to $0.61/gal in 2030. In the Low case, it was assumed that LCFS credits reach 50 percent of the price ceiling ($0.30/gal) in 2030, reflecting a scenario where widespread availability of biodiesel drives down credit prices.

Energy price growth rates

Table 28 shows the 10-year compound annual growth rates for residential electricity, natural gas, and gasoline prices under the Mid scenarios. Note that the same gasoline price forecast was used for each IOU service territory. Over the coming decade, electric rates are forecast to grow more slowly than natural gas rates or gasoline prices.

Table 28: 10-Year Compound Annual Growth Rates (Nominal) for Residential Energy Prices

	Electricity	Natural Gas (Mid)	Gasoline (Mid)*
PG&E	3.2%	6.0%	5.4%
SCE/SoCalGas	3.0%	6.2%	5.4%
SDG&E	3.9%	6.3%	5.4%

*Not dependent on IOU

Energy Bills for a Representative High Energy-Use Household

As shown in Figure 34 and Figure 35, electricity and natural gas rates differ by IOU, and thus customer energy bills will vary by IOU service territory. Customer bills will also vary within a given IOU territory based on factors such as CARE assistance eligibility, climate zone, building type, occupancy, vehicle miles driven, electrification status, and electric rate option.

In this section, household energy bills are presented for a single representative home. While it is common to model rate and bill impacts based on the average household, these forecasts can be misleading as California has a wide diversity of building stock as well as variation across climate zones. The analysis presented here

[159] 2019 IEPR Final GHG Allowance Price Scenarios, https://efiling.energy.ca.gov/GetDocument.aspx?tn=231777&DocumentContentId=63623

focuses on a 1990s-vintage single-family home in a hot climate zone[160] as a representative household with higher-than-average energy costs.

Table 29 shows annual electricity and gas demands for this representative household, which are derived from building simulations done for the 2019 E3 report "Residential Building Electrification in California".[161] The energy demands of this household are greater than the average Californian household, and thus the bill projections presented here are not comparable to energy bills for average energy usage households shown earlier in this paper, such as in Figure 7 through Figure 9.

For electricity, the CPUC generally considers average residential consumption to be 6,000 kWh/year[162] – the representative customer considered in this Section uses 36 percent more electricity. For gas, PG&E forecasts 38.4 MMBtu/year of natural gas usage for an average mixed-fuel residential customer in their service territory[163] – the representative customer in this Section uses 14 percent more natural gas. In choosing this household, the goal is to demonstrate the bill impacts for customers who are particularly sensitive to energy price increases. As will be explained in the subsequent chapter, many of the inland areas where summer air conditioning demands are especially high are also where affordability concerns are most pronounced, making it particularly important to understand the energy bill outlook for these areas.

Finally, note that this analysis also includes gasoline costs for a more complete picture of household energy expenditures. Household gasoline usage in this Section assumes one personal vehicle driven 13,900 miles per year[164] at 31 miles per gallon.[165]

Table 29: Annual Energy Demands for a Representative Household With Above Average Energy Use in a Hot Climate Zone

Representative Household	Annual Usage
Electricity	8,150 kWh
Natural Gas	43.9 MMBtu
Gasoline	448 gal

[160] The CEC divides the state of California into a number of climate zones, which determine energy efficiency standards. The climate zone selected for this analysis is Climate Zone 12, which is located in the Stockton/Sacramento area. More information here: https://www.energy.ca.gov/programs-and-topics/programs/building-energy-efficiency-standards/climate-zone-tool-maps-and

[161] E3, "Residential Building Electrification in California" (2019). https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf

[162] This is based on the usage level cited in legal bill inserts for PG&E's 2020 GRC Phase II, SCE's 2021 GRC Phase II, and SDG&E's 2019 GRC Phase II applications

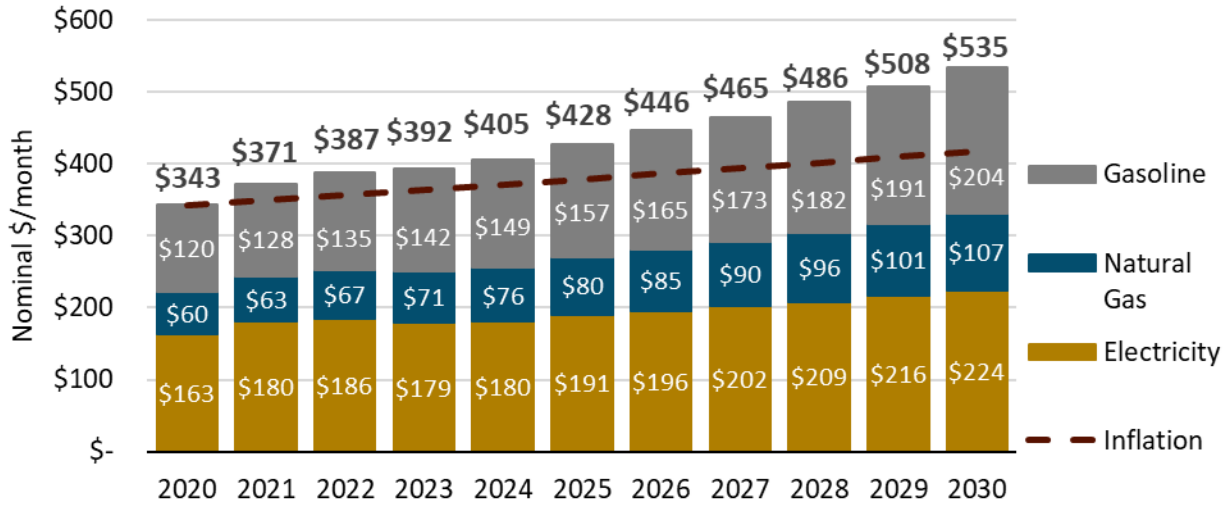
[163] PG&E Average Residential Gas Rate and Bill (January 2021). https://www.pge.com/tariffs/Residential.pdf

[164] California Air Resources Board (2020). https://arb.ca.gov/emfac/

[165] 2020, midsize sedan. ICCT, "Update of electric vehicle costs in the United State through 2030" (2019). https://theicct.org/sites/default/files/publications/EV_cost_2020_2030_20190401.pdf

Energy costs were modeled for this representative household assuming PG&E natural gas and electric rates. Appendix A also presents analogous results for customers with the same household energy usage assuming SCE/SoCalGas and SDG&E electricity and natural gas rates. Although the specific climate zone used in this analysis does not explicitly describe customers in SCE/SoCalGas or SDG&E service territories, these energy demands are largely reflective of California's inland climate zones. In Appendix A, these same energy demands are used in conjunction with the SCE/SoCalGas and SDG&E electric and natural gas rates to illustrate the impact of different IOU rates on energy bills.

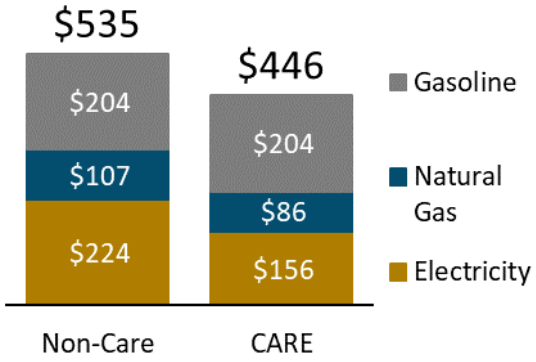
Figure 37: Average Monthly Energy Costs from 2020-2030 for Representative Household With Above Average Energy Use in a Hot Climate Zone on PG&E rates



With these assumptions established, it is possible to estimate how energy bills for this representative customer will change over time. Using the Mid case forecasts for natural gas and gasoline, and assuming simple volumetric rates for both electricity and natural gas in the PG&E service territory, Figure 37 illustrates that average monthly energy bills for this household are forecast to grow steadily over the decade, outpacing 2 percent inflation. If household income grows approximately at the rate of inflation, then energy burden (*i.e.*, energy costs as a share of income) will rise over the decade. Since this customer's energy usage is not assumed to change over time, all of the increase in costs is due to growth in electricity and natural gas rates and gasoline prices.

Figure 37 illustrates that average monthly energy bills for this household grow steadily over the decade, outpacing 2 percent inflation. If household income grows approximately at the rate of inflation, then energy burden (*i.e.*, energy costs as a share of income) will rise over the decade. Under these rate forecasts, electricity bills rise more slowly than natural gas bills or gasoline costs.

Figure 38: 2030 Average Monthly Energy Costs for Representative Household With Above Average Energy Use in a Hot Climate Zone on PG&E Rates With and Without CARE Discounts



The growth in energy costs over the decade suggests that California's households may increasingly struggle with energy affordability. The primary existing policy to help low-income customers pay their energy bills is the CARE program. Households enrolled in CARE receive a 30-35 percent discount on their electric bill and a 20 percent discount on their natural gas bill. Figure 38 shows 2030 monthly energy bills for the representative household described above with and without CARE discounts (30 percent on electricity, 20 percent on gas). While CARE provides a significant reduction in electricity and natural gas bills, it does not reduce the substantial gasoline costs for this customer. Although subsidizing gasoline consumption would have negative emissions impacts, policies that reduce vehicle miles driven, *e.g.,* by reducing commute distances and/or supporting transit options, would reduce both household energy bills and emissions.

Electrification of vehicles and/or building appliances can also provide opportunities for California households to reduce their energy bills. Electrification is considered later in this section.

Impact of Electric-Sector GHG Target on Household Energy Bills

Senate Bill 32 (2016) requires California's GHG emissions to reach 40 percent of 1990 levels by 2030. The California Air Resource Board (CARB) leads a Scoping Plan process, updated at least every 5 years, to determine what policies are necessary to meet the state's climate goals. As part of the 2017 Scoping Plan, CARB developed a range of electric-sector GHG targets for 2030 that could be consistent with the economywide targets. This range is currently 30-53 million metric tonnes (MMT) for the electric sector in 2030.

In the 2019-2020 IRP process, the CPUC initially developed a 2030 emissions target of 46 MMT. After receiving feedback from stakeholders, the CPUC required California's load-serving entities to submit two portfolios: one corresponding to a 46 MMT target and one corresponding to a stricter 38 MMT target.

The analysis presented here illustrates the bill impact of pursuing a more stringent GHG target for the electric sector. For this analysis, the RESOLVE model was used to calculate the incremental costs of meeting a 2030 electric-sector GHG target of 38 MMT relative to a baseline of 46 MMT, and those costs were added to the baseline costs developed in the CRT. In lieu of developing IOU rate forecasts that are explicitly tied to a 46 MMT or 38 MMT case, this incremental cost methodology is illustrative of the additional costs of achieving the stricter GHG target.

To calculate these incremental costs, RESOLVE was used to model two scenarios in which the 2030 emissions constraint is held at 46 MMT and at 38 MMT. In the 38 MMT case, the model builds additional renewable and storage capacity, increasing renewable procurement costs while reducing fuel costs associated with gas generation. The analysis showed the net impact on the 2030 CAISO-wide generation revenue requirement to be $1.1B on top of a baseline CAISO-wide generation revenue requirement of $23B.

Using IOU cost allocation and sales forecasts for bundled residential customers from the Cost and Rate Tracking tool, a 2030 rate impact of +0.6-0.8 c/kWh was estimated as a result of the stricter GHG target of 38 MMT. Due to a lack of data availability, it was not possible to prepare independent rate impacts for each IOU. It is expected that this range is applicable to IOU bundled residential customers of the three electric IOUs, assuming the methodology for allocating generation costs to residential customers does not change substantially by 2030.

Figure 39: 2030 Monthly Energy Costs for a Representative Household With Above Average Energy Use in a Hot Climate Zone on PG&E rates, Comparing 46 MMT and 38 MMT Electric Sector Emissions Targets and With Different Levels of Electrification

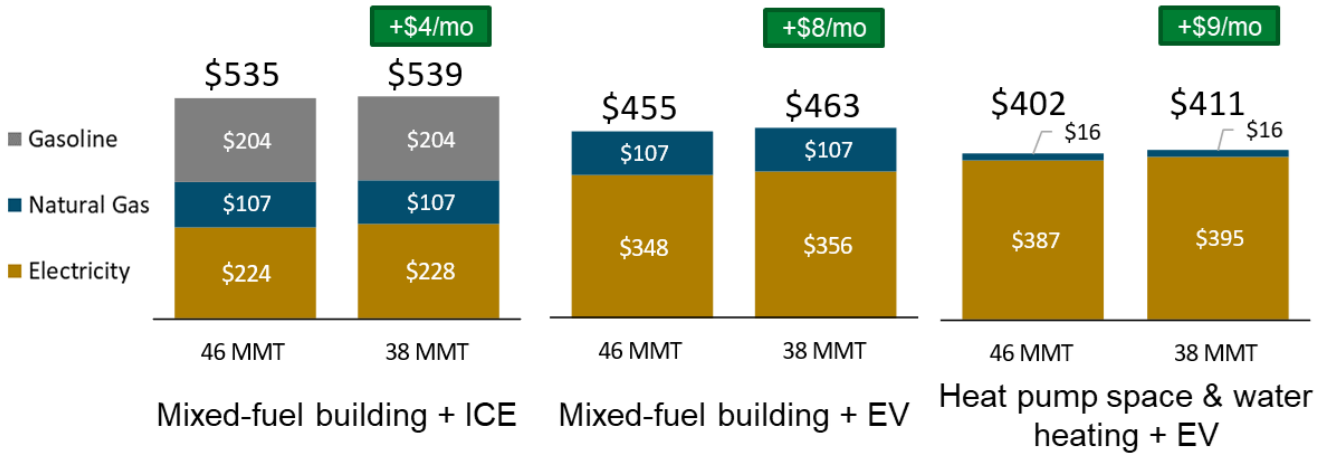


Figure 39 shows the corresponding impact on monthly energy costs for the representative household with above average energy. Two variations on this customer were also considered: a customer in the same mixed-fuel building who drives an EV, and a customer who drives an EV and has undergone "retrofit" electrification of space and water heating (but not cooking and clothes drying). Assuming a rate increase of 0.7c/kWh for the more aggressive GHG target, it is anticipated that the mixed-fuel customer with an

internal combustion engine vehicle (ICE) would see an impact of +$4/month in their energy costs. The mixed-fuel customer with an EV would see an impact of +$8/month and the electrified customer with an EV would see an impact of +$9/month.

This result is one of the key conclusions from the RECC: for all three customers considered, the bill impact associated with the stricter GHG target is relatively small. Although the impact is larger for the electrified customers, their overall energy costs are considerably lower. The next section takes a closer look at how vehicle and building electrification affect customer energy costs under a range of assumptions.

Impacts of Electrification on Customer Energy Costs

This section uses the same bundled residential average electricity rate, natural gas rate, and gasoline price forecasts previously described, as well as the same household energy demands for the representative above average energy usage customer.

Energy Costs for Customers Who Adopt Vehicle and Building Electrification Technologies

Electrification of vehicle and building technologies represents a key pillar for decarbonizing California's economy. Together, vehicles and buildings represent more than half of the state's emissions. Electrification reduces emissions by enabling large gains in efficiency and leveraging the state's increasingly decarbonized electricity supply. Electrification also provides local air quality benefits by reducing the combustion of fossil fuels in homes, business, and neighborhoods. As regulators and lawmakers consider what regulations and policies will be necessary to achieve California's climate goals, it is important to evaluate the customer cost-effectiveness of different electrification technologies.

One key question is whether rising electric rates may affect electrification cost-effectiveness by 2030. This section considers operating costs associated with adopting an electric vehicle or electric building technologies over the period 2020-2030. Although the upfront capital costs of electrification are an important part of cost-effectiveness, this section is focused on operating costs (energy costs plus maintenance costs) and thus upfront capital costs are not directly included in this analysis.

The analysis presented in this section is distinct from Section 3.5. That section specifically considered the impact of transportation electrification program costs on baseline electric rates. This section considers cost-effectiveness for a customer looking to adopt an electric vehicle or electrify their home. Subsequently, the impact of a *High Electrification* case on electric rates is considered, *i.e.*, how changes in costs and sales would impact customer rates relative to a *Reference* case.

Light-Duty Vehicle Electrification

This section compares operating costs for light-duty electric vehicles (EVs) and conventional internal combustion engine vehicles (ICEs). Input data include the bundled residential electric rate and gasoline price forecasts described previously, vehicle efficiency forecasts from the International Council on Clean Transportation (ICCT)[166] and the assumption of 90 percent efficient EV charging infrastructure. It is assumed that customers drive 13,900 miles per year based on CARB's EMFAC database.[167] Finally, it is assumed that all EV owners are on a Time of Use (TOU) rate designed for EV owners: PG&E EV-2A, SCE TOU-D-Prime, or SDG&E EV-TOU-5. To model these TOU rates, it is assumed that each rate structure stays the same over the decade and that rates in all periods change proportionally with any changes in the simple volumetric rate over time. In other words, if off-peak rates on PG&E's EV-2A tariff are 66 percent of the average volumetric rate in 2020, it is assumed that they will grow by 2030 to be 66 percent of the average volumetric rate in that year.

TOU rates for EV owners enable drivers to save money by managing their charging. Managed charging profiles were developed for the three TOU rates and an unmanaged charging profile was developed corresponding to a customer who immediately charges his or her EV upon returning home from any trip. Charging profiles were developed using E3's EV Load Shape Tool, which includes household trip data from the National Household Travel Survey and optimizes charging costs while ensuring that customers have enough charge to meet their driving needs. It was found that managed charging would enable PG&E and SCE customers to charge at a 20 percent discount from the average volumetric rate and SDG&E customers could charge at a 40 percent discount due to very low overnight rates. Conversely, unmanaged charging would lead PG&E and SCE customers to pay more than the average volumetric rate, whereas SDG&E customers still see a slight discount. These estimates allocate a portion of the monthly fixed electricity fees in the SCE and SDG&E rates to EV charging.

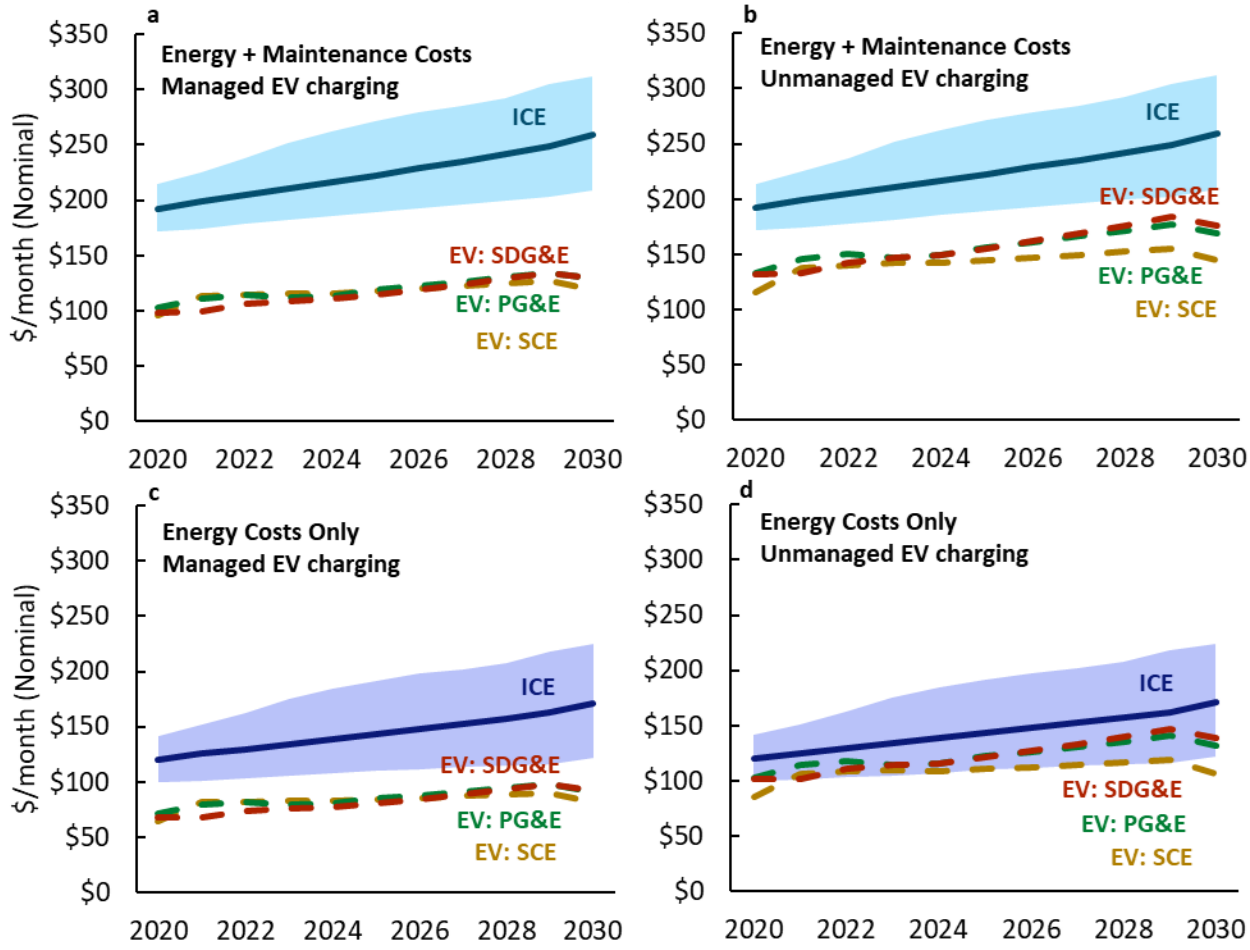
Maintenance costs are another important component of vehicle operating costs. ICCT data indicate that per-mile maintenance costs for ICEs are more than twice as high as for EVs. As these are not strictly energy costs, the analysis here is presented based on monthly operating costs (energy plus maintenance costs) as well as energy costs alone (not including maintenance costs).

Figure 40 shows four different frameworks for evaluating the potential cost savings from EVs. Under a Mid gasoline price forecast, EVs owners see cost savings throughout the decade in all four frameworks. In 2030, EV owners who manage charging are forecast to save $130-$140/month in operating costs (energy plus maintenance costs) as compared to an ICE owner (Figure 40a), depending on IOU. Customers who do not manage their charging see operating cost savings of $85-$115/month (Figure 40b). Reduced maintenance costs account for $50/month of these savings, so energy cost savings alone are forecast to be $80-$90/month in 2030 for customers using managed charging (Figure 40c), and $35-65/month for customers using unmanaged charging (Figure 40d).

[166] ICCT, "Update of electric vehicle costs in the United State through 2030" (2019). https://theicct.org/sites/default/files/publications/EV_cost_2020_2030_20190401.pdf

[167] California Air Resources Board (2020). https://arb.ca.gov/emfac/

Figure 40: Operating Costs for an ICE Under a Range of Gasoline Price Forecasts and for EVs in Three IOU Service Territories Assuming Managed and Unmanaged Charging



Under a Low gasoline price forecast (bottom of blue shaded area), EVs still show cost savings in three of the four frameworks. However, Figure 40d shows that, under the most pessimistic assumptions (Low gasoline price forecast, unmanaged charging, maintenance savings excluded), EVs may have incremental energy costs above ICEs. These graphs show that operating cost savings from light-duty vehicle electrification will vary based on many factors, but the savings are robust across a range of assumptions. Even in the scenario where low gasoline prices eliminate the energy cost savings, EV owners would still see overall savings due to lower maintenance costs.

Residential Building Electrification

This section considers the impacts of residential building electrification on household energy bills for a representative above average energy usage household in a hot climate zone. While buildings and climate vary

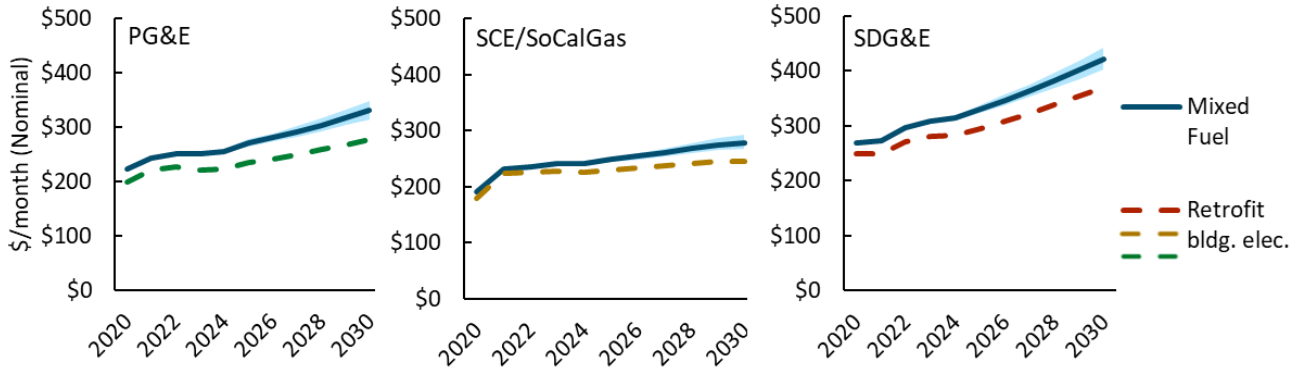
across IOU territories, the same household is considered for all three IOUs to isolate the impact of different IOU rates. This analysis considers both a 1990s-vintage single-family home that undergoes "retrofit" electrification of space and water heating, as well as a new all-electric single-family home (with distinct energy demands) that includes electric space and water heating, cooking and clothes drying. Energy costs for customers who rely on delivered fuels such as propane to meet home energy needs are not considered. The cost-effectiveness of building electrification would look considerably different for those customers.

Simple average volumetric electric rates were used for this analysis to provide directional energy cost comparisons between natural gas and electric end uses, while not considering the impact of rate design. Although utilities are transitioning to default TOU rates for residential customers, these customers may still opt for tiered rates or other TOU rate structures. As a result, it cannot be assumed that a mixed-fuel and electrified customer would be on the same rate. Overall, today's TOU rates may support the customer cost-effectiveness of building electrification, as electrified technologies add load outside of peak air conditioning hours.

Figure 41 shows average monthly home energy bills (electricity plus natural gas) for a 1990s-vintage home considering retrofit electrification of space and water heating. Retrofit electrification provides this representative customer with substantial energy cost savings under all three IOU electric and gas rates. Notably, these cost savings are evident even under the Low natural gas price scenario. The primary source of these cost savings is equipment efficiency: high-end heat pump heating, ventilation, and air conditioning (HVAC) units and heat pump water heaters available today use between one third and one quarter of the energy of their gas counterparts.[168] Although gas and electricity are priced using different units, these efficiency benefits can result in substantial cost savings. Bill savings will vary based on building type and climate zone. In California's moderate climate zones, where temperatures rarely fall below freezing and heat pumps function at high efficiencies, energy cost savings will be greater for homes with larger demands for space and water heating (*i.e.*, larger homes, homes with higher occupancy, less well-insulated homes, and regions with colder temperatures).

[168] E3, "Residential Building Electrification in California" (2019). https://www.ethree.com/wp-content/uploads/2019/04/E3_Residential_Building_Electrification_in_California_April_2019.pdf

Figure 41: Monthly Home Energy Bills (Electricity Plus Natural Gas) for a Representative Above Average Energy Usage Home in a Hot Climate Zone Considering Retrofit Electrification of Space and Water Heating in Three IOU Service Territories

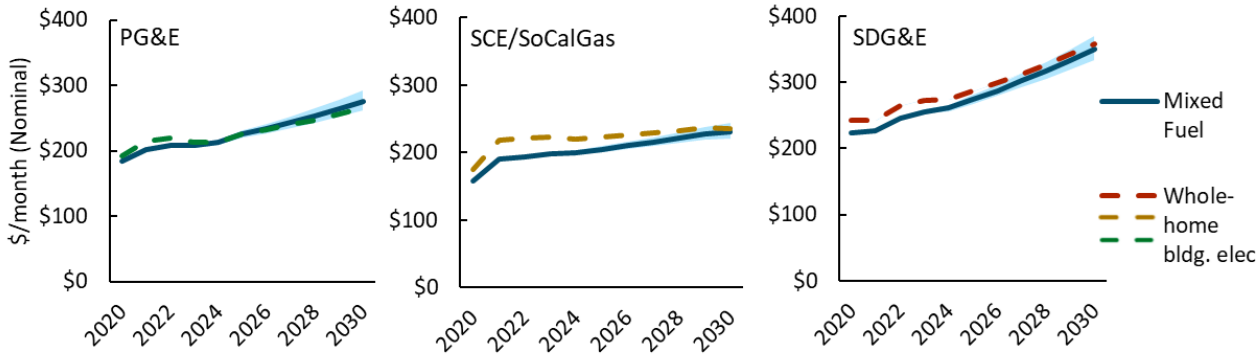


While not considered in this analysis, upfront capital costs may complicate this picture as heat pump space and water heaters may have a higher equipment and/or installation cost than corresponding gas appliances. However, heat pump HVAC units provide both space heating and air conditioning. Thus, the electrified home may save on capital costs when considering the cost of replacing an existing furnace and air conditioner with a single device.

All-electric construction of a new single-family home in a hot climate zone such as Stockton was also considered. This includes electrification of space and water heating plus cooking and clothes drying. To understand the impact of IOU rates on energy costs, customer solar was not included for this household. Figure 42 shows energy costs using rates for each IOU. The results indicate that energy costs for mixed-fuel and all-electric homes are likely to be similar over the decade and whether the all-electric home sees net bill savings or costs is sensitive to the trajectory of natural gas rates (*i.e.*, Low, Mid, or High scenario).

There are two reasons why all-electric homes may not provide the same level of energy cost savings as retrofit electrification of HVAC and water heating only. First, new homes are more energy-efficient than existing homes, reducing space heating demands and the associated energy savings from a heat pump HVAC system. Second, while heat pump HVAC units and water heaters can see 3-4x improvements in efficiency versus gas appliances, heat pump clothes dryers and induction stoves only see 2x efficiency improvement, diluting the energy cost savings from the retrofit case shown above.

Figure 42: Monthly Energy Bills (Electricity Plus Natural Gas) for a New Mixed-Fuel Home and a New All-Electric Home in a Hot Climate Zone in Three IOU Service Territories



Capital costs are not included in these calculations. However, upfront capital cost savings may favor electrification of new homes. Although electric devices may be more expensive than their gas counterparts, the all-electric home does not need an air conditioner (as this is covered by the heat pump) and the all-electric home will avoid the cost of connecting to the gas distribution system, part of which is generally paid by the homebuilder.

As the energy costs for all-electric and mixed-fuel new homes are likely to be similar throughout the decade, trends in gas and electric rates, as well as policy decisions or incentives, may ultimately determine whether all-electric customers see net bill savings or costs. The customer cost-effectiveness of all-electric new homes represents an important policy consideration for achieving emissions reductions in buildings.

Impact of Electrification on Electric Rates

The previous section describes energy costs for customers adopting electric technologies. A separate question is what the impact of electrification will be for non-adopting customers. Prior work has indicated that building electrification may lead to increases in natural gas rates for remaining gas customers as gas sales decline.[169,170] The impact of electrification on electric rates is more complicated, as electrification will increase both electric system costs and retail electricity sales. To explore the impact of electrification on electric rates, a *High Electrification* scenario was considered that has additional costs and additional sales relative to a *Reference* case. This analysis was used to calculate a range of likely rate impacts for residential customers.

[169] "The Challenge of Retail Gas in California's Low-Carbon Future." CEC-500-2019-055-F. https://ww2.energy.ca.gov/2019publications/CEC-500-2019-055/CEC-500-2019-055-F.pdf

[170] Gridworks, "California's Gas System in Transition." https://gridworks.org/wp-content/uploads/2019/09/CA_Gas_System_in_Transition.pdf

The *Reference* scenario reflects sales assumptions from the 2019 IEPR Mid Demand case. The *Reference* scenario has 4 million EVs and plug-in hybrids on the road by 2030 (statewide) with negligible electric medium- and heavy-duty vehicles and negligible building electrification. The *High Electrification* scenario, developed in E3's CA Pathways model, sees 7 million EVs and plug-in hybrids by 2030 along with 200,000 medium- and heavy -duty vehicles and buses, plus an additional 1.1 million electrified homes and a doubling of commercial building electrification (versus *Reference*). While the *Reference* case has 15 TWh of CAISO-wide vehicle and building electrification load in 2030, the *High Electrification* scenario adds another 18 TWh of electrification load by 2030 for a total of 33 TWh.

The additional electrification load will increase electric system costs in three categories: resource procurement needed to serve load, electrification programs, and transmission and distribution (T&D) infrastructure. Incremental procurement costs were calculated by running both scenarios in the RESOLVE model. Results indicate an additional $1.96B in 2030 procurement costs would be needed to support the additional load in the *High Electrification* case, on top of a baseline CAISO-wide generation revenue requirement of $23B. These costs correspond to the costs of new generation resources plus the costs of transmission upgrades required to support interconnection of these resources, but not transmission or distribution costs corresponding to load increases (see below). These procurement costs likely reflect an upper bound estimate, as resource cost forecasts for solar and battery storage have fallen since the model inputs were developed in 2018.

To calculate electrification program costs, the baseline estimate of IOU program costs, which are based on utility cost filings, was used. These indicate that ~$30 in annualized costs are required to support one incremental MWh of electrification load. For low and high estimates, $20-$40 per MWh of electrification load was assumed. This corresponds to an estimated $540M in additional 2030 electrification program costs for the *High Electrification* scenario, with a range of $360M-$720M.

Finally, to calculate T&D infrastructure costs corresponding to increased sales, 2020 costs from the California Avoided Cost Calculator[171] averaged across IOUs were used, along with 4 percent nominal escalation based on data from the Bureau of Labor Statistics (BLS) Producer Price Index.[172] The result was $60/kW-yr, i.e. $60 of additional T&D annual revenue requirement for each kW of incremental peak load due to electrification. There is a range of potential peak load impacts for the *High Electrification* case. Based on load shapes from IEPR and E3 modeling, 1.9 GW of additional peak load was estimated. Based on preliminary analysis of distribution system impacts, the peak impact could likely be halved with widespread managed EV charging. Conversely, non-diversified EV charging could result in the peak impact tripling. This range of peak load impacts leads to 2030 incremental T&D costs of $55M-$340M, with a base estimate of $110M.

[171] 2020 Avoided Cost Calculator, https://www.cpuc.ca.gov/general.aspx?id=5267

[172] BLS PPI industry data for Electric power distribution-Pacific, not seasonally adjusted. PPI Series PCU221122221122419, Jan 2015 through Nov 2020.

Table 30: Incremental Costs Associated with High Electrification Scenario

Cost component	Unitized cost	Source	2030 Mid cost *(Low-High)*	% of 2030 Rev Req *(Low-High)*
Resource procurement	NA	RESOLVE model	$1.96B	3.8%
Electrification programs	$30/MWh (annual rev req impact)	IOU baseline forecast	$540M *($360M-$720M)*	1.1% *(0.7%-1.4%)*
T&D infrastructure	$60/kW-yr	CA Avoided Cost Calculator, BLS	$110M *($55M-$340M)*	0.2% *(0.1%-0.7%)*
Total	--	--	$2.61B *($2.38B-$2.96B)*	5.1% *(4.7%-5.8%)*

Table 30 shows incremental costs associated with the high electrification scenario, along with the impact on the 2030 CAISO-wide revenue requirement of $51B (*Reference* case). The high electrification scenario adds 4.7 percent to 5.8 percent to the 2030 revenue requirement, driven primarily by additional resource procurement costs.

The proportional increase in electricity sales is larger than the increase in costs. The *High Electrification* scenario has 18 TWh of increased retail sales in 2030, corresponding to an 8.5 percent increase in sales. The result is that system average rates would fall by 0.6-0.9c/kWh. An interesting question is what level of cost increases would be necessary for rates to rise in the *High Electrification* scenario. The resource procurement costs already reflect an upper bound estimate, as described above. Thus, for the *High Electrification* scenario to result in rate increases, electrification program and T&D infrastructure costs would need to be more than double the upper bound estimates in Table 30.

The impact on bundled residential average rates was also considered using IOU-provided cost allocation data. Relative to the system-wide increases in costs and sales, bundled residential customers see a smaller (proportional) increase in revenue requirement and a larger (proportional) increase in sales. In addition, baseline residential rates are higher than system average rates, leading to larger absolute changes in rates. Taking the Mid cost estimates above, residential rates for the three IOUs would fall by 1.4-2.1c/kWh under the *High Electrification* scenario (relative to the Reference scenario based on the IEPR Mid Demand case). As explained previously, due to data limitations, it is not possible to prepare independent rate impacts for each IOU. It is expected that this range of impacts is applicable to IOU bundled residential customers of the three electric IOUs, assuming the methodology for allocation of distribution, transmission, program, and generation costs does not change substantially by 2030.

Summary of RECC Findings

Energy prices are forecasted to grow faster than inflation over the coming decade, increasing energy affordability concerns for California households. This analysis considered how the choice of electric-sector GHG target would affect energy costs and found that a stricter 2030 emissions target would lead to some bill increase for residential customers. On the other hand, it was found that building and vehicle electrification technologies represent an opportunity for customers to dramatically reduce their overall energy costs.

It was also demonstrated that operating cost savings from electrification will vary based on many factors. For light-duty vehicle electrification, operating cost savings are robust across a range of assumptions. For building electrification, operating cost savings will vary depending on IOU, natural gas rate assumptions, and end uses electrified. In addition, building type and climate zone will have an impact on electrification cost-effectiveness that has not been quantitatively considered here. It was also shown that rapid adoption of vehicle and building electrification technologies would likely have the benefit of reducing residential electric rates by 2030. While this would reduce energy costs for all California households, cost savings would be largest for customers with electric vehicles or electrified homes. The impact of electrification on natural gas rates was not considered here.

Electrification of vehicles and buildings is widely understood to be a pillar of decarbonizing the state's economy. In many cases, vehicle and/or building electrification can also provide opportunities to reduce household energy costs. However, households that cannot afford the upfront costs associated with electrification will miss out on these energy cost savings. This is an important consideration in the context of equity, since it implies that low-income families may not be able to offset the incremental costs associated with rising energy prices by reducing their natural gas, gasoline, and vehicle maintenance costs through electrification.

3.7 Affordability Framework

Affordability of utility services cannot be measured based on the magnitude of utility bills alone. Electricity and natural gas are essential services, and consumers necessarily must purchase them to maintain a healthy living standard and meaningfully participate in society. Unlike other products or services, which customers are able to forego if prices rise too high, essential utility services will continue to be consumed regardless of price. This means that for low-income households, increases in utility bills will crowd out other purchases rather than affect energy usage behavior. Instead of observing actual consumption behavior or simply comparing changes in utility bills to inflation, it is necessary to develop metrics that consider the costs of essential services in relation to the socioeconomic conditions of the households that are paying for those services.

CPUC-Developed Affordability Metrics

The CPUC has developed metrics that take into account socioeconomic conditions of representative low-income households when considering customers' ability to pay for essential services such as electricity. Specifically, in 2020 three metrics were adopted in Decision (D.) 20-07-032 (Decision) to measure the affordability of essential services: the affordability ratio (AR), socioeconomic vulnerability index (SEVI), and hours at minimum wage (HM).

Affordability Ratio

The affordability ratio (AR) metric quantifies the percentage of a representative household's income that would be used to pay for an essential utility service, after non-discretionary expenses such as housing and other essential utility service charges are deducted from the household's income. The higher an AR, the less affordable the utility service. The AR may be calculated for a single essential utility service, a combination of services, or all essential utility services combined. In the context of discussing this metric, the term "bundled AR" is used to describe the affordability of electricity, natural gas, communications, and water utility services combined.

AR may be calculated for any given income level in a given area. For example, the AR for a household at the 20^{th} percentile income level, meaning that the household's income level is only higher than 20 percent of households in the area, would be an AR_{20} figure. The AR for a household at the 50^{th} percentile of income, meaning a median income household, would be an AR_{50} figure. The AR metric is also sensitive to geographic variations in cost-of-living, which can impact the amount of income available to pay for essential utility service. AR can be calculated using publicly available data at the most geographically granular scale, census block group, or larger aggregations such as an entire utility service territory or State-wide.

Hours at Minimum Wage

The hours at minimum wage metric quantifies the hours of earned employment at the local minimum wage necessary for a household to pay for essential utility service charges. Thus, the metric allows the CPUC and stakeholders to conceive of essential utility service charges in terms of something most people can relate to – hours of labor. The minimum wage-based metric also implicitly considers the impact of essential utility service charges on lower-income customers regardless of the socioeconomic conditions of the community as a whole.

Socioeconomic Vulnerability Index

The socioeconomic vulnerability index (SEVI) metric represents the relative socioeconomic standing of census tracts, referred to as "communities," related to poverty, unemployment, educational attainment, linguistic isolation, and percentage of income spent on housing. This metric therefore considers how a rate

change may affect one community's ability to pay more than another's. The goal of the SEVI metric in this context is to highlight those communities where uniform changes in rates may have a disproportionate impact. Thus, the SEVI metric allows for an affordability assessment that is independent of the absolute value of essential utility service charges.

Advantages and Limitations of CPUC-Developed Affordability Metrics

These metrics are capable of measuring affordability outcomes at whatever level of geographic granularity is desired, so long as socioeconomic data of sufficient specificity are available and can be aligned with utility billing data. The CPUC has developed methodologies to estimate values for the three metrics described above at geographic scales smaller than utility climate zones, which is the geographic level at which the cost of an essential level of electricity usage is uniform.[173] This allows the CPUC to understand how socioeconomic factors affect the affordability of utility services, rather than just relying on the magnitude of bills as an indicator for affordability.

This is important because it allows the CPUC to measure how differences in socioeconomic factors affect the ability to pay for energy services and how much of a burden utility bills can be for households at various income levels. The degree to which these outcomes are disparate for households in different parts of the state helps the CPUC understand heterogeneity in utility affordability and quantify how much more difficult it is to pay for electricity in less affluent areas. Because the affordability ratio metric can be calculated for households at different points in the income distribution within a given area, this metric also allows for a better understanding of economic disparities within a community, in addition to differences between communities in different geographic areas.

The inclusion of non-discretionary costs in the affordability ratio metric, specifically housing costs and other utility services, provides an important piece of additional context when considering utility bills. Housing costs in particular are quite high in many parts of California, so simply considering bills in relation to household income levels (for example, by looking at a metric such as "energy burden," which expresses energy bills as a percentage of gross household income) does not account for these costs which have a significant impact on a household's ability to pay for electricity. The inclusion of housing costs allows for comparison of affordability between different parts of the state.

While the CPUC-developed affordability metrics provide benefits over other affordability metrics, they do have important limitations. Specifically, the inclusion of socioeconomic variables in the metrics means that predicting how affordability will change in future years is a more involved exercise than simply forecasting electricity rates and bills. Estimating future values of the affordability ratio requires estimates of household incomes and housing costs for specific geographic areas and for specific points on the income distribution. Forecasting SEVI values will require granular predictions of how unemployment, educational attainment,

[173] Because baseline allowances are set based on a customer's climate zone and volumetric electric rates are uniform across a utility's service territory for customers on a given tariff, the price of an "essential" level of electricity usage (defined as the baseline allowance of electricity) is determined by a customer's climate zone and electric provider. Therefore, the CPUC's affordability metrics are able to measure affordability within geographic areas where an essential level of electricity usage is of a uniform price.

poverty rates, and other socioeconomic variables will evolve over time. Predicting HM values will require some idea of how local minimum wage laws will change over time. The CPUC has not established how these forecasts will be produced for forward-looking affordability assessments. This work is part of the scope of the second phase of the Affordability OIR [R.18-07-006], which is currently underway.

Current State of Utility Affordability in California

The CPUC is able to use these metrics to understand the *current* state of affordability in California. CPUC staff recently issued the first annual Affordability Report, which provides estimates of the metrics based on 2019 data, which is the most recent data available for many of the metric components. Because the results in this report are based on 2019 data, they do not account for the impacts of the COVID-19 pandemic. The economic disparities presented in the report reflect conditions that existed before the pandemic, and those disparities have likely worsened since the beginning of 2020. A recent Center on Budget and Policy Priorities analysis of the Census Bureau's Household Pulse Survey[174] found that, during the period December 9th through the 21,st 2020, 14 percent of all adults in the country reported that their household sometimes or often did not have enough to eat in the prior seven days, compared to 3.4 percent during the entire 12 months of 2019. In California during the period November 25th through December 21st, 40 percent of adults responded that they had difficulty paying for usual household expenses.[175]

The Affordability Report contains a number of insights into the current state of bundled utility affordability. Specifically, the metrics highlight the stark disparity in affordability concerns among low-income households across the state. The results show that there are a handful of geographic areas within the state where households on the lower end of the income distribution spend a much larger proportion of their disposable income on utility services compared to low-income households in the rest of the state. Approximately 11.2 percent of households are in areas with AR_{20} values[176] of at least 35 percent, while the remaining 88.8 percent are in areas with much lower values, as can be seen in Figure 43.[177] A higher AR value indicates that utility services are less affordable, because it means a larger proportion of discretionary income must be devoted to paying for utility services. Thus, Figure 43 shows that a small but significant proportion of low-income households in the state (i.e., households on the left side of the distribution) pay a much higher percentage of their discretionary income for vital utility services when compared to low-income households elsewhere in the state.

[174] The Household Pulse Survey is a recent initiative by the Census Bureau to track the social and economic impacts of the pandemic through a quick turnaround survey, with data released every two weeks. More information here: https://www.census.gov/data/experimental-data-products/household-pulse-survey.html

[175] Center on Budget and Policy Priorities, "Tracking the COVID-19 Recession's Effects on Food, Housing, and Employment Hardships." January 8, 2021. https://www.cbpp.org/sites/default/files/atoms/files/8-13-20pov.pdf

[176] AR_{20} is the selected as the focal point of this assessment because households at the 20th percentile of the income distribution earn considerably less than the median household, but do not necessarily qualify for assistance programs such as CARE.

[177] The plot presents AR_{20} results broken down by geographic areas called PUMAs, or Public Use Microdata Areas. These are Census Bureau-defined geographic areas that are comprised of multiple census tracts. There are 265 PUMAs in California. Depending on population density, a single PUMA may contain several less populous counties or cover just a portion of a more populous county. PUMAs are delineated by metropolitan areas and other "meaningful geographies," yielding areas with similar socioeconomic profiles.

This is an important point to understand because it shows that there are specific geographic areas within the state where affordability concerns are most acute, and those communities are significantly worse off than the rest of the state even when differences in housing costs are accounted for. Using affordability metrics that rely on service territory- or statewide-averages, it is not possible to identify these sorts of vulnerable communities.

The analysis also demonstrates that median-income households can much more easily afford utility services than lower income households. AR values for median income households (AR_{50} values) are fairly uniform across the state, as illustrated by Figure 44, which shows the distribution of AR values for 20th and 50th percentile income households across the state. This graph shows that AR_{50} values are relatively low compared to AR values for 20th percentile income households (AR_{20} values), and they are less than 10 percent for the vast majority of the state.

Figure 43: Distribution of Bundled Residential AR_{20} Values by Percent of Households (2019)

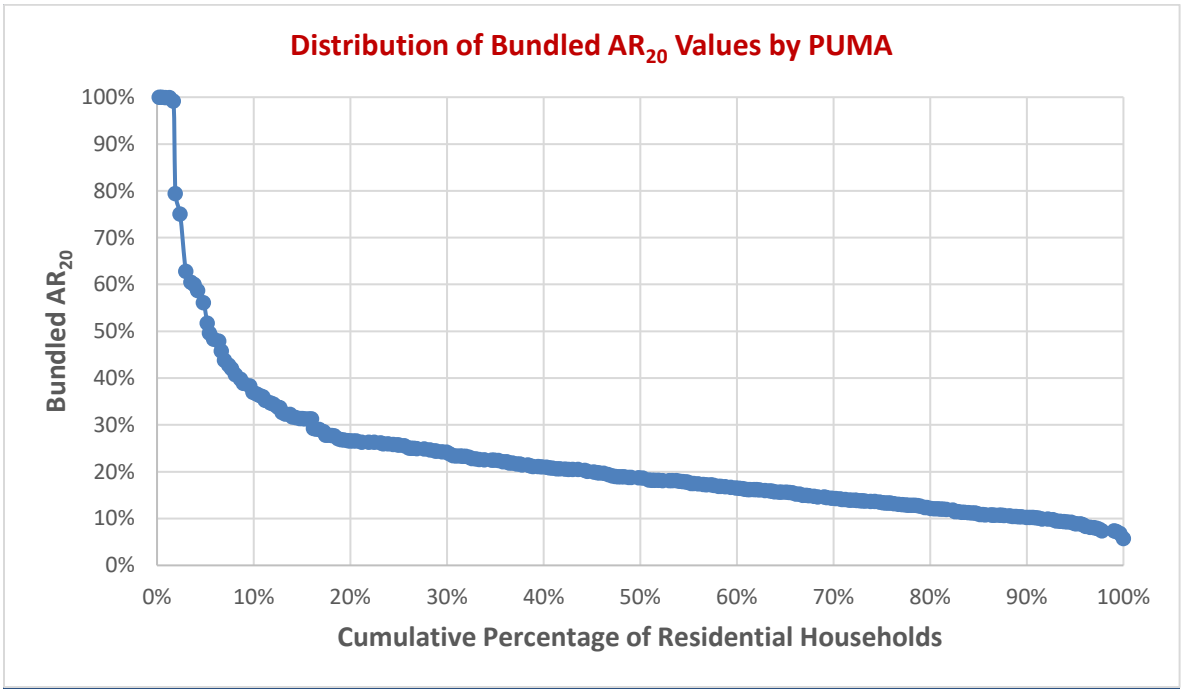
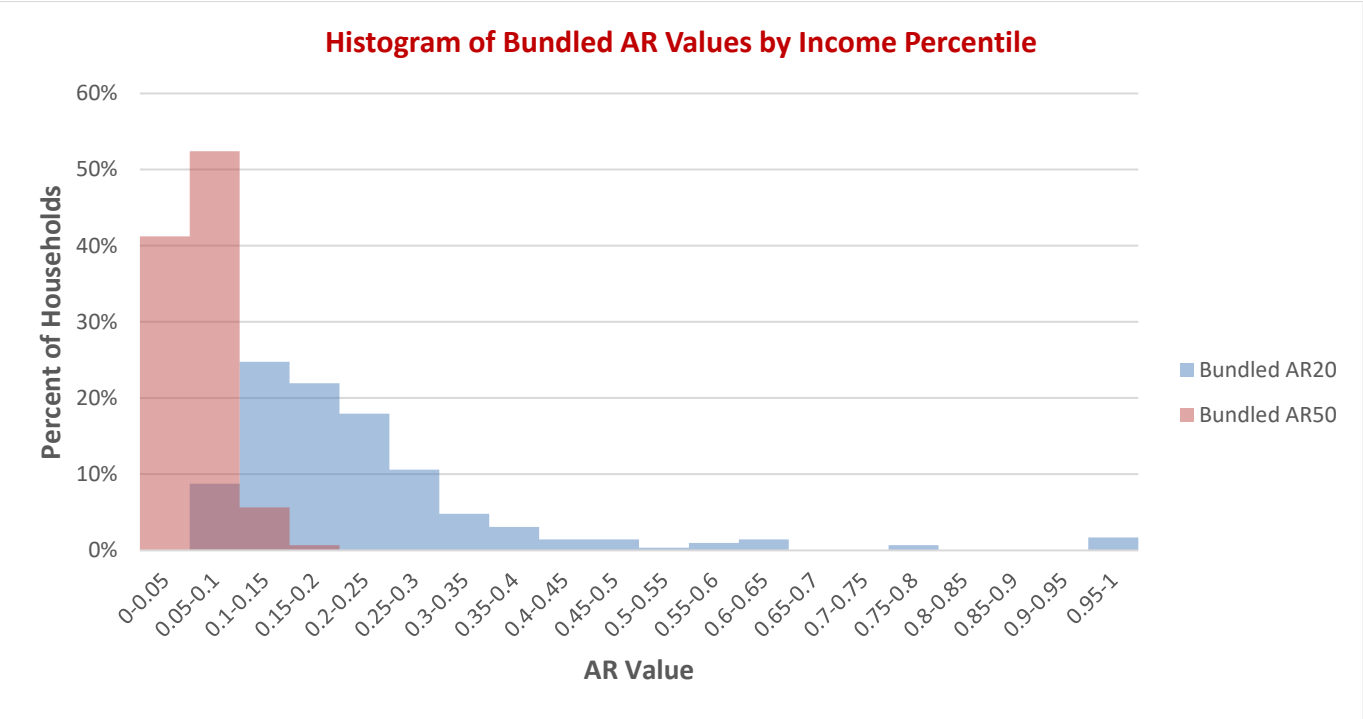
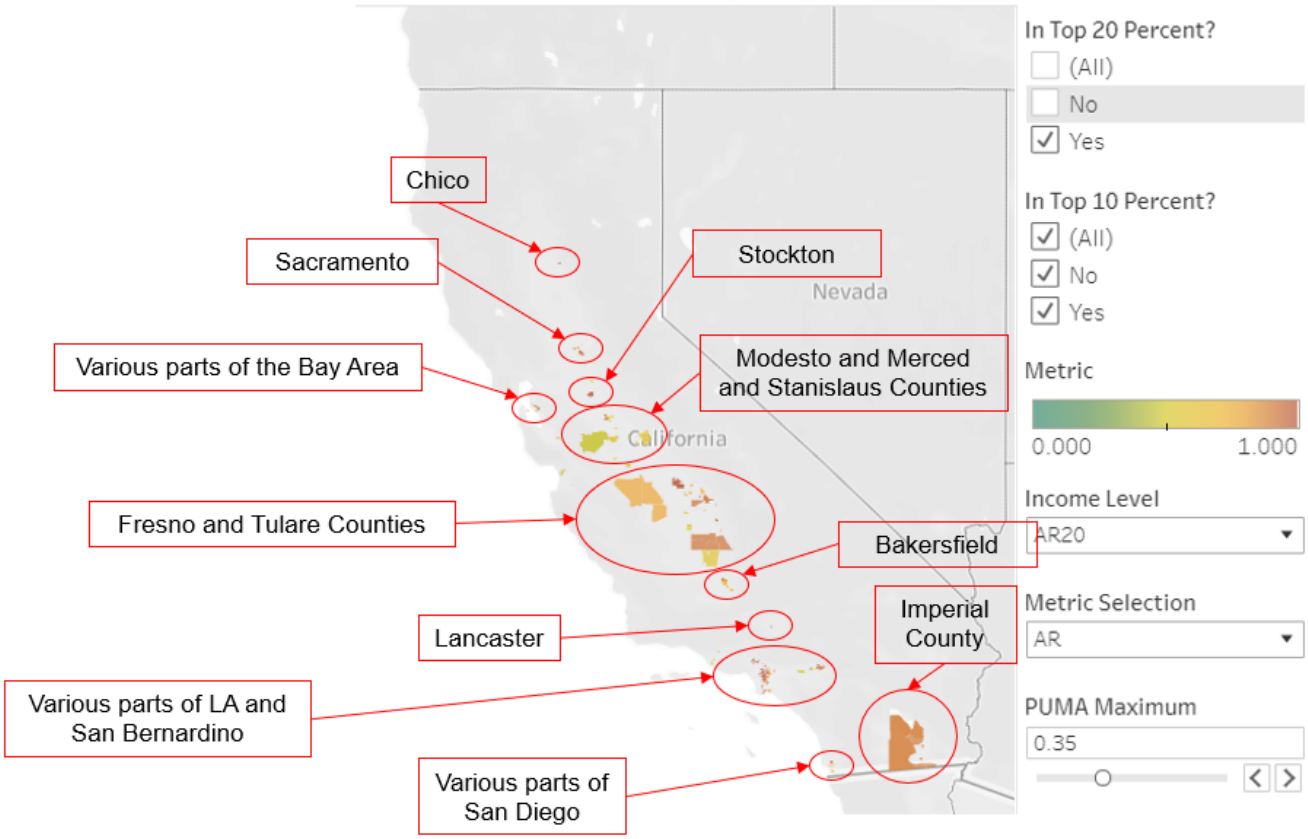


Figure 44: Histogram of Bundled AR Values by Income Percentile



The analysis also identifies the specific geographic areas where utility services are currently the least affordable for low-income households (as measured by AR_{20}) and where residents are most vulnerable to future increases in essential service charges (as measured by SEVI). In these communities, customers already face affordability challenges and are least equipped to handle further increases in utility costs. The areas with the highest values of both metrics have been identified as areas of particular concern. This includes Oakland, Stockton, Fresno, Modesto, Tulare County, Bakersfield, San Bernardino, and many parts of Los Angeles, as shown in Figure 45. These results reflect the state of affordability as of 2019, and without a geographically granular forecast of income and housing costs across the state it is difficult to definitively say how this outlook will evolve over the coming decade. However, based on the bill projections presented earlier in this report, it may be worth paying particular attention to the affordability of electricity in the San Diego area, since SDG&E bills are expected to rise more than the other electric IOUs.

Figure 45: Census Tracts with Top 20 Percent of Bundled AR_{20} and SEVI Values



Socioeconomic Uncertainties and Future Predictions

As mentioned previously, these results are based on 2019 data, and thus reflect the pre-pandemic state of utility affordability. Given the unprecedented nature of the economic recession that resulted from the pandemic-induced shutdown of California's economy and the persisting uncertainty around how the federal government will respond to the economic crisis, it is unclear how quickly the economy will rebound once life returns to normal.

There is particular uncertainty around how quickly employment rates and incomes will rebound for lower-income households, since recent experience from the prior economic recession showed that socioeconomically disadvantaged households did not fare as well during the ensuing economic recovery. A study of wealth changes in the aftermath of the Great Recession found that the median wealth of households which were in the top quintile of the income distribution fell to 81 percent of their 2003 level in 2011, whereas the median wealth of households in the bottom income quintile fell to 26 percent of their

2003 level in 2011, indicating that lower-income households faced a rockier road on the path to recovery.[178] These disparities continued to be evident even five years later: the median wealth of lower-income families in 2016 was 58 percent of the 2007 level, while the median wealth of upper-income families in 2016 was 110 percent of the 2007 level.[179]

Perhaps even harder to predict will be the future of housing costs in California in the long-term. It is unclear to what extent remote working will be a permanent fixture in American work culture, and how that will affect where Californians choose to live, whether they need to commute, and what this will mean for service-industry jobs that previously catered to people who worked in centralized office locations. Several companies have already announced that remote work will be an option for their employees even once the pandemic is over. The economic and real estate ramifications of these changes may not be fully understood for years to come.

[178] Pfeffer F, Danziger S, Schoeni R. "Wealth disparities before and after the Great Recession." The ANNALS of the American Academy of Political and Social Science. 2013;650(1):98–123. https://www.ncbi.nlm.nih.gov/pmc/articles/PMC4200506/

[179] Kochhar R and Cilluffo A. "How wealth inequality has changed in the U.S. since the Great Recession, by race, ethnicity and income." Pew Research Center. November 1, 2017. https://www.pewresearch.org/fact-tank/2017/11/01/how-wealth-inequality-has-changed-in-the-u-s-since-the-great-recession-by-race-ethnicity-and-income/#:~:text=Consequently%2C%20the%20recession%20drove%20wealth,that%20has%20doubled%20since%201983.

IV. Utility Cost Cutting Proposals in Fulfillment of PU Code Sec 913.1

The following weblink to the CPUC's Energy Division Retail Rates webpage contains links to the reports submitted by PG&E, SCE, SDG&E, and SoCalGas, pursuant to Public Utilities Code Section 913.1:

IOU Proposals for Limiting Costs

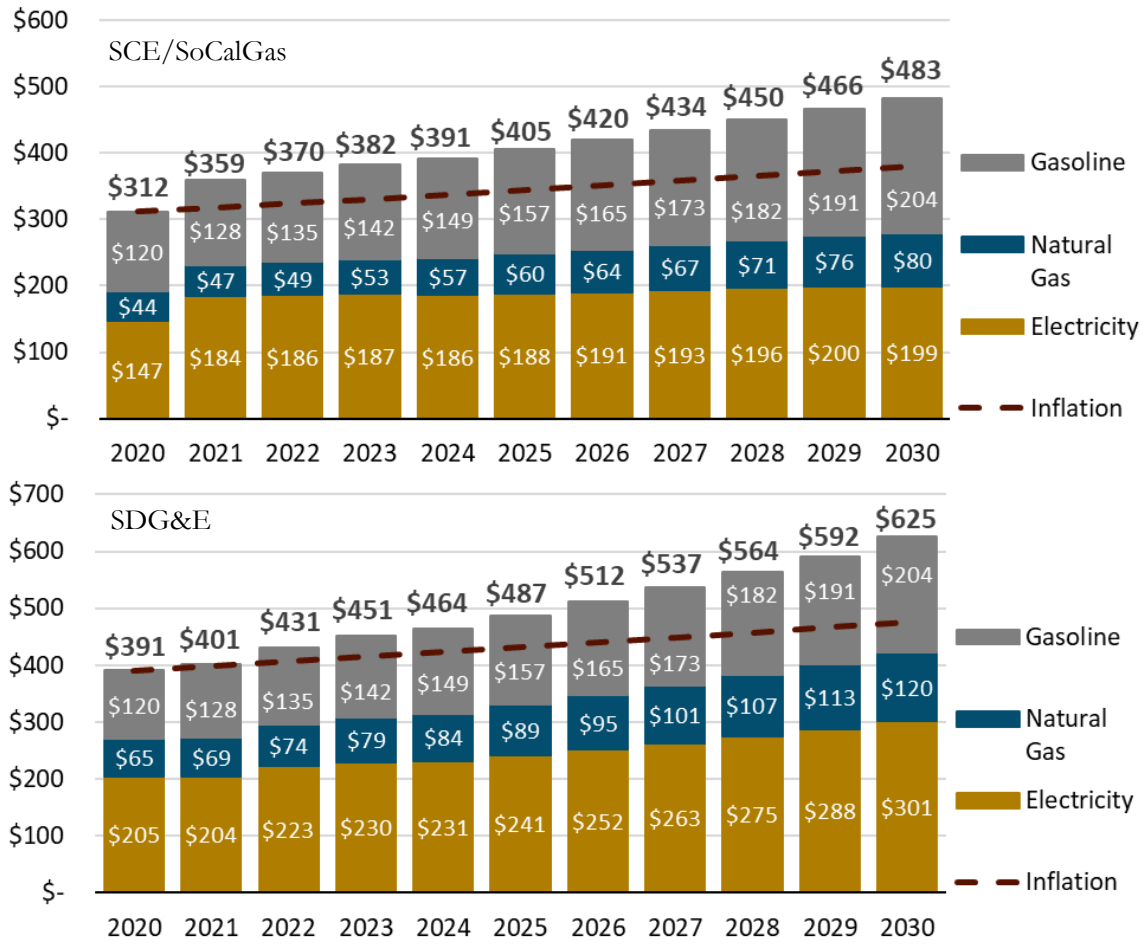
V. Conclusion

This white paper documents the general trajectory of costs and bundled residential rates over the next decade as the DER market expands, electrification progresses, wildfire mitigation spending and rate base investments continue to rise. This not a comprehensive evaluation and exhaustive ranking of all categories of cost, but rather an attempt to estimate long term costs alongside a distillation of affordability impacts for economically vulnerable Californians. In so doing, it warns of the need for increased prudence and equity in continued investment in the grid of the future while acknowledging that more examination is needed to understand the extent to which the load management benefits of a maturing DER marketplace might offset the potential for shifting costs. Furthermore, it raises crucial questions about the prudence of IOU proposals for capital additions and the potential for exacerbating such cost shifts and resulting bill impacts. Ultimately, the foregoing analysis is intended to engender practical thinking about strategies for utility cost containment, improved valuation of grid benefits of new technologies, and addressing affordability concerns for those customers most in need of protection.

APPENDIX A: ENERGY COSTS FOR ABOVE AVERAGE ENERGY USAGE HOME ON SCE/SOCALGAS AND SDG&E RATES

Electric rate forecasts (Figure 34) and natural gas rate forecasts (Figure 35) were developed for the three large IOUs. A representative household in a hot climate zone was also introduced (Table 29) and energy costs for this customer were shown based on PG&E rates (Figure 37). Variants of Figure 37 are presented here for customers on SCE/SoCalGas rates and SDG&E rates. Although a hot climate zone does not explicitly describe customers in SCE/SoCalGas or SDG&E service territories, these same energy demands were used across all IOUs to illustrate the impact of the different IOU rates on energy bills.

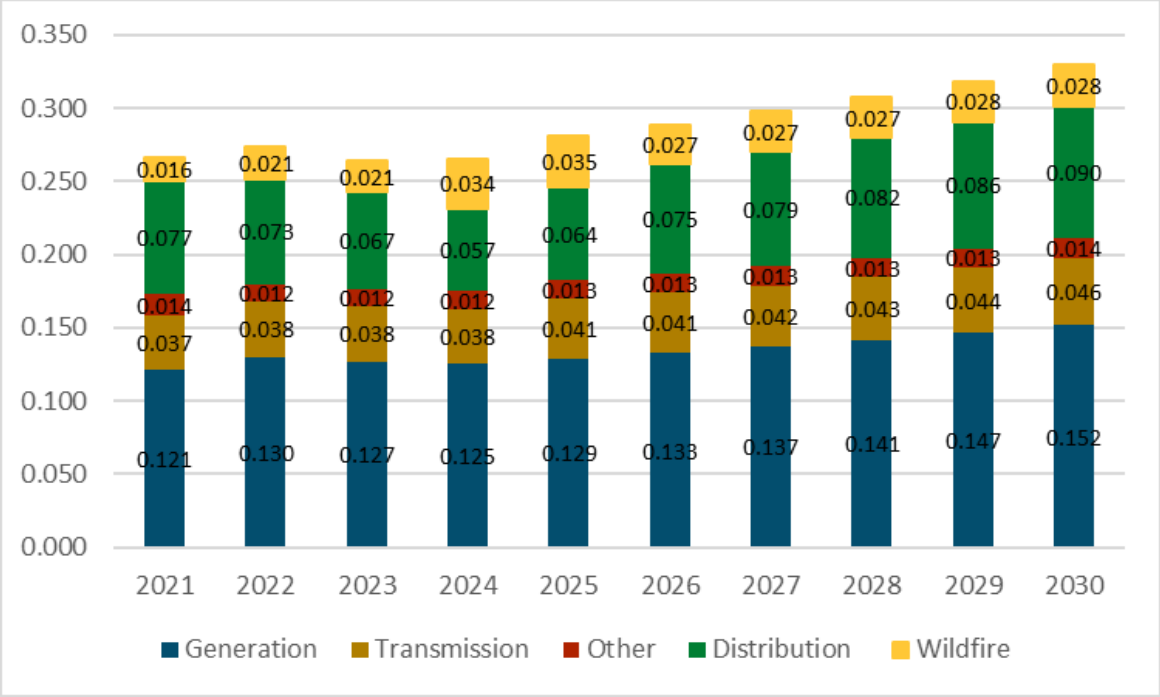
Figure 46: Average Monthly Energy Costs from 2020-2030 for Representative Above Average Energy Usage Home in a Hot Climate Zone on SCE/SoCalGas Rates and SDG&E Rates



APPENDIX B: FORECASTED BUNDLED RESIDENTIAL RATES - EMBEDDED RATE COMPONENTS BY NOMINAL $/KWH

Forecasted bundled residential rates in Figure 31 through Figure 33 are shown below with embedded rate component data.[180]

Figure 47: PG&E Forecasted Bundled Residential Rates ($ nominal/kWh), All Embedded Rate Components

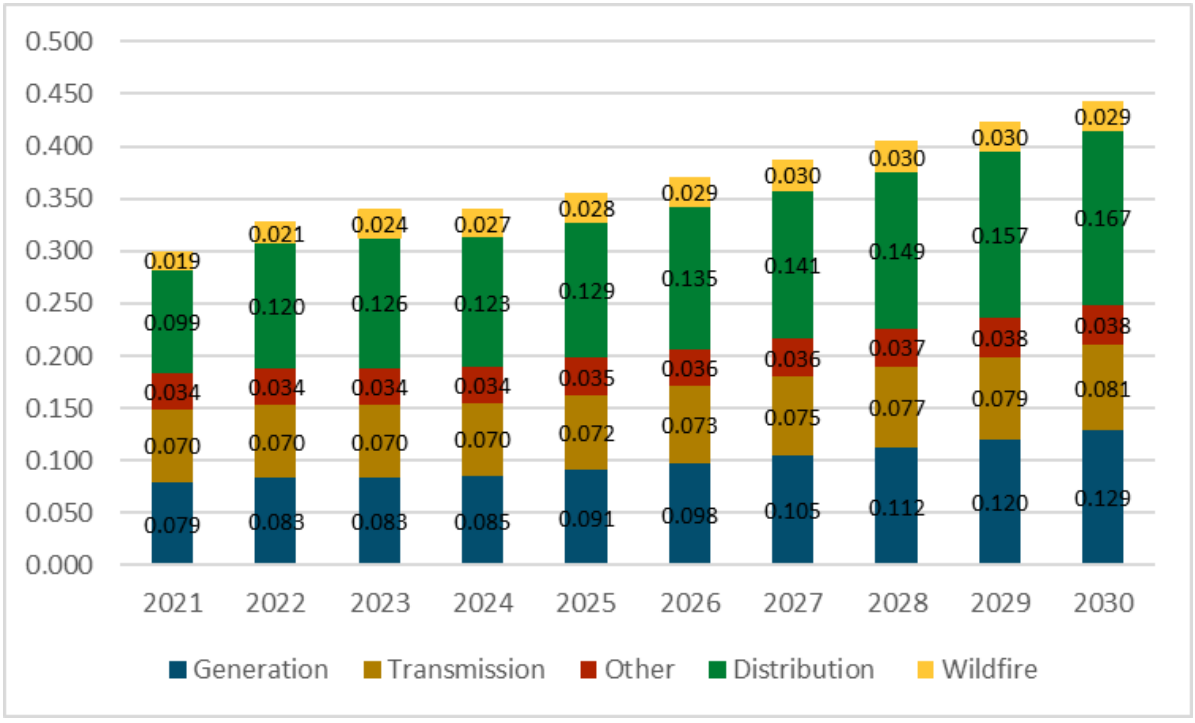


[180] The rates in Figures Figure 47 through Figure 49 are intended solely to facilitate discussion related to this white paper and are not to be used for any other purpose.

Figure 48: SCE Forecasted Bundled Residential Rates ($ nominal/kWh), All Embedded Rate Components



Figure 49: SDG&E Forecasted Bundled Residential Rates ($ nominal/kWh), All Embedded Rate Components



Note on Addenda

The following addenda supplement the draft white paper that was released prior to the February 24, 2021 CPUC En Banc hearing. Addenda 1 and 2 were prepared by CPUC staff, while Addenda 3 and 4 were submitted by external subject matter experts who do not necessarily reflect the views or opinions of the CPUC.

Addendum 1 covers historical natural gas cost trends, the outlook for future natural gas costs, and proposals to limit those costs, in fulfillment of the requirements of PU Code Section 913.1. Addendum 2 is a synopsis of the ideas presented by panelists at the En Banc hearing, as well as a summary of the public comments that were submitted following the En Banc hearing. Addendum 3 is a submission from Professor David Roland-Holst of University of California, Berkeley and covers several topics related to affordability, equity, and the framework used to evaluate those issues including prospective tools that may be needed to enhance the policymaking process. Addendum 4 is a submission from Mark LeBel and Carl Linville of the Regulatory Assistance Project (RAP), and discusses proposals for equitable cost allocation and pricing as they relate to transportation electrification and distributed energy resources.

ADDENDUM 1: NATURAL GAS COST AND RATE TRENDS

Background and Status

This natural gas addendum to the SB 695 report was prepared to complete its compliance with Public Utilities (PU) Code section 913.1. It requires the CPUC to report recommendations on how to limit cost and rate increases, consistent with the state's energy and environmental goals, including goals to reduce emissions of greenhouse gases.

The CPUC regulates the natural gas utility services of more than 10 million customers served by Pacific Gas & Electric (PG&E), Southern California Gas (SoCalGas), San Diego Gas & Electric (SDG&E), and several smaller utilities.[181] Critical elements of the Public Utilities Code related to gas services require that the CPUC:

1. Evaluate the reasonableness of natural gas rates and rate changes;
2. Oversee Core Transport Agent (CTA) rules[182] and consumer protection matters;
3. Oversee the adoption of standards and incentives for biomethane production;
4. Oversee the implementation of utilities' Pipeline Safety Enhancement Plans (PSEP) to pressure test or replace all intrastate transmission pipelines that do not have a record of a pressure test;[183] and
5. Determine the feasibility of minimizing or eliminating use of SoCalGas Aliso Canyon gas storage facility while still preserving energy reliability.[184]

These mandates are reflected in ongoing activities in formal rate cases, cost allocation proceedings, several renewable natural gas efforts, and safety-oriented proceedings.

Gas customers are divided into two main categories—core and noncore customers. Residential and small commercial customers generally fall into the core category. Noncore customers include large commercial customers, including electric generators, refineries, hospitals, and manufacturers. The utilities are responsible for procuring and delivering natural gas to most core customers. Noncore customers make their own arrangements to procure the natural gas and rely on the utilities for the delivery of the natural gas. Some core customers have chosen to have a third-party CTA procure natural gas for them.

Natural gas utility costs, other than the cost of purchasing the gas commodity itself, are generally addressed in general rate case (GRC) proceedings and are composed of: capital gas transportation or transmission, distribution, storage costs; system operations, maintenance, customer service costs; administrative and general costs; and public purpose program costs. Transmission consists of the backbone and local transportation systems. The utilities' backbone provides service on the transmission pipelines from system receipt points to customers or to the local transmission system. Local transmission transports gas from backbone pipelines and storage fields to the utilities' distribution system. The actual cost of purchasing the natural gas is a pass-

[181] Public Utilities Code Section 913.1(b) mandates that gas corporations with 500,000 or more retail customers in California study and report on measures the corporation recommends be undertaken to limit costs and rate increases. The large natural gas Investor-Owned Utilities (IOU) that are required by Public Utilities Code Section 913.1(b) to submit Senate Bill (SB) 695 reports are PG&E, SoCalGas, and SDG&E.

[182] Core Transport Agents (CTAs) procure gas for core customers such as residential and small commercial customers as an alternative to the utility. A CTA customer does not pay the utilities' procurement rate.

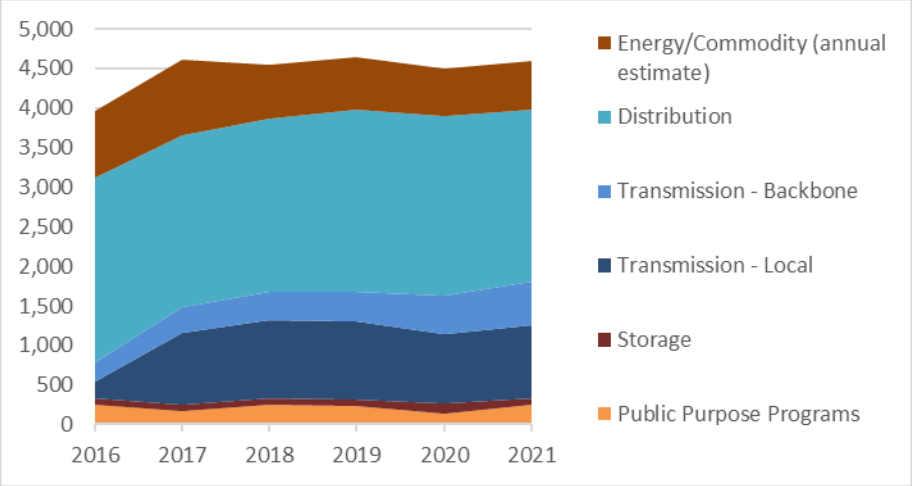
[183] Public Utilities Code Section 958: https://codes.findlaw.com/ca/public-utilities-code/puc-sect-958.html.

[184] Public Utilities Code Section 714: https://codes.findlaw.com/ca/public-utilities-code/puc-sect-714.html.

through to the customer, meaning the cost is not marked-up, and the costs are adjusted monthly on customer bills. See figures below for PG&E, SoCalGas and SDG&E.[185]

PG&E Revenue Requirement by Rate Category

Figure 1: 2016–2021 PG&E January 1 Revenue Requirement by Rate Category ($ millions)



Revenue requirement is the total annual revenue required by a public utility to recover the cost of providing service to its customers including a fair return on its investments. PG&E's total authorized gas costs, or gas revenue requirement, has increased by approximately 16.1 percent since 2016. From 2020 to 2021, PG&E's gas revenue requirement increased by 2.3 percent. The underlying revenue requirement components from 2020-2021 changed by the following percentages:

- Energy/Commodity increased by 3.5 percent,
- Distribution decreased by 3.8 percent,
- Backbone Transmission increased by 11.2 percent,
- Local Transmission increased by 5.7 percent,
- Storage decreased by 41.2 percent[186] and
- Public Purpose Programs increased by 94.6 percent.[187]

[185] All data is from 2016 – 2020 IOU responses to Energy Division SB 695 Report data requests. Core procurement revenue requirement is an annual estimate and all other revenue requirements are authorized revenue requirements. For all IOUs, the core procurement revenue requirement estimate is lower in 2020 than in 2019 due to a forecasted decrease in the weighted average cost of gas in 2020.

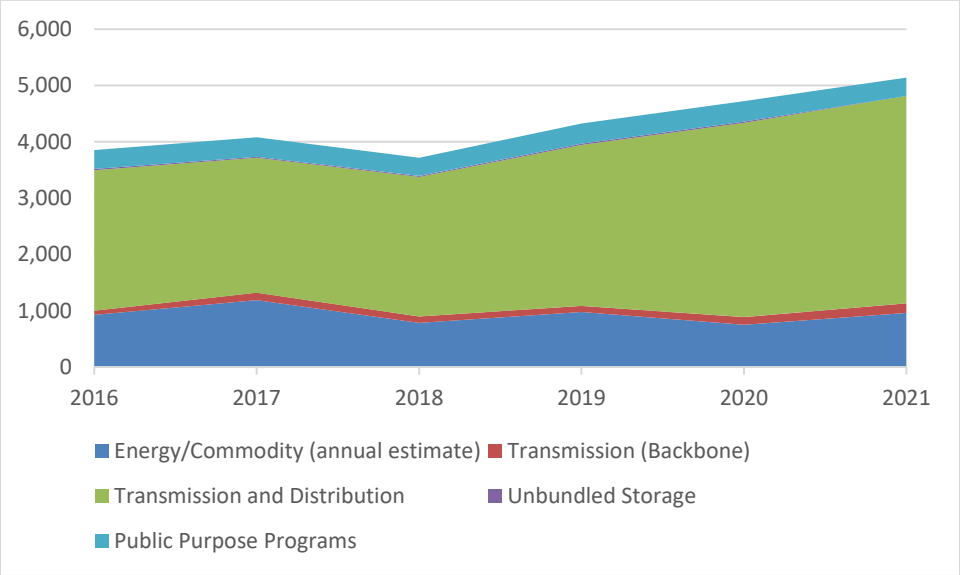
[186] The primary drivers of the 41.2 percent decrease in Storage costs are, as adopted in PG&E's 2019 GT&S D.19-09-025, is a reduction of approximately $43 million for the 2019 GT&S undercollection costs related to storage and the adoption of the Natural Gas Storage Strategy (NGSS).

[187] The natural gas PPP surcharge funds the following programs: Energy Efficiency (EE), Energy Savings Assistance (ESA), Statewide Marketing Education and Outreach, CARE, and public-interest R&D. In 2020, the ESA account balance included credits (accrued in 2018-

The Distribution component accounts for the largest portion of the 2021 revenue requirement.[188] The primary driver of the increase to the backbone transmission costs relates to targeted investments that will modernize PG&E's gas system, such as the expansion of automatic or remotely operated shut-off valves on segments of its gas transmission pipelines located in heavily populated areas. The valves will give PG&E operators the capability to remotely shut off gas flows without having to dispatch crews. PG&E completed its PSEP scope of work in 2018, at a total cost of $2.42 billion. PG&E continues to modernize its gas system as part of its overall transmission portfolio following the company's risk reduction strategy.

SoCalGas Revenue Requirement by Rate Category

Figure 2: 2016–2021 SoCalGas January 1 Revenue Requirement by Rate Category ($ millions)



Revenue requirement authorized in GRCs include the costs of operating and maintaining the utility system, capital investments in facilities and assets depreciated over its useful life, and a rate of return on invested capital for the utility. Since 2016, SoCalGas's revenue requirement has increased by about 33 percent, with about a 9 percent increase from 2020 to 2021. Energy/Commodity are related to activities for procuring gas for core customers, and include gas commodity costs and brokerage fees, but exclude backbone transmission service (BTS) costs.[189] Transmission (Backbone) refers to BTS costs that are forecast to be collected as part of core commodity charges. Transmission revenue refers to base margin revenue, revenue related to regulatory account balances, other non-base margin items like PSEP, and recovery of greenhouse gas related funds. This

2019); these credits were fully refunded to customers in 2020, resulting in a lower 2020 PPP rate. The primary reason the 2021 PPP rate will increase by 94.6% is due to the fact that customers will no long receive the ESA account balance credits they received in 2020.

[188] The Distribution, Backbone Transmission, Local Transmission, and Storge revenues are collected via PG&E's transportation rate component of the gas bill.

[189] Backbone Transmission Service provides service on SoCalGas high-volume transmission pipelines from system receipt points to customers or to the local transmission system.

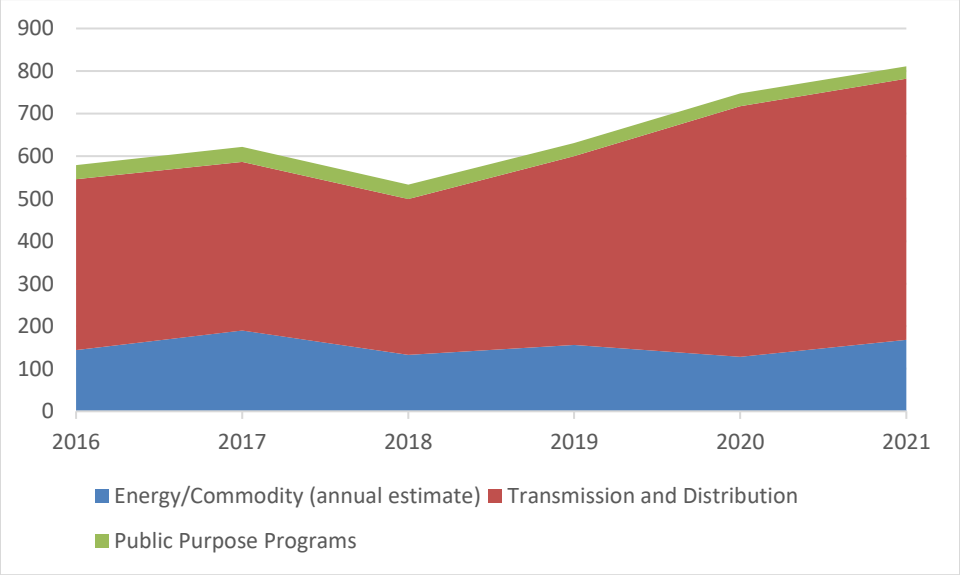
includes revenues related to the noncore portion of BTS but excludes the core portion of BTS. Revenue requirement components, from 2020 to 2021 changed by the following percentages:

- Energy/Commodity increased by 18.7 percent,
- Transmission (Backbone) increased by 3.2 percent,
- Transmission and Distribution increased by 71.7 percent, and
- Public Purpose Programs increased by 6.3 percent.

Transmission costs, which include both transmission and distribution, comprise the largest portion of the 2020-2021 revenue requirement increase. The 2021 transmission revenue requirement increases are primarily due to the implementation of SoCalGas' 2019 GRC Phase 1 decision[190] attrition for 2021. A large part of the revenue requirement increases in the 2019 GRC represent costs for incremental safety-related programs and activities that are being added to the GRC for the first time because of the Risk Assessment Mitigation Phase (RAMP).[191] In addition, there is an increase in greenhouse gas compliance cost, leak abatement costs, and amounts from decisions on the utility's PSEP. To date, SoCalGas has spent over $2 billion on PSEP.[192]

SDG&E Revenue Requirement by Rate Category

Figure 3: 2016–2021 SDG&E January 1 Revenue Requirement by Rate Category ($ millions)



SDG&E's gas revenue requirement has increased by approximately 40 percent since 2016, with about a 9 percent increase from 2020 to 2021. Energy/Commodity relates to activities for procuring gas for core

[190] *See* D.19-09-051.

[191] The CPUC developed a risk-based framework and the RAMP phase requires SDG&E and SoCalGas to identify key safety risks and to propose programs to mitigate these risks.

[192] January 2021 SoCalGas PSEP Update, Appendix D: https://www.socalgas.com/sites/default/files/SCG-SDGE%20Monthly%20PSEP%20Status%20Report%20202101.pdf.

customers and includes gas commodity costs, brokerage fees, and BTS costs. Revenue requirement components, from 2020 to 2021, changed by the following percentages:

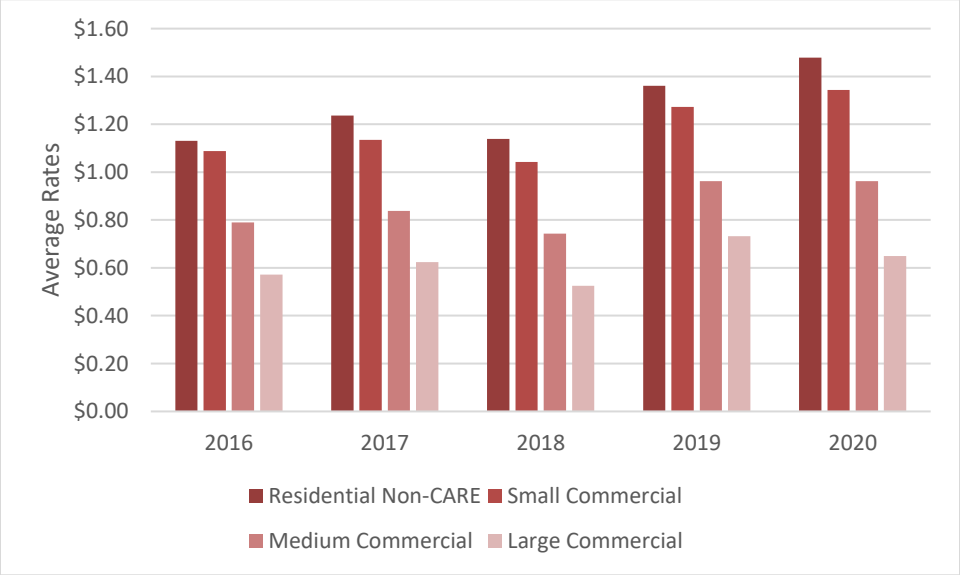
- Energy/Commodity increased by 21 percent,
- Transmission and Distribution increased by 76 percent, and
- Public Purpose Programs increased by 4 percent.

Transmission costs comprise the largest proportion of the 2020-2021 revenue requirement increase. The 2021 increase in transmission revenue requirement is primarily due to the implementation of the GRC decision[193] post-test year adjustment for 2021[194], partially offset by a decrease in the amount of costs recorded in balancing accounts that are being amortized in 2021. Transmission costs also include amounts from decisions addressing the utility's overall PSEP work. SDG&E has spent more than $603 million on PSEP to date.

Average Rates by Customer Class

A breakdown of average rates by customer class is shown for SoCalGas, SDG&E, and PG&E in Figures 4 through 6. Each class shows an upward trend during this period (2016 to 2020). Residential and small business customer classes have higher average rates than the medium and large customers with lower average rates. Residential and small business customers pay higher rates than industrial customers using larger quantities of natural gas because core customers are more expensive to serve and have greater reliability. The fixed costs of serving larger customers is recovered over larger number of therms, which result in lower rates per therm.

Figure 4: SoCalGas Average Rates, By Class, Rates in Effect January 1



[193] *Id.*

[194] The revenue requirement authorized in the 2019 GRC decision (D.19-09-051) is the amount of revenue the utility needs to earn in a test year (2019) and post-test years (2020 and 2021) in order to provide service to its customers.

Figure 5: SDG&E Average Rates, By Class, Rates in Effect January 1

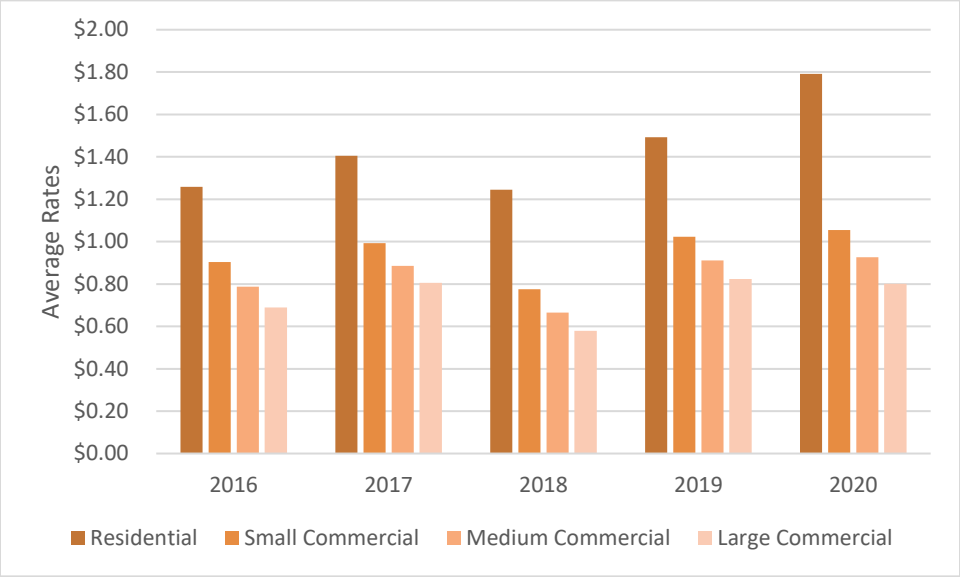
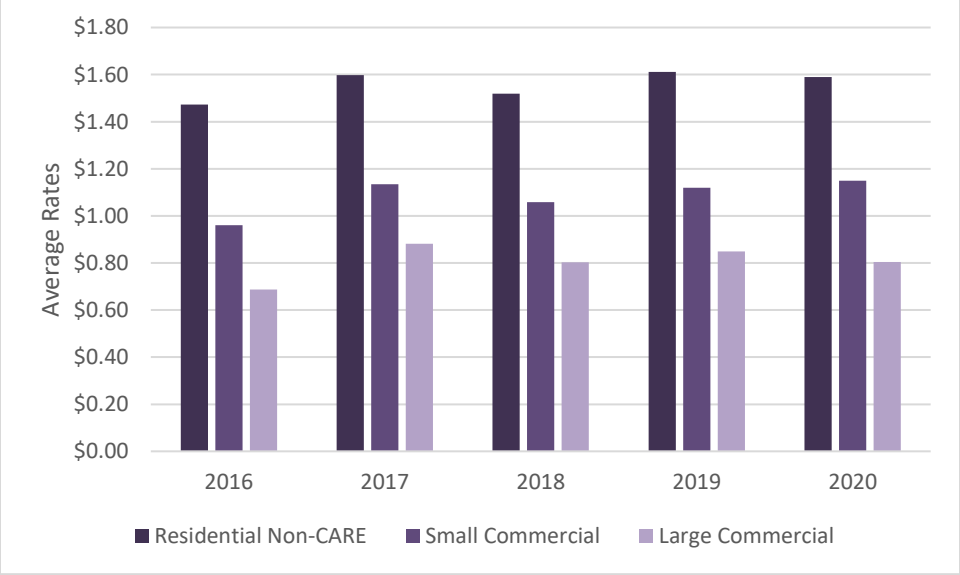


Figure 6: PG&E Average Rates, By Class, Rates in Effect January 1



Cost and Rates Containment

The CPUC has undertaken actions to limit utility cost and rate increases during the succeeding 12 months (May 1, 2021–April 30, 2022) through scrutiny of gas utility revenue requirements in GRCs and corresponding scrutiny of gas rates in cost allocation proceedings and advice letters. Gas rates can be defined as revenue requirement divided by sales. Changes to revenue requirement, determined in GRCs, and forecasted sales demand, determined in cost allocation proceedings, impact the actual rates for gas services. Similarly, changes

to forecasted demand and the allocation of the revenue requirements across customer classes impact the gas rates experienced by individual customers.

PG&E

GRC Review

In 2020, the CPUC reviewed the reasonableness of the gas costs in the settlement agreement filed in PG&E's 2020 GRC. The CPUC adopted the settlement agreement in D.20-12-005, which approved $2.0 billion[195] in revenues to be collected in gas rates from PG&E customers in 2020. The settlement agreement was an agreement reached by PG&E and several parties[196] regarding PG&E's gas and electric revenue requirements for 2020-2022.

Residential Baseline Restructuring

In PG&E's Gas Cost Allocation Proceeding (GCAP), the CPUC mitigated PG&E's residential customer bill impacts via ratemaking actions resulting from the adoption of CPUC D.18-10-040 and D.19-10-034.

a) D.18-10-040 modified PG&E's winter baseline structure, increasing the Tier 1 baseline levels for December and January which allows customers to use more gas at the lower Tier 1 rate, thereby mitigating residential customers' bill volatility during the winter months;
b) D.19-10-034 increased the minimum monthly transportation bill from $3 to $4, thereby lowering residential customers' volumetric rates to further dampen monthly bill volatility;
c) D.19-10-034 ordered that residential customers' Tier 1 and Tier 2 rate differentials[197] be narrowed over four years; doing so will further help reduce excess bill volatility.

SoCalGas and SDG&E

PSEP Review

On November 13, 2018, SoCalGas and SDG&E (the Joint Applicants) filed Application 18-11-010 for review of the reasonableness of PSEP costs for 44 pipeline projects and 39 bundled valve projects. The Joint Applicants stated that they have spent approximately $854 million in capital expenditures and $86.7 million in Operations and Maintenance expenses.

[195] D.20-12-005 Appendix B, Table 1-B, Line 1

[196] The Settling Parties include PG&E, the Public Advocates Office of the CPUC (Cal Advocates), The Utility Reform Network (TURN), Center for Accessible Technology (CforAT) , National Diversity Coalition (NDC), Small Business Utility Advocates (SBUA), Coalition of California Utility Employees (CUE), the Office of the Safety Advocate of the California Public Utilities Commission (OSA).

[197] The baseline "Tier 1" allowance provides a low rate for basic gas needs. Customers pay a higher Tier 2 rate if they use more gas than the baseline allowance. The baseline allowance various by PG&E Climate Zone.

In its August 27, 2020 decision, D.20-08-034, the CPUC adopted a Settlement Agreement resolving issues raised in A.18-11-010. Decision 20-08-034 granted the Joint Applicants a total of $34.6 million in PSEP costs or $4 million less than the Joint Applicants requested.

GRC Additional Years' Revenues

In April 2020, SoCalGas and SDG&E filed a joint petition to modify the decision from their 2017 general rate case to extend it two additional years (also known as "attrition years") as directed in the January 2020 Rate Case Plan decision.[198] The CPUC issued a Proposed Decision on March 19, 2021, proposing revenue requirements of $2.3 and $2.4 billion for SDG&E and $3.3 and $3.4 billion for SoCalGas for 2022 and 2023, respectively. These revenue requirements are slightly less than the original utilities' requests made in the petition. The CPUC proposed an escalation factor index to determine the amount of revenues to be collected for those two additional years, which reflects the impacts of COVID-19 pandemic on ratepayers. This reduced the utilities' initial requested relief by $12.9 million and $19.5 million for SoCalGas and $7.1 million and $29.8 million for SDG&E, for 2022 and 2023, respectively. This revenue requirement reductions resulted in a more just and reasonable rates for customers.

Gas Costs Incentives

The Gas Cost Incentive Mechanism (GCIM) provides SoCalGas with a financial incentive to purchase and transport gas for core ratepayers at a cost that is equal to, or less than, prevailing market prices. The GCIM compares actual monthly purchased gas costs (commodity and transportation) to monthly benchmarks over the 12-month (April to March) period.

On June 15, 2020, SoCalGas submitted an application[199] seeking approval of a shareholder reward of $12,806,448 for its GCIM gas procurement performance on behalf of the core customers of SoCalGas and SDG&E for the period April 1, 2019 through March 31, 2020 (also known as "Year 26"). costs (commodity and transportation) to monthly benchmarks over the 12-month (April to March) period. D.21-02-004 was issued on February 11, 2021, approving SoCalGas' request. SoCalGas' recorded gas costs were $81 below the benchmark, which resulted in core ratepayer gas commodity costs that were $69 million below prevailing market price.

TCAP Residential Baseline Restructuring

In February 2020, the CPUC adopted Triennial Cost Allocation Proceeding (TCAP) D.20-02-045, approving SoCalGas' proposal to implement SB 711 (Hill, 2017). SB 711 required the CPUC to make efforts to minimize bill volatility for residential customers. It explicitly authorized the CPUC to do this by modifying the length of baseline seasons or defining additional baseline seasons. The CPUC adopted a two-part process to adjust

[198] *See* D.20-01-002.
[199] *See* A.19-06-009.

SoCalGas baseline calculations: 1) update the baseline allowances by reducing the residential baseline quantities so that the baseline is 70 percent of average household usage in winter and 60 percent of average household usage in summer[200] and 2) modify the baseline seasons to divide the winter season into On-Peak (December, January, and February) and Off-Peak (November, March, and April), and retain the summer season as May through October. SoCalGas is expected to complete the billing modifications necessary to implement the modified baseline seasons beginning May 1, 2021.[201] This will result in a slight decrease in residential customers gas bills.

All Investor-Owned Utilities

Risk Spending Accountability Report (RSAR) Reviews

In December 2014, the CPUC issued D.14-12-025, which directed the investor-owned utilities under its jurisdiction to prepare annual reports comparing GRC-authorized and actual spending on risk mitigation projects and explain any discrepancies. In 2020, CPUC staff reviewed the Risk Spending Accountability Reports (RSARs) filed by the investor-owned utilities (IOUs) and identified spending patterns of concern with respect to the provision of safe and reliable gas and electric service. The RSAR reviews provide stakeholders in the general rate case process useful information regarding the IOUs' spending on major work categories for cost containment consideration in the next GRCs.

PG&E submitted its RSAR on March 30, 2020. CPUC's Energy Division Staff reviewed[202] and provided recommendations to include more detailed explanations of spending and unit variances that describe the decision-making process and the source and diversion of funds.

SDG&E and SoCalGas submitted their RSAR on March 31, 2020. CPUC's Energy Division Staff reviewed[203], highlighting cost shifting between accounts, activities, or categories. This is the first official round of RSARs (see D.19-04-020), and parties to SDG&E and SoCalGas' GRC (D.19-09-051) served official comments to the review, which were included in the final report.

Activities and Proceedings in the Upcoming 12 Months (May 1, 2021–April 30, 2022)

OIR to Establish Policies, Processes, and Rules to Ensure Safe and Reliable Gas Systems in California and Perform Long-Term Gas System Planning

[200] SoCalGas' current previous baseline allowances have had been in effect since 2002.

[201] *See* SoCalGas Advice Letter 5778, approved in April 2021.

[202] Risk Spending Accountability Reports: https://www.cpuc.ca.gov/General.aspx?id=6442461400

[203] *Id.*

On January 16, 2020, the CPUC opened a rulemaking[204] to analyze long-term planning for the California natural gas system given the forecasted reductions in natural gas demand over the next 25 years. The proceeding has three tracks, with the first two tracks focused on shorter term needs to potentially adjust gas system planning and reliability standards. The third track will focus on regulatory solutions and planning strategy that the CPUC should implement to ensure that, as the demand for fossil natural gas declines, gas utilities maintain safe and reliable gas systems at just and reasonable rates, with minimal or no stranded costs.

PG&E Recovery of 2011-2014 GT&S Capital Expenditures

On July 31, 2020, PG&E filed A.20-07-020 requesting cost recovery of $512 million for gas transmission and storage (GT&S) capital expenditures that it incurred in 2011 to 2014 above the costs that the Commission had authorized in D.11-04-031.

PG&E previously requested recovery of these GT&S capital expenditures in PG&E's 2015 GT&S rate case (A.13-12-012). Decision 16-06-056 disallowed the recovery of these capital expenditures but allowed PG&E to seek recovery of these GT&S costs in a future application, after the Commission's Safety and Enforcement Division (SED) or a third party performs an audit of the reasonableness of these costs. SED completed the audit and issued a report (Audit Report) with its findings on June 2, 2020.

Now that SED has issued the Audit Report, PG&E seeks approval to receive $416.3 million of revenue requirement, relating to the $512 million in 2011-2014 GT&S capital expenditures that D.16-06-056 ordered for further review and certification. To minimize the impact on customers, PG&E proposes to amortize most of the $416.3 million revenue requirement over 36 months starting in April 2021. This proceeding is ongoing.

Aliso Canyon Order Instituting Investigation

On February 9, 2017, the CPUC opened the Aliso Canyon proceeding, Investigation I.17-02-002, as directed by SB 380 (Pavley, 2016). SB 380 required the CPUC to "determine the feasibility of minimizing or eliminating the use of the SoCalGas Aliso Canyon Natural Gas Storage Facility while still maintaining energy and electric reliability for the region." The proceeding was divided into three phases. In Phase 1, Energy Division staff worked with stakeholders to determine the assumptions and scenarios to be used in modeling. In Phase 2, which is still ongoing, Energy Division staff performed the modeling agreed upon in Phase 1. Parties have reviewed the modeling report and some parties have requested additional modeling to be done. In Phase 3, which is also underway, a third-party consultant is modeling changes to the existing gas and electric infrastructure that would allow Aliso Canyon to be closed by 2027 or 2035.

The CPUC is also using this proceeding to determine the facility's maximum allowable gas storage inventory. SB 380 had directed the CPUC Executive Director to make that determination based on an annual report produced by the CPUC, but that code section expired on January 1, 2021, so the Commission has formalized the process in this proceeding.

[204] *See* R.20-01-007.

Decisions on both Phase 2 and Phase 3 are expected in late 2021 or early 2022.

OIR to Implement Dairy Biomethane Pilots

Pursuant to SB 1383 (Lara, 2016), the CPUC opened a rulemaking[205] to establish dairy biomethane natural gas pipeline injection demonstration projects. In 2018, the CPUC along with the Air Resources Board and the Department of Food and Agriculture, put forth a pilot solicitation and selected six projects for construction. Contracts between utilities and developers of the six pilot projects have been signed and are under review at the CPUC. Construction of these projects should take approximately two years for interconnection to occur. Upon completion, the new dairy biomethane facilities will convert biogas from dairy digesters into renewable natural gas (RNG) for heating and transportation purposes and move California closer to its goal of reducing methane emissions by 40 percent below 2013 levels by 2030. The pilots will undergo evaluation processes to determine GHG reduction levels and project goal attainment. Forecasted costs associated with the six pilot projects are estimated to be approximately $133 million and any deviation from those cost estimates will be reviewed as part of the CPUC's cost review work. Due to delays experienced as a result of the COVID-19 pandemic, the first of these projects was adjusted to come online in 2021 and the last of these projects will now come online in 2022.

Biomethane Procurement Considerations (SB 1440 Implementation)

In response to SB 1440 (Hueso, 2018), Phase 4 of R.13-02-008 was opened in order to explore, among other things, whether to create a biomethane procurement program. An Energy Division Staff Proposal will make recommendations on whether and to what extent it is necessary to authorize the gas utilities to procure biomethane in an effort to help California reduce methane emissions consistent with the goals outlined in SB 1383. Parties will comment on the Staff Proposal, and the Commission will ultimately decide whether to adopt its recommendations.

OIR to Aid Disadvantaged Communities in the San Joaquin Valley

On March 26, 2015, the CPUC opened a rulemaking[206] to implement Assembly Bill (AB) 2672 (Perea, 2014). The CPUC was directed to analyze the economic feasibility of certain energy options including: (a) extending natural gas pipelines; (b) increasing existing program subsidies to residential customers; and (c) other alternatives that would increase access to affordable energy. The Phase I decision adopted the methodology for identification of communities meeting the statutory definition of a San Joaquin Valley (SJV) Disadvantaged Community under Section 783.5. Phase II of the rulemaking adopted D.18-12-015 which approved $56 million in funding for electrification pilot projects in 11 SJV communities and a natural gas pilot project in one community. Implementation of the pilots has begun and will be ongoing throughout 2021. As of

[205] *See* R.17-06-015.
[206] *See* R.15-03-010.

December 31, 2020, 320 homes have completed assessments for the pilot. A major focus of 2021 will be completing installation of the electrification and natural gas measures in those homes and all subsequent homes that receive assessments.

OIR to Evaluate Mobile Home Park Pilot Program and Adopt Programmatic Modifications

On April 16, 2018, the CPUC opened a rulemaking,[207] R.18-04-018, to evaluate the Mobile Home Park Pilot Program (MHP Pilot Program), consider programmatic modifications, and determine if a permanent program is appropriate. Initially adopted in D.14-03-021, the MHP Pilot program converted gas and electric master metered/sub-metered mobile home parks to direct utility services. The CPUC Safety and Enforcement Division's Gas Safety and Reliability Branch (GSRB) determined the priority of MHP conversions based primarily on safety, reliability, capacity and efficiency considerations.

On April 16, 2020, the CPUC adopted D.20-04-004, finding that the pilot met its goals. Total expenditures for converting MHP gas and electric hookups in 2014-2018 were $612 million, and 25,000 MHP spaces were converted to utility service. Apart from minor revisions, for the 2021-2030 period, D.20-04-004 retains the features of the pilot. Of the approximately 380,000 spaces in the 4,900 MHPs in California, the MHP Utility Conversion program will aim to convert 50 percent of MHP spaces by 2030 in the areas served by the large gas and electric utilities, and 100 percent of MHP spaces in the case of the smaller electric-only utilities to direct utility services. The estimated annual costs for gas and electric conversion are $237 million for all eight utilities implementing the program. The total costs over the 2021-2030 period will be over $2 billion, to be covered by ratepayers and reviewed in the utilities' GRCs.

SoCalGas Application to Offer a Voluntary Renewable Natural Gas Tariff

On February 2, 2019, SoCalGas and SDG&E filed a joint Application[208] requesting authorization to offer a Voluntary Renewable Natural Gas Tariff (VRNGT) program that would allow eligible residential and non-residential customers to procure all or some of their natural gas from renewable sources. On December 17, 2020, the CPUC voted to adopt D.20-12-022 and allow SoCalGas and SDG&E to offer a modified VRNGT program that incorporates biomethane procurement targets that are in line with SB 1440.[209] The goal of the adopted VRNGT program is to accelerate the use of biomethane, to capture methane to develop biomethane supplies, and to reduce Short-Lived Climate Pollutants (SLCPs) and other GHG emissions in California. Having a pilot program in advance of the implementation of SB 1440 may help utilities and customers gain experience in using biomethane as part of gas service, expand upon the existing biomethane market in California, and provide the CPUC with valuable information to inform future statewide biomethane procurement policies. SoCalGas and SDG&E have until June 17, 2021, to decide whether they intend to offer

[207] *See* R.18-04-018.
[208] *See* A.19-02-015
[209] *See* D.20-12-022

a program. If they decide to do so, the CPUC will monitor the implementation and offering of the VRNGT for the next five years, to determine if it should continue.

SoCalGas, SDG&E, PG&E, and Southwest Gas Joint Application to Conduct Hydrogen Blending Demonstration Projects

On November 20, 2020, SoCalGas, SDG&E, PG&E and Southwest Gas (Joint Utilities) filed a joint application [210] regarding hydrogen-related additions or revisions to the Standard Renewable Gas Interconnection Tariff (SRGI Tariff). The Application was filed to comply with a November 21, 2019 Ruling by Commissioner Clifford Rechtschaffen, opening Phase 4 (Phase 4 Ruling) of the Order Instituting Rulemaking to Adopt Biomethane Standards and Requirements, Pipeline Open Access Rules, and Related Enforcement Provisions (Rulemaking 13-02-008). In the Application, the Joint Utilities propose a definition of "renewable hydrogen", but this issue was transferred to the proceeding, where it will be addressed. The Joint Utilities decline to offer revisions to the SRGI Tariff to allow injection of hydrogen in the Application because they have insufficient confidence that public safety, pipeline integrity, and reliability will not be compromised. In this Application, the Joint Utilities seek approval of memorandum accounts for each respective Utility. Additionally, SoCalGas and SDG&E propose a hydrogen blending demonstration program that they expect will help inform any future establishment of any appropriate hydrogen injection standards, protocols, and agreements. The cost estimate for the proposed five-year demonstration program is $32 million. The assigned Commissioner and Administrative Law Judge are evaluating the Application.

In 2020, the Commission contracted with the University of California at Riverside to conduct a study of safe levels of injection of hydrogen into the gas distribution system and provide recommendations. The study should be completed in Fall 2021. The Commission has also approved expenditure of ratepayer funds for research on blending hydrogen in the gas distribution system as part of the California Energy Commission's gas natural research budget (Resolution G-3571, approved November 5, 2020) and authorized SoCalGas expenditure of ratepayer funds on research on renewable hydrogen production (Resolution G-3573, approved March 18, 2021).

PG&E Application 20-08-023 to Amend Ruby Pipeline Contract

On August 28, 2020, PG&E filed Application 20-08-023 to seek approval of amendments to two contracts executed between Ruby Pipeline, LLC and PG&E. The Application seeks approval of various contract amendments which were negotiated between the parties to resolve a contract dispute resulting from PG&E's bankruptcy and downgrading of its credit rating. A decision is expected this summer.

[210] *See* A.20-11-004.

SoCalGas/SDG&E Line 1600 Repairs and Replacement

In A.15-09-013, SoCalGas and SDG&E applied for a Certificate of Public Convenience and Necessity (CPCN) for the construction of a new transmission pipeline, Line 3602. The utilities also proposed to reclassify an existing transmission pipeline, Line 1600, from transmission to distribution to avoid potential customer rate impacts due to required pressure testing. In Phase One of the proceeding, the Commission evaluated the need for the proposed project pertaining to safety, reliability, resiliency, and operational flexibility and to resolve basic planning assumptions and standards that may inform the California Environmental Quality Act (CEQA)/National Environmental Policy Act (NEPA) process. On June 21, 2018, the Commission denied SDG&E's and SoCalGas' request for a CPCN for the proposed Line 3602 project.[211]

The Commission opened a second phase to review cost forecasts pertaining to the SoCalGas/SDG&E's Line 1600 PSEP.[212] Under the approved plan, SoCalGas/SDG&E will replace segments of the line located in high consequence areas and hydrotest parts of the line located in non-high consequence areas. The project is estimated to cost $677 million, with $630 million anticipated to be capital expenditures and $47 million estimated to be operating expenses. Phase 2 of this proceeding will enable the CPUC to provide appropriate guidance regarding the reasonableness of the cost estimates, cost containment strategies, ratemaking and accounting treatment. D.20-02-024 did not grant cost recovery in this phase; however, reasonableness review of the cost forecasts established in this phase will occur in later GRCs.

On August 12, 2020, pursuant to the decision, SoCalGas and SDG&E submitted testimony presenting forecasted costs for the SED-approved test-or-replace plan. On September 11, 2020, parties jointly filed a report following a meeting to confer on the issues. The assigned Commissioner and Administrative Law Judge will determine the next steps, including the scheduling of a prehearing conference and issuance of an amended scoping memo.

[211] *See* D.18-08-028.

[212] *See* D.20-02-024.

ADDENDUM 2: EN BANC HEARING AND COMMENT SUMMARY

Background and Overview

The En Banc hearing held on February 24, 2021 to discuss electricity costs, rates, and affordability in California produced a highly engaging discussion on a range of topics. In addition to the ideas and observations put forth by panelists on the day of the hearing, written comments were submitted by stakeholders in the following weeks. This exchange of ideas provides an important foundation for future work on controlling the growth of electric rates, while ensuring that the state's policy priorities are adequately funded.

This addendum to the white paper provides a summary of the discussion, based on the panelists' observations and stakeholders' comments.

Summary of En Banc Panelists' Presentations

The En Banc hearing consisted of three panels, as well as an introductory presentation by CPUC staff to review the key findings from the white paper. A summary of the presentations from the three panels is provided here. All points summarized here reflect the comments made by the panelists on the day of the En Banc hearing and do not include any analysis of their recommendations.

Panel 1: Can We Afford the Future?

The first panel was focused on understanding the electric rate outlook, as well as its implications for affordability, equity, and California's ambitious climate goals.

Mike Campbell (Public Advocates Office)

Mike Campbell, a manager with the Public Advocates Office, put the current residential electric rate outlook in the context of recent historical trends. Electric rates for the three big IOUs started outpacing inflation in the mid-2010s, though SCE was able to keep rate increases relatively close to inflation until fairly recently. Large wildfire expenditures are expected to push rates higher in the near future. Furthermore, electric sales have declined in recent years, meaning that the increasing revenue requirement cannot be offset by higher sales to keep volumetric rates down. This drop in sales can be attributed to the proliferation of rooftop solar. There are equity concerns associated with this trend, as the cost shift is negatively impacting customers who are unable to adopt rooftop solar and those customers tend to be in lower income and minority households. Finally, based on Public Advocates Office's comparison of electric and gasoline fuel costs, it is already cheaper to fuel a conventional internal combustion engine (ICE) vehicle than it is to charge an EV for non-CARE

customers in SDG&E's territory and that will also be the case for the other two IOUs by the end of this decade. In considering how to design EV rates, it is important to keep in mind equity considerations in addition to electrification goals.

Mad Stano (Greenlining Institute)

Mad Stano, a senior legal counsel with the Greenlining Institute, discussed the inequitable distribution of costs and benefits of California's energy policies. Electric rates are currently unaffordable, and rate reform must prioritize protecting vulnerable populations. The unaffordability of electric rates is demonstrated by the high dollar amount of arrearages that existed even before the start of the pandemic, and the recent recession has exacerbated the economic woes of already vulnerable communities. Inability to pay for electricity has dire consequences, and it is in this context that any proposed rate increase should be seen. Furthermore, Stano argued that decarbonization of California's electric grid will not occur under inequitable financing and rate schemes. Low-income households have less access to cost-saving technologies such as rooftop solar, EVs, and home electrification. With lower income households unable to electrify their homes, they will be left paying for stranded natural gas assets. Stano argued that the CPUC should stop bifurcating ratemaking for electricity and natural gas, and the CPUC must develop more protections for low-income households. Stano presented data showing that uptake of distributed energy resource (DER) technologies has been lowest in vulnerable communities, where the marginal environmental benefits would be the greatest. The conclusion is that the state needs to design DER programs so that they encourage participation in lower income communities.

Michael Colvin (Environmental Defense Fund)

Michael Colvin, a director at the Environmental Defense Fund (EDF), discussed the benefits of prioritizing medium- and heavy-duty EV adoption in vulnerable communities. California has some of the worst air quality in the country, with hot spots located in disadvantaged communities. Colvin suggests targeting policy changes (rate design; baseline usage allocation; marketing, education, and outreach; and electric vehicle infrastructure) in these same areas so that the air quality benefits of EV adoption can be maximized. Adoption will be driven by rate design, so it is important to keep electric rates low and predictable in order to keep the total cost of ownership of electric medium- and heavy-duty vehicles low. Another key component of total cost of ownership is charging infrastructure, so he recommended that multiple models for charging infrastructure deployment be considered including a role for ratepayer-funding. EVs can provide grid support services so they should be viewed as a resource.

David Rapson (University of California, Davis)

David Rapson, a professor of economics at UC Davis, presented his findings on three research questions: (1) How effective are EV subsidies? (2) Do energy prices affect EV demand? (3) How much electricity do EVs

consume? On the first question, Rapson finds that subsidies are very effective at promoting EV adoption as demonstrated by the impact of a tax credit that Georgia had previously offered. Based on his research, he also found that in California a total subsidy (state plus federal) of $15,000 to $25,000 was needed for each incremental EV purchased. This translates to a total cost of $12 billion to $18 billion in state plus federal subsidies if California is to reach its 2025 goal of 1.5 million EVs. On the second question, Rapson found that high electricity prices inhibit EV demand (a $0.10/kWh increase in electricity prices yields a 15% decrease in EV demand) and that high gasoline prices encourage EV demand (a $0.50/gallon increase in gasoline prices yields a 30% increase in EV demand). On the third question, Rapson presented data suggesting that EV owners were using far less electricity than had been previously estimated (2.9 kWh/day compared to the previously measured 7.2 kWh/day which had been based on dedicated EV meters from a limited sample of customers). It is possible that, as battery ranges increase, this electricity usage amount may increase in the future.

Panel 2: What Strategies for Cost Control or Reduction Do We Need to Explore?

The second panel explored options for reigning in costs so that electric rates can be kept at an affordable level.

Robert Kenney (Pacific Gas and Electric)

Robert Kenney, a vice president at Pacific Gas and Electric (PG&E), presented some initiatives that PG&E is undertaking to control costs while still delivering on its commitments to clean energy and wildfire risk reduction. The presentation included PG&E's plans to pursue operational efficiencies (work and resource planning, contract management, sale of excess renewable energy, sale of surplus properties, and headquarters redesign) that are expected to provide $1 billion in savings per year through 2025. Kenney also presented on plans to expand the sale of licenses allowing wireless providers to attach equipment to PG&E's transmission assets, which would generate $973 million in upfront revenue.

Carla Peterman (Southern California Edison)

Carla Peterman, a senior vice president at Southern California Edison (SCE), discussed SCE's efforts to control costs. The presentation mainly focused on SCE's plans to reduce wildfire insurance costs through customer-funded self-insurance. AB 1054 requires utilities to carry $1 billion in wildfire insurance, which currently costs SCE about $400 million/year. This includes multiple layers of coverage, and SCE has identified that it could save significant money by self-insuring for the highest cost coverage (the first layers of the "insurance tower"), so long as claims over a multi-year period do not exceed the premiums that would be paid to a commercial insurer. This could also result in more competitive pricing for the insurance that SCE continues to purchase through a commercial insurer.

Scott Crider (San Diego Gas & Electric)

Scott Crider, the Chief Customer Officer for San Diego Gas & Electric (SDG&E), presented on SDG&E's efforts to improve efficiency through use of technology. This includes the use of robotic process automation to automate repetitive tasks, which is expected will save the company over 700,000 hours of labor capacity by 2024. As machine learning technology progresses, more advanced tasks may be automated. Crider also discussed the use of drones to inspect assets, which should improve reliability and reduce wildfire risks while decreasing operating costs, and more advanced modeling of wildfire risks to help prioritize wildfire mitigation spending. Crider also highlighted the role of declining sales on electricity rates, particularly because of the high penetration of rooftop solar in SDG&E's territory and the relative lack of commercial and industrial load to offset the decline of residential loads. If sales in SDG&E's territory had been flat since 2012, the system average rate would be 15% lower. As a result, NEM reform is vital to keeping rates affordable.

Jennifer Dowdell (The Utility Reform Network)

Jennifer Dowdell, a senior policy expert at The Utility Reform Network (TURN), presented a set of recommendations to control utility cost growth. The recommendations were centered around three principles: (1) affordability must directly inform utility revenue requests, (2) investment in societal benefits should not create shareholder windfalls at ratepayers' detriment, and (3) diverse investment should be encouraged to reduce pressure on rates. In support of the first principle, Dowdell recommended three actions: apply the findings and methodology of the Affordability Rulemaking (R.18-07-006) to current and upcoming revenue requests; require IOUs to submit an alternative, CPI-constrained revenue proposal to reduce "anchor bias" in rate cases; and use Risk Spend Efficiency data to transparently prioritize the most cost-effective safety spending. In support of the second principle, Dowdell recommended three actions: consider CA-state asset ownership and alternative ratemaking structures for climate goal infrastructure; fund customer-side infrastructure on expense rather than capital basis; and consider general state funding of societal benefits as a less regressive alternative to ratepayer funding. In support of the third principle, Dowdell recommended two actions: favor non-utility ownership for behind-the-meter grid enhancements; and look for opportunities to leverage sources of funding other than ratepayer dollars.

Betony Jones (NextGen Policy and Inclusive Economics)

Betony Jones, an advisor to NextGen Policy and the founder and CEO of Inclusive Economics, discussed the employment and economic benefits associated with EV charging infrastructure investments and wildfire spending. Jones quantified the economic impact associated with $10 billion of wildfire spending and estimated that it would produce on net 22,000 jobs, $2.3 billion of labor income, and $6.6 billion of increased economic activity. This is driven by shifting household spending, which tends to trickle out of the state, to in-state infrastructure spending. If households earning less than $100,000 were shielded from any rate impacts

associated with the spending, the net benefits would increase to 36,000 jobs, $3.2 billion of labor income, and $8.8 billion of increased economic activity. This increase in net benefits is driven by the fact that lower income households' spending patterns tend to keep money in-state compared to money spent by wealthier households. Jones then discussed energy affordability more generally, pointing out that affordability is a function of the amount of energy used, the rates charged, and the amount of income available for energy spending. She suggested that rather than thinking about this as an energy affordability crisis, it might make more sense to think of this as a poverty crisis, in which case policymakers should be considering the economic impact of spending. As such, utilities should pay attention to their labor, wage, and diversity standards since the jobs they are creating also affect energy affordability.

Rick Umoff (Solar Energy Industries Association)

Rick Umoff, a senior director and counsel at the Solar Energy Industries Association (SEIA), presented strategies for using DERs to address affordability concerns. Umoff first discussed the need for NEM to evolve as a reflection of changing grid needs. According to Umoff, NEM is helping the state achieve its GHG and reliability goals, as well as driving the adoption of behind the meter storage. Going forward, it is important to expand access to distributed solar and storage so that low income households, disadvantaged communities, and renters can participate. He stressed the need for policy changes to be implemented gradually and predictably so as to attract private capital to meet the state's climate goals cost-effectively. He also highlighted the role NEM has played in jumpstarting the solar industry in California. Umoff then presented three strategies for leveraging distributed solar and storage: (1) using low-cost renewable energy to support electrification and DER deployment, (2) reducing grid costs and enhancing resilience through DERs, and (3) encouraging DER deployment to help meet the state's climate and land conservation goals.

Panel 3: Do We Need a Paradigm Shift in How California Funds Climate Change Initiatives?

The final panel considered options for fundamentally changing how the state funds climate change initiatives.

Severin Borenstein (University of California, Berkeley)

Severin Borenstein, a professor at UC Berkeley, presented his proposal for an equitable electric rate design.[213] He first reviewed two of the goals of electric rate design: to communicate to consumers the social marginal cost of electricity consumption (so that it incentivizes efficiency and without disincentivizing electrification) and to provide sufficient revenue to the utilities to cover their costs. An efficient rate design would price electricity at the social marginal cost, but California's rates are far higher than the social marginal cost. Marginal

[213] Borenstein S, Fowlie M, and Sallee J. (Feb 2021). Designing Electricity Rates for An Equitable Energy Transition. *Energy Institute at Haas Working Paper*. https://haas.berkeley.edu/wp-content/uploads/WP314.pdf

costs make up only about 1/3 of the price of electricity in California. Fixed costs are a large component of volumetric rates. Borenstein argued that this is essentially a highly regressive tax to pay for infrastructure and public purpose programs. One alternative would be to pay for public purpose programs, climate change initiatives, wildfire spending, and infrastructure through taxpayer dollars instead of ratepayer dollars, though this might not be politically popular. Another equitable alternative would be an income-based fixed charge, where the amount charged progressively increases for higher income households.

Mark LeBel (Regulatory Assistance Project)

Mark LeBel, an associate with the Regulatory Assistance Project (RAP), discussed advanced rate design options that would allow for the efficient revenue collection without distorting price signals. LeBel started by reviewing the competing goals of electric rate design and how one could theoretically develop an efficient rate design. The problem with this process is that, at the end, there is a lump of costs beyond the marginal costs that cannot be included in the rate without distorting the efficient price signal. LeBel presented an example advanced rate that addresses the revenue shortfall issue while maintaining an efficient price signal. This example rate includes a customer charge, demand charge, a bidirectional per kWh charge on imports and exports, and symmetric time varying pricing with a critical peak price. LeBel suggested that this rate could be applied to a large set of customers who can be moved onto a more sophisticated rate fairly quickly (larger customers, customers with DERs, etc.).

LeBel also suggested that subdividing the residential rate class would give policymakers an additional tool for allocating costs. The main innovation of this advanced rate design is the bidirectional charge on imports and exports, which would recover fixed costs from customers with DERs and would be tied to the customer size. LeBel also presented an alternative solution: Ramsey pricing. In Ramsey pricing, residual costs are placed on the least elastic pricing element of the rate design, which is often the customer charge. However, this can be regressive. If the charge is tiered based on income, it gives the highest income users an incentive to defect from the grid. This approach can be difficult to implement because elasticity is not always obvious, and it also puts a lot of pressure on regulators to monitor costs.

Michael Wara (Woods Institute for the Environment at Stanford University)

Michael Wara, a director at the Woods Institute for the Environment at Stanford University, discussed ideas for reducing wildfire costs without compromising the state's goals for reducing wildfire risks and impacts. Wara started with three broad comments about the day's discussion: (1) rates are an extremely regressive way of funding programs, (2) the real affordability challenge in California is housing, and (3) the En Banc white paper reflects a best possible scenario whereas in reality there is quite a bit of risk. The key takeaway from the white paper for him was that there is no margin for error, and so the goal should be to create some headroom in case something goes wrong, making additional spending unavoidable.

With regard to wildfire spending, climate modeling suggests that wildfire risks are going to get worse over time and Wara's suggestion was to continue moving towards risk-based prioritization of spending. Furthermore, Wara suggested expanding the scope of this risk-based analysis to more than just utility activities. The state needs to look at all activities that address wildfires, including fuels reduction and home hardening. The Wildfire Safety Division may be able to take this sort of holistic look once it is a part of the California Natural Resources Agency. This analysis should include consideration of how to reduce the impacts of wildfires rather than just eliminating all possible ignition sources. Finally, Wara addressed the cost shift that is inherent in wildfire spending: the shift of costs from wildfire-prone parts of the distribution system to non-wildfire prone parts of the system. One possible solution is to consider a separate rate for customers in Tier 3 wildfire areas that better reflects the cost to serve them. Geographic segregation of rates is challenging, but worth considering. Wara closed his presentation by touching on the opportunity for DERs to provide resilience in the face of wildfire risks, and particularly the opportunity for EVs to serve as backup generation.

Anthony Kinslow II (Gemini Energy Solutions; Stanford University)

Anthony Kinslow II, CEO of Gemini Energy Solutions and a lecturer at Stanford University, presented ways the design, implementation, and evaluation of climate change initiatives can be improved to ensure more equitable outcomes. First, Kinslow discussed how long delays in program implementation and evaluation hurt the effectiveness of programs because it delays positive and negative feedback loops from being used to improve program performance. Faster feedback results in more impactful and cost-effective program delivery. Next, Kinslow discussed the importance of sufficient educational outreach to make sure communities are aware of programs that are available to them. Community Based Organizations (CBOs) play an important role in this process, and they should be compensated for their work in an equitable way. Next, Kinslow discussed how, if it is not possible to take inclusive actions at scale because of rules that prevent such actions, it is necessary to change the rules. In general, the actions should be guided by the goals of the system, which he said are captured in the CPUC's Environmental and Social Justice (ESJ) Action Plan. Finally, Kinslow talked about how problematic perceptions drive the paradigms we use to develop the goals, rules, and structures of the system that produce our programs. Racial biases need to be identified and corrected to ensure that the final outcomes are equitable.

Mark Toney (The Utility Reform Network)

Mark Toney, the Executive Director of TURN, discussed changes in the way the state thinks about how to achieve its climate change goals. In particular, Toney was focused on finding ways to end ratepayer funding of non-utility climate change initiatives (such as vehicle and building electrification). He proposed three paradigm shifts: (1) replace ratepayer subsidies with regulatory mandates, (2) develop alternative revenue streams to replace ratepayer subsidies, and (3) push agencies other than the CPUC to take the lead in designing and implementing climate change programs (because when the CPUC takes the lead, it means ratepayers will pay for the program). Toney provided examples for how to accomplish each of his paradigm shifts, including the Governor's recent mandate that all new vehicles sold by 2035 be zero emission vehicles; a proposal to

require all existing homes sold in California to be electrified; and imposing a carbon fee on ICE vehicles and using that revenue to build EV infrastructure. He also encouraged the CPUC to advocate against legislative mandates paid for by ratepayers.

Summary of Stakeholder Comments

A total of fourteen stakeholder organizations submitted comments following the En Banc hearing, as well as several individual commenters not affiliated with any organization. Individual comment filings can be found on the CPUC's En Banc website.[214] A summary of their comments is presented here, organized by topic. All points summarized here reflect the comments made by stakeholders and does not include any analysis of their recommendations.

Transportation and Building Electrification

Comments pertaining to transportation electrification (TE) and building electrification (BE) were submitted by PG&E, SCE, SDG&E, Center for Energy Efficiency and Renewable Technology (CEERT), 350 Bay Area, and the Port of Long Beach.

PG&E expressed their support for TE and highlighted a variety of mechanisms through which they've encouraged the adoption of electric vehicles (access to infrastructure, rebate programs, education and outreach, and pilot studies). They pointed out that the CEC's recent AB 2127 Assessment of charging infrastructure needs found that significant deployment of charging ports is needed to achieve the state's EV goals. In their view, as private investment picks up pace, public and customer funded support should continue to play a role and should be focused on market segments that will be missed by private third-party providers, such as multi-unit dwellings in disadvantaged communities. PG&E also agreed with the white paper's modeling of the rate impacts of TE programs: based on current programs and a simple doubling of program spending in the latter half of the decade, rate impacts will be minimal. They also agreed with the white paper's discussion of the potential for TE programs to have a downward pressure on rates by spreading fixed costs across a greater amount of kWh. They highlighted a study conducted by Synapse Energy, which found that from 2012 to 2018, EVs provided $350M more in revenue compared to costs (programs, T&D, capacity, and generation) in PG&E's territory. That net benefit was $600M if SCE's territory was included as well.

PG&E expressed optimism that the cost of EVs will continue to decline to the point where they have lower upfront costs than ICE vehicles, and that IOUs will play a part by continuing to fund EV rebates through low-carbon fuel standard (LCFS) revenues. PG&E indicated that they intend to propose later this year a used EV rebate funded through LCFS, with an additional rebate amount for low-income customers. They encouraged adoption of a final TE investment framework in the Rulemaking to Continue the Development of Rates and Infrastructure for Vehicle Electrification (R.18-12-006) that allows IOUs flexibility to quickly roll out supportive programs to promote EVs.

[214] https://www.cpuc.ca.gov/General.aspx?id=6442468423

SCE noted that, while the white paper discusses whether or not TE will place a downward pressure on rates, it does not adequately acknowledge the important role that electrification will play in helping the state achieve its goal of carbon neutrality by 2045. As laid out in SCE's Pathway 2045 analysis, decarbonization of the electric grid combined with TE and BE is the most cost-effective way to achieve California's GHG reduction goals. This analysis also shows that electrification will reduce the average household's overall energy bills by one third by 2045. In SCE's view, this long-term perspective is important when considering near-term investments in electrification.

SDG&E appreciated the white paper's discussion of electrification and its potential to offset rate pressures but noted that the current residential rate structure is hampering electrification efforts. They said that this is because electricity prices priced above marginal costs disincentivize electrification and the associated increase in system sales. SDG&E says that although electrification is supported through technology-specific tariffs, this creates the unintended consequence of cost shift from participants to non-participants.

CEERT also appreciated the white paper's discussion of the potential for electrification to put downward pressure on rates. They advocated for higher electric sales to be coupled with increased renewable generation procurement. They were also concerned with the CPUC's recent activity in the Emergency Reliability proceeding (R.20-11-003). They contend that the CPUC should not be adding expensive natural gas generation capacity. According to CEERT, the last big near-term opportunity to invest in clean energy is procurement in the Integrated Resource Planning (IRP) proceeding (R.20-05-003). CEERT was also concerned that electrification will lead to higher natural gas rates, and that this issue should be a priority in the Gas Reliability proceeding (R.20-01-007) and the Aliso Canyon Alternatives Investigation (I.17-02-002).

350 Bay Area agreed with the white paper's analysis of electrification on household energy bills, particularly because the analysis included an outlook on all energy spending in addition to electric bills. They said that the modeling results suggest that policy solutions should focus on lowering the barriers to participation in electrification so that low and middle-income households can realize these savings.

The Port of Long Beach recommended that the white paper include a specific discussion of goods movement (medium and heavy-duty vehicles, rail, vessels at berth, and off-road vehicles) because it is an important part of the TE conversation. They said that the white paper should add a section discussing commercial rates charged to customers who operate medium- and heavy-duty vehicles and off-road vehicles, including demand charges during peak hours, capacity charges, and impacts on fleet customers, including consideration of large capital investments needed to be compliant with Executive Order N-79-20 (Governor Newsom's Executive Order calling for elimination of new internal combustion passenger vehicles by 2035). They said that the white paper should also look at actions the CPUC can take to support specific state TE requirements, including the Advanced Clean Trucks Regulation (Executive Order R-20-004) and the At Berth Regulation (approved by Office of Administrative Law on January 1, 2021, Section 2299.3, Section 931118.3, and Section 93130). They also advocated for including the impact of the rapid growth of medium- and heavy-duty EVs in future projections of electric load, as they feel use of these vehicles will grow rapidly.

Distributed Energy Resources and Net Energy Metering

Comments related to distributed energy resources (DERs) and net energy metering (NEM) were submitted by PG&E, SCE, SDG&E, CEERT, 350 Bay Area, Indivisible, California Alliance for Clean Energy (CACE), Sustainable Systems Research Foundation (SSRF), Microgrids Resources Coalition (MRC), and several unaffiliated commenters.

PG&E appreciated the white paper's section on NEM and the reference to the Lookback Study's findings: that NEM is currently not cost-effective for all customers and shifts costs from participants to non-participants. PG&E also noted the white paper's findings that the cost shift largely benefits an affluent group of customers at the expense of less affluent customers. PG&E's view is that DER programs that are not cost-effective have an impact on affordability, and that the resulting cost shift from participants to non-participants should be limited in the absence of a strong policy motivation.

SCE said that the revenue shift from NEM participants to non-participants is inequitable because participants tend to be older homeowners in high income areas whereas non-participants tend to be lower income. SCE claims that the NEM subsidy on a per participating customer basis is $1,800, which is quite high compared to the CARE subsidy of $375 per customer. In addition to avoiding T&D costs, NEM customers get compensated for energy at a rate of eight times what it costs to procure utility scale solar. To address these cost shift issues, SCE submitted proposals to restructure the NEM rate in Rulemaking 20-08-020.

SDG&E highlighted the role that declining sales, driven by state programs to promote energy efficiency and customer adoption of DERs, has played a key role in driving up volumetric electric rates over the last several years. SDG&E noted that, had electric sales held constant at 2012 levels, system average rates would be 15% lower and residential average rates would be 20% lower than they are currently. Sales has had such a dramatic impact on rates because fixed and sunk costs are recovered through volumetric rates. SDG&E said that NEM customers, who are generally wealthier, able to avoid the high volumetric rates through self-consumption and export credits, leaving low-to-middle income customers to shoulder the fixed and sunk costs because they cannot afford rooftop solar installations. SDG&E claimed that the cost shift is estimated to be $3 billion per year statewide. SDG&E urged using this report to the legislature as an opportunity to highlight the role of declining sales in increasing rates and to advocate for fixed cost solutions.

CEERT acknowledged the cost-shift concerns highlighted by the white paper but encouraged the CPUC to include benefits associated with distribution investment deferral and other grid benefits into any future rates analysis. CEERT also encouraged the CPUC to update the rates analysis in the white paper to reflect any updated NEM 3.0 rate structure.

350 Bay Area recommended that the white paper include references to a pair of recent studies showing the impact of accelerating DER growth on grid costs.[215, 216] 350 Bay Area said these studies show that interconnection of DERs on the distribution grid result in big cost savings, that DERs lead to electricity rates also decreasing over time, and that DERs enable more clean utility scale variable generation to be deployed efficiently. They also said that increase in energy efficiency and rooftop solar in California has led to the cancellation of numerous transmission projects in 2017-2018, saving $2.6 billion in capital costs and $10 billion in future operations, maintenance, and return on equity costs. 350 Bay Area also took issue with the use of the ratepayer impact measure (RIM) cost/benefit test to assess NEM, advocating for the use of the total resource cost (TRC) test instead.

Indivisible, CACE, and SSRF submitted similar comments expressing concern about the amount of discussion in the white paper about the cost shift associated with DERs. They urged the CPUC to promote the growth of DERs instead. They made the statement that tariffs and price signals for distributed solar and microgrids are helping to reduce costs for all ratepayers.

MRC also submitted comments expressing concern about the amount of discussion in the white paper about DERs and cost shift. MRC said that the CPUC should be more focused on controlling the other cost drivers identified in the white paper, such as increasing transmission project costs, rather than the cost shift associated with DERs. They also said that DERs and microgrids reduce the need for risky, expensive, vulnerable transmission infrastructure.

Several unaffiliated commenters also responded to the white paper and En Banc hearing by advocating for the full range of benefits of DERs to be included in any CPUC analysis of NEM. Many of these comments reflected the statements made by CEERT, 350 Bay Area, Indivisible, CACE, SSRF, and MRC.

Capital Costs, Rate Base, and Return on Equity

Comments concerning capital costs, rate base, and return on equity (ROE) were submitted by PG&E, SCE, SDG&E, the Center for Sustainable Energy (CSE), Indivisible, CACE, SSRF, and MRC.

PG&E provided background on the role that capital financing plays in the utility industry in order to provide additional context for the white paper's findings regarding rate base and ROE. PG&E said that ROE does not guarantee any level of profit, since IOUs still need to manage overall costs (capital and O&M) so that they come in under the authorized revenue requirement. Investments in unneeded assets run the risk of disallowances that reduce profit, contrary to white paper's assertion that IOUs have an incentive to increase

[215] Net-Zero America: Potential Pathways, Infrastructure, and Impacts, interim report, Princeton University, Princeton, NJ, December 15, 2020. Available at: https://environmenthalfcentury.princeton.edu/sites/g/files/toruqf331/files/2020-12/Princeton_NZA_Interim_Report_15_Dec_2020_FINAL.pdf

[216] Why Local Solar For All Costs Less: A New Road Map For The Lowest Cost Grid; Christopher Clack et al, 1 December, 2020. Available at: https://www.vibrantcleanenergy.com/wp-content/uploads/2020/12/WhyDERs_ES_Final.pdf

rate base in order to earn higher profits. According to PG&E, IOU profits reflect compensation to shareholders for the time value of their money as well as for bearing risk. Higher risks necessitate higher profits, and therefore the cost of capital is high in California because of the high risk compared to elsewhere in the country. PG&E also pointed out that the revenue requirement of rate base has held steady at about 1/3 of total cost of electric service for many decades, indicating that rate base has been growing at about the same rate as other utility costs. Finally, PG&E said that the CPUC has some control over the growth in rate base through depreciation rates. Rate base growth can be slowed through higher depreciation rates, which would increase rates in the short-term but slow growth in the long-term. PG&E said that consumer advocates have historically preferred lower depreciation rates.

SCE also sought to provide additional context for the rate base growth findings in the white paper. SCE said that growth in rate base is driven by safety, reliability, and risk mitigation spending. These investments undergo vetting by the CPUC and stakeholders. From 2009 to 2019, SCE's capital spending was within 1% of GRC-authorized capital funding, which they say demonstrates that there is no systematic attempt to overspend. Further, they said that over the last several years SCE has attempted to increase net salvage rates which would offset rate base. However, they say that the CPUC has adopted lower net salvage rates than requested out of concern for near-term rates, which has shifted costs to the future. SCE also argued that an adequate ROE is necessary to ensure that IOUs can raise sufficient capital to make improvements to infrastructure, and that a low ROE would increase customer costs in the long run by hurting SCE's credit rating.

SDG&E made similar comments, arguing that SDG&E needs access to capital markets to fund wildfire mitigation efforts, among other investments. If ROE is set too low, it would force SDG&E to rely more on debt financing which would hurt SDG&E's credit ratings and increase borrowing costs. This would be passed on to ratepayers. SDG&E also said that financial stability of the company is important in the context of the ongoing pandemic; COVID-19 protections have led to a doubling of delinquent account balances in 2020 compared to 2019. SDG&E says that it needs to be financially sound to fund the growing undercollection of delinquent account balances.

CSE questioned why the authorized ROEs for California IOUs have not been reduced considering interest rates on borrowed money having fallen to historically low levels. They suggested that the CPUC consider whether the gap between the cost of equity and the cost of debt is justified. Furthermore, CSE recommended looking into the ratio between debt and equity, and whether it makes sense for IOUs to take on more debt.

Indivisible, CACE, and SSRF urged the CPUC to reduce the IOUs authorized ROE.

MRC also said that it is unacceptable for the CPUC to be authorizing exorbitant profits for IOUs in the middle of a pandemic and economic recession when the IOUs' grids have had several prolonged shutoffs. They said that the CPUC should minimize capital investments in order to reduce shareholder returns and provide relief to ratepayers.

Wildfire Costs

Comments specifically about wildfire costs were submitted by PG&E and SCE. Some stakeholders also made references to wildfire costs in their comments while discussing other issues, but those are captured under the other topic headings.

PG&E used their comments to draw attention to how highly uncertain wildfire costs will be over the next few years, and as a result how uncertain the white paper's rate projections are. PG&E recognized that there is limited information on which to base any projections for wildfire costs, and revenue requirement in general, and that the approach taken in the white paper is based on the best information available at the time. However, there is still significant uncertainty as demonstrated by the fact that the white paper provides two scenarios related to wildfire mitigation costs.

SCE highlighted the role that wildfire costs, particularly grid hardening, along with public purpose programs has had on rate growth. SCE argues that these investments are time sensitive given the existential risk that wildfires pose to Californians, and as such it is inappropriate to focus solely on electric rates growing faster than inflation. SCE also used their comments to reiterate the cost-saving potential of their customer-funded self-insurance proposal. SCE explained that AB 1054 requires IOUs to procure insurance for the first $1 billion of coverage, which is currently costing SCE $450 million/year and includes $80 million of co-insurance and $50 million of self-insured retention, making net coverage only $870 million. SCE said that by self-insuring the company could save hundreds of millions of dollars, so long as actual claims do not exceed the avoided cost of insurance over a multi-year period.

Transmission Costs

Comments on transmission costs were submitted by PG&E, SCE, CEERT, 350 Bay Area, and unaffiliated commenter Jan Dietrick.

PG&E sought to more fully contextualize the white paper's discussion of historical transmission costs. First, PG&E said that the white paper highlights that the transmission access charge (TAC) has been increasing while gross system load has declined, but fails to mention that the growth of distributed resources has led to many customers using the grid as a "battery exporting surplus energy onto the system when the sun is shining and drawing energy from the grid after the sun sets." PG&E said that it would be better to compare TAC to total energy consumption, which is total energy demand inclusive of distributed generation. PG&E said that the white paper should also acknowledge that the "duck curve" (CAISO's term for the shape of the state's net load graph due to the renewable-driven midday trough and steep late afternoon/evening upward ramp) requires fast and flexible ramping, which is useful context when discussing increasing transmission costs. PG&E also suggested alternate ways of presenting the transmission cost data from the white paper.

PG&E pointed out that the 5-year, 21% increase in capital additions presented in the white paper is equivalent to an annual 3.9% increase over a 5-year period. PG&E also pointed out that the white paper states that the average age of a transmission asset is 36 years, but there are many different types of assets with very different

years of useful life. PG&E also objected to the white paper's direct comparison between PG&E, SCE, and SDG&E's transmission systems without any mention of the very different scale, terrain, and system needs in the different service territories.

SCE also sought to provide additional context for the rising transmission costs identified in the white paper. First, SCE emphasized that their transmission revenue requirement actually decreased between 2016 and 2021, unlike PG&E and SDG&E. SCE also said that the recent growth in transmission revenue requirement has been driven by several factors outside of IOU control: the state's renewable portfolio standard (RPS), long permitting processes, and changes to transmission projects' scopes, routes, and undergrounding obligations. SCE also responded to the white paper's assertion that Federal Energy Regulatory Commission (FERC) ROE incentives drive costs up by saying that "the incentives are designed to promote efficient use of transmission and provide other customer benefits through market efficiencies." SCE said that these incentives helped drive three key transmission projects which support greater renewable integration.

CEERT urged that a more comprehensive analysis of transmission costs is needed in order to balance the goals of decarbonizing the grid and mitigating rate and bill impacts. CEERT said that the white paper analysis does not sufficiently distinguish between wildfire mitigation, other capital investments, network expansion to support load growth, generator interconnection, and capital maintenance. These distinctions are needed in order to identify why rates are increasing and develop appropriate mitigation strategies. CEERT also says that evaluation of transmission costs should recognize which projects contribute to lower generation costs. CEERT also voiced their frustration with the new stakeholder transmission asset review (STAR) spreadsheet that is now being used to report transmission project costs because so many details were withheld due to confidentiality concerns.

350 Bay Area expressed their support for additional oversight of "self-approved" transmission projects and for elimination of the FERC incentive to participate in the CAISO, which is already required by state law. They also recommended that the CPUC look at "the impact of transmission cost allocation and the failure to incorporate ratepayer transmission cost impacts in procurement practices." According to 350 Bay Area, customers' transmission fees are based on metered electricity usage regardless of how much of their energy is sourced through transmission. They also said that in front of meter DERs are not properly modeled in IRP proceedings because models do not differentiate between resources that require transmission grid and those that do not.

Unaffiliated commenter Jan Dietrick expressed concern that transmission costs are rising faster than other electric costs. In particular, Dietrick advocated for TAC to be fairly allocated between IOU service territories and municipal utility territories. Dietrick also said that the price distortion blocks the development of renewable energy projects such as community microgrids, which is a particular problem in Santa Barbara County because it is located where PG&E and SCE's service territories meet.

Natural Gas Costs

Comments on natural gas costs were received from CEERT.

CEERT said that the white paper does not adequately consider natural gas rates and bills, which are also affordability issues. CEERT said that "burner tip" prices for natural gas have been very volatile in California over the past decade as a result of multiple disasters, and that this has implications for both natural gas and electric rates. These disasters, which include the San Bruno explosion and the Aliso Canyon disaster, have necessitated significant investment in natural gas infrastructure which has the same affordability and equity implications that were discussed in the context of electric bills in the white paper. Furthermore, CEERT said that gas and electric prices are linked due to continued over-reliance on natural gas generation. When natural gas prices spike, it causes electric spot prices to spike which gets recovered from customers through the energy resource recovery account (ERRA). However, CEERT says that the "ERRA trigger" that initiates a CPUC investigation into price spikes has only occurred once in last 10 years, showing how little monitoring there is of gas price volatility.

Alternative Revenue Sources, Rate Structures, Cost Saving Opportunities, and Ideas for Improving the Ratemaking Process

This section covers recommendations made by stakeholders for offsetting IOU revenue requirements, changing the electric rate structure in order to address equity and cost recovery concerns, reducing costs, and improving the ratemaking approval process. Comments were submitted by PG&E, SCE, SDG&E, CEERT, CSE, American Clean Power (ACP), Indivisible, CACE, and SSRF.

PG&E agreed with some of the panelists in that using energy bills alone to pay for climate programs is regressive and deters electricity use even as the state is trying to promote electrification. They said that non-energy bill funding can be more progressive than volumetric energy rates, and PG&E was encouraged that some panelists suggested "regional pricing, pricing for T&D assets tied to locational risk, progressive flat-rate components, rate design approaches that preserve marginal pricing, tax funding of energy bill components, and decision-making that would expand to include more non-energy-industry and climate-affected parties." Commenting on the white paper's bill projections for a hypothetical customer in a hot climate zone, PG&E noted that customers in hot climate zones pay a disproportionate amount for fixed costs compared to low usage customers. PG&E encouraged adoption of residential fixed charges to reduce volumetric rates, better represent cost causation, and reduce the disincentive for electrification.

SCE provided several recommendations for cost reduction. In addition to the customer-funded self-insurance proposal described previously, SCE advocated for eliminating the fixed energy price option for must-take contracts with qualifying facilities (QFs). SCE says that this would prevent procurement from QFs at above market prices. FERC Order 872 eliminated this option, but the CPUC has not followed suit. SCE also recommended extending the Southern California Gas (SoCalGas) operational flow order (OFO) reduced penalty structure during summer months because this would stabilize gas prices, which would thus stabilize electricity prices. This provision is currently scheduled to sunset in September 2021. SCE also recommended allowing IOUs more flexibility in selling renewable energy credits (RECs) by making three changes: permitting sales of RECs below annual RPS targets while still using Tier 1 advice letters, eliminating price floor on RECs,

and allowing contract terms of up to 10 years. Finally, SCE agreed with the proposal from some of the panelists to fund public policy programs through statewide funding.

SDG&E agreed with Professor Borenstein's proposal to allow for fixed cost recovery outside of volumetric rates through a progressive fixed charge structure. SDG&E said that this proposal would prevent avoidance of fixed costs, lower volumetric rates, and reduce disincentives for electrification without having to resort to technology-specific tariffs. However, they noted that implementing such a proposal would require legislative action since there are currently limits on fixed charges.

CEERT strongly recommended that the CPUC explore options to fund transmission expenses in such a way that they are not shouldered by ratepayers. They note that the FERC-regulated TAC allows a generous rate of return that they say is the equivalent of an 18% interest rate for financing those investments. Instead, CEERT suggested evaluating the proposal put forward by Betony Jones (sic: this was proposed by Jennifer Dowdell) of publicly financed or state-owned transmission assets. They noted that using a tax free, state backed revenue bond to finance transmission expenditures would yield an interest rate of about 5%. CEERT also recommended looking into cooperative development of transmission projects with municipal utilities.

CSE provided extensive comments on the CPUC's ratemaking process and how to improve it. CSE recommended that the CPUC take control of the rate setting narrative by telling IOUs that rates need to be at a certain level as a starting point for rate case applications rather than allowing IOUs to apply for a certain amount of revenue requirement. CSE said that this would put the burden on the IOUs to find ways to reduce costs. CSE also said that the current rate setting process allows IOUs to propose a certain amount of spending and only respond to specific objections brought forward by parties, rather than justifying all spending. Furthermore, CSE said that the CPUC has become too reliant on settlement negotiations. According to CSE, settlements do not ensure that the revenue requests are reasonable, and adoption of settlements over multiple cycles has eroded the CPUC's ability to hold IOUs responsible for its spending. The CPUC should instead fully review requests.

CSE also agreed with panelists' proposals to shift funding for programs that provide societal benefits from ratepayers to taxpayers. According to CSE, this would be less regressive and would also reduce geographic cross-subsidization, such as when customers of a utility in areas that are not prone to wildfires have to pay for equipment hardening in the same utility's wildfire-prone areas. Finally, CSE recommended allowing fixed charges, arguing that it is questionable whether high volumetric rates actually drive conservation since customers only care about their bills rather than the rates that determine them. CSE argued that high volumetric rates might discourage home and vehicle electrification without changing other usage behavior.

ACP noted that there is a proposal under consideration in the public charge indifference adjustment (PCIA) rulemaking for reallocating products within utilities' portfolios (PCIA Working Group 3 Final Report) which they support. ACP supports this proposal because it would right-size the IOUs' supply portfolios which is important considering the amount of load shifting that is expected.

Indivisible, CACE, and SSRF said that the CPUC should stop and investigate IOU lobbying and advocacy that is funded by ratepayer dollars.

General Comments, Drivers of Rate Growth, and Improvements to Modeling

General comments not covered in the other topic categories, including comments on general drivers of rate growth and suggestions for improvements to the white paper and the rate modeling, are summarized here. Comments covered include those submitted by PG&E, SCE, SDG&E, TURN, the Western States Petroleum Association (WSPA), Indivisible, CACE, SSRF, 350 Bay Area, and ACP.

PG&E discussed the drivers of rate growth, which include not just the cost of climate change initiatives but the impacts of climate change as well. These costs are high and growing. PG&E also discussed the uncertainty in the rate forecasting, which include uncertainty in future revenue requirements (as described previously when discussing wildfire costs) as well as uncertainty in electric sales. EVs and building electrification may contribute to significant sales growth, but that uncertain growth may not be adequately captured in the California Energy Commission's (CEC) Integrated Energy Policy Report (IEPR), which was one of the main inputs for the rate forecast presented in the white paper. PG&E also appreciated the use of the cost and rate tracking (CRT) tool in the rates analysis and looks forward to continuing to develop this tool with the CPUC.

SCE talked about the time-sensitive nature of the grid hardening and clean energy programs funded through rates, and how that should be taken into account when considering the pace of rate growth. SCE said that they have kept rate growth lower than the other IOUs and lower than inflation over the past few decades, but that is no longer possible given the wildfire and climate challenges the state now faces. These investments should be viewed in terms of the benefits they provide in addition to the costs they impose.

SDG&E identified the main drivers of their rate increases: transmission and distribution investments (including wildfire mitigation), public purpose programs, technology subsidies, and a decline in sales due to successful energy efficiency and DER programs. SDG&E also said that their bills remain low compared to other IOUs nationwide, and because incomes in their territory are higher than average as well, electricity burden is lower than average compared to the other California IOUs.

TURN provided a number of recommendations for improving the rate modeling, as well as suggestions for sensitivity scenarios to consider. TURN suggested that the CRT be run for a range of scenarios rather than a single scenario to help understand the implications of uncertainty surrounding a few of the key inputs. TURN was only able to provide suggestions for scenarios based on PG&E's CRT model, since the other IOUs have not made their models publicly available. The additional scenarios they recommended address the uncertainty in revenue requirement growth, especially transmission and distribution revenue requirement, as well as uncertainty in the sales forecast. They also suggested an additional sensitivity scenario for higher than expected wildfire and clean energy infrastructure spending. Finally, TURN recommended presenting results for CARE and non-CARE rates separately.

WSPA expressed concern that the white paper did not address costs and affordability for all rate classes. Specifically, the paper did not address commercial and industrial (C&I) customers. WSPA warned that if rates for these customers become too burdensome, they may elect to secure alternative electric services which would have negative consequences for residential customers. WSPA referenced Energy Information

Administration (EIA) data that they say shows that California's industrial rates are non-competitive and excessive today, and will worsen if they take the same trajectory as the forecasted residential rates. According to WSPA, the EIA data shows an inverse relationship between electric rates and C&I demand and revenue contributions, which is a warning sign if C&I rates are expected to increase. Costs that are currently allocated to C&I customers would be shifted to residential customers.

350 Bay Area recommended specific wording changes to strengthen the white paper.

ACP provided feedback on PG&E's proposed cost-cutting ideas, saying that they are uninformative and vague. ACP felt that PG&E should instead talk about how it can use its revenue requirement more effectively to meet its obligations as a Transmission Owner. ACP also discussed how the drop in the cost of utility-scale renewables, combined with the recent extension of federal tax incentives for renewables projects, could benefit Californians if the state provides direction for near-term procurement of new renewables resources. ACP also provided recommendations for improving the Historical Cost and Rate Trends section of the white paper. Specifically, they said the paper should evaluate how past investments in bulk transmission have enabled clean energy resources to compete for power contracts, thus reducing the generation component of rates. Finally, ACP recommended including in the discussion of affordability that clean energy provides high paying jobs for low-income households.

Indivisible, CACE, and SSRF said that the white paper identifies the major reasons behind increasing electric bills: excessive transmission spending, wildfire mitigation costs, and IOU ROE. In their opinion, the IOUs do not care about affordability and equity, and are using these talking points as propaganda to oppose DERs.

ADDENDUM 3: ADDITIONAL CONSIDERATIONS ON CUSTOMER EQUITY AND THE AFFORDABILITY EVALUATION FRAMEWORK – DAVID ROLAND-HOLST (UC BERKELEY)

Background

Setting electricity rates is one of the most consequential policy responsibilities in California. These administered prices drive primary energy use, technology investment, and billions of dollars of enterprise and household expenditure across the world's fifth largest economy. For these reasons, decisions in the rate setting process should be supported by the highest quality data and assessment methods. Fortunately, today's information and analysis technologies offer unprecedented detail and timeliness of data and sophisticated tools for analysis and forecasting. With the right combination of institutional and independent partners, the CPUC can make investments that most effectively support robust decision making, transparent stakeholder engagement, and fulfill its multifaceted goals for economic and social progress in California.

This section focuses on a few issues related to formation of rate policy and assessment of rate impacts. In particular, these notes discuss existing approaches to estimation of past, present, and future rate impacts and discuss opportunities for developing new data and analytical resources to improve these. The discussion will address three primary topics:

- Policy Coherence – Rate Policy in a Statewide Context
- Affordability/Equity Issues
    a. Heterogeneity of affordability
    b. Demand inelasticity for electricity, especially among low-income customers
    c. Rates as a mechanism for addressing equity issues
- Investing in Assessment and Decision Support Capacity
    a. Time Horizon
    b. Uncertainty
    c. Stakeholder Engagement and Policy Dialog

Policy Coherence

Before examining more detailed issues of rate policy, it is worth considering this in a larger, multi-agency setting. The macroeconomic, technological, and social significance of electricity rate policy has already been emphasized, but the implications of this for "coherence" with other state policy deserves careful consideration. The CPUC's regulatory mission is clearly defined, yet its policies inevitably interact with actions and goals of other public institutions. To the extent that these are complementary, policy coherence can achieve synergies for effective use of public resources. In other circumstances, policies may offset or even conflict with one another. One example of this is reconciling emergent climate risks with existing ones.

The state's path breaking climate initiatives are based on shared perception of the future costs of global warming. While these were firmly established on the basis of information available during the legislative run-up to AB32 and in subsequent iterations of the Scoping Plan, RPS, SB350, etc., more recent experience has dramatically escalated and foreshortened these risks. Rapidly changing events, like recent catastrophic wildfires, present a challenge to policy coherence if short term risk management "crowds out" longer-term commitments because of fiscal constraints. Both types of defensive public investment remain necessary, and if new fiscal commitment is needed it is important to consider not just averted damages but the real and lasting benefits from all types of climate investments. Empirical studies have identified direct and indirect benefits of California's renewable energy buildout, including job creation, public health benefits, and savings to energy users and all those who benefit indirectly from their expenditures on other goods and services. Depending upon the economic and air quality benefits associated with renewable deployment, postponing such investments will differentially impact Californians in important ways. Examples below illustrate this.

Of course, deferring renewable deployment would also have costs, both in terms of elevated climate risk/damage and health impacts of continued reliance on more emission-intensive power generation. A recent example of this occurred when uncertainty about current and future renewable capacity contributed to delaying retirement of backstop gas generation plants around the state.[217]

In other cases, there is less direct contention between objectives, but incremental costs may have to be covered to reconcile them. An important example of this is the "Build Back Better" agenda, committing replacement and renewal of infrastructure to higher standards of mitigation and climate resilience.

[217] Wood Mackenzie. "California's power market balancing act: Why the state won't let go of nine gas plants set to retire this year." August, 2020. https://www.woodmac.com/news/editorial/californias-balancing-act/californias-power-market-balancing-act-full-report/

Example: The Water/Energy Nexus

Electric power and water are essential resources for California. Since the of both are significantly regulated and intimately linked across the economy, it is reasonable to ask if more coherent policies could improve their services, e.g. making them more affordable, inclusive, or sustainable. The term "Water/Energy Nexus" refers to the state's extensive use of energy services for water conveyance, heating, and treatment. Taken together, these uses comprise a substantial share of state electric power demand, representing significant direct and indirect costs for public and private rate payers. In recognition of this, the CPUC has for years sponsored programs and decision support tools to promote water use efficiency and cost-effectiveness. What has received less attention recently is the potential for water services to support electric power. This perspective is changing because of two important trends: rapid expansion of intermittent renewable energy and emerging needs for more water storage capacity to compensate for early runoff. In particular, research on pumped hydropower storage and allied technologies has the potential to transform state water infrastructure in the service of greater renewable capacity use, water conservation, and more cost-effective grid development.[218,219]

Because of spatial mismatches between renewable water supplies and demand, California has a very extensive water conveyance system, including the flagship California Aqueduct, a system of canals, tunnels, and pipelines extending over 600 miles across the state. Recognizing the energy storage potential of water, the Aqueduct already includes many pumping stations to lift water over higher elevations, complemented by hydropower stations to recover energy from the descending water. While these increase the efficiency of statewide conveyance, they only realize a fraction of the energy potential that could be captured by integrating solar and wind power resources. Such a system would combine renewable power sites with higher elevation reservoirs and paired pumping-hydropower facilities to fill them using surplus and intermittent power. Releases back into the aqueduct or other state canals can be timed to smooth water transfers and reduce upstream peak load pumping. State canals like the aqueduct can even contribute to renewable capacity by covering them with solar panels, utilizing a large existing easement for clean power production and reducing evaporation loss.[220] Finally, spatial dispersion of these water/energy resources makes them ideal candidates for local public/private investment partnerships that promote local investment, employment, clean energy, and water use efficiency.

Equity Issues and Energy Affordability

Heterogeneity of Affordability

California state agencies are ever more aware of the importance of accounting for more diverse stakeholder interests and most are making substantial investments in assessment and decision tools that recognize this. The CPUC is no exception and has funded significant efforts to better address differentiated ratepayer needs and economic circumstances in ways that advance state policy objectives. These efforts should be reaffirmed

[218] Hunt, Julian D., Edward Byers, Yoshihide Wada, Simon Parkinson, David E. H. J. Gernaat, Simon Langan, Detlef P. van Vuuren, Keywan Riahi. "Global resource potential of seasonal pumped hydropower storage for energy and water storage." Nature Communications, 2020; 11 (1) DOI: 10.1038/s41467-020-14555-y

[219] https://www.sciencedaily.com/releases/2020/02/200219152854.htm

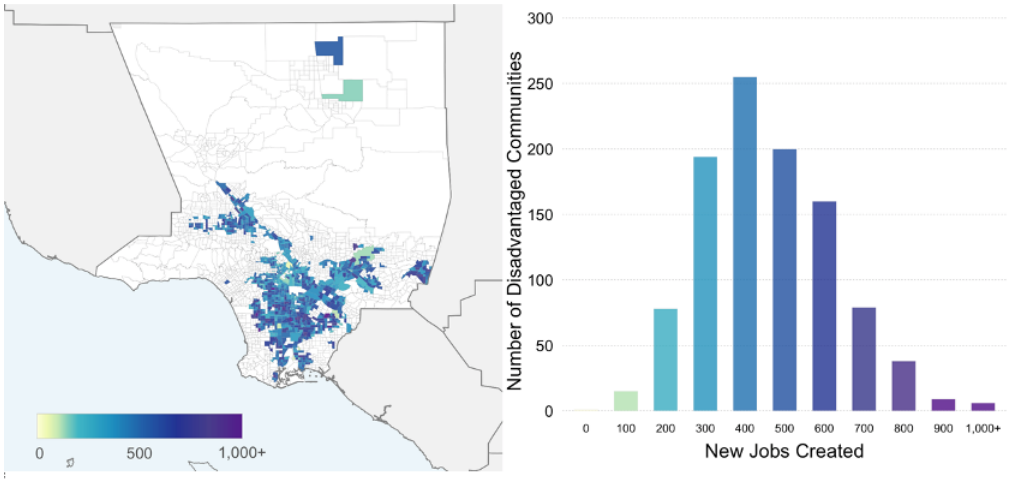
[220] A recent UC Davis study estimated these losses to be 27 acre-foot/day, or about 20,000 acre-foot/year. At a price of $107 per acre-foot, the total cost of evaporation comes to over 2 million dollars per year that is lost due to evaporation.

with new and more determined commitments to use the state's rich data resources for more effective policy targeting.

More fully identifying the heterogeneity in affordability among the state's residents is vital to helping those who are most at risk of losing utility services due to non-payment or having to forego spending on other essential goods and services. Past efforts to characterize electricity affordability have relied on overly broad metrics which measure changes in average rates and bills for entire IOU service territories or even for the entire state. Because of income and wealth inequalities, which have grown wider in recent decades, this approach can fail to identify specific communities where high electric bills are more of an affordability concern than they are for the average residential customer. The CPUC's recently developed affordability metrics as part of R.18-07-006 seek to incorporate these socioeconomic considerations into evaluations of utility service affordability.

Example: Employment and Public Health Benefits of Renewable Energy Deployment

Figure 1: Job Creation: Disadvantaged Communities in Los Angeles Median Scenario for LTES



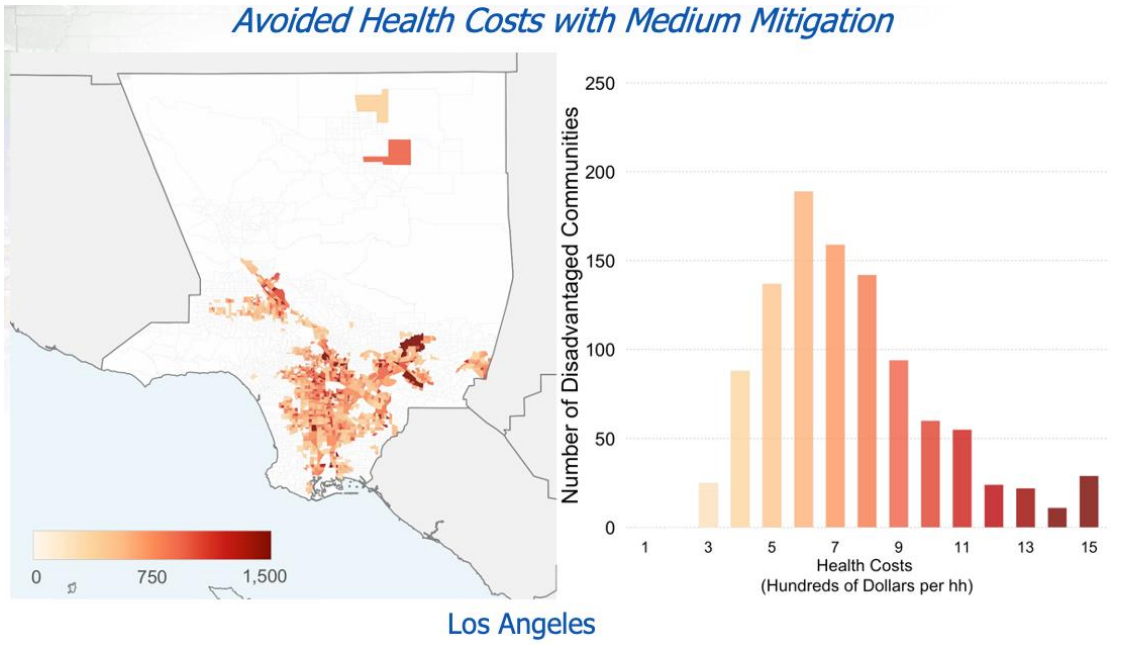
- Because workers in DACs are disproportionately employed in service and construction industries, 475,000 of the 940,000 jobs created are in Los Angeles are in DACs (50%).
- On average, 500 jobs created per DAC and more than 1,000 jobs created in five DACs.

Extensive research has already documented that the impacts of climate change are likely to disproportionally impact the state's Disadvantaged Communities (DACs). It is essential that distributional economic impacts be incorporated into ongoing state policy deliberations to identify how benefits and costs are borne across diverse communities. Two studies for the CEC and CAISO evaluated the economic stimulus and air quality benefits from measures included in California Senate Bill 350 and Executive Order B-30-15.[221] Using a long-term forecasting model, this assessment identified job creation and health benefits across the state's DACs. More specifically, this hi-resolution spatial analysis revealed that renewable energy investments actually created

[221] http://bearecon.com/portfolio- item/cec-ltes/ and http://bearecon.com/portfolio-item/caiso-sb350/

a higher proportion of new jobs as well as higher absolute and relative health benefits in these low-income areas than for non-DACs.

Figure 2: Sample DAC Air Quality Scenario Results



- Average DAC households avoid $677/hh in costs while non-DACS avoid $511/hh.
- Los Angeles includes DACs with some of the highest PM 2.5 exposure (~90th percentile), Ozone exposure (~93rd percentile) and disease incidence (~99th percentile in asthma).
- Avoided health costs due to predicted reduction in both PM2.5 and Ozone concentrations in the region.

Demand inelasticity for electricity, especially among low-income customers

Energy efficiency and affordability are both laudable policy goals, but they differ in important ways and can be partially conflicting, especially in an energy market with heterogeneous actors. The ability of customers to manage their energy consumption depends on the particular characteristics of residential and commercial users. As a practical matter, this means rate setting and allied policies must be designed and implemented carefully and supported by the best available information. Here only a few salient issues on the demand side are highlighted.

Commercial demand in California has been relatively stable in composition, although emergent opportunities for independent renewable development and combined heat and power have eroded demand and, as discussed in an example below, undermined the capacity of tiered pricing to cover legacy infrastructure and power contracting costs. In recent years, large new energy-intensive users like data farms have also created new models of self-sufficiency, using distributed generation, storage, and integration technologies that are increasingly scalable. Despite these technical disruptions, however, the commercial side of electricity demand remains the most predictable and financially sound part of the IOU-serviced market.

Residential demand is differentiated along several important dimensions. Firstly, and fundamentally, the residential consumer population is divided between homeowners and tenants whose property is owned by someone else.[222] Rate changes have different effects on these groups. For owners, higher rates present an incentive to invest in distributed energy resources. For tenants, who rarely invest in durable appliances or efficiency retrofits, higher rates simply encourage them to ration energy use.

Lower income households tend to be tenants. This means their energy demand is intrinsically more inflexible (inelastic) for several reasons. Firstly, they do not have discretion or even purchasing power to replace durable appliances or retrofit their premises. Second, if they are already constrained to meeting only their basic energy needs, rate increases may not result in substantial reduction in energy use but rather deprive them of other consumption goods and services. Finally, the same constraints imply that rate reduction (by subsidy or otherwise) may sharply increase their demand. The last two conditions imply that demand response is asymmetric, inelastic to rate increases but elastic to rate reduction – doubly difficult to predict.

Affordability is certainly an appropriate policy objective with respect to low-income customers, and means-calibrated rate setting can address this with available information, but reasoning presented in the next section, suggests that (per capita) basic need subsidies may be a more effective policy instrument. More subtle functional diversity also exists within income groups. For example, residential customers at most income levels will have different adjustment options, and be impacted differentially, depending on their ownership status. Because tenants may lack property rights to choose technologies, as well as collateral to finance technology adoption, this group should probably be treated differently, especially in income categories where energy services are less affordable. Ultimately, then, like student financial aid, affordability policies should account for assets as well as income.

To summarize, for policy goals related to energy efficiency and its attendant economic and environmental benefits, rates are less effective policy instruments when targeting lower income households for three reasons.

- A higher proportion of low-income energy demand is not discretionary, meaning their demand response will be more inelastic against rising rates.
- Many low-income groups have more limited options for choosing energy use technologies, from used (less efficient) cars to appliances and home (e.g. insulation) investment choices (made not by them but by their landlords).
- Tenancy can undermine the potential for rates to stimulate adoption of more energy efficient technologies. This can be better be achieved by incentives that target landlords.

Generally speaking, much more research is needed on demand responsiveness to retail electricity rates, taking account of both income and asset ownership patterns.

[222] Strictly speaking, this is also true of commercial users (especially small businesses), but household demand is a category where heterogeneity has greater policy significance.

Rates as a mechanism for addressing equity and welfare issues

Finally, it should be recognized that rate structure is a relatively inefficient instrument to advance either efficiency or equity objectives. Standards and owner incentives can be more effective ways to promote efficient technology adoption.

From the equity perspective, energy affordability is part of a larger policy agenda of social protection, securing basic needs for lower income groups so they have adequate energy services and are not paying for them at the expense of other necessities. A large body of public health evidence suggests that energy rationing is detrimental to health and other dimensions of human welfare, and strategies of this kind are nearly universal in more advanced economies.[223,224] Typically, however, they are recognized and managed as incomes policies and administered by fiscal agencies. One of the most important examples of this is food stamps, which secures purchasing power for essential nutrition. Although the policy targets an essential commodity, it is not administered at the sector level – neither USDA, the agrifood sector, nor other food consumers are responsible for managing or financing this program (except as general taxpayers).

In addition to discussing expected rate, bill, and affordability changes based on the modeling work done for this white paper and other sponsored research, it is worth discussing the uncertainty inherent in some of the underlying assumptions and how the rate and affordability evaluation framework in general can be improved.

Investing in Assessment and Decision Support Capacity

The complexity of today's energy economy is such that policies based on intuition, rule-of-thumb, or short-term deterministic partial equilibrium models are unlikely to achieve anything approaching optimality. The CPUC should consider further investments in decision support. By comparison to past decades, there are now important data and assessment technologies available to strengthen the CPUC's capacity for policy design and implementation. The following represent broad categories of technical capacity, and more detailed needs assessment is recommended in each context.[225]

Time Horizon

There is currently a temporal mismatch between some electric power sector modeling (1-2 years; IEPR and RESOLVE are exceptions here) and state energy/climate policy horizons and milestones (decadal) – where longer term models are needed. The result is a lower degree of coherence in interagency policy and statewide policy dialog. The burden of expanding modeling can be shared to some extent across agencies, but even for individual use these models do not need to be built from scratch. In other words, agency investments can complement each other and investments can be made in competitive independent information resources and expertise. For example, state budget decision making is supported by dynamic forecasting under the

[223] Jessel, Sonal, Samantha Sawyer, and Diana Hernández. "Energy, poverty, and health in climate change: a comprehensive review of an emerging literature." Frontiers in public health 7 (2019): 357.

[224] Thomson, Harriet, Carolyn Snell, and Stefan Bouzarovski. "Health, well-being and energy poverty in Europe: A comparative study of 32 European countries." International Journal of Environmental Research and Public Health 14, no. 6 (2017): 584.

[225] With respect to this and related capacity needs, assessment could be done internally or as part of independent program reviews.

supervision of the Department of Finance, using a combination of internal, shorter term models and external (commercial) national and global forecasting models.

Uncertainty

Uncertainty is endemic to all forecasting, but modern assessment tools seek to limit this as a policy risk by modeling uncertainty explicitly. In the present context, relevant risks relate to the impacts of rate decisions based on limited information about future costs and other market decisions. Most of the CPUC's current decision support models (CRT, RECC) could benefit from more statistically robust scenario tools that explicitly recognize any uncertainty and measure its potential risks. In addition to "natural" uncertainty arising continuously from world events, risks in energy modeling can arise from behavioral responses and modeling bias.

Example: Unintended Consequences of Electricity Rate Stratification

A primary source of policy uncertainty arises from behavior, i.e. responses to rate making decisions that alter use or technology adoption patterns. Assuming that these remain relatively constant, rate change can lead to unwelcome surprises, as the following two examples make clear.

Industrial rates - for a variety of reasons, but usually because of large, fixed cost commitments (infrastructure or long-term contracting), average total system costs can rise above marginal costs. If rate structure is "progressive", rate stratification tends to shift these fixed costs to higher tiers. This approach creates incentives for financially able ratepayers to invest in independent power sources, opting out of higher tiers, undermining the financial integrity and perhaps the equity objectives of the rate structure.

Residential rates - a similar situation arose in residential electricity markets with household PV promotion about two decades ago. At that time, stratified rates increased the incentive for wealthier households to invest enough in PV to "drop down" in the rate structure, offsetting enough of their load to evade the progressive rates for the same (or even greater) total household energy consumption. Again, differentiated rates created "adverse selection" - defection of higher income customers from higher tiers, undermining system financing and equity objectives.

The most effective defense against this kind of uncertainty is systematic ex ante assessment, usually done with policy scenario modeling as part of established forecasting activity. This can be in-house or competitively provided but should be vetted by some kind of independent oversight such as a Technical Advisory Board or mandatory peer review. In most cases, this approach cannot eradicate policy risk but is more likely to promote adaptive response and investments in timely, high quality data. As part of a more complete assessment framework, three strategies can improve reliability against uncertainty.

Explicit Risk Modeling or Sensitivity Analysis

Thanks to over 50 years of statistical work in support of strategic policy making, there is now a large suite of tools for modeling uncertainty. This is complemented by a vast amount of work in financial analysis, but those tools would be more relevant to regulated private enterprises. This general approach, called Monte Carlo methods, has been used for decades in finance and engineering to elucidate systemic uncertainties and manage attendant risk. Simpler "stress test" models of stochastic net present value inform most large project investments, but the spirit of all these approaches is the same. The same approach has been applied in economic forecasting, mainly intended to overcome uncertainty about underlying behavioral assumptions and states of nature.[226,227,228] These analytical approaches strengthen capacity for early warning and adaptive policy.

Diversification of Data Sources

Assessment methods that rely on limited data are generally recognized to yield estimates with commensurately limited statistical confidence. When data may also be subject to reporting bias (conscious or otherwise), reliability is further undermined. Generally, the gold standard for statistical work, whether it be forecasting or cross-comparison, is randomized sampling with recourse to independent resampling and auditing. To limit the risk of weaker samples, a comparison framework that incorporates independent information is recommended. In this present context, this would mean cost and other data comparisons across a variety of electric power jurisdictions, nationally and even internationally, adjusting as appropriate for local resource costs. In addition to strengthening estimation confidence, this approach can help identify emerging disparities between local and economywide conditions, either of which might undermine policy effectiveness.

Example: Data Resources within the Industry

The rate setting process relies critically on IOU reporting of costs and related information, but there remain significant opportunities to leverage other information resources within the industry. As a result of decades of investment in one of the California's most inclusive supply chains (electricity services), the IOUs have an enormous reserve of data. In today's information economy, this data is an economic asset that, subject to appropriate use standards, could generate very substantial revenue for them and long-term innovation benefits for the overall state economy. Marketing IOU data would serve at least two important purposes: 1) Generate income that can offset required electricity revenue as well as emergent costs (e.g. wildfire); 2) Support broader innovation capacity in electric power, use technology, and many other dimensions of the state's energy system. California is home to some of the most innovative data use companies in the world, and their efforts to match increasingly diverse consumer populations with innovative technology and other producers of goods and services have dramatically increased rates of technology development and diffusion.

[226] Thissen, Mark. A classification of uncertainty in empirical modelling. Graduate School/Research Institute Systems, Organisation and Management, 1998.

[227] Belgodere, Antoine, and Charles Vellutini. "Identifying key elasticities in a forecasting model: a Monte Carlo approach." Applied Economics Letters 18, no. 17 (2011): 1619-1622.

[228] Borenstein, Severin, James Bushnell, Frank A. Wolak, and Matthew Zaragoza-Watkins. "Expecting the unexpected: Emissions uncertainty and environmental market design." American Economic Review 109, no. 11 (2019): 3953-77.

Historical and Cross-Sector Comparison

A third approach to managing uncertainty in regulatory modeling is to evaluate assessment approaches over time and across the national electric power sector. Often called "back casting" or performance comparison, these approaches compare policy expectations at the time of enactment with subsequent outcomes, either confined to California or across a variety of regulatory jurisdictions. To the extent that disparities of outcomes (e.g. use patterns, profitability, etc.) diverge from expectations, and especially to the extent that such divergence is systematic, it may be possible to identify risks in current practices.

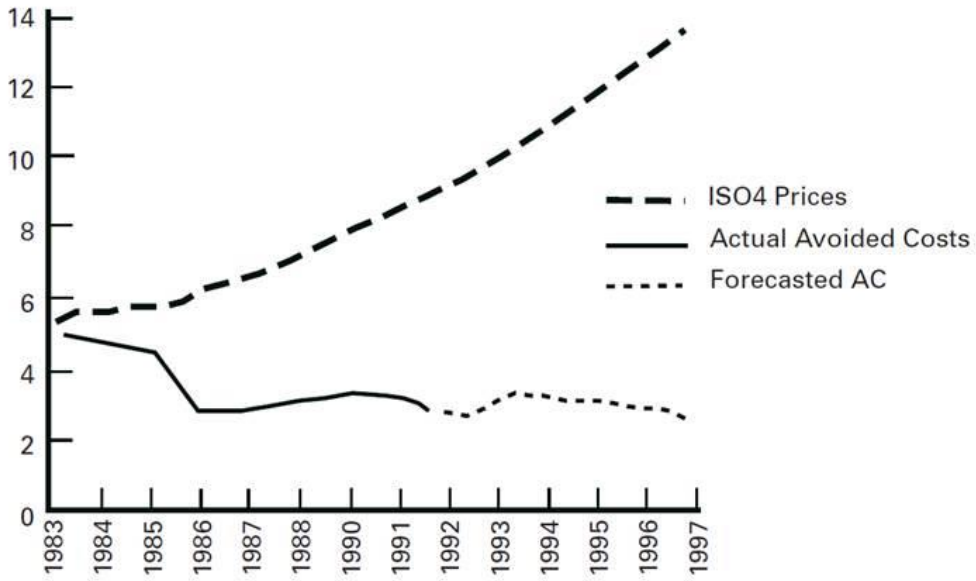
Example: ISO4 prices and avoided cost

In a 1993 report, the CPUC directed it's directed its Division of Strategic Planning to undertake a comprehensive review of the "...conditions the electric industry currently confronts, as well as future trends likely to influence the industry." This report concluded that the state should reform its regulatory program for two reasons:[229]

"California's current regulatory framework, significant portions of which were developed under circumstances that no longer obtain, is ill-suited to today's electric services industry.

The state's current regulatory approach may not be compatible with the industry structure likely to emerge in the ensuing decades."

Figure 3: ISO4 Contract Prices and Observed Avoided Utility Costs



Primary evidence in the report included a contracting system called the Interim Standard Offer 4 (ISO4). Intended to limit risks to utilities from combined market and technology uncertainties that might seem familiar today, the ISO4 system was negotiated on the basis of the utilities' forecast of future fuel prices and other key assumptions needed to estimate long-run avoided costs. The result led to explosive oversubscription, with

[229] https://docs.cpuc.ca.gov/published/report/3822.htm

15x the expected commitment from Qualifying Facilities that would be expected in a competitive market. The systematic gap in Figure 3 reveals two dangers that arise with regulated resource contracting: inflexibility and moral hazard. The first factor shifted the cost of systematic uncertainty to rate payers, while the second provided adverse incentives in negotiation, mainly biased disclosure of private information. As has been learned from Cap and Trade and related programs, tradeable rights systems can deliver efficiency without rigid contracts or disclosure requirements. These principles, independent evidence and adaptable, market-based policy instruments offer valuable guidance to navigate a new generation of systemic uncertainties.

Stakeholder Engagement

Although rarely acknowledged, one of the most important co-benefits of California's pathbreaking climate policy initiatives is increased commitment to transparent and timely stakeholder engagement. Although it requires foresight and additional initial investment, more inclusive policy dialog generally yields more robust policy, recruiting beneficiaries to support decisions and identifying adjustment needs of others to improve those decisions. This kind of engagement is most effectively supported by public information about detailed policy impacts, and agencies that invest in this can greatly facilitate their progress toward stable long term policy implementation. In contrast, policies taken forward without timely and informed public engagement have often been vulnerable to legal and other challenges.

The most relevant capacity needs in this area are detailed data that reflect the essential heterogeneity across stakeholders including energy needs, use technologies, and socioeconomic initial conditions. We are fortunate to live in an era with relatively abundant data, and this can be leveraged with modern analytical and visualization tools to more effectively inform decision makers and stakeholders. By investing in this as internal capacity, agencies can "level the playing field" of policy awareness for smaller but much more numerous (enterprise and household) stakeholders on the demand side of electricity markets.

Example: EV Adoption Benefits the Overall Economy

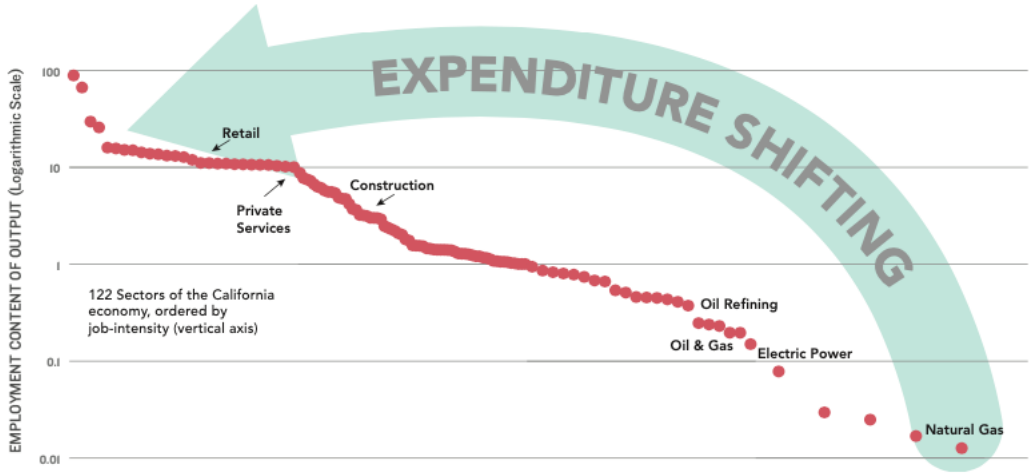
The capacity of detailed, forward looking policy assessment to inform public opinion is illustrated by a recent study of more rapid Electric Vehicle adoption.[230] This independent analysis showed significant macroeconomic benefits and broad-based job creation, benefiting millions of Californians whether or not they buy an EV or the cars are made here. Like E3's gasoline price scenarios and current research indicating that EV technology will lower vehicle costs, EV adoption can provide direct stimulus to California whether the state makes the cars or not. Growth stimulus from energy fuel saving is subtler, but also more pervasive. Promoting energy efficiency (in vehicles, appliances, or any durable goods) saves money for households and enterprises. These savings will be diverted to other expenditures, the majority of which (in California) go to in-state services that employ workers from all skill levels and demographics and are non-tradable, meaning these new jobs cannot be outsourced.

To see how potent this growth driver is, note that 70 percent of California aggregate demand (gross state product, or GSP) is household consumption and 70 percent of this goes to services. Thus, about half of incremental income or diverted expenditure can be expected to go to the service category of employment—

[230] https://www.next10.org/publications/ev-benefits

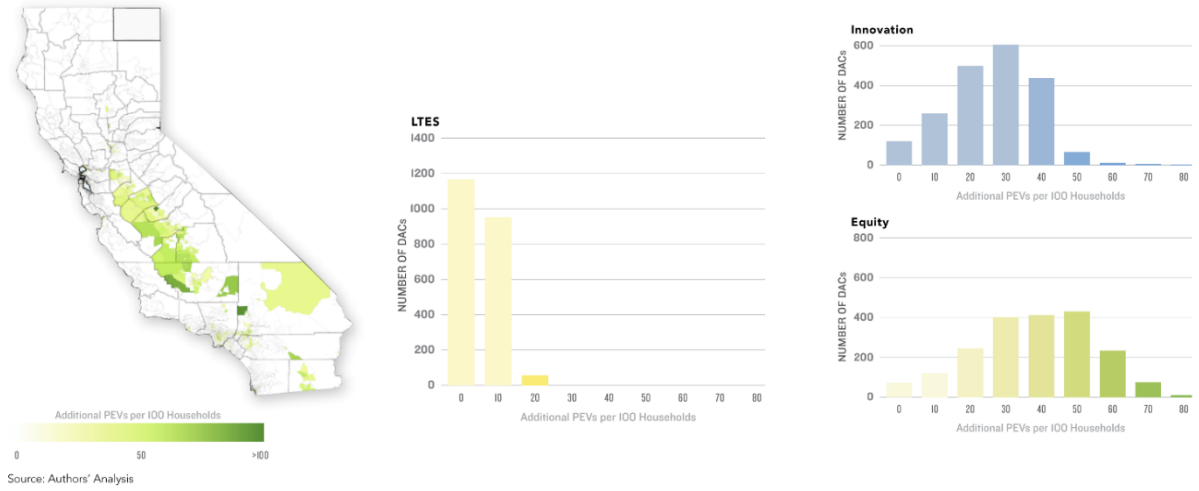
the most labor-intensive and skill-diverse in the economy. As Figure 4 makes clear, the carbon fuel supply chain is among the least employment intensive, and this after deducting a significant import cost share. Jobs per million of revenue in the service sector are one to 10 times greater than the same metric in the carbon fuel supply chain, and the difference is far too large to be offset by wage inequality. Simply put, if you save a dollar at the gas pump, you will spend about two-thirds of it on services, stimulating much stronger in-state job growth.

Figure 4: Job Creation Through Expenditure Shifting



Source: Authors calculations based on data from the US Bureau of Economic Analysis, US Bureau of Labor Statistics, and California Department of Finance[79]

Figure 5: EV Adoption in Disadvantaged Communities



Source: Authors' Analysis

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ADDENDUM 4: CONCEPTS FOR EQUITABLE COST ALLOCATION AND EFFICIENT PRICING – MARK LEBEL AND CARL LINVILL (REGULATORY ASSISTANCE PROJECT)

Transportation Electrification Considerations

Consumer Economics of Transportation Electrification

Economics of transportation electrification should generally be based on total cost of ownership, where a comparison of fuel costs between two different vehicle types is only one component.[231] To understand the real choices that face consumers, the base price of the vehicles, any necessary upfront charging investments, non-fuel operation and maintenance costs, tax incentives, rebates, taxes and fees as well as the relative impacts of environmental regulations (e.g., the Zero-Emission Vehicle program from the California Air Resources Board) also need to be considered. Factors that are not strictly monetary will also impact consumer preferences, such as the availability of public charging to meet certain needs or the broader public health and societal impacts of different technologies. This means that many different policy levers can promote transportation electrification. Creating opportunities for low-cost EV charging, either through convenient time-varying rate differentials or a variety of other cost allocation and rate design options, can certainly help but should be viewed in this broader context.

In the earlier stages of transportation electrification, electric vehicles often had a substantially higher upfront price than internal combustion engine (ICE) options, even after rebates and tax incentives. This led, quite fairly, to an emphasis on the lower fuel and maintenance costs of electric options as ways to overcome that upfront disparity in the minds of consumers. However, as battery costs are dropping over time, vehicle price parity may be reached in the next few years, and there are scenarios where electric vehicles will be cheaper than comparable ICE options. Larger batteries and increased ranges are also improving the attractiveness of EVs to consumers. These changes may reduce the pressure on fueling costs as a key building block of the consumer case for EVs, at least for some market segments.

In this context, creating realistic weighted average fuel cost projections for different categories of transportation electrification could be a helpful step, that could reveal disparities across different market segments and geographies. Different EV charging applications fall into different customer classes with different rate structures and price levels, which in turn determine the cost of EV charging. For the residential market segment, many EV adopters may charge predominantly at home and pay on the basis of residential rate structures. However, most other charging applications will take place under commercial and industrial (C&I) rates. These C&I rates typically have substantial demand charges, which can adversely

[231] Beneficial Electrification of Transportation (Jan. 2019), pp. 29-33, Regulatory Assistance Project https://www.raponline.org/knowledge-center/beneficial-electrification-of-transportation/

impact the economics of EV charging.[232] Any EV adopters without dedicated parking at home may have higher costs due to frequent usage of public fast charging.[233] Similarly, light-duty fleet electrification and medium- to heavy-duty electrification will be substantially impacted by demand charges. California has started to reform these rates for EV charging, but additional reforms will be needed.

Such a fuel cost analysis by segment can help public policy developments across the board, both for rate structures and the many other policy levers to accelerate equitable EV adoption. To the extent that the problem is either general (high rates across the board) or specific (high costs for certain types of transportation electrification), the solution could differ substantially. That could include efforts to hold down costs across the board or efforts to reform certain types of rate structures (e.g., demand charges). Narrowly tailored issues, either geographically or by market segment, may be easier to solve with reforms to electricity rate structures, particularly if win-win solutions can also promote efficiency and equity. To the extent that the issue is high electric costs generally, that may indicate that the best policy levers to promote electrification will be outside of electric regulation, through broadly available EV rebates or air quality regulations. A broad effort to shield EV charging from generally high electricity costs, through either discount rate options or separate EV rate classes, is possible to promote higher adoption rates. But such policies may primarily move those costs onto other customers.

Allocation of Costs for Transportation Electrification Programs

Over the past several years, California has developed a range of ambitious utility transportation electrification programs, whose costs will be recovered through electricity rates. This includes rebates for customer-owned charging stations, utility investments and expenses in make-ready infrastructure and charging equipment, and any directly related investments on the shared portion of the electricity system. To date, these costs have been recovered broadly across all customers and rate classes.

The question now: is there a more equitable and efficient way to charge these EV program costs, including specifically to EV adopters who benefit from these programs? In that context, it is important to recognize that EV adoption, and thus the utility programs that enable adoption, provide a range of ratepayer and societal benefits that should be properly accounted for.[234] Furthermore, the purpose of these programs is to accelerate EV adoption, which could run counter to any effort to charge costs more specifically to EV drivers. That would particularly be the case with any market segments that are already facing unreasonably high charging costs, as discussed above. Utility EV use cases and customer behavior on new high powered

[232] Demand charge reform is likely worth pursuing beyond the context of transportation electrification, since most demand charges do not provide a good marginal cost price signal and do not allocate costs equitably across customers. See Demand Charges: What Are They Good For? (Nov. 2020), Regulatory Assistance Project: https://www.raponline.org/knowledge-center/demand-charges-what-are-they-good-for/ and Smart Non-Residential Rate Design (Dec. 2017), Regulatory Assistance Project: https://www.raponline.org/knowledge-center/smart-non-residential-rate-design/

[233] Adding to the complexity of this analysis, many charging applications are not necessarily priced at the marginal cost of electricity but rather have prices based on a wider array of considerations depending on the service provider and the owners' business model. In some circumstances, this can mean free or low-cost charging as an amenity but, in other circumstances, this can lead to higher priced charging because it entails the recovery of other relevant costs, such as the end-use charging equipment, or the provision of bundled services. Of course, the relevant electricity rates will still influence decisions by the owners and operators of these charging stations, even if the final customer pricing is not directly linked.

[234] The clearest example is demand management program costs specifically for EVs, whether they are integrated into utility TE programs or not, which should be treated like other demand management programs and allocated either on the basis of class participation or system benefits.

EV rate options (e.g., SDG&E's new EV-HP rate and PG&E's analog) will be evaluated carefully over the next year to assess whether and to what extent rate design tweaks will be necessary to promote more equity as California promotes swift adoption.

But in the longer term, striking a balance between goals of faster transportation electrification and equitable cost allocation should help promote the greater good.[235] One set of options would involve changing the nature of the programs themselves. For example, instead of spreading costs of individual projects across many customers, the programs could effectively be used for **on-bill financing** of each project, where the customer who benefits pays off the utility costs of their own installation over time. "Pay-as-you-save" features can be incorporated in these programs so that customers are guaranteed to save on their monthly bills from day one.[236]

Another set of options would still spread individual project costs over groups of customers but in a more targeted fashion. In general, a portion of transportation electrification program costs could be directly allocated to a category of identifiable EV accounts, either accounts who have participated in a utility EV program (perhaps starting from a certain cutoff date) or any other administratively feasible way to identify EV customers. To take a more specific illustrative example, make-ready costs for a broad category of level two charging stations could be tracked and program participants in this category, possibly exempting certain participants that meet certainty equity criteria with respect to low-income and disadvantaged communities, would have a rate rider that includes recovery of some or all of those costs. Such an approach does have additional administrative costs compared to a more traditional broad brush allocation technique. However, nearly any approach to target costs more specifically to participants will share those difficulties.

Equity Considerations for a Robust Distributed Energy Resources Future

California, as a leader in the development of distributed solar, has been at the forefront of measures to reform compensation for customer-sited renewable generation. Starting from a simple net energy metering ("NEM") policy of retail rate credits and monthly netting, the California PUC laid out a roadmap in 2016 for a bundle of reforms called "NEM 2.0":

- Modest one-time interconnection charges;
- A requirement for NEM customers to be on a time-of-use rate, with netting taking place within each one-hour period; and
- Non-bypassable charges (which cannot be offset by credits) are billed based on a more granular measurement of all imports from the distribution grid.

As distributed solar penetration continues to grow in California, additional steps can be taken to improve the cost-causation basis of rate design for customer-sited renewable generation, including solar but potentially

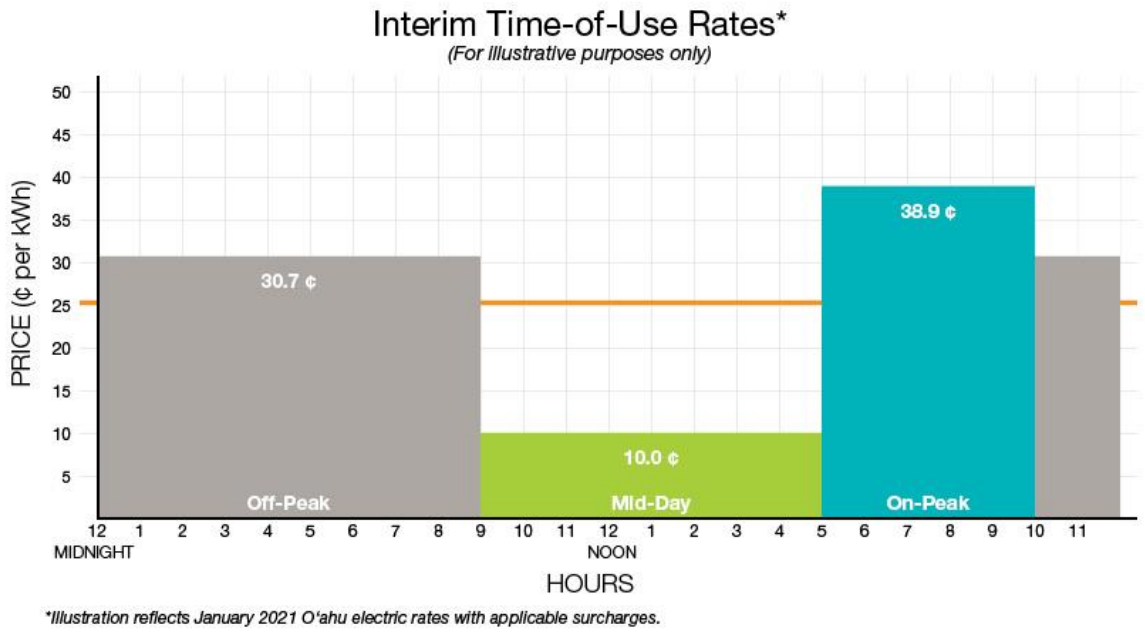
[235] *See* Electric Cost Allocation for a New Era: A Manual (Jan. 2020) pp. 86-89, Regulatory Assistance Project: https://www.raponline.org/wp-content/uploads/2020/01/rap-lazar-chernick-marcus-lebel-electric-cost-allocation-new-era-2020-january.pdf
[236] https://www.cleanenergyworks.org/clean-transit/

extending to other technologies that allow customers to export energy to the grid like storage, and ensure equitable allocation of costs. Gradualism will continue to be an important principle as these transitions happen, both for any current net energy metering customers who are placed on new rate structures,[237] but also for clean energy industries who must adapt to new economic considerations.

Balancing granularity with understandability for small customers

A moderate path for reform would be to keep "net energy metering" as a mechanism but continue to change the specifics of how it operates. More granular time-varying rates would improve the economic basis of distributed energy resource compensation under net energy metering – naturally reducing any hidden cost shifts and incentivizing smarter customer behavior (load management, storage, and generation to the extent dispatchable). This transition would need to be balanced with customer understandability and the reality that some cost shifts will be contained in any broad rate structures.

For residential and small commercial customer classes, hourly pricing would be too complex in most cases until sophisticated energy management technology is widely available and affordable. Moving from relatively simple TOU rates - two- or three-periods and winter/summer seasons – to more sophisticated TOU rates – three- or four-periods and improved seasonal distinctions – with a critical peak pricing element, should be a significant improvement towards the ultimate goal of smarter pricing for all customers and equitable and efficient cost allocation.[238]



https://www.hawaiianelectric.com/products-and-services/save-energy-and-money/time-of-use-program

[237] Both NEM 1.0 and NEM 2.0 customers have a 20-year legacy period under each respective structure. However, all NEM customers must take service on an applicable rate which may change over time.
[238] See Smart Rate Design for a Smart Future (July 2015), Regulatory Assistance Project: https://www.raponline.org/knowledge-center/smart-rate-design-for-a-smart-future/

Some segmentation of traditional rate classes may be warranted. Technology-specific rate classes are rarely a good idea, but the residential rate class could be segmented into a "simple" subclass and an "advanced" subclass. Larger users and distributed generation customers could be required to be in the advanced subclass with more complex rates. Smaller users and low-income customers could be placed into the simple subclass, where the rate reforms are more gradual and have less customer risk, such as a peak-time rebate instead of critical peak pricing. This type of segmentation may allow for faster progress towards more complex rate structures by addressing key concerns about technology discrimination and bill impacts on vulnerable customers.

Granular Value-based Export Credit Structures for Larger DER Projects

For larger DER facilities, such as on-site projects for C&I customers, community solar or a broader remote net metering program, California could consider an export credit structure like the NY value of distributed energy resources (VDER) tariff:

- Hourly energy pricing based on wholesale markets;
- Time-based credits for avoided capacity costs (generation and delivery); and
- An environmental value for zero- and low-emissions generation technologies.

Such a pricing scheme addresses directly concerns about cost shifting by aligning export compensation explicitly with value. The NY VDER tariff also includes locational distinctions for many of its elements. Of course, this pricing can be integrated with broader policy efforts. The original VDER tariff included a **"market transition credit"** for community solar projects that provided a step down over time between the previous policy framework and the VDER tariff. This market transition credit has since been replaced with a "community credit" for certain categories of projects.

Two-way kWh Charge for DER Customers with Load

The above concepts provide a pathway towards more efficient and equitable pricing for the vast majority of electric system costs, short-run marginal energy costs, environmental externalities as well as long-run marginal capacity costs for generation, transmission and distribution. However, this does not address administrative and general costs, or potentially other categories of residual costs. Famously, Bonbright noted that there are no fixed principles for allocating and charging these costs and the debate is typically left to other related policy concerns.[239] One potential category of residual costs could be the backbone of the distribution network, which was originally built to deliver energy to customers from the centralized grid, but now the distribution backbone must be built and maintained to handle two-way flow of energy.

While some utilities and consultants argue that these costs should be recovered through customer charges or demand charges, those methods typically have significant downsides, including bill impacts on small users,

[239] Bonbright, James C. (1961), Principles of Public Utility Rates, Columbia University Press, at p. 348: https://www.raponline.org/knowledge-center/principles-of-public-utility-rates/

insufficient linkage to marginal costs, and the inability of customers to understand and manage their bills. In some circumstances, those downsides can be mitigated if the charges are designed and limited appropriately. A more efficient and equitable option could be a two-way kWh charge on both imports and exports, spreading these costs over a larger billing determinant in a non-discriminatory manner.[240] This new billing determinant corresponds directly to a broader conception of how DG customers use the grid, as well as a reasonable metric of the "size" of a customer. Another key feature of this concept is that it avoids undue discrimination because the *rate* is the same across all customers within the class, and the reform is that it applies both to imports and exports. Close attention should be paid so that only certain categories of costs are included in this rate.

[240] See Designing Distributed Generation Tariffs Well (Nov. 2013), Regulatory Assistance Project: https://www.raponline.org/knowledge-center/designing-distributed-generation-tariffs-well/

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June 6, 2023

MEMORANDUM FOR: Interested parties

FROM: Megan Kirkeby, Deputy Director
Division of Housing Policy Development

SUBJECT: **2023 State Income Limits**

Attached are briefing materials and 2023 State Income Limits that are now in effect, replacing the previous 2022 State Income Limits. Income limits reflect updated median income and household income levels for acutely low -, extremely low-, very low-, low-, and moderate-income households for California's 58 counties. The 2023 State Income Limits are on the Department of Housing and Community Development (HCD) website at https://www.hcd.ca.gov/grants-and-funding/income-limits/state-and-federal-income-rent-and-loan-value-limits.

State Income Limits apply to designated programs, are used to determine applicant eligibility (based on the level of household income) and may be used to calculate affordable housing costs for applicable housing assistance programs. Use of State Income Limits are subject to a particular program's definition of income, family, family size, effective dates, and other factors. In addition, definitions applicable to income categories, criteria, and geographic areas sometimes differ depending on the funding source and program, resulting in some programs using other income limits.

The attached briefing materials detail California's 2023 Income Limits and were updated based on: (1) changes to income limits the U.S. Department of Housing and Urban Development (HUD) released on May 15, 2023, for its Public Housing, Section 8, Section 202 and Section 811 programs and (2) adjustments HCD made based on State statutory provisions and its 2013 Hold Harmless (HH) Policy. Since 2013, HCD's HH Policy has held State Income Limits harmless from any decreases in household income limits and median income levels that HUD may apply to the Public Housing and Section 8 Income Limits. HUD determined its HH Policy was no longer necessary due to federal law changes in 2008 (Public Law 110-98) prohibiting rent decreases in federal or private activity bond funded projects.

For questions concerning State Income Limits, please see the Questions and Answers on page 5. You can also contact HCD staff at (916) 263-2911.

Overview

The Department of Housing and Community Development (HCD), pursuant to Health & Safety Code Section 50093(c), must file updates to its State Income Limits with the Office of Administrative Law. HCD annually updates these income limits based on U.S. Department of Housing and Urban Development (HUD) revisions to the Public Housing and Section 8 Income Limits that HUD most recently released on May 15, 2023.

HUD annually updates its Public Housing and Section 8 Income Limits to reflect changes in median family income levels for different size households and income limits for extremely low-, very low-, and low-income households. HCD, pursuant to statutory provisions, makes the following additional revisions: (1) if necessary, increase a county's area median income to equal California's non-metropolitan median income, (2) adjusts area median income and household income category levels to not result in any decrease for any year after 2009 pursuant to HCD's February 2013 Hold Harmless (HH) Policy (HCD's HH Policy was implemented to replace HUD's HH Policy, discontinued in 2009, to not decrease income limits and area median income levels below a prior year's highest level), and (3) determines income limits for California's acutely low-income and moderate-income category.

Following are brief summaries of technical methodologies used by HUD and HCD in updating income limits for different household income categories. For additional information, please refer to HUD's briefing materials at https://www.huduser.gov/portal/datasets/il//il23/IncomeLimitsMethodology-FY23.pdf

HUD Methodology

HUD Public Housing and Section 8 Income Limits begin with the production of median family incomes. HUD uses the Section 8 program's Fair Market Rent (FMR) area definitions in developing median incomes, which means developing median incomes for each metropolitan area, parts of some metropolitan areas, and each non-metropolitan county. The 2023 FMR area definitions for California are unchanged from last year. HUD calculates Income Limits for every FMR area with adjustments for family size and for areas with unusually high or low family income or housing-cost-to-income relationships.

Extremely Low-Income

In determining the extremely low-income limit, HUD uses the Federal Poverty Guidelines, published by the Department of Health and Human Services. The poverty guidelines are a simplified version of the federal poverty thresholds used for administrative purposes — for instance, determining financial eligibility for certain federal programs. HUD compares the appropriate poverty guideline with 60% of the very low-income limit and chooses the greater of the two as the extremely low-income limit. The value may not exceed the very low-income level.

Very Low-Income

The very low-income limits are the basis for the extremely low- and low-income limits. The very low-income limit typically reflects 50 percent of median family income (MFI), and HUD's MFI figure generally equals two times HUD's 4-person very low-income limit. However, HUD may adjust the very low-income limit for an area or county to account for conditions that warrant special considerations. As such, the very low-income limit may not always equal 50% MFI.

Low-Income

In general, most low-income limits represent the higher level of: (1) 80 percent of MFI or, (2) 80 percent of state non-metropolitan median family income. However, due to adjustments that HUD sometimes makes to the very low-income limit, strictly calculating low-income limits as 80 percent of MFI could produce unintended anomalies inconsistent with statutory intent (e.g., very low-income limits being higher than low-income limits). Therefore, HUD's briefing materials specify that, with some exceptions,

the low-income limit reflect 160 percent of the very low-income limit. HUD may apply additional adjustments to areas with unusually high or low housing-costs-to-income relationships and for other reasons. This can result in low-income limits exceeding MFI in certain counties.

Median Family Income/Area Median Income

HUD references and estimates the MFI in calculating the income limits. California law and State Income Limits reference Area Median Income (AMI) that, pursuant to Health & Safety Code 50093(c), means the MFI of a geographic area, estimated by HUD for its Section 8 Program.

In estimating FY 2023 median family incomes, HUD uses median family income data (as opposed to median household income data) from the 2021 American Community Survey (ACS) as calculated by the Census Bureau. The Census Bureau produces two types of ACS estimates: the "one-year" data, which represent estimates as of 2021; and the "five-year" data, which represent estimates as of 2017-2021 (but are inflated to 2021 dollars). HUD would ordinarily have used the ACS 2020 data for FY 2023. However, due to interruptions to data collection caused by the Covid-19 pandemic, the Census Bureau did not release special tabulations of ACS 2020 one-year data. HUD requires special tabulations of the ACS to match its custom HMFA definitions described above.

HUD uses the 2021 American Community Survey (ACS) median family income data (as opposed to household income data) as the basis of FY 2023 Income Limits for all areas of California. HUD uses an inflation forecast from the Congressional Budget Office (CBO) in updating ACS estimates. For FY 2023, CBO has produced a forecast CPI of 303.948, which divided by annual 2021 of 270.971 is 1.122 (an increase of 12.2 percent).

For additional information on MFI's please see HUD's briefing materials at https://www.huduser.gov/portal/datasets/il/il23/Medians-Methodology-FY23.pdf.

Adjustment Calculations

HUD may apply adjustments to areas with unusually high or low family income, uneven housing-cost-to-income relationship, or other reasons. For example, HUD applies an increase if the four-person very low-income limit would otherwise be less than the amount at which 35 percent of it equals 85 percent of the annualized two-bedroom Section 8 FMR (or 40th percentile rent in 50th percentile FMR areas). The purpose is to increase the income limit for areas where rental-housing costs are unusually high in relation to the median income.

In certain cases, HUD also applies an adjustment to the income limits based on the state non-metropolitan median family income level. In addition, HUD restricts adjustments, so income limits do not increase more than five percent of the previous year's very low-income figure OR twice the increase in the national MFI as measured by the American Community Survey, whichever is greater. For the 2023 income limits, the cap is twice the annualized change from ACS 2019 to ACS 2021, which is 5.92 percent. This adjustment does not apply to the extremely low-income limits.

Please refer to HUD briefing materials for additional information on the adjustment calculations.

Income Limit Calculations for Household Sizes Other Than 4-Persons

The income limit statute requires adjustments for family size. The legislative history and conference committee report indicates that Congress intended that income limits should be higher for larger families and lower for smaller families. The same family size adjustments apply to all income limits, except extremely low-income limits, which are set at the poverty income threshold. They are as follows:

Number of Persons in Household:	1	2	3	4	5	6	7	8
Adjustments:	70%	80%	90%	Base	108%	116%	124%	132%

Income Limit Calculations for Household Sizes Greater Than 8-Persons
For households of more than eight persons, refer to the formula at the end of the table for 2023 Income Limits. Due to the adjustments HUD can make to income limits in a given county, table data should be the only method used to determine program eligibility. Arithmetic calculations are applicable only when a household has more than eight members. Please refer to HUD's briefing material for additional information on family size adjustments.

HCD Methodology

State law (see, e.g., Health & Safety Code Section 50093) prescribes the methodology HCD uses to update the State Income Limits. HCD utilizes HUD's Public Housing and Section 8 Income Limits. HCD's methodology involves: (1) if necessary, increasing a county's median income established by HUD to equal California's non-metropolitan county median income determined by HUD, (2) applying HCD's HH Policy, in effect since 2013, to not allow decreases in area median income levels and household income category levels, (3) applying to the median income the same family size adjustments HUD applies to the income limits, (4) determining income limit levels applicable to California's acutely low-income households defined by law as household income not exceeding 15 percent of county area median income, and (5) determining income limit levels applicable to California's moderate-income households defined by law as household income not exceeding 120 percent of county area median income.

Area Median Income and Income Category Levels
HCD, pursuant to federal and State law, adjusts median income levels for all counties so they are not less than the non-metropolitan county median income established by HUD ($83,800 for 2023). Next, HCD applies its HH policy to ensure area median income and income limits for all household income categories do not fall below any level achieved in the prior year. Health and Safety Code section 50093 requires HCD to adjust the AMI for family size in accordance with adjustment factors adopted by HUD and illustrated on the previous page. This establishes that the MFI published by HUD equals the four-person AMI for California counties.

Acutely low-Income Levels
Chapter 345, Statues of 2021 (Assembly Bill 1043) established California's acutely low-income levels. See Health & Safety Code, § 50063.5. After calculating the 4-person area median income (AMI) level as previously described, HCD sets the maximum acutely low-income limit to equal 15 percent of the county's AMI, adjusted for family size.

Moderate-Income Levels
HCD is responsible for establishing California's moderate-income limit levels. After calculating the 4-person area median income (AMI) level as previously described, HCD sets the maximum moderate-income limit to equal 120 percent of the county's AMI, adjusted for family size.

Applicability of California's Official State Income Limits
Applicability of the State Income Limits are subject to particular programs as program definitions of factors such as income, family, and household size vary. Some programs, such as Multifamily Tax Subsidy Projects (MTSPs), use different income limits. For MTSPs, separate income limits apply per provisions of the Housing and Economic Recovery Act (HERA) of 2008 (Public Law 110-289). Income limits for MTSPs are used to determine qualification levels as well as set maximum rental rates for projects funded with tax credits authorized under Section 42 of the Internal Revenue Code (Code). In addition, MTSP income limits apply to projects financed with tax-exempt housing bonds issued to provide qualified residential rental development under Section 142 of the Code. These income limits are available at http://www.huduser.org/datasets/mtsp.html.

Questions and Answers

In Los Angeles, as well as several other counties in the state, why does the very low-income limit not equal 50% of the AMI (or the low-income limit not equal 80% of the AMI)?

There are many exceptions to the arithmetic calculation of income limits. These include adjustments for high housing cost relative to income, the application of state nonmetropolitan income limits in low-income areas, and national maximums in high-income areas. **In Los Angeles County, as well as several others, the magnitude of these adjustments results in the low-income limit exceeding the AMI.** These exceptions are detailed in the FY 2023 Income Limits Methodology Document, https://www.huduser.gov/portal/datasets/il/il23/Medians-Methodology-FY23.pdf.

For further information on the exact adjustments made to an individual area of the country, please see HUD's FY 2023 Income Limits Documentation System. The documentation system is available at https://www.huduser.gov/portal/datasets/il/il2023/select_Geography.odn. Once the area in question is selected, a summary of the area's median income, Very Low-Income, Extremely Low-Income, and Low-Income Limits are displayed. Detailed calculations are obtained by selecting the relevant links.

Why don't the income limits for my area reflect recent gains?

Although HUD uses the most recent data available concerning local area incomes, there is still a lag between when the data are collected and when the data are available for use. For example, FY 2023 Income Limits are calculated using 2017-2021 5-year American Community Survey (ACS) data, and one-year 2021 data where possible. This is a two-year lag, so more current trends in median family income levels are not available.

HUD estimates Median Family Income (MFI) annually for each metropolitan area and non-metropolitan county. The basis for HUD's median family incomes is data from the American Community Survey, table B19113 - MEDIAN FAMILY INCOME IN THE PAST 12 MONTHS. A Consumer Price Index (CPI) forecast as published by the Bureau of Labor Statistics is used in the trend factor calculation to bring the 2021 ACS data forward to FY 2023.

For additional details concerning the use of the ACS in HUD's calculations of MFI, please see HUD's FY 2023 Median Family Income methodology document, at https://www.huduser.gov/portal/datasets/il/il23/Medians-Methodology-FY23.pdf

Additionally, full documentation of all calculations for Median Family Incomes are available in the FY 2023 Median Family Income and the FY 2023 Income Limits Documentation System. These systems are available at https://www.huduser.gov/portal/datasets/il/il2023/select_Geography.odn

Why didn't the income limits for my county change from last year?

HCD's Hold Harmless Policy likely prevented the income limits from decreasing from last year's levels and has maintained them despite a decrease in median income and/or income limits published by HUD.

Why do the income limits or area median income for my county not match what was published by HUD?

HCD adjusts each county's area median income to at least equal the state non-metropolitan county median income, as published by HUD. Further, HCD's Hold Harmless Policy prevents any decrease in income limits or median family income published by HUD to be applied to State Income Limits.

Section 6932. 2023 Income Limits

Number of Persons in Household:		1	2	3	4	5	6	7	8
Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
Alameda County Area Median Income: $147,900	Acutely Low	15550	17750	20000	22200	24000	25750	27550	29300
	Extremely Low	31050	35500	39950	44350	47900	51450	55000	58550
	Very Low Income	51800	59200	66600	73950	79900	85800	91700	97650
	Low Income	78550	89750	100950	112150	121150	130100	139100	148050
	Median Income	103550	118300	133100	**147900**	159750	171550	183400	195250
	Moderate Income	124250	142000	159750	177500	191700	205900	220100	234300
Alpine County Area Median Income: $114,600	Acutely Low	12050	13750	15500	17200	18600	19950	21350	22700
	Extremely Low	20200	23100	26000	30000	35140	40280	45420	50560
	Very Low Income	33650	38450	43250	48050	51900	55750	59600	63450
	Low Income	53850	61550	69250	76900	83100	89250	95400	101550
	Median Income	80200	91700	103150	**114600**	123750	132950	142100	151250
	Moderate Income	96250	110000	123750	137500	148500	159500	170500	181500
Amador County Area Median Income: $101,200	Acutely Low	10650	12150	13700	15200	16400	17650	18850	20050
	Extremely Low	19250	22000	24860	30000	35140	40280	45420	50560
	Very Low Income	32100	36700	41300	45850	49550	53200	56900	60550
	Low Income	51350	58700	66050	73350	79250	85100	91000	96850
	Median Income	70850	80950	91100	**101200**	109300	117400	125500	133600
	Moderate Income	85000	97150	109300	121450	131150	140900	150600	160300
Butte County Area Median Income: $91,600	Acutely Low	9650	11000	12400	13750	14850	15950	17050	18150
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	64100	73300	82450	**91600**	98950	106250	113600	120900
	Moderate Income	76950	87900	98900	109900	118700	127500	136300	145050
Calaveras County Area Median Income: $96,200	Acutely Low	10100	11550	13000	14450	15600	16750	17900	19050
	Extremely Low	20050	22900	25750	30000	35140	40280	45420	50560
	Very Low Income	33400	38150	42900	47650	51500	55300	59100	62900
	Low Income	53400	61000	68650	76250	82350	88450	94550	100650
	Median Income	67350	76950	86600	**96200**	103900	111600	119300	127000
	Moderate Income	80800	92350	103900	115450	124700	133900	143150	152400
Colusa County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Contra Costa County Area Median Income: $147,900	Acutely Low	15550	17750	20000	22200	24000	25750	27550	29300
	Extremely Low	31050	35500	39950	44350	47900	51450	55000	58550
	Very Low Income	51800	59200	66600	73950	79900	85800	91700	97650
	Low Income	78550	89750	100950	112150	121150	130100	139100	148050
	Median Income	103550	118300	133100	**147900**	159750	171550	183400	195250
	Moderate Income	124250	142000	159750	177500	191700	205900	220100	234300

Number of Persons in Household:		1	2	3	4	5	6	7	8
Del Norte County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
El Dorado County Area Median Income: $113,900	Acutely Low	11950	13700	15400	17100	18450	19850	21200	22550
	Extremely Low	22550	25750	28950	32150	35140	40280	45420	50560
	Very Low Income	37550	42900	48250	53600	57900	62200	66500	70800
	Low Income	60050	68600	77200	85750	92650	99500	106350	113200
	Median Income	79750	91100	102500	**113900**	123000	132100	141250	150350
	Moderate Income	95700	109350	123050	136700	147650	158550	169500	180450
Fresno County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Glenn County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Humboldt County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Imperial County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Inyo County Area Median Income: $85,400	Acutely Low	8950	10250	11500	12800	13800	14850	15850	16900
	Extremely Low	17950	20500	24860	30000	35140	40280	45420	50560
	Very Low Income	29900	34200	38450	42700	46150	49550	52950	56400
	Low Income	47850	54650	61500	68300	73800	79250	84700	90200
	Median Income	59800	68300	76850	**85400**	92250	99050	105900	112750
	Moderate Income	71750	82000	92250	102500	110700	118900	127100	135300

Number of Persons in Household:		1	2	3	4	5	6	7	8
Kern County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Kings County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Lake County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Lassen County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17650	20150	24860	30000	35140	40280	45420	50560
	Very Low Income	29350	33550	37750	41900	45300	48650	52000	55350
	Low Income	46950	53650	60350	67050	72450	77800	83150	88550
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Los Angeles County Area Median Income: $98,200	Acutely Low	10350	11800	13300	14750	15950	17100	18300	19450
	Extremely Low	26500	30300	34100	37850	40900	43950	46950	50560
	Very Low Income	44150	50450	56750	63050	68100	73150	78200	83250
	Low Income	70650	80750	90850	100900	109000	117050	125150	133200
	Median Income	68750	78550	88400	**98200**	106050	113900	121750	129600
	Moderate Income	82500	94300	106050	117850	127300	136700	146150	155550
Madera County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Marin County Area Median Income: $175,000	Acutely Low	18400	21000	23650	26250	28350	30450	32550	34650
	Extremely Low	39150	44750	50350	55900	60400	64850	69350	73800
	Very Low Income	65250	74600	83900	93200	100700	108150	115600	123050
	Low Income	104400	119300	134200	149100	161050	173000	184900	196850
	Median Income	122500	140000	157500	**175000**	189000	203000	217000	231000
	Moderate Income	147000	168000	189000	210000	226800	243600	260400	277200

Number of Persons in Household:		1	2	3	4	5	6	7	8
Mariposa County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Mendocino County Area Median Income: $89,700	Acutely Low	9400	10750	12100	13450	14550	15600	16700	17750
	Extremely Low	17850	20400	24860	30000	35140	40280	45420	50560
	Very Low Income	29750	34000	38250	42500	45900	49300	52700	56100
	Low Income	47600	54400	61200	68000	73450	78900	84350	89800
	Median Income	62800	71750	80750	**89700**	96900	104050	111250	118400
	Moderate Income	75350	86100	96900	107650	116250	124850	133500	142100
Merced County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Modoc County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Mono County Area Median Income: $95,800	Acutely Low	10050	11500	12900	14350	15500	16650	17800	18950
	Extremely Low	17850	20400	24860	30000	35140	40280	45420	50560
	Very Low Income	29750	34000	38250	42500	45900	49300	52700	56100
	Low Income	47600	54400	61200	68000	73450	78900	84350	89800
	Median Income	67050	76650	86200	**95800**	103450	111150	118800	126450
	Moderate Income	80450	91950	103450	114950	124150	133350	142550	151750
Monterey County Area Median Income: $100,400	Acutely Low	10550	12050	13550	15050	16250	17450	18650	19850
	Extremely Low	25300	28900	32500	36100	39000	41900	45420	50560
	Very Low Income	42150	48200	54200	60200	65050	69850	74650	79500
	Low Income	67450	77100	86750	96350	104100	111800	119500	127200
	Median Income	70300	80300	90350	**100400**	108450	116450	124500	132550
	Moderate Income	84350	96400	108450	120500	130150	139800	149400	159050
Napa County Area Median Income: $129,600	Acutely Low	13600	15550	17500	19450	21000	22550	24100	25650
	Extremely Low	28050	32050	36050	40050	43300	46500	49700	52900
	Very Low Income	46750	53400	60100	66750	72100	77450	82800	88150
	Low Income	74700	85400	96050	106700	115250	123800	132350	140850
	Median Income	90700	103700	116650	**129600**	139950	150350	160700	171050
	Moderate Income	108850	124400	139950	155500	167950	180400	192800	205250

Number of Persons in Household:		1	2	3	4	5	6	7	8
Nevada County Area Median Income: $112,500	Acutely Low	11850	13500	15200	16900	18250	19600	20950	22300
	Extremely Low	21900	25000	28150	31250	35140	40280	45420	50560
	Very Low Income	36500	41700	46900	52100	56300	60450	64650	68800
	Low Income	58350	66700	75050	83350	90050	96700	103400	110050
	Median Income	78750	90000	101250	**112500**	121500	130500	139500	148500
	Moderate Income	94500	108000	121500	135000	145800	156600	167400	178200
Orange County Area Median Income: $127,800	Acutely Low	13400	15300	17250	19150	20700	22200	23750	25300
	Extremely Low	30150	34450	38750	43050	46500	49950	53400	56850
	Very Low Income	50250	57400	64600	71750	77500	83250	89000	94750
	Low Income	80400	91850	103350	114800	124000	133200	142400	151550
	Median Income	89450	102250	115000	**127800**	138000	148250	158450	168700
	Moderate Income	107350	122700	138000	153350	165600	177900	190150	202400
Placer County Area Median Income: $113,900	Acutely Low	11950	13700	15400	17100	18450	19850	21200	22550
	Extremely Low	22550	25750	28950	32150	35140	40280	45420	50560
	Very Low Income	37550	42900	48250	53600	57900	62200	66500	70800
	Low Income	60050	68600	77200	85750	92650	99500	106350	113200
	Median Income	79750	91100	102500	**113900**	123000	132100	141250	150350
	Moderate Income	95700	109350	123050	136700	147650	158550	169500	180450
Plumas County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17650	20150	24860	30000	35140	40280	45420	50560
	Very Low Income	29350	33550	37750	41900	45300	48650	52000	55350
	Low Income	46950	53650	60350	67050	72450	77800	83150	88550
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Riverside County Area Median Income: $94,500	Acutely Low	9950	11350	12800	14200	15350	16450	17600	18750
	Extremely Low	19600	22400	25200	30000	35140	40280	45420	50560
	Very Low Income	32650	37300	41950	46600	50350	54100	57800	61550
	Low Income	52200	59650	67100	74550	80550	86500	92450	98450
	Median Income	66150	75600	85050	**94500**	102050	109600	117200	124750
	Moderate Income	79400	90700	102050	113400	122450	131550	140600	149700
Sacramento County Area Median Income: $113,900	Acutely Low	11950	13700	15400	17100	18450	19850	21200	22550
	Extremely Low	22550	25750	28950	32150	35140	40280	45420	50560
	Very Low Income	37550	42900	48250	53600	57900	62200	66500	70800
	Low Income	60050	68600	77200	85750	92650	99500	106350	113200
	Median Income	79750	91100	102500	**113900**	123000	132100	141250	150350
	Moderate Income	95700	109350	123050	136700	147650	158550	169500	180450
San Benito County Area Median Income: $140,200	Acutely Low	14750	16850	18950	21050	22750	24400	26100	27800
	Extremely Low	23400	26750	30100	33400	36100	40280	45420	50560
	Very Low Income	39000	44550	50100	55650	60150	64600	69050	73500
	Low Income	62350	71250	80150	89050	96200	103300	110450	117550
	Median Income	98150	112150	126200	**140200**	151400	162650	173850	185050
	Moderate Income	117750	134600	151450	168250	181700	195150	208650	222100

Number of Persons in Household:		1	2	3	4	5	6	7	8
San Bernardino County Area Median Income: $94,500	Acutely Low	9950	11350	12800	14200	15350	16450	17600	18750
	Extremely Low	19600	22400	25200	30000	35140	40280	45420	50560
	Very Low Income	32650	37300	41950	46600	50350	54100	57800	61550
	Low Income	52200	59650	67100	74550	80550	86500	92450	98450
	Median Income	66150	75600	85050	**94500**	102050	109600	117200	124750
	Moderate Income	79400	90700	102050	113400	122450	131550	140600	149700
San Diego County Area Median Income: $116,800	Acutely Low	12250	14000	15750	17500	18900	20300	21700	23100
	Extremely Low	28950	33100	37250	41350	44700	48000	51300	54600
	Very Low Income	48250	55150	62050	68900	74450	79950	85450	90950
	Low Income	77200	88200	99250	110250	119100	127900	136750	145550
	Median Income	81750	93450	105100	**116800**	126150	135500	144850	154200
	Moderate Income	98100	112100	126150	140150	151350	162550	173800	185000
San Francisco County Area Median Income: $175,000	Acutely Low	18400	21000	23650	26250	28350	30450	32550	34650
	Extremely Low	39150	44750	50350	55900	60400	64850	69350	73800
	Very Low Income	65250	74600	83900	93200	100700	108150	115600	123050
	Low Income	104400	119300	134200	149100	161050	173000	184900	196850
	Median Income	122500	140000	157500	**175000**	189000	203000	217000	231000
	Moderate Income	147000	168000	189000	210000	226800	243600	260400	277200
San Joaquin County Area Median Income: $100,300	Acutely Low	10550	12050	13550	15050	16250	17450	18650	19850
	Extremely Low	18450	21050	24860	30000	35140	40280	45420	50560
	Very Low Income	30700	35100	39500	43850	47400	50900	54400	57900
	Low Income	49100	56100	63100	70100	75750	81350	86950	92550
	Median Income	70200	80250	90250	**100300**	108300	116350	124350	132400
	Moderate Income	84250	96300	108300	120350	130000	139600	149250	158850
San Luis Obispo County Area Median Income: $113,100	Acutely Low	11850	13550	15250	16950	18300	19650	21000	22350
	Extremely Low	24350	27800	31300	34750	37550	40350	45420	50560
	Very Low Income	40550	46350	52150	57900	62550	67200	71800	76450
	Low Income	64900	74150	83400	92650	100100	107500	114900	122300
	Median Income	79150	90500	101800	**113100**	122150	131200	140250	149300
	Moderate Income	95000	108550	122150	135700	146550	157400	168250	179100
San Mateo County Area Median Income: $175,000	Acutely Low	18400	21000	23650	26250	28350	30450	32550	34650
	Extremely Low	39150	44750	50350	55900	60400	64850	69350	73800
	Very Low Income	65250	74600	83900	93200	100700	108150	115600	123050
	Low Income	104400	119300	134200	149100	161050	173000	184900	196850
	Median Income	122500	140000	157500	**175000**	189000	203000	217000	231000
	Moderate Income	147000	168000	189000	210000	226800	243600	260400	277200
Santa Barbara County Area Median Income: $107,300	Acutely Low	11250	12900	14500	16100	17400	18700	19950	21250
	Extremely Low	31050	35500	39950	44350	47900	51450	55000	58550
	Very Low Income	51800	59200	66600	73950	79900	85800	91700	97650
	Low Income	82950	94800	106650	118500	128000	137500	146950	156450
	Median Income	75100	85850	96550	**107300**	115900	124450	133050	141650
	Moderate Income	90150	103000	115900	128750	139050	149350	159650	169950

Number of Persons in Household:		1	2	3	4	5	6	7	8
Santa Clara County Area Median Income: $181,300	Acutely Low	19050	21750	24500	27200	29400	31550	33750	35900
	Extremely Low	37450	42800	48150	53500	57800	62100	66350	70650
	Very Low Income	62450	71400	80300	89200	96350	103500	110650	117750
	Low Income	96000	109700	123400	137100	148100	159050	170050	181000
	Median Income	126900	145050	163150	**181300**	195800	210300	224800	239300
	Moderate Income	152300	174050	195800	217550	234950	252350	269750	287150
Santa Cruz County Area Median Income: $132,800	Acutely Low	13950	15900	17900	19900	21500	23100	24700	26250
	Extremely Low	34600	39550	44500	49400	53400	57350	61300	65250
	Very Low Income	57650	65900	74150	82350	88950	95550	102150	108750
	Low Income	92500	105700	118900	132100	142700	153250	163850	174400
	Median Income	92950	106250	119500	**132800**	143400	154050	164650	175300
	Moderate Income	111550	127500	143400	159350	172100	184850	197600	210350
Shasta County Area Median Income: $89,800	Acutely Low	9400	10750	12100	13450	14550	15600	16700	17750
	Extremely Low	17650	20200	24860	30000	35140	40280	45420	50560
	Very Low Income	29400	33600	37800	42000	45400	48750	52100	55450
	Low Income	47050	53800	60500	67200	72600	78000	83350	88750
	Median Income	62850	71850	80800	**89800**	97000	104150	111350	118550
	Moderate Income	75450	86200	97000	107750	116350	125000	133600	142250
Sierra County Area Median Income: $90,000	Acutely Low	9450	10800	12150	13500	14600	15650	16750	17800
	Extremely Low	18900	21600	24860	30000	35140	40280	45420	50560
	Very Low Income	31500	36000	40500	45000	48600	52200	55800	59400
	Low Income	50400	57600	64800	72000	77800	83550	89300	95050
	Median Income	63000	72000	81000	**90000**	97200	104400	111600	118800
	Moderate Income	75600	86400	97200	108000	116650	125300	133900	142550
Siskiyou County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Solano County Area Median Income: $112,600	Acutely Low	11850	13500	15200	16900	18250	19600	20950	22300
	Extremely Low	24050	27450	30900	34300	37050	40280	45420	50560
	Very Low Income	40050	45800	51500	57200	61800	66400	70950	75550
	Low Income	64050	73200	82350	91500	98850	106150	113500	120800
	Median Income	78800	90100	101350	**112600**	121600	130600	139600	148650
	Moderate Income	94550	108100	121600	135100	145900	156700	167500	178350
Sonoma County Area Median Income: $128,100	Acutely Low	13450	15350	17300	19200	20750	22250	23800	25350
	Extremely Low	26450	30200	34000	37750	40800	43800	46850	50560
	Very Low Income	44050	50350	56650	62900	67950	73000	78000	83050
	Low Income	70500	80550	90600	100650	108750	116800	124850	132900
	Median Income	89650	102500	115300	**128100**	138350	148600	158850	169100
	Moderate Income	107600	122950	138350	153700	166000	178300	190600	202900

Number of Persons in Household:		1	2	3	4	5	6	7	8
Stanislaus County Area Median Income: $92,600	Acutely Low	9750	11100	12500	13900	15000	16100	17250	18350
	Extremely Low	17750	20250	24860	30000	35140	40280	45420	50560
	Very Low Income	29550	33800	38000	42200	45600	49000	52350	55750
	Low Income	47250	54000	60750	67500	72900	78300	83700	89100
	Median Income	64800	74100	83350	**92600**	100000	107400	114800	122250
	Moderate Income	77750	88900	100000	111100	120000	128900	137750	146650
Sutter County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Tehama County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Trinity County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Tulare County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750
Tuolumne County Area Median Income: $97,700	Acutely Low	10250	11700	13200	14650	15800	17000	18150	19350
	Extremely Low	18550	21200	24860	30000	35140	40280	45420	50560
	Very Low Income	30850	35250	39650	44050	47600	51100	54650	58150
	Low Income	49350	56400	63450	70450	76100	81750	87400	93000
	Median Income	68400	78150	87950	**97700**	105500	113350	121150	128950
	Moderate Income	82100	93800	105550	117250	126650	136000	145400	154750
Ventura County Area Median Income: $123,500	Acutely Low	13000	14850	16700	18550	20050	21500	23000	24500
	Extremely Low	27900	31900	35900	39850	43050	46250	49450	52650
	Very Low Income	46500	53150	59800	66400	71750	77050	82350	87650
	Low Income	74400	85000	95650	106250	114750	123250	131750	140250
	Median Income	86450	98800	111150	**123500**	133400	143250	153150	163000
	Moderate Income	103750	118550	133400	148200	160050	171900	183750	195600

Number of Persons in Household:		1	2	3	4	5	6	7	8
Yolo County Area Median Income: $114,000	Acutely Low	11950	13700	15400	17100	18450	19850	21200	22550
	Extremely Low	22050	25200	28350	31450	35140	40280	45420	50560
	Very Low Income	36750	42000	47250	52450	56650	60850	65050	69250
	Low Income	58750	67150	75550	83900	90650	97350	104050	110750
	Median Income	79800	91200	102600	**114000**	123100	132250	141350	150500
	Moderate Income	95750	109450	123100	136800	147750	158700	169650	180600

Yuba County Area Median Income: $83,800	Acutely Low	8800	10050	11300	12550	13550	14550	15550	16550
	Extremely Low	17350	19800	24860	30000	35140	40280	45420	50560
	Very Low Income	28900	33000	37150	41250	44550	47850	51150	54450
	Low Income	46200	52800	59400	65950	71250	76550	81800	87100
	Median Income	58650	67050	75400	**83800**	90500	97200	103900	110600
	Moderate Income	70400	80450	90500	100550	108600	116650	124700	132750

Instructions:

Eligibility Determination:

Use household size income category figures in this chart. Determine eligibililty based on actual number of persons in household and total of gross income for all persons.

Determination of Income Limit for Households Larger than Eight Persons:

Per person (PP) adjustment above 8: (1) multiply 4-person income limit by eight percent (8%),
(2) multiply result by number of persons in excess of eight,
(3) add the amount to the 8-person income limit, and (4) round to the nearest $50.

Nine Person Calculation - Example County

E X A M P L E	4 persons	8% PP Adj	+ 8 person	=9 persons
Acutely Low	12,550	1004	16,550	17,550
Extremely Low	30,000	2400	50,560	52,950
Very Low Income	41,250	3300	54,450	57,750
Lower Income	65,950	5276	87,100	92,400
Moderate Income	100,550	8044	132,750	140,800

Ten Person Calculation - Example County

4 persons	8 person +	8% Adj x 2	=10 persons
12,550	16,550	2008	18,550
30,000	50,560	4800	55,350
41,250	54,450	6600	61,050
65,950	87,100	10552	97,650
100,550	132,750	16088	148,850

Calculation of Housing Cost and Rent:

Refer to Heath & Safety Code Sections 50052.5 and 50053. Use benchmark household size and multiply against applicable percentages defined in H&SC using Area Median Income identified in this chart.

Determination of Household Size:

For projects with no federal assistance, household size is set at number of bedrooms in unit plus one.
For projects with federal assistance, household size may be set by multiplying 1.5 by the number of bedrooms in unit.

HUD Income Limits release: 5/15/2023

HUD FY 2023 California median incomes:
State median income: $109,200
Metropolitan county median income: $110,000
Non-metropolitan county median income: $83,800

Note: Authority cited: Section 50093, Health and Safety Code. Reference: Sections 50063.5, 50079.5, 50093, 50105 and 50106, Health and Safety Code.

DEPARTMENT OF HOUSING AND COMMUNITY DEVELOPMENT
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April 26, 2018

MEMORANDUM FOR: Interested parties

FROM: Zachary Olmstead, Deputy Director
Division of Housing Policy Development

SUBJECT: **State Income Limits for 2018**

Attached are briefing materials and State Income Limits for 2018 that are now in effect and replace 2017 State Income Limits. Income limits reflect updated median income and household income levels for extremely low-, very low-, low-, and moderate-income households for California's 58 counties. The 2018 State Income Limits are on the Department of Housing and Community Development (HCD) website at http://www.hcd.ca.gov/grants-funding/income-limits/state-and-federal-income-limits.shtml.

State Income Limits apply to designated programs, are used to determine applicant eligibility (based on the level of household income), and may be used to calculate affordable housing costs for applicable housing assistance programs. Use of State Income Limits are subject to a particular program's definition of income, family, family size, effective dates, and other factors. In addition, definitions applicable to income categories, criteria, and geographic areas sometimes differ depending on the funding source and program, resulting in some programs using other income limits.

The attached briefing materials detail California's 2018 Income Limits and were updated based on: (1) changes to income limits the U.S. Department of Housing and Urban Development (HUD) released on April 1, 2018 for its Public Housing and Section 8 Housing Choice Voucher Program and (2) adjustments HCD made based on State statutory provisions and its 2013 Hold Harmless (HH) Policy. Since 2013, HCD's HH Policy has held State Income Limits harmless from any decreases in household income limits and median income levels that HUD may apply to the Section 8 Income Limits. HUD determined its HH Policy was no longer necessary due to federal law changes in 2008 (Public Law 110-98) prohibiting rent decreases in federal or private activity bond funded projects.

For questions concerning State Income Limits, please contact HCD staff at (916) 263-2911.

2018 State Income Limits Briefing Materials
California Code of Regulations, Title 25, Section 6932

Overview

The Department of Housing and Community Development (HCD), pursuant to Health & Safety Code Section 50093(c), must file updates to its State Income Limits with the Office of Administrative Law. HCD annually updates these income limits based on U.S. Department of Housing and Urban Development (HUD) revisions to the Public Housing and Section 8 Housing Choice Voucher Program that HUD released on April 1, 2018.

HUD annually updates its Section 8 Income Limits to reflect changes in median family income levels for different size households and income limits for extremely low, very low, and low-income households. HCD, pursuant to statutory provisions, makes the following additional revisions: (1) If necessary, increase a county's area median income to equal California's non-metropolitan median income, (2) adjusts area median income and household income category levels to not result in any decrease for any year after 2009 pursuant to HCD's February 2013 HH Policy. HCD's HH Policy was implemented to replace HUD's HH Policy, discontinued in 2009, to not decrease income limits and area median income levels below a prior year's highest level and, (3) determines income limits for California's moderate-income category.

Following are brief summaries of technical methodologies used by HUD and HCD in updating income limits for different household income categories. For additional information, please refer to HUD's briefing materials at https://www.huduser.gov/portal/datasets/il//il18/IncomeLimitsMethodology-FY18.pdf.

HUD Methodology

HUD Section 8 Income Limits begin with the production of median family incomes. HUD uses the Section 8 program's Fair Market Rent (FMR) area definitions in developing median incomes, which means developing median incomes for each metropolitan area, parts of some metropolitan areas, and each non-metropolitan county. The 2018 FMR area definitions are unchanged from last year. HUD calculates Section 8 Income Limits for every FMR area with adjustments for family size and for areas with unusually high or low family income or housing-cost-to-income relationships.

Extremely Low-Income

In determining the extremely low-income limit, HUD uses the Federal Poverty Guidelines, published by the Department of Health and Human Services. HUD compares the appropriate poverty guideline with 60% of the very low-income limit and choose the greater of the two. The value may not exceed the very low-income level.

Very Low-Income

The very low-income limits are the basis for all other income limits. The very low-income limit typically reflects 50 percent of median family income (MFI) and HUD's MFI figure generally equals two times HUD's 4-person very low-income limit. HUD may adjust the very low-income limit for an area or county to account for conditions that warrant special considerations. As such, the very low-income limit may not always equal 50% MFI.

Low-Income

In general, most low-income limits represent the higher level of: (1) 80 percent of MFI or, (2) 80 percent of state non-metropolitan median family income. However, due to adjustments that HUD sometimes makes to the very low-income limit, strictly calculating low-income limits as 80 percent of MFI could produce unintended anomalies inconsistent with statutory intent (e.g. very low-income limits being higher than low-income limits).Therefore, HUD's briefing materials specify that, with some exceptions, the low-income limit reflect 160 percent of the very low-income limit.

HUD may apply additional adjustments to areas with unusually high or low housing-costs-to-income relationships and for other reasons. This could result in low-income limits exceeding MFI.

Median Family Income/Area Median Income
HUD references and estimates the MFI in calculating the income limits. California law and State Income Limits reference Area Median Income (AMI) that, pursuant to Health & Safety Code 50093(c), means the MFI of a geographic area, estimated by HUD for its Section 8 Program.

HUD's calculations of Section 8 Income Limits begin with the production of MFI estimates. This year, MFI estimates use the 2015 American Community Survey. HUD then adjusts the survey data to account for anticipated income growth by applying the Consumer Price Index inflation forecast published by the Congressional Budget Office through mid-2018. HUD uses the MFI to calculate very low-income limits, used as the basis to calculate income limits for other income categories. For additional information, please see HUD's methodology describing 2018 MFI's at https://www.huduser.gov/portal/datasets/il/il18/Medians-Methodology-FY18r.pdf.

Adjustment Calculations
HUD may apply adjustments to areas with unusually high or low family income, uneven housing-cost-to-income relationship, or other reasons. For example, HUD applies an increase if the four-person very low-income limit would otherwise be less than the amount at which 35 percent of it equals 85 percent of the annualized two-bedroom Section 8 FMR (or 40th percentile rent in 50th percentile FMR areas). The purpose is to increase the income limit for areas where rental-housing costs are unusually high in relation to the median income.

In certain cases, HUD also applies an adjustment to the income limits based on the state non-metropolitan median family income level. In addition, HUD restricts adjustments so income limits do not increase more than five percent of the previous year's very low-income figure OR twice the increase in the national MFI, whichever is greater. For the 2018 income limits, the maximum increase is 11.5% from the previous year. This adjustment does not apply to the extremely low-income limits.

Please refer to HUD briefing materials for additional information on the adjustment calculations.

Income Limit Calculations for Household Sizes Other Than 4-Persons
The income limit statute requires adjustments for family size. The legislative history and conference committee report indicates that Congress intended that income limits should be higher for larger families and lower for smaller families. The same family size adjustments apply to all income limits, except extremely low-income limits, which are set at the poverty income threshold. They are as follows:

Number of Persons in Household:	1	2	3	4	5	6	7	8
Adjustments:	70%	80%	90%	Base	108%	116%	124%	132%

Income Limit Calculations for Household Sizes Greater Than 8-Persons
For households of more than eight persons, refer to the formula at the end of the table for 2018 Income Limits. Due to the adjustments HUD can make to income limits in a given county, table data should be the only method used to determine program eligibility. Arithmetic calculations are applicable only when a household has more than eight members. Please refer to HUD's briefing material for additional information on family size adjustments.

HCD Methodology

State law (Health & Safety Code Section 50093, et. seq.) prescribes the methodology HCD uses to update the State Income Limits. HCD utilizes HUD's Section 8 Housing Choice Voucher Program Income Limits. HCD's methodology involves: (1) increasing a counties' median income established by HUD to equal California's non-metropolitan county median income determined by HUD, (2) applying HCD's HH Policy, in effect since 2013, to not allow decreases in area median income levels and household income category levels, and (3) determining income limit levels applicable to California's moderate-income households defined by law as household income not exceeding 120 percent of county area median income.

Area Median Income and Income Category Levels

HCD, pursuant to federal and State law, adjusts median income levels for all to counties so they are not less than the non-metropolitan county median income established by HUD ($59,700 for 2018). Next, HCD, for all counties, applies its HH policy to ensure area median income and income limits for all household income categories do not fall below any level achieved in the prior year.

Moderate-Income Levels

HCD is responsible for establishing California's moderate-income limit levels. After calculating the 4-person area median income (AMI) level as previously described, HCD sets the maximum moderate-income limit to equal 120 percent of the county's AMI.

Applicability of California's Official State Income Limits

Applicability of the State Income Limits are subject to particular programs as program definitions of factors such as income, family, and household size, etc. vary. Some programs, such as Multifamily Tax Subsidy Projects (MTSPs), use different income limits. For MTSPs, separate income limits apply per provisions of the Housing and Economic Recovery Act (HERA) of 2008 (Public Law 110-289). Income limits for MTSPs are used to determine qualification levels as well as set maximum rental rates for projects funded with tax credits authorized under Section 42 of the Internal Revenue Code (Code). In addition, MTSP income limits apply to projects financed with tax-exempt housing bonds issued to provide qualified residential rental development under Section 142 of the Code. These income limits are available at http://www.huduser.org/datasets/mtsp.html.

Section 6932. 2018 Income Limits

County	Income Category	Number of Persons in Household							
		1	2	3	4	5	6	7	8
Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
Alameda County	Extremely Low	24400	27900	31400	34850	37650	40450	43250	46050
4-Person	Very Low Income	40700	46500	52300	58100	62750	67400	72050	76700
Area Median Income:	Low Income	62750	71700	80650	89600	96800	103950	111150	118300
$104,400	**Median Income**	73100	83500	93950	**104400**	112750	121100	129450	137800
	Moderate Income	87700	100250	112750	125300	135300	145350	155350	165400
Alpine County	Extremely Low	18150	20750	23350	25900	29420	33740	38060	42380
4-Person	Very Low Income	30250	34600	38900	43200	46700	50150	53600	57050
Area Median Income:	Low Income	46100	52650	59250	65800	71100	76350	81600	86900
$94,900	**Median Income**	66450	75900	85400	**94900**	102500	110100	117700	125250
	Moderate Income	79750	91100	102500	113900	123000	132100	141250	150350
Amador County	Extremely Low	15500	17700	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	25800	29450	33150	36800	39750	42700	45650	48600
Area Median Income:	Low Income	41250	47150	53050	58900	63650	68350	73050	77750
$73,600	**Median Income**	51500	58900	66250	**73600**	79500	85400	91250	97150
	Moderate Income	61800	70650	79450	88300	95350	102450	109500	116550
Butte County	Extremely Low	13200	16460	20780	25100	29420	33740	37550	41320
4-Person	Very Low Income	21950	25050	28200	31300	33850	36350	38850	41350
Area Median Income:	Low Income	35100	40100	45100	50100	54150	58150	62150	66150
$62,600	**Median Income**	43800	50100	56350	**62600**	67600	72600	77600	82650
	Moderate Income	52550	60100	67600	75100	81100	87100	93100	99150
Calaveras County	Extremely Low	15200	17400	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	25350	28950	32550	36150	39050	41950	44850	47750
Area Median Income:	Low Income	40500	46300	52100	57850	62500	67150	71750	76400
$72,300	**Median Income**	50600	57850	65050	**72300**	78100	83850	89650	95450
	Moderate Income	60700	69400	78100	86750	93700	100650	107550	114500
Colusa County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Contra Costa County	Extremely Low	24400	27900	31400	34850	37650	40450	43250	46050
4-Person	Very Low Income	40700	46500	52300	58100	62750	67400	72050	76700
Area Median Income:	Low Income	62750	71700	80650	89600	96800	103950	111150	118300
$104,400	**Median Income**	73100	83500	93950	**104400**	112750	121100	129450	137800
	Moderate Income	87700	100250	112750	125300	135300	145350	155350	165400
Del Norte County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900

County	Income Category	Number of Persons in Household							
		1	2	3	4	5	6	7	8
Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
El Dorado County	Extremely Low	16850	19250	21650	25100	29420	33740	38060	42380
4-Person	Very Low Income	28050	32050	36050	40050	43300	46500	49700	52900
Area Median Income:	Low Income	44900	51300	57700	64100	69250	74400	79500	84650
$80,100	**Median Income**	56050	64100	72100	**80100**	86500	92900	99300	105750
	Moderate Income	67250	76900	86500	96100	103800	111500	119150	126850
Fresno County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Glenn County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Humboldt County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Imperial County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Inyo County	Extremely Low	15150	17300	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	25200	28800	32400	36000	38900	41800	44650	47550
Area Median Income:	Low Income	40350	46100	51850	57600	62250	66850	71450	76050
$72,000	**Median Income**	50400	57600	64800	**72000**	77750	83500	89300	95050
	Moderate Income	60500	69100	77750	86400	93300	100200	107150	114050
Kern County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Kings County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900

County	Income Category	Number of Persons in Household							
		1	2	3	4	5	6	7	8
Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
Lake County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Lassen County	Extremely Low	14600	16650	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	24300	27800	31250	34700	37500	40300	43050	45850
Area Median Income:	Low Income	38850	44400	49950	55500	59950	64400	68850	73300
$69,400	**Median Income**	48600	55500	62450	**69400**	74950	80500	86050	91600
	Moderate Income	58300	66650	74950	83300	89950	96650	103300	109950
Los Angeles County	Extremely Low	20350	23250	26150	29050	31400	33740	38060	42380
4-Person	Very Low Income	33950	38800	43650	48450	52350	56250	60100	64000
Area Median Income:	Low Income	54250	62000	69750	77500	83700	89900	96100	102300
$69,300	**Median Income**	48500	55450	62350	**69300**	74850	80400	85950	91500
	Moderate Income	58200	66500	74850	83150	89800	96450	103100	109750
Madera County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Marin County	Extremely Low	30800	35200	39600	44000	47550	51050	54600	58100
4-Person	Very Low Income	51350	58650	66000	73300	79200	85050	90900	96800
Area Median Income:	Low Income	82200	93950	105700	117400	126800	136200	145600	155000
$118,400	**Median Income**	82900	94700	106550	**118400**	127850	137350	146800	156300
	Moderate Income	99450	113700	127900	142100	153450	164850	176200	187550
Mariposa County	Extremely Low	13800	16460	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	22950	26200	29500	32750	35400	38000	40650	43250
Area Median Income:	Low Income	36700	41950	47200	52400	56600	60800	65000	69200
$65,500	**Median Income**	45850	52400	58950	**65500**	70750	76000	81200	86450
	Moderate Income	55000	62900	70750	78600	84900	91200	97450	103750
Mendocino County	Extremely Low	12800	16460	20780	25100	29420	33740	37600	40200
4-Person	Very Low Income	21350	24400	27450	30450	32900	35350	37800	40200
Area Median Income:	Low Income	34100	39000	43850	48700	52600	56500	60400	64300
$60,600	**Median Income**	42400	48500	54550	**60600**	65450	70300	75150	80000
	Moderate Income	50900	58150	65450	72700	78500	84350	90150	95950
Merced County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900

County	Income Category	Number of Persons in Household							
		1	2	3	4	5	6	7	8
Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
Modoc County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Mono County	Extremely Low	17050	19500	21950	25100	29420	33740	38060	42380
4-Person	Very Low Income	28450	32500	36550	40600	43850	47100	50350	53600
Area Median Income:	Low Income	44750	51150	57550	63900	69050	74150	79250	84350
$81,200	**Median Income**	56850	64950	73100	**81200**	87700	94200	100700	107200
	Moderate Income	68200	77950	87700	97450	105250	113050	120850	128650
Monterey County	Extremely Low	17550	20050	22550	25100	29420	33740	38060	42380
4-Person	Very Low Income	29250	33400	37600	41750	45100	48450	51800	55150
Area Median Income:	Low Income	46800	53450	60150	66800	72150	77500	82850	88200
$69,100	**Median Income**	48350	55300	62200	**69100**	74650	80150	85700	91200
	Moderate Income	58050	66300	74600	82900	89550	96150	102800	109450
Napa County	Extremely Low	19600	22400	25200	27950	30200	33740	38060	42380
4-Person	Very Low Income	32600	37250	41900	46550	50300	54000	57750	61450
Area Median Income:	Low Income	52150	59600	67050	74500	80500	86450	92400	98350
$91,000	**Median Income**	63700	72800	81900	**91000**	98300	105550	112850	120100
	Moderate Income	76450	87350	98300	109200	117950	126650	135400	144150
Nevada County	Extremely Low	16100	18400	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	26850	30700	34550	38350	41450	44500	47600	50650
Area Median Income:	Low Income	42950	49050	55200	61300	66250	71150	76050	80950
$73,500	**Median Income**	51450	58800	66150	**73500**	79400	85250	91150	97000
	Moderate Income	61750	70550	79400	88200	95250	102300	109350	116400
Orange County	Extremely Low	23000	26250	29550	32800	35450	38050	40700	43300
4-Person	Very Low Income	38300	43750	49200	54650	59050	63400	67800	72150
Area Median Income:	Low Income	61250	70000	78750	87450	94450	101450	108450	115450
$92,700	**Median Income**	64900	74150	83450	**92700**	100100	107550	114950	122350
	Moderate Income	77900	89000	100150	111250	120150	129050	137950	146850
Placer County	Extremely Low	16850	19250	21650	25100	29420	33740	38060	42380
4-Person	Very Low Income	28050	32050	36050	40050	43300	46500	49700	52900
Area Median Income:	Low Income	44900	51300	57700	64100	69250	74400	79500	84650
$80,100	**Median Income**	56050	64100	72100	**80100**	86500	92900	99300	105750
	Moderate Income	67250	76900	86500	96100	103800	111500	119150	126850
Plumas County	Extremely Low	13300	16460	20780	25100	29420	33740	38060	41800
4-Person	Very Low Income	22200	25350	28500	31650	34200	36750	39250	41800
Area Median Income:	Low Income	35500	40550	45600	50650	54750	58800	62850	66900
$63,300	**Median Income**	44300	50650	56950	**63300**	68350	73450	78500	83550
	Moderate Income	53150	60750	68350	75950	82050	88100	94200	100250

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		1	2	3	4	5	6	7	8
Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
Riverside County	Extremely Low	14150	16460	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	23600	27000	30350	33700	36400	39100	41800	44500
Area Median Income:	Low Income	37750	43150	48550	53900	58250	62550	66850	71150
$65,800	**Median Income**	46050	52650	59200	**65800**	71050	76350	81600	86850
	Moderate Income	55250	63150	71050	78950	85250	91600	97900	104200
Sacramento County	Extremely Low	16850	19250	21650	25100	29420	33740	38060	42380
4-Person	Very Low Income	28050	32050	36050	40050	43300	46500	49700	52900
Area Median Income:	Low Income	44900	51300	57700	64100	69250	74400	79500	84650
$80,100	**Median Income**	56050	64100	72100	**80100**	86500	92900	99300	105750
	Moderate Income	67250	76900	86500	96100	103800	111500	119150	126850
San Benito County	Extremely Low	19600	22400	25200	27950	30200	33740	38060	42380
4-Person	Very Low Income	32600	37250	41900	46550	50300	54000	57750	61450
Area Median Income:	Low Income	52200	59650	67100	74550	80550	86500	92450	98450
$81,100	**Median Income**	56750	64900	73000	**81100**	87600	94100	100550	107050
	Moderate Income	68100	77850	87550	97300	105100	112850	120650	128450
San Bernardino County	Extremely Low	14150	16460	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	23600	27000	30350	33700	36400	39100	41800	44500
Area Median Income:	Low Income	37750	43150	48550	53900	58250	62550	66850	71150
$65,800	**Median Income**	46050	52650	59200	**65800**	71050	76350	81600	86850
	Moderate Income	55250	63150	71050	78950	85250	91600	97900	104200
San Diego County	Extremely Low	20450	23400	26300	29200	31550	33900	38060	42380
4-Person	Very Low Income	34100	38950	43800	48650	52550	56450	60350	64250
Area Median Income:	Low Income	54500	62300	70100	77850	84100	90350	96550	102800
$81,800	**Median Income**	57250	65450	73600	**81800**	88350	94900	101450	108000
	Moderate Income	68700	78500	88350	98150	106000	113850	121700	129550
San Francisco County	Extremely Low	30800	35200	39600	44000	47550	51050	54600	58100
4-Person	Very Low Income	51350	58650	66000	73300	79200	85050	90900	96800
Area Median Income:	Low Income	82200	93950	105700	117400	126800	136200	145600	155000
$118,400	**Median Income**	82900	94700	106550	**118400**	127850	137350	146800	156300
	Moderate Income	99450	113700	127900	142100	153450	164850	176200	187550
San Joaquin County	Extremely Low	13950	16460	20780	25100	29420	33740	38060	42050
4-Person	Very Low Income	23250	26550	29850	33150	35850	38500	41150	43800
Area Median Income:	Low Income	37150	42450	47750	53050	57300	61550	65800	70050
$66,300	**Median Income**	46400	53050	59650	**66300**	71600	76900	82200	87500
	Moderate Income	55700	63650	71600	79550	85900	92300	98650	105000
San Luis Obispo County	Extremely Low	17500	20000	22500	25100	29420	33740	38060	42380
4-Person	Very Low Income	29150	33300	37450	41600	44950	48300	51600	54950
Area Median Income:	Low Income	46600	53250	59900	66550	71900	77200	82550	87850
$83,200	**Median Income**	58250	66550	74900	**83200**	89850	96500	103150	109800
	Moderate Income	69900	79900	89850	99850	107850	115850	123800	131800

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		1	2	3	4	5	6	7	8
Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
San Mateo County	Extremely Low	30800	35200	39600	44000	47550	51050	54600	58100
4-Person	Very Low Income	51350	58650	66000	73300	79200	85050	90900	96800
Area Median Income:	Low Income	82200	93950	105700	117400	126800	136200	145600	155000
$118,400	**Median Income**	82900	94700	106550	**118400**	127850	137350	146800	156300
	Moderate Income	99450	113700	127900	142100	153450	164850	176200	187550
Santa Barbara County	Extremely Low	21100	24100	27100	30100	32550	34950	38060	42380
4-Person	Very Low Income	35150	40150	45150	50150	54200	58200	62200	66200
Area Median Income:	Low Income	56250	64250	72300	80300	86750	93150	99600	106000
$79,600	**Median Income**	55700	63700	71650	**79600**	85950	92350	98700	105050
	Moderate Income	66850	76400	85950	95500	103150	110800	118400	126050
Santa Clara County	Extremely Low	27950	31950	35950	39900	43100	46300	49500	52700
4-Person	Very Low Income	46550	53200	59850	66500	71850	77150	82500	87800
Area Median Income:	Low Income	66150	75600	85050	94450	102050	109600	117150	124700
$125,200	**Median Income**	87650	100150	112700	**125200**	135200	145250	155250	165250
	Moderate Income	105200	120200	135250	150250	162250	174300	186300	198350
Santa Cruz County	Extremely Low	23450	26800	30150	33500	36200	38900	41550	44250
4-Person	Very Low Income	39100	44650	50250	55800	60300	64750	69200	73700
Area Median Income:	Low Income	62650	71600	80550	89450	96650	103800	110950	118100
$87,000	**Median Income**	60900	69600	78300	**87000**	93950	100900	107900	114850
	Moderate Income	73100	83500	93950	104400	112750	121100	129450	137800
Shasta County	Extremely Low	13000	16460	20780	25100	29420	33740	38060	40800
4-Person	Very Low Income	21650	24750	27850	30900	33400	35850	38350	40800
Area Median Income:	Low Income	34650	39600	44550	49450	53450	57400	61350	65300
$61,800	**Median Income**	43250	49450	55600	**61800**	66750	71700	76650	81600
	Moderate Income	51900	59300	66750	74150	80100	86000	91950	97900
Sierra County	Extremely Low	14800	16900	20780	25100	29420	33740	38060	42380
4-Person	Very Low Income	24650	28150	31650	35150	38000	40800	43600	46400
Area Median Income:	Low Income	39400	45000	50650	56250	60750	65250	69750	74250
$71,800	**Median Income**	50250	57450	64600	**71800**	77550	83300	89050	94800
	Moderate Income	60300	68900	77550	86150	93050	99950	106850	113700
Siskiyou County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Solano County	Extremely Low	17600	20100	22600	25100	29420	33740	38060	42380
4-Person	Very Low Income	29300	33500	37700	41850	45200	48550	51900	55250
Area Median Income:	Low Income	46900	53600	60300	66950	72350	77700	83050	88400
$83,700	**Median Income**	58600	66950	75350	**83700**	90400	97100	103800	110500
	Moderate Income	70300	80350	90400	100450	108500	116500	124550	132600

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Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
Sonoma County	Extremely Low	20650	23600	26550	29450	31850	34200	38060	42380
4-Person	Very Low Income	34400	39300	44200	49100	53050	57000	60900	64850
Area Median Income:	Low Income	55000	62850	70700	78550	84850	91150	97450	103700
$84,100	**Median Income**	58850	67300	75700	**84100**	90850	97550	104300	111000
	Moderate Income	70650	80700	90800	100900	108950	117050	125100	133200
Stanislaus County	Extremely Low	13050	16460	20780	25100	29420	33740	37650	40100
4-Person	Very Low Income	21700	24800	27900	31000	33500	36000	38450	40950
Area Median Income:	Low Income	34750	39700	44650	49600	53600	57550	61550	65500
$62,000	**Median Income**	43400	49600	55800	**62000**	66950	71900	76900	81850
	Moderate Income	52100	59500	66950	74400	80350	86300	92250	98200
Sutter County	Extremely Low	12600	16460	20780	25100	29420	33740	37200	39600
4-Person	Very Low Income	21000	24000	27000	30000	32400	34800	37200	39600
Area Median Income:	Low Income	33600	38400	43200	48000	51850	55700	59550	63400
$60,000	**Median Income**	42000	48000	54000	**60000**	64800	69600	74400	79200
	Moderate Income	50400	57600	64800	72000	77750	83500	89300	95050
Tehama County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Trinity County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Tulare County	Extremely Low	12600	16460	20780	25100	29420	33740	37140	39550
4-Person	Very Low Income	21000	24000	27000	29950	32350	34750	37150	39550
Area Median Income:	Low Income	33550	38350	43150	47900	51750	55600	59400	63250
$59,900	**Median Income**	41950	47900	53900	**59900**	64700	69500	74300	79050
	Moderate Income	50350	57500	64700	71900	77650	83400	89150	94900
Tuolumne County	Extremely Low	13950	16460	20780	25100	29420	33740	38060	41750
4-Person	Very Low Income	23250	26600	29900	33200	35900	38550	41200	43850
Area Median Income:	Low Income	37200	42500	47800	53100	57350	61600	65850	70100
$66,700	**Median Income**	46700	53350	60050	**66700**	72050	77350	82700	88050
	Moderate Income	56050	64050	72050	80050	86450	92850	99250	105650
Ventura County	Extremely Low	21300	24350	27400	30400	32850	35300	38060	42380
4-Person	Very Low Income	35500	40600	45650	50700	54800	58850	62900	66950
Area Median Income:	Low Income	56800	64900	73000	81100	87600	94100	100600	107100
$96,000	**Median Income**	67200	76800	86400	**96000**	103700	111350	119050	126700
	Moderate Income	80650	92150	103700	115200	124400	133650	142850	152050

County	Income Category	Number of Persons in Household							
		1	2	3	4	5	6	7	8
Last page instructs how to use income limits to determine applicant eligibility and calculate affordable housing cost and rent									
Yolo County	Extremely Low	17500	20000	22500	25100	29420	33740	38060	42380
4-Person	Very Low Income	29150	33300	37450	41600	44950	48300	51600	54950
Area Median Income:	Low Income	46600	53250	59900	66550	71900	77200	82550	87850
$85,100	**Median Income**	59550	68100	76600	**85100**	91900	98700	105500	112350
	Moderate Income	71450	81700	91900	102100	110250	118450	126600	134750
Yuba County	Extremely Low	12600	16460	20780	25100	29420	33740	37200	39600
4-Person	Very Low Income	21000	24000	27000	30000	32400	34800	37200	39600
Area Median Income:	Low Income	33600	38400	43200	48000	51850	55700	59550	63400
$60,000	**Median Income**	42000	48000	54000	**60000**	64800	69600	74400	79200
	Moderate Income	50400	57600	64800	72000	77750	83500	89300	95050

Instructions:

Eligibility Determination:

Use household size income category figures in this chart. Determine eligibililty based on actual number of persons in household and total of gross income for all persons.

Determination of Income Limit for Households Larger than Eight Persons:

Per person (PP) adjustment above 8: (1) multiply 4-person income limit by eight percent (8%), (2) multiply result by number of persons in excess of eight, (3) add the amount to the 8-person income limit, and (4) round to the nearest $50.

Yuba County

E X A M P L E	4 persons	8% PP Adj	+ 8 persons	=9 persons	8 person +	8% Adj x 2	=10 persons
Extremely Low	25,100	2008	39,550	41,550	39,550	4016	43,550
Very Low Income	30,000	2400	39,550	41,950	39,550	4800	44,350
Lower Income	48,000	3840	63,250	67,100	63,250	7680	70,950
Moderate Income	72,000	5760	94,900	100,650	94,900	11520	106,400

Calculation of Housing Cost and Rent:

Refer to Heath & Safety Code Sections 50052.5 and 50053. Use benchmark household size and multiply against applicable percentages defined in H&SC using Area Median Income identified in this chart.

Determination of Household Size:

For projects with no federal assistance, household size is set at number of bedrooms in unit plus one.

For projects with federal assistance, household size may be set by multiplying 1.5 against the number of bedrooms in unit.

HUD Income Limits release: 4/1/2018

HUD FY 2018 California median incomes:

State median income: $77,500

Metropolitan county median income: $78,200

Non-metropolitan county median income: $59,700

Note: Authority cited: Section 50093, Health and Safety Code. Reference: Sections 50079.5, 50093, 50105 and 50106, Health and Safety Code.



Living Without Power

HEALTH IMPACTS OF UTILITY SHUTOFFS IN CALIFORNIA

A Report by TURN - The Utility Reform Network

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We owe a debt of gratitude to the grassroots community partners, public health partners, policy and data research partners, funding partners, and utility companies for making this project possible.

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Rickie Brown, Sonia Jimenez, Maritza Maksimow, Barbara Nevarez, Rosie Ulloa-Sanchez

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Pastor Benjamin Briggs, Demita Burgess

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Housing Long Beach
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To the 800 California residents who shared their stories with us, Thank You!

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Mark Toney, Ph.D. has served as executive director of TURN–The Utility Reform Network since 2008, promoting affordable green energy and phone service through legal advocacy, grassroots organizing, and policy campaigns. He earned his B.A. in political science from Brown University, his Ph.D. in sociology from UC Berkeley, and he has been recognized as a Kellogg National Leadership Fellow, National Science Foundation Fellow, and Echoing Green Fellow.

A Note About the Data

In preparing this report, TURN relied on two primary sources of data. We used public data provided by the utilities in their periodic "Disconnection Data Reports" submitted to the California Public Utilities Commission in Rulemaking (R.) 10-02-005 between 2010 and the present. Most of those reports are available online at: https://apps.cpuc.ca.gov/apex/f?p=401:57:0::NO. We refer to this data as "Disconnections Rulemaking Data" throughout this report.

TURN also used ZIP code level disconnections data provided directly to us by the utilities in response to a TURN data request. We refer to this data as "Utility ZIP Code Data" throughout this report.

TURN appreciates the cooperation of PG&E, Southern California Edison, SDG&E and SoCal Gas for providing longitudinal disconnections data disaggregated to the ZIP code level for this research project.

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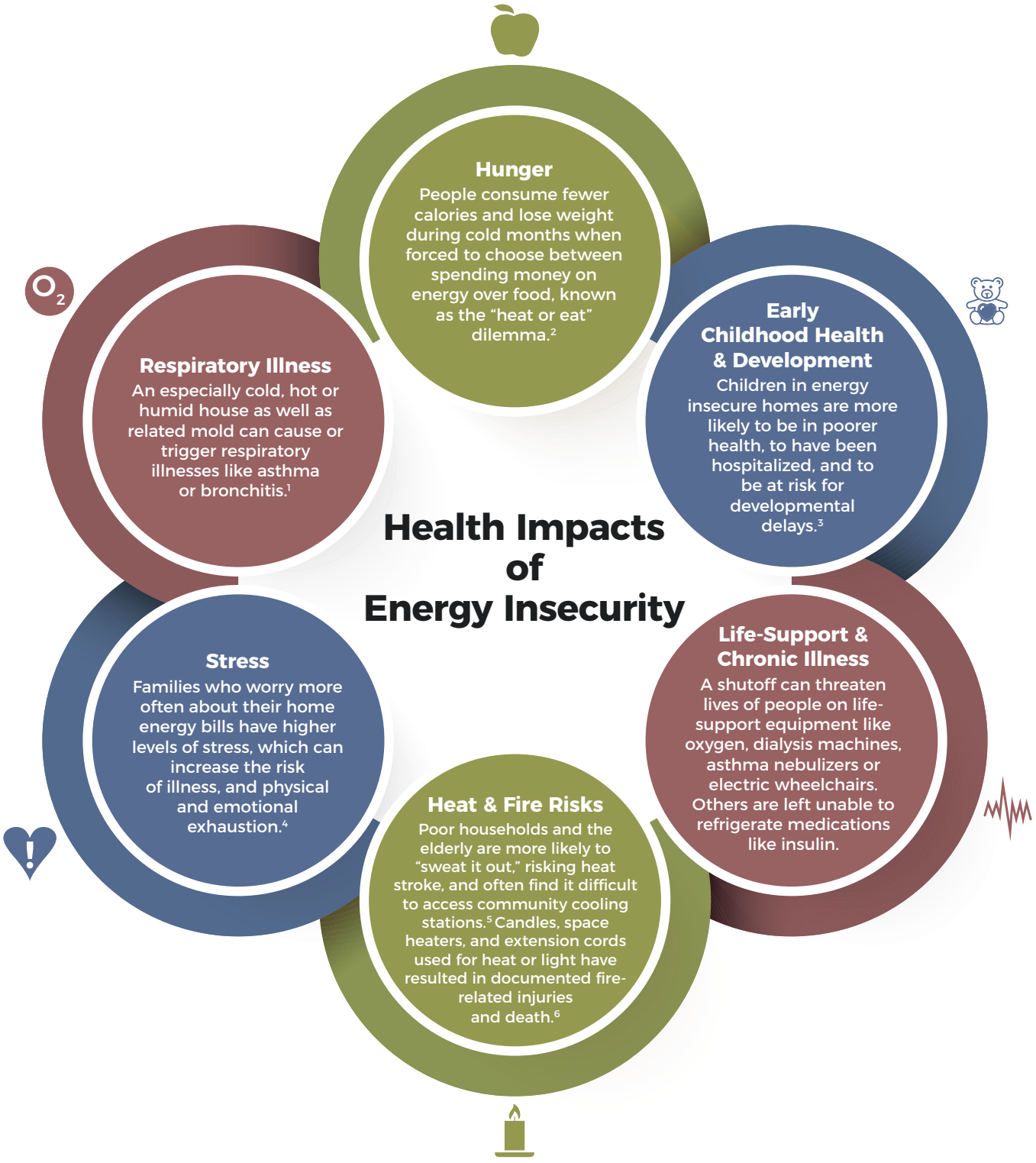
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Public Health Impacted by Energy Insecurity

Energy insecurity impacts the health and safety of 25% of California families threatened by utility shutoffs, especially children and people who are medically vulnerable. People whose utility service is shut off, or who are threatened with disconnection, face stress, hunger, respiratory illness, and heat and fire risks. Early childhood health and development can be compromised. Energy insecurity threatens the lives of people with chronic illness and those living on life-support.



Community Surveys Document Energy Insecurity

Key findings of a TURN survey of 750 low-income households conducted by grassroots community partners in Fresno, Long Beach, San Diego, Oakland, San Bernardino, and Stockton document the difficult tradeoffs between paying their utility bill or for rent, food, and healthcare.

4 out of 5 (81%)	Felt their utility bills are too high
1 out of 3 (36%)	Cut back on buying food in order to pay their utility bill
2 out of 3 (61%)	Experienced a shutoff in the last 3 years and had food spoil in their refrigerator because there was no electricity in their home
1 out of 3 (38%)	Had a family member who was unable to complete homework assignments due to a lack of light
1 out of 4	Had a hard time keeping up with their hygiene because they could not bathe or shower
16%	Got sick because they could not heat their home
1 out of 10	Were unable to go to work for one or more days
1 in 20	Were injured due to a lack of light, kept children home from school, experienced heatstroke or another illness because they couldn't cool their home, or became sick because an electric medical device they needed was unavailable due to a shutoff
3 out of 5 (56%)	Were shut off and burned candles for light
1 out of 5 (17%)	Ran extension cords from a neighbor's home
14%	Turned their oven on and left it open for warmth. Another 14% were forced to warm water on a gas stove or over a fire in order to bathe

California Households Shut Off 886,000 Times by Utilities Last Year

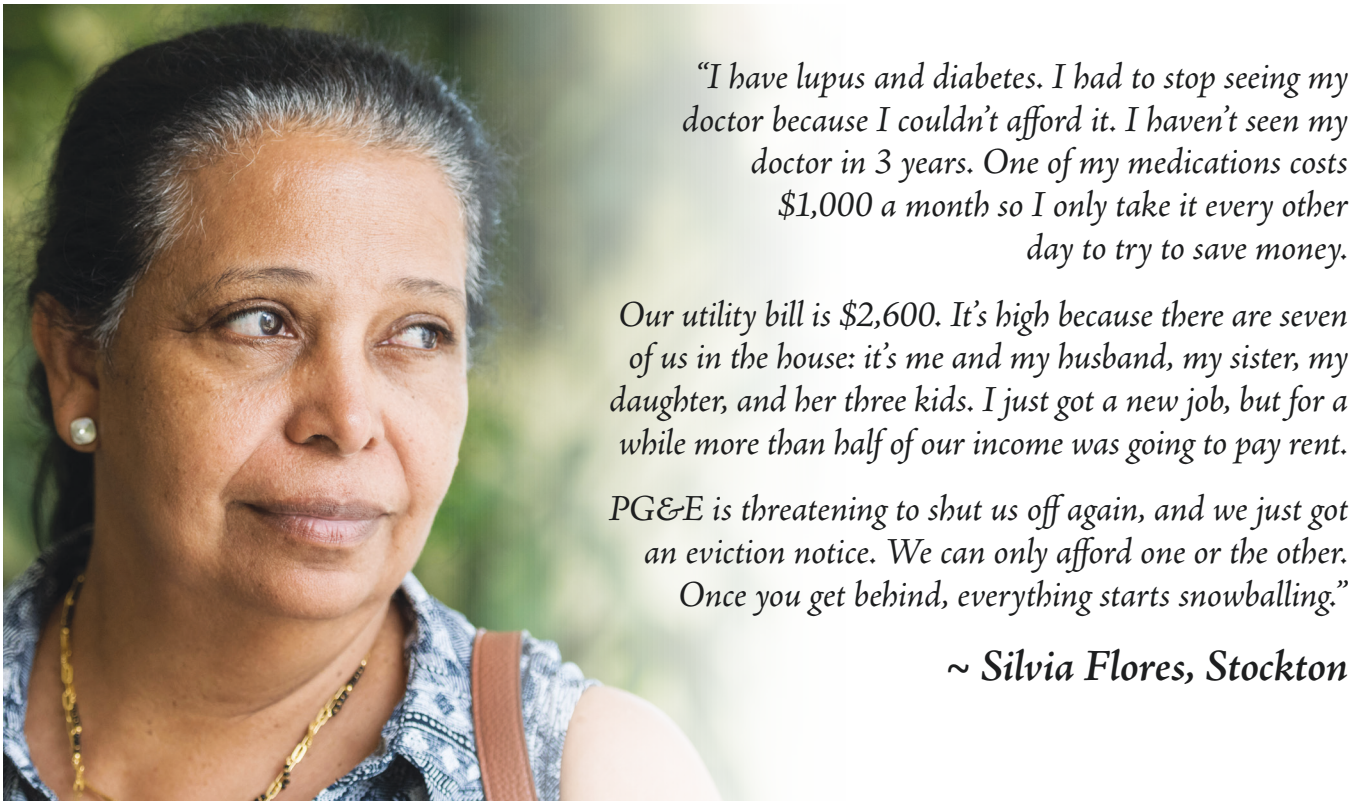
There were 886,000 households in California shut off by PG&E, Edison, SDG&E and SoCal Gas in 2017, impacting more than 2.5 million people, most of whom are children. Those most affected by energy insecurity include families struggling to make ends meet, communities of color, immigrants, people for whom English is not a first language, elders, and people with disabilities.

Energy insecurity is on the rise and utility disconnections have reached crisis levels across the U.S., according to a recently released report by the NAACP.[7] Electricity and gas are as much a basic need in our lives as water and housing—indeed, remaining in affordable housing often hinges on one's ability to pay utility bills. As expressed by Robert Huerta of Poverello House, a social service agency in Fresno, "a home without electricity is not fit for human habitation."

Energy bills represent the second-highest housing cost—exceeded only by mortgage or rent—and comprise up to 41% of income for families struggling to make ends meet.[8] Shutoffs in California have increased by over 50% in just 7 years. Since 2009, shutoffs have resulted in the deaths of at least 11 California residents due to fires caused by candles, extension cords or carbon monoxide poisoning from portable heaters.[9]

Living Without Power documents energy insecurity and public health threats by:

- Mapping utility disconnections in California so that we can see where and in what communities they are concentrated
- Partnering with grassroots communities across northern, central, and southern California to conduct community research linking utility shutoffs with health impact
- Sharing stories and lived experiences of California residents struggling with energy insecurity to humanize them and remove the stigma of being shut off



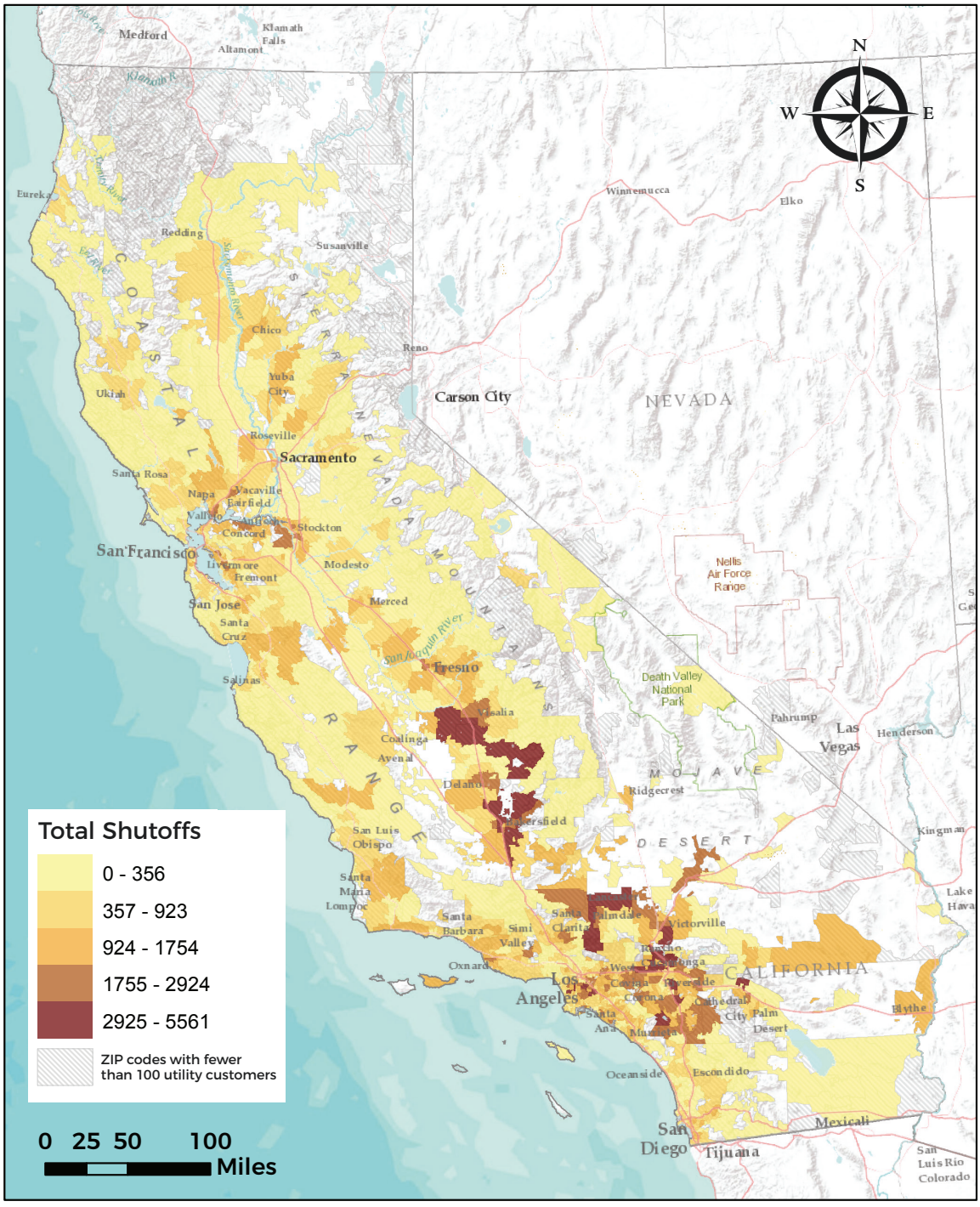
"I have lupus and diabetes. I had to stop seeing my doctor because I couldn't afford it. I haven't seen my doctor in 3 years. One of my medications costs $1,000 a month so I only take it every other day to try to save money.

Our utility bill is $2,600. It's high because there are seven of us in the house: it's me and my husband, my sister, my daughter, and her three kids. I just got a new job, but for a while more than half of our income was going to pay rent.

PG&E is threatening to shut us off again, and we just got an eviction notice. We can only afford one or the other. Once you get behind, everything starts snowballing."

~ Silvia Flores, Stockton

Utility Shutoffs in California by ZIP Code



Source: Utility ZIP Code Data

In 2016, California households experienced 884,380 disconnections conducted by PG&E, Edison, SoCal Gas, and SDG&E. Shutoffs disproportionately impact children, low-income communities, and communities of color.

Energy Insecurity Impacts 25% of California Families

Because of differences in policy and practice across the utilities, there is no single metric that can adequately represent the number of families for whom energy is priced beyond reach in California. For example, SDG&E allows its customers to carry larger debts before shutting them off and Edison sent 28% of its customers at least one 48-hour notice. However, when we look at a combination of the following factors, it is clear that at least a quarter of California's utility customers is living with energy insecurity:

- 16% of utility customers received at least one 48-hour disconnection notice in 2016
- 12% of utility customers were at least 2 months behind on their utility bills in December 2016
- 5.3 shutoffs for every 100 households in California in 2016

According to various metrics, between 19% and 28% of utility customers are living with energy insecurity in California.

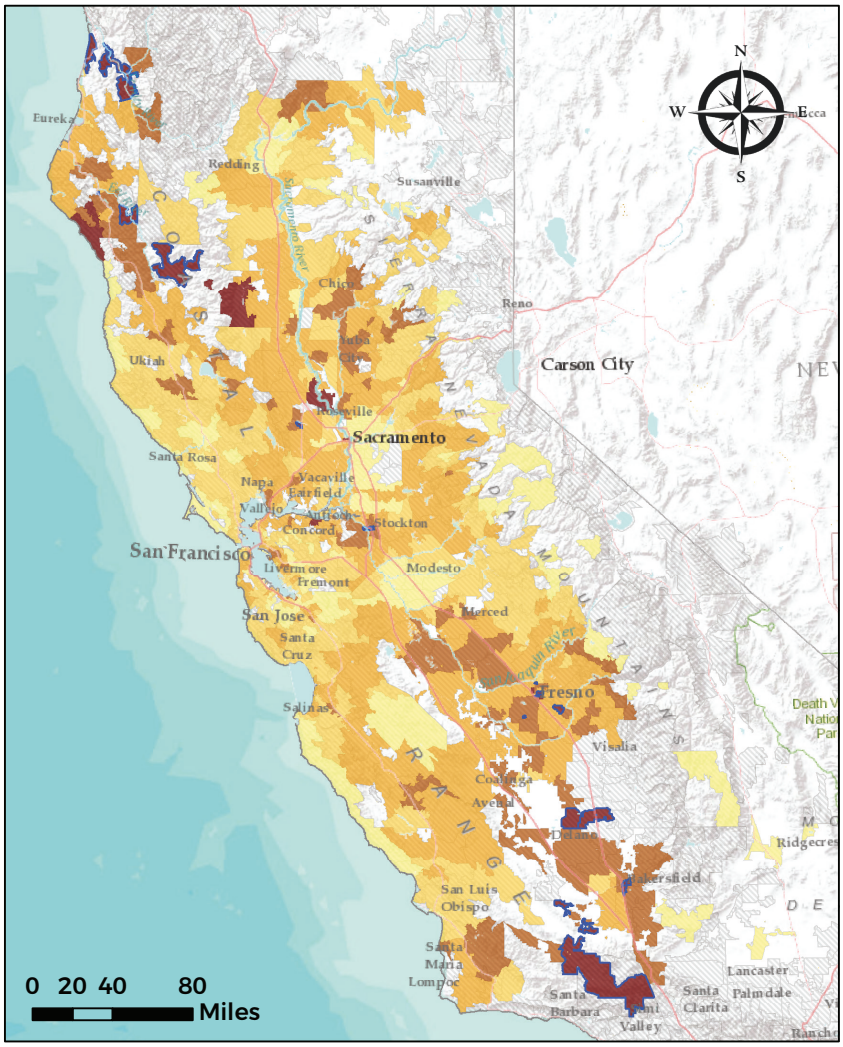
	Average total customers	Unique 48-hour disconnection notices	Percent of customers receiving notices	Customers 60+ days in arrears in Dec 2016	Percent of customers 60+ days in arrears in Dec 2016	Total shutoffs	Shutoff rate
PG&E	5,451,347	785,004	14%	528,230	10%	312,007	5.7%
Edison	4,353,680	1,234,601	28%	495,726	11%	402,761	9.2%
SoCal Gas	5,496,386	609,960	11%	758,239	14%	129,545	2.3%
SDG&E	1,350,527	78,915	6%	255,240	19%	40,067	2.9%

Source: Disconnections Rulemaking Data. Shutoff rates show the number of shutoffs per total customers, not the percentage of customers experiencing disconnection.

"I felt powerless when SDG&E refused to give me a payment plan. I ended up having to get a payday loan. My family is trying to use air conditioning less, but it makes our home so uncomfortable some days. Now, SDG&E wants a $200 deposit. I just can't keep up."

~ Bob, San Diego

2016 PG&E Shutoff Rates by ZIP Code

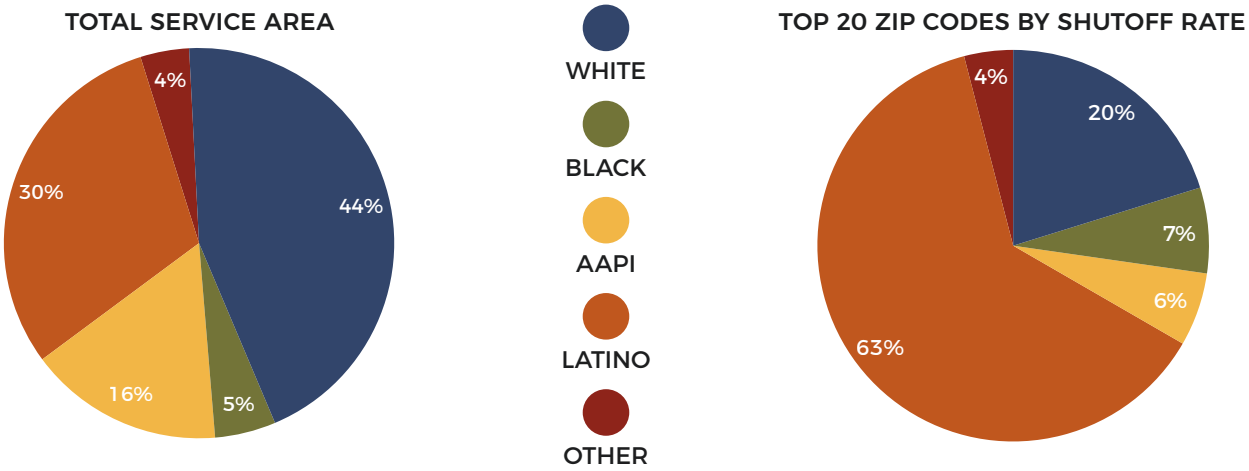


Shutoff Rates

- 0% - 3%
- 3.1% - 6%
- 6.1% - 10%
- 10.1% - 16%
- 16.1% - 28.1%
- 20 ZIP codes with highest shutoff rates
- ZIP codes with fewer than 100 PG&E customers

Source: PG&E ZIP Code Data. Shutoff rates show the number of shutoffs per total customers, not the percentage of customers experiencing disconnection. Only ZIP codes with over 100 PG&E customers in 2016 are displayed.

Racial Demographics: PG&E



Source: Utility ZIP Code Data and 2011-2015 American Community Survey, US Census Bureau

Communities Burdened by PG&E Shutoffs

Latino and Native Communities Hit Hardest

PG&E conducted over 312,000 shutoffs in 2016. In 2016, the top 20 ZIP codes had shutoff rates from 17% to 28%. In the 7 ZIP codes with the highest shutoff rates, there was at least 1 shutoff for every 4 PG&E customers.

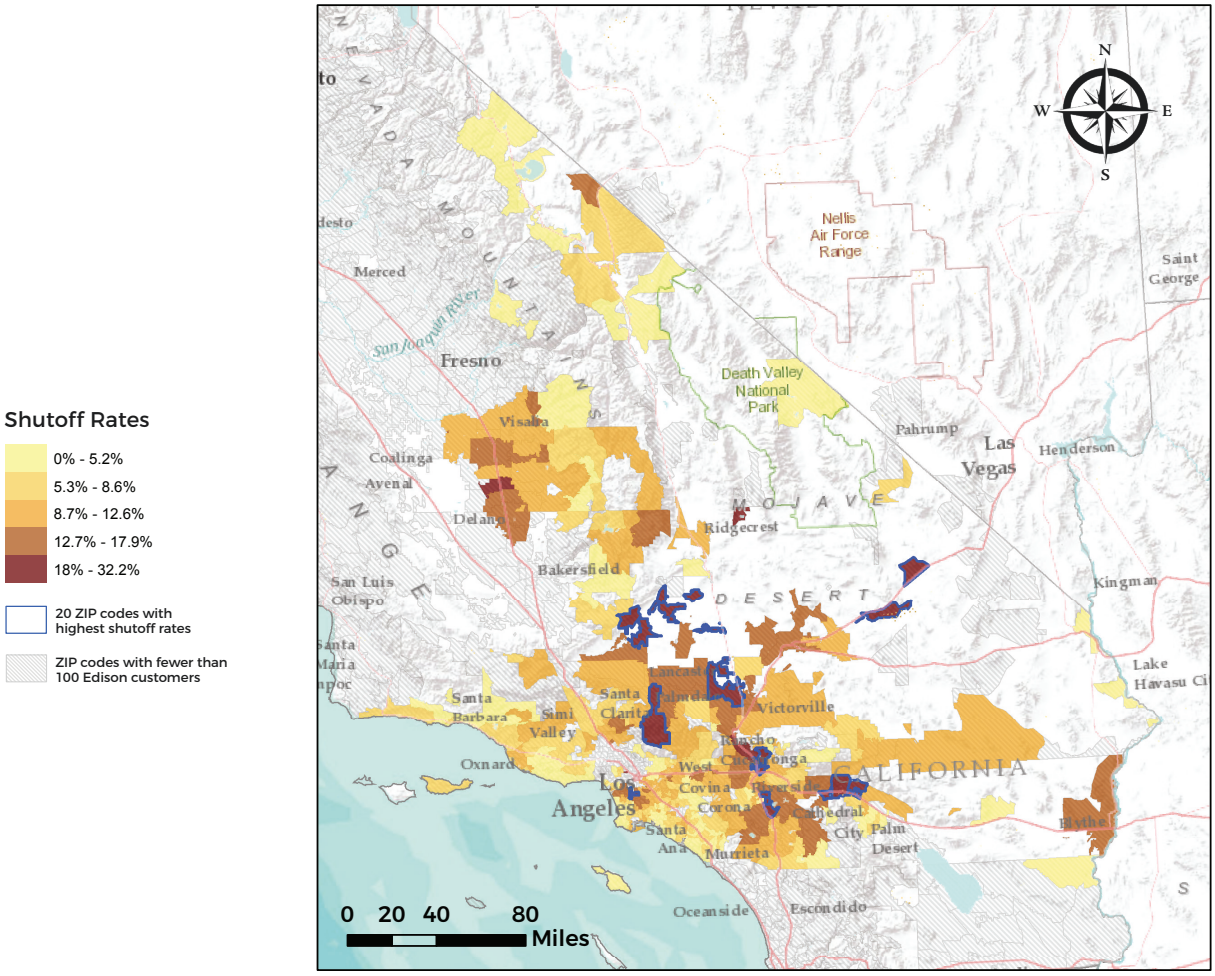
Racial disparities in the distribution of shutoffs are most evident with respect to the Latino population. While Latinos make up about a third (31%) of people living in PG&E's service territory, they comprise almost two-thirds (62%) of those living in ZIP codes with the highest shutoff rates. It is also important to note that the fourth highest rate of disconnections (26%) is experienced by people living on the Hoopa reservation.

Highest Shutoff Rates by ZIP in 2016: PG&E

Rank	ZIP Code	Total Customers	Total Shutoffs	Shutoff Rate	Location
1	95511	121	34	28%	Alderpoint
2	93701	2783	751	27%	Fresno
3	93201	316	83	26%	Alpaugh
4	95546	1073	281	26%	Hoopa
5	95202	2526	641	25%	Stockton
6	93301	3829	970	25%	Bakersfield
7	95555	223	56	25%	Orick
8	93219	131	30	23%	Earlimart
9	95428	901	190	21%	Covelo
10	93652	129	27	21%	Raisin City
11	95203	4201	866	21%	Stockton
12	93304	11823	2396	20%	Bakersfield
13	93224	123	24	20%	Fellows
14	93650	765	147	19%	Fresno
15	93305	9677	1836	19%	Bakersfield
16	95653	144	27	19%	Madison
17	95571	176	31	18%	Weott
18	93252	433	76	18%	Maricopa
19	93616	484	83	17%	Del Ray
20	93703	8490	1446	17%	Fresno

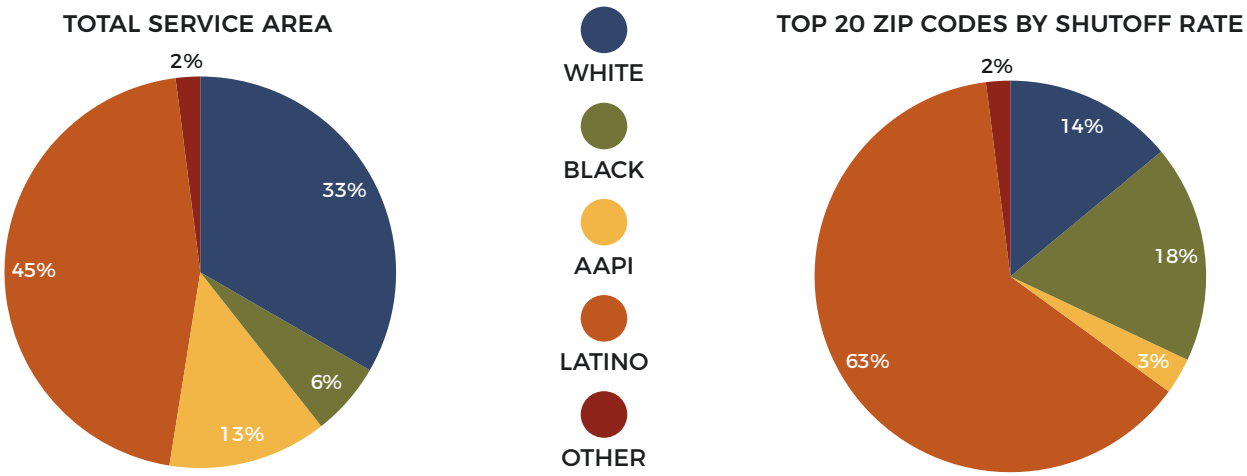
Source: Utility ZIP Code Data

2016 Edison Shutoff Rates by ZIP Code



Source: Edison ZIP Code Data. Shutoff rates show the number of shutoffs per total customers, not the percentage of customers experiencing disconnection. Only ZIP codes with over 100 Edison customers in 2016 are displayed.

Racial Demographics: Edison



Source: Utility ZIP Code Data and 2011-2015 American Community Survey, US Census Bureau

Communities Burdened by Edison Shutoffs

Latino and Black Communities Hit Hardest

Edison conducted over 400,000 shutoffs in 2016. The ZIP codes with the highest shutoff rates are concentrated in Riverside, San Bernardino, Los Angeles, and Kern Counties. In the ZIP codes with the highest shutoff rate, Edison conducted 1 shutoff for every 3 customers. They conducted at least 1 shutoff for every 5 customers in 13 ZIP codes.

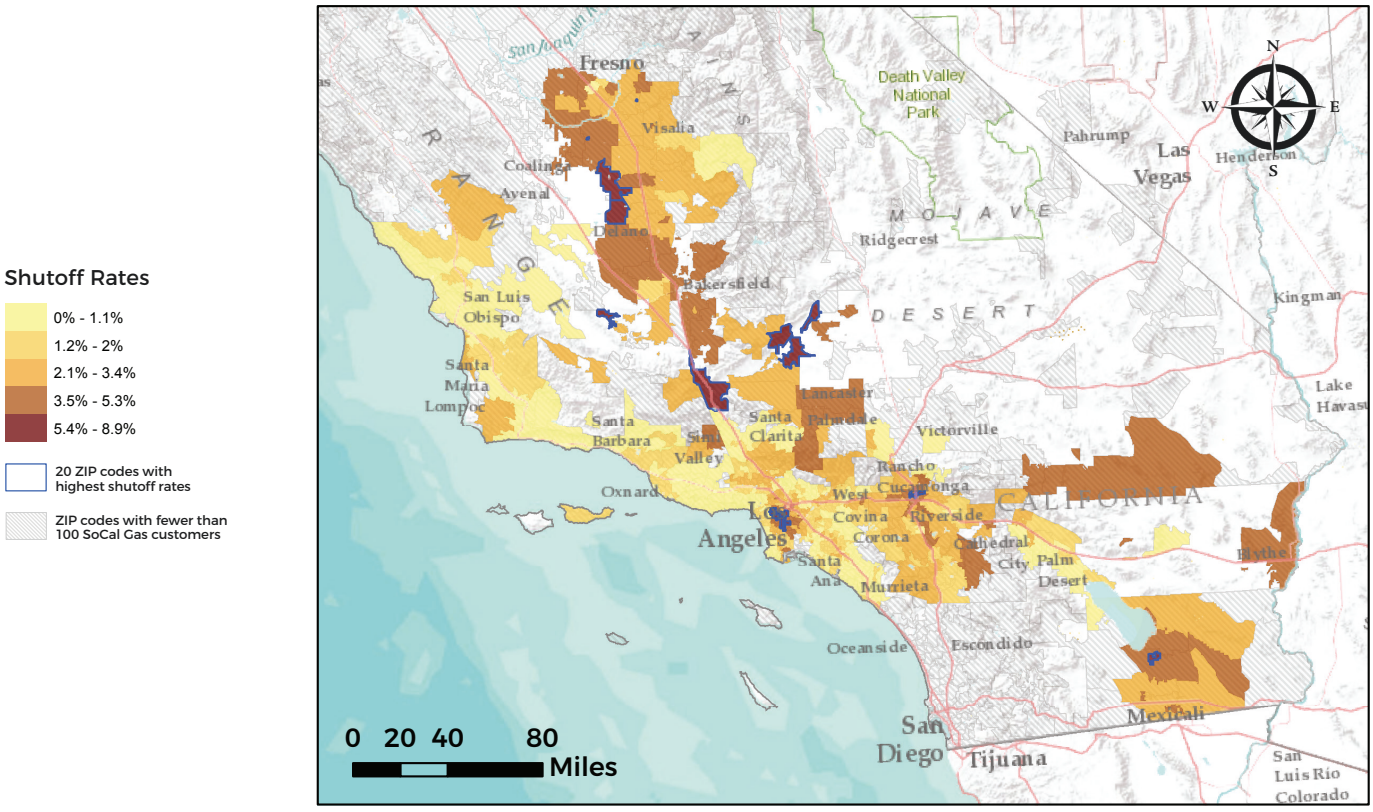
One third of the population in Edison's service territory is white. The other 67% of the service territory is made up of people of color. However, in the 20 ZIP codes with the highest shutoff rates, less than 1 out of 6 people are white, while 4 out of 5 are people of color. Latinos make up just under half of those in the service territory (45%) but represent almost two thirds (63%) of the people in the ZIP codes with the highest shutoff rates. Similarly, Black people comprise 6% of those living in Edison territory, but triple to 18% of those living in ZIP codes with the highest shutoff rates. Four out of every 5 people in the high shutoff rate ZIP codes are Black or Latino.

Highest Shutoff Rates by ZIP in 2016: Edison

Rank	ZIP Code	Total Customers	Total Shutoffs	Shutoff Rate	Location
1	92401	608	196	32%	San Bernardino
2	92258	152	46	30%	North Palm Springs
3	92301	9,764	2,335	24%	Adelanto
4	92405	9,618	2,235	23%	San Bernardino
5	92404	19,024	4,332	23%	San Bernardino
6	93501	2,120	470	22%	Mojave
7	92230	887	195	22%	Cabazon
8	92410	13,306	2,907	22%	San Bernardino
9	92551	7,151	1,475	21%	Moreno Valley
10	90044	8,307	1,675	20%	Los Angeles
11	92553	20,667	4,145	20%	Moreno Valley
12	93550	23,005	4,573	20%	Palmdale
13	92240	13,494	2,672	20%	Desert Hot Springs
14	92309	190	37	19%	Baker
15	92282	551	107	19%	Whitewater
16	90002	3,276	628	19%	Los Angeles
17	92408	3,805	728	19%	San Bernardino
18	92571	13,408	2,553	19%	Perris
19	93516	877	165	19%	Boron
20	93505	5,006	937	19%	California City

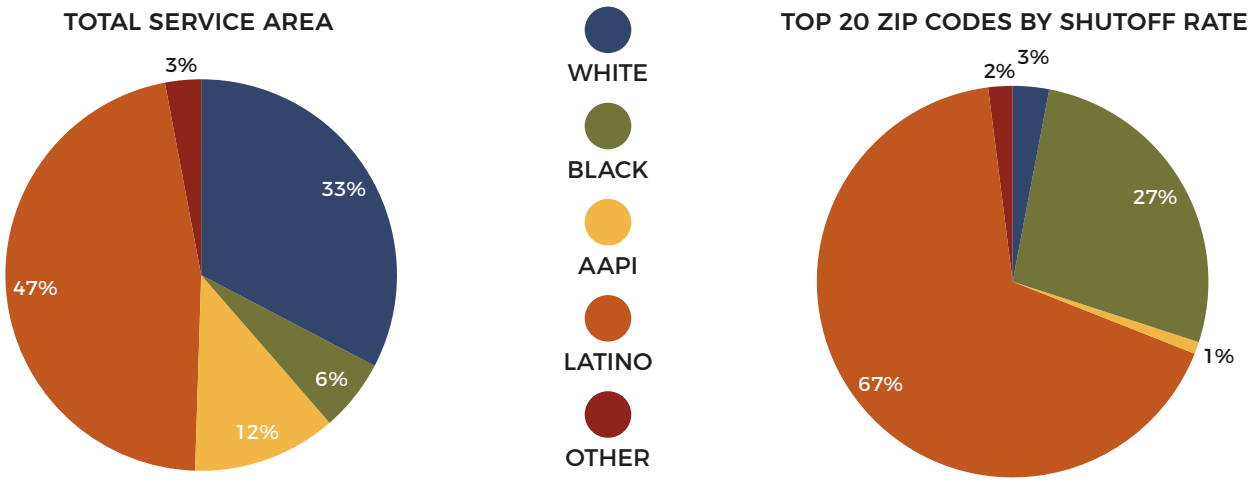
Source: Utility ZIP Code Data

2016 SoCal Gas Shutoff Rates by ZIP Code



Source: SoCal Gas ZIP Code Data. Shutoff rates show the number of shutoffs per total customers, not the percentage of customers experiencing disconnection. Only ZIP codes with over 100 SoCal Gas customers in 2016 are displayed.

Racial Demographics: SoCal Gas



Source: Utility ZIP Code Data and 2011-2015 American Community Survey, US Census Bureau

Communities Burdened by SoCal Gas Shutoffs

Latino and Black Communities Hit Hardest

SoCal Gas conducted almost 130,000 shutoffs in 2016. Most troubling for Southern California residents is the fact that 5 of the top 20 highest shutoff rate ZIP codes for SoCal Gas also appear in the top 20 ZIP code list for Edison (See the highlighted fields in the tables above and below).

The 20 ZIP codes with the highest shutoff rates per total customers in SoCal Gas's service territory range from 5% to 9%. Half of these ZIP codes are concentrated in the City of Los Angeles with the others in Imperial (1); Kern (3); Kings (2); Tulare (2); and San Bernardino Counties (2).

One out of 3 people in SoCal Gas's service territory is white and 67% are people of color. The disproportionate impact of shutoffs along racial lines is stark in SoCal Gas's territory. While Latinos make up just under half of the households in SoCal Gas's territory (47%), they comprise fully 67% of the people in the 20 ZIP codes with the highest shutoff rates. The disparity with regard to the Black population is much larger in the highest shutoff rate ZIP codes. The Black population is four and a half times greater in the ZIP codes with the highest shutoff rates than in the total SoCal Gas service territory—jumping up from 6% to 27%.

Highest Shutoff Rates by ZIP in 2016: SoCal Gas

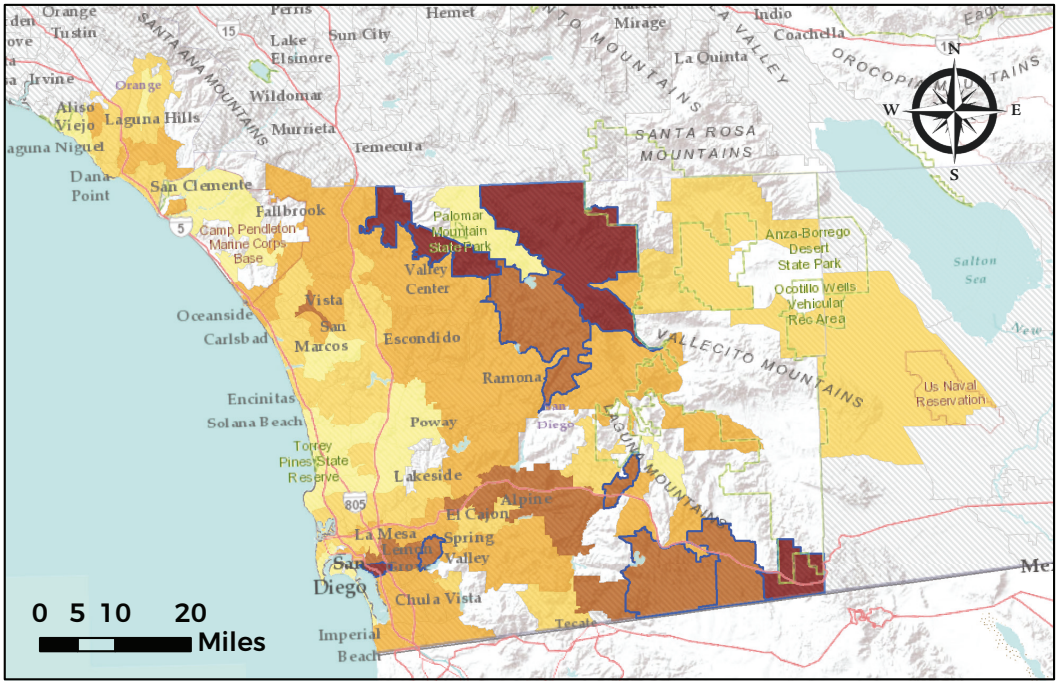
Rank	ZIP Code	Total Customers	Total Shutoffs	Shutoff Rate	Location
1	92401	707	63	9%	San Bernardino
2	90003	19567	1606	8%	Los Angeles
3	93666	151	12	8%	Sultana
4	93202	1402	108	8%	Armona
5	93224	127	9	7%	Fellows
6	93501	1888	128	7%	Mojave
7	90037	17621	1182	7%	Los Angeles
8	92281	725	47	6%	Westmorland
9	90062	10097	652	6%	Los Angeles
10	90044	29392	1882	6%	Los Angeles
11	90061	7970	503	6%	Los Angeles
12	93212	4907	305	6%	Corcoran
13	90011	23734	1472	6%	Los Angeles
14	90008	16162	996	6%	Los Angeles
15	93243	509	31	6%	Lebec
16	93201	250	14	6%	Alpaugh
17	90002	12028	668	6%	Los Angeles
18	90016	18270	1006	6%	Los Angeles
19	90043	18144	998	6%	Los Angeles
20	92410	14329	785	5%	San Bernardino

Source: Utility ZIP Code Data

2016 SDG&E Shutoff Rates by ZIP Code

Shutoff Rates

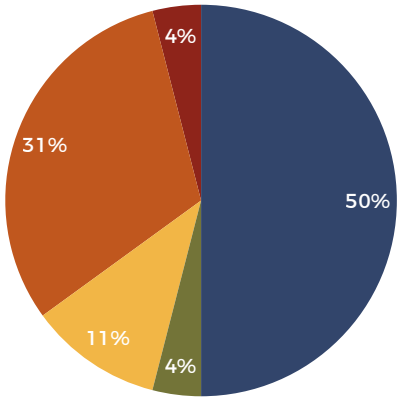
- 0% - 1.7%
- 1.8% - 3%
- 3.1% - 4.3%
- 4.4% - 6.5%
- 6.6% - 12.7%
- 10 ZIP codes with highest shutoff rates
- ZIP codes with fewer than 100 SDG&E Gas customers



Source: SDG&E ZIP Code Data. Shutoff rates show the number of shutoffs per total customers, not the percentage of customers experiencing disconnection. Only ZIP codes with over 100 SDG&E customers in 2016 are displayed.

Racial Demographics: SDG&E

TOTAL SERVICE AREA



WHITE

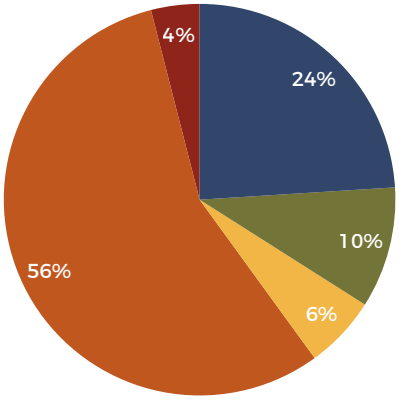
BLACK

AAPI

LATINO

OTHER

TOP 10 ZIP CODES BY SHUTOFF RATE



Source: Utility ZIP Code Data and 2011-2015 American Community Survey, US Census Bureau

Communities Burdened by SDG&E Shutoffs

Latino and Black Communities Hit Hardest

SDG&E conducted over 40,000 shutoffs in 2016.

All of the 10 ZIP codes with the highest shutoff rates per total customers in SDG&E's service territory are located in San Diego County and are distributed among 10 different cities. The shutoff rates range from 5% to 13%.

Half of the people in SDG&E's territory are white and half are people of color. Although Latinos comprise only 3 out of 10 people in the service territory, they are more than half (56%) of the population in the ZIP codes with the highest shutoff rates.[10] Blacks are also disproportionately represented in the highest shutoff rate ZIP codes. Although they represent only 4% of the total service territory, Black families comprise 10% of the people in the highest shutoff rate ZIP codes.

Highest Shutoff Rates by ZIP in 2016: SDG&E

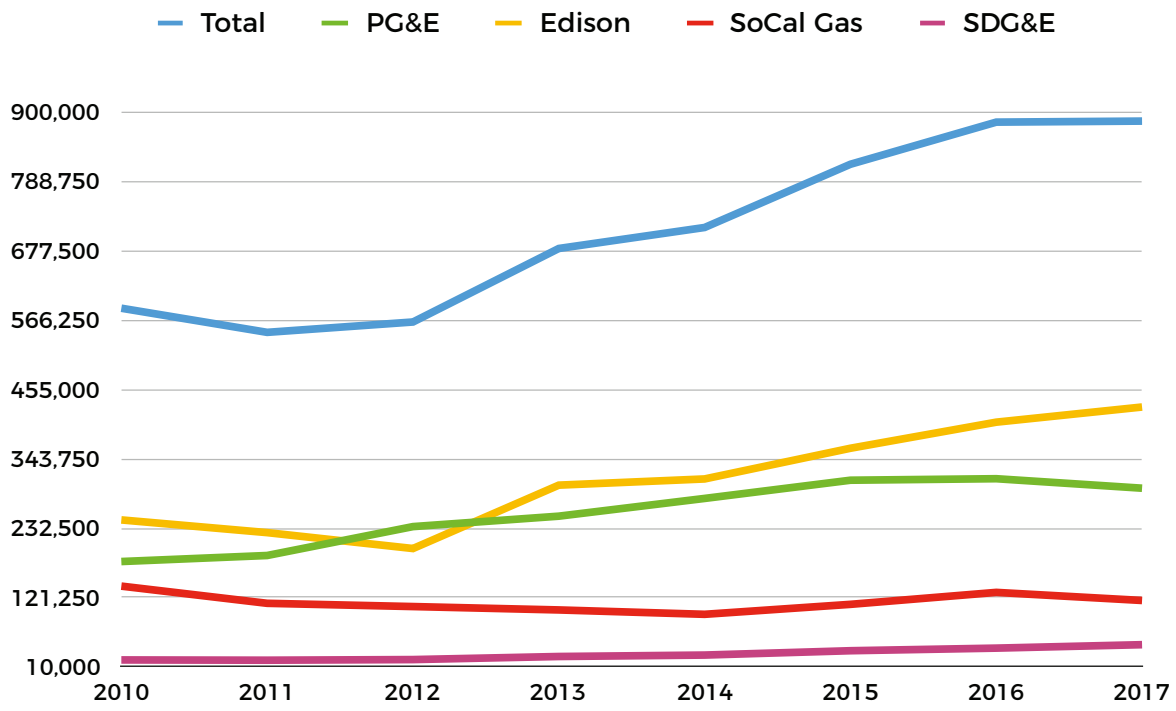
Rank	ZIP Code	Total Customers	Total Shutoffs	Shutoff Rate	Location
1	92059	585	74	13%	Pala
2	92086	457	38	8%	Warner Springs
3	91934	306	24	8%	Jacumba Hot Springs
4	92113	13,588	1,025	8%	San Diego
5	92061	1,065	77	7%	Pauma Valley
6	91906	1,330	87	7%	Campo
7	91905	778	47	6%	Boulevard
8	91931	102	6	6%	Gautay
9	92070	383	22	6%	Santa Ysabel
10	91977	20,644	1,117	5%	Spring Valley

Source: Utility ZIP Code Data

Shutoffs Have Skyrocketed Since 2010

Since 2010, shutoffs have increased by over 50%. At the height of the Great Recession there were just over half a million shutoffs by the utilities. That number has skyrocketed to over 886,000 shutoffs in 2017—roughly equivalent to all of the households in San Diego and San Francisco combined.

Shutoff Trends



Source: Disconnections Rulemaking Data

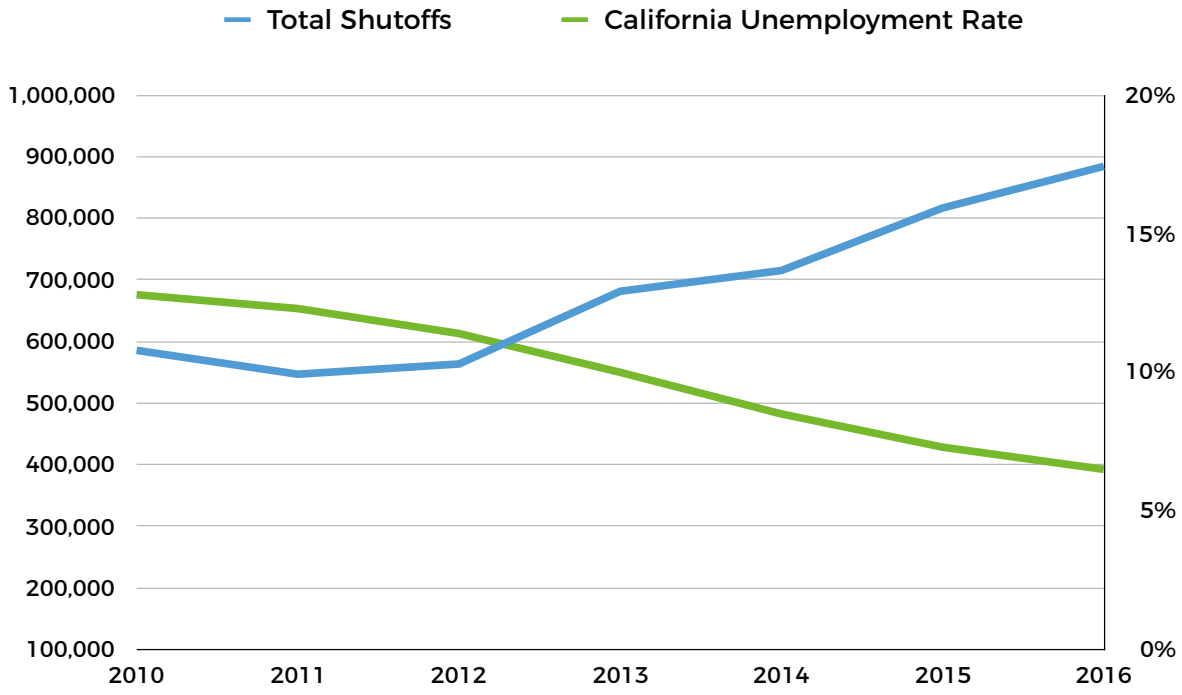
While SoCal Gas has seen a slight decrease in their shutoff rate per customer—dropping from 2.6% in 2010 to 2.4% in 2016—all other utilities have seen their shutoff rates increase in the same time period.

Electric Shutoff Rates Skyrocket

	2010	2016
PG&E	3.4%	5.7%
Edison	5.8%	9.3%
SoCal Gas	2.6%	2.4%
SDG&E	1.7%	3.0%

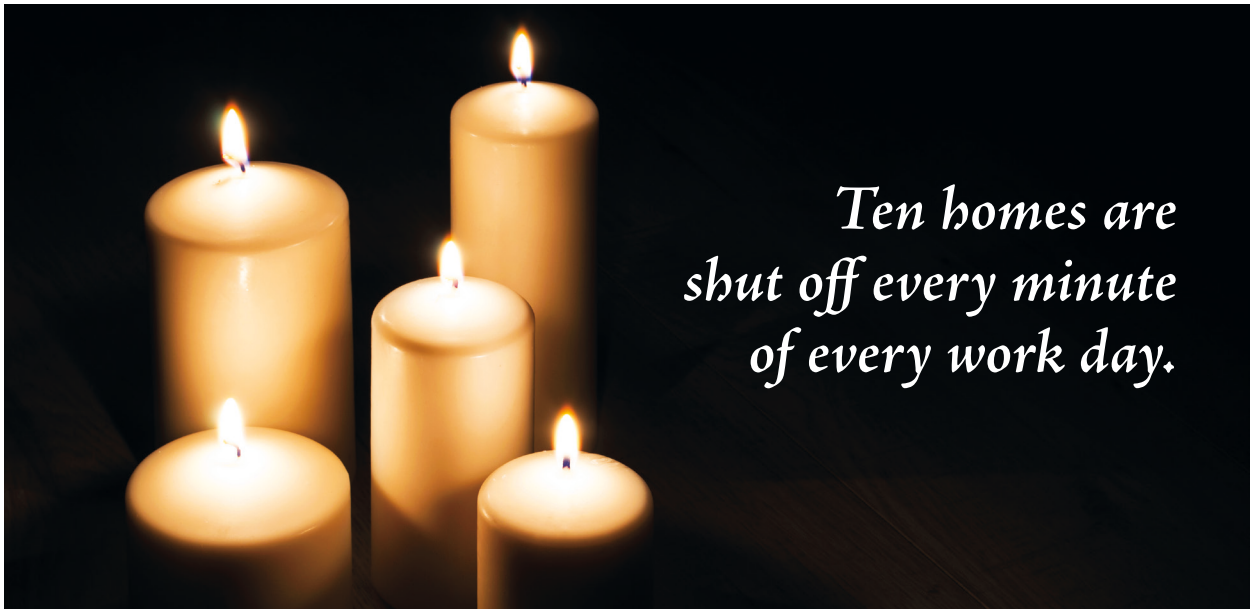
Source: Disconnections Rulemaking Data. Shutoff rates show the number of shutoffs per total customers, not the percentage of customers experiencing disconnection.

Total Shutoffs vs Median Household Income and Unemployment Rate



Source: U.S. Census Bureau, American Community Survey1-Year Estimates, 2010-2016

Even as the economy has recovered, the number of people shut off continues to rise. For instance, California's unemployment rate fell from almost 13% in 2010 to 6.5% in 2016. During that same time period, when shutoffs were increasing from 585,672 to 884,380, California's median income increased by over $4,000.





"During those months after I realized how high my bill was, I had to walk around in sweatpants, sweaters, and even went to bed with a hat on my head trying to keep warm. For someone who is a senior citizen, living on a fixed income, with medical conditions, particularly arthritis – you have to have heat or it becomes even more debilitating. Something has to be done because we are suffering."

~ Ernestine J. Wilson, Oakland

Shutoffs Increase at Highest Rate for Customers Who Don't Qualify for Discounts

Skyrocketing shutoffs for customers whose income is too high to qualify for CARE or FERA discounts provide strong evidence that monthly utility bills are too high for the majority of California residents.

California Alternate Rates for Energy (CARE) provides a 30-35% discount to customers at or below 200% of the Federal Poverty Line, and has a participation rate of over 80%.

Family Electric Rate Assistance (FERA) provides a 12% discount to families of 3 or more whose household incomes fall between 200% and 250% of the Federal Poverty Line. Unlike CARE, FERA is very under-enrolled with a participation rate of about 13%.

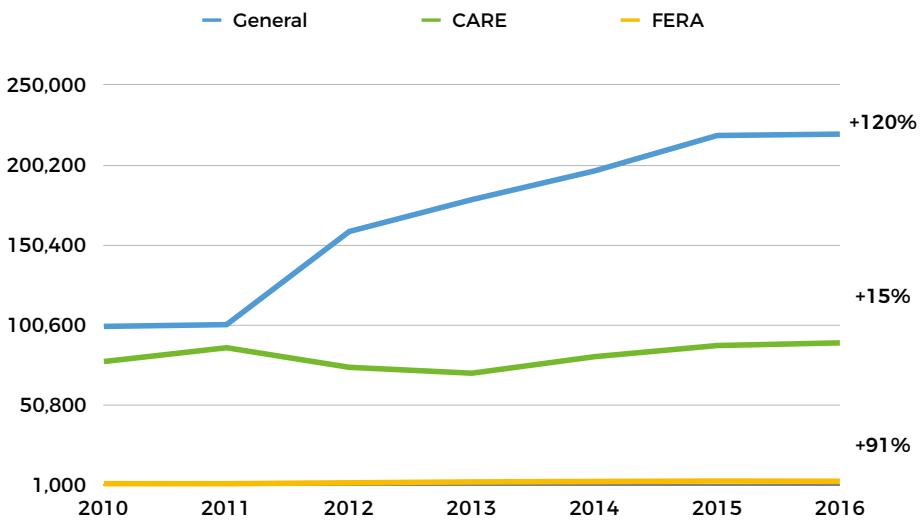
"My electricity was shut off over a month ago. I have 3 children. All our refrigerated food spoiled. PG&E won't reconnect my service unless I pay them more than $2,000. I just can't afford it."

~ Lisandra, Fresno

Pacific Gas & Electric Company

Since 2010, shutoffs among PG&E CARE customers increased 15%. Among FERA customers shutoffs almost doubled—a 91% increase. Shutoffs among customers who were not enrolled in an assistance program showed a 120% increase—more than doubling from about 99,637 to 219,411.

Shutoff Trends by Customer Type: PG&E

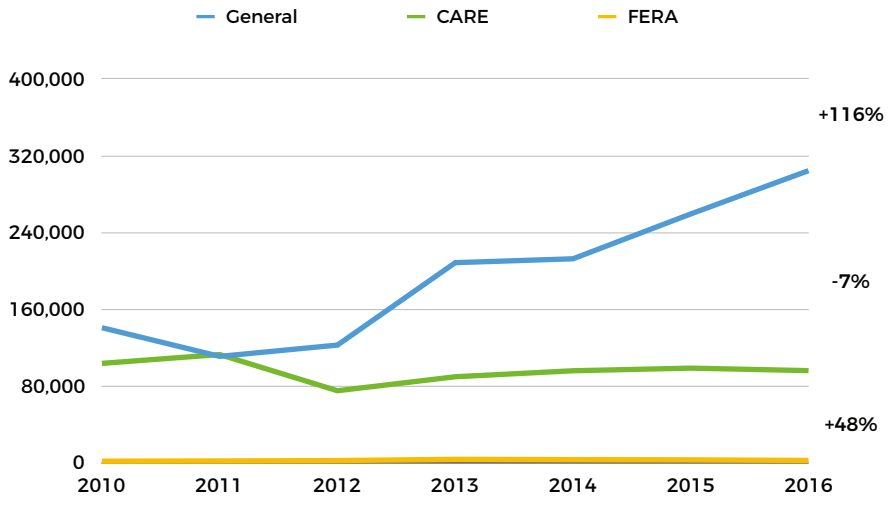


Source: Disconnections Rulemaking Data

Southern California Edison

Edison's CARE customers experienced a 7% drop in shutoffs from 2010 to 2016. Shutoffs among FERA customers increased by 48%. General customers experienced a 116% rise in shutoffs, doubling from 140,717 shutoffs in 2010 to over 300,000 shutoffs in 2016.

Shutoff Trends by Customer Type: Edison

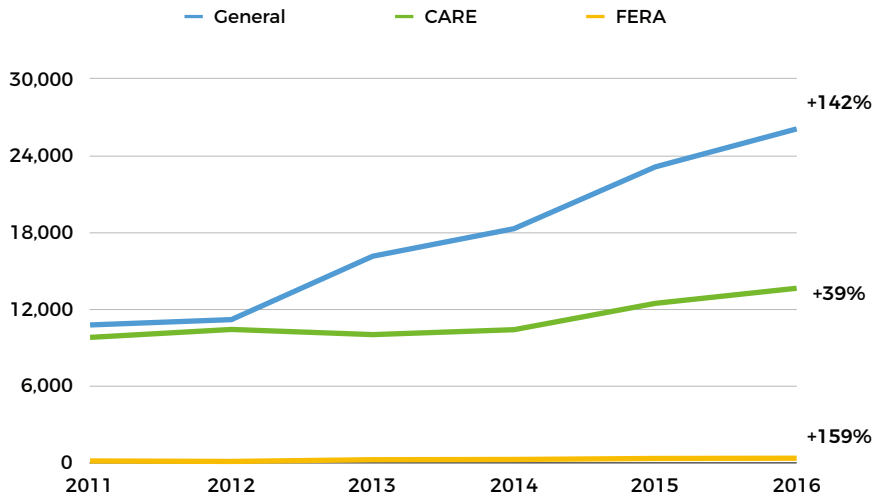


Source: Disconnections Rulemaking Data

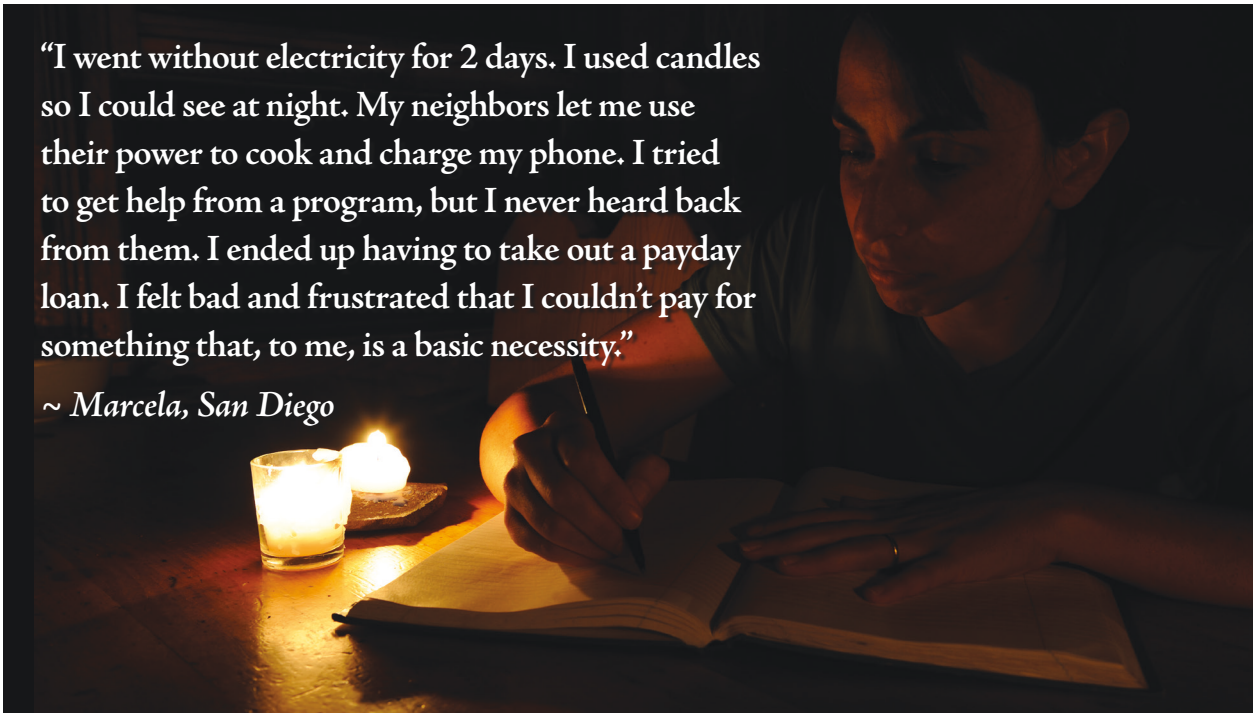
San Diego Gas & Electric

Shutoffs among SDG&E CARE customers increased 39% between 2011 and 2016. SDG&E more than doubled the number of shutoffs among both the general population (142%) and their FERA customers (159%).

Shutoff Trends by Customer Type: SDG&E



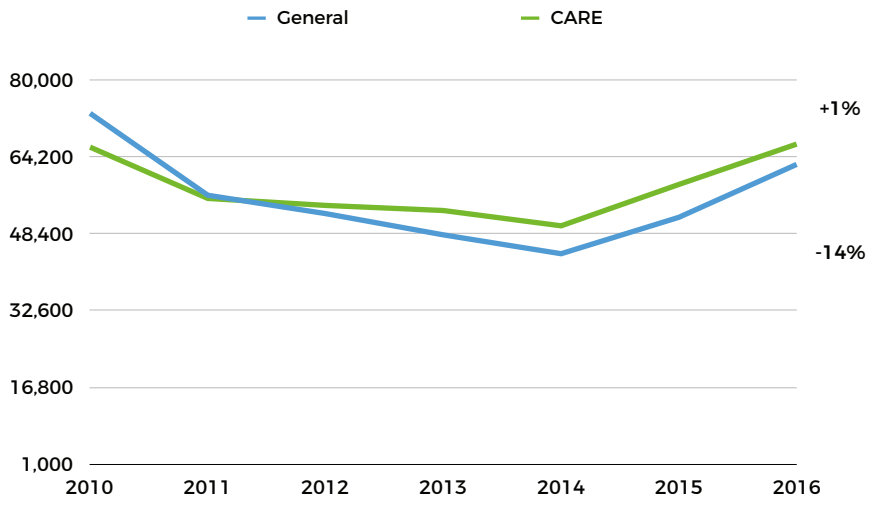
Source: Disconnections Rulemaking Data



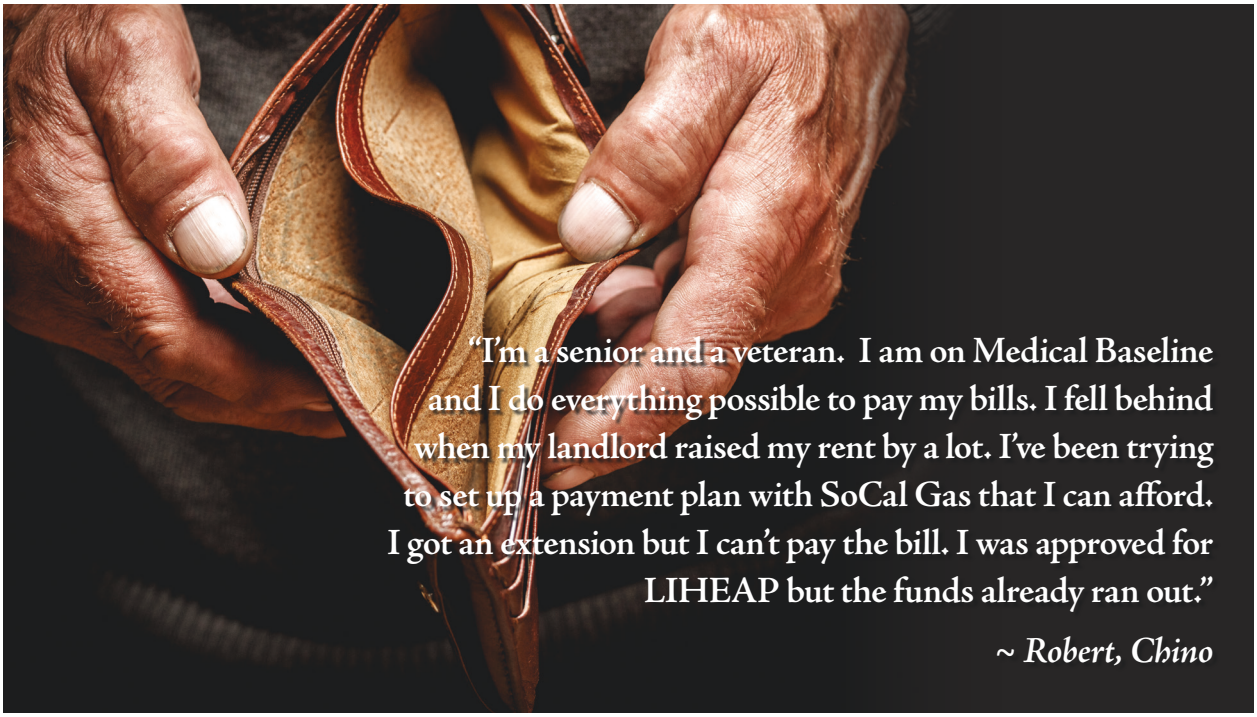
Southern California Gas Company

Southern California Gas showed different trends over time. Both CARE customers and general customers experienced a decrease in disconnections between 2010 and 2014. From 2014 to 2016, both groups experienced an increase in shutoffs. SoCal Gas is also the only major utility who shut off more CARE customers than general customers in 2016.

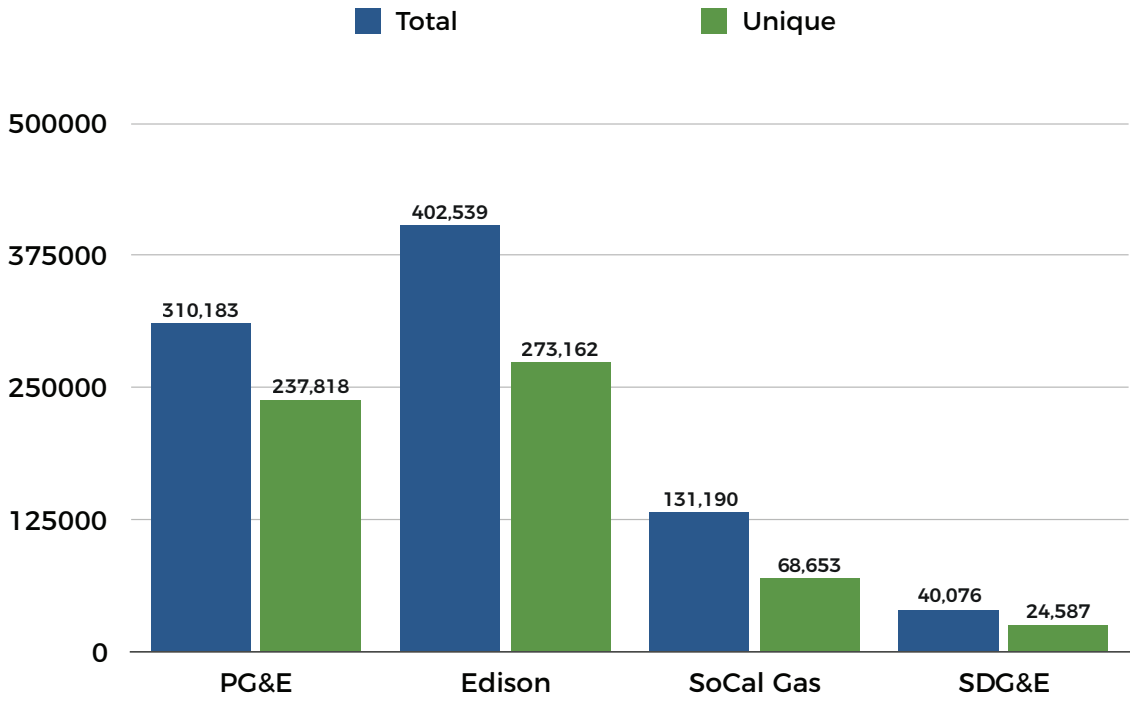
Shutoff Trends by Customer Type: SoCal Gas



Source: Disconnections Rulemaking Data



Multiple Shutoffs in 2016



Source: Utility ZIP Code Data

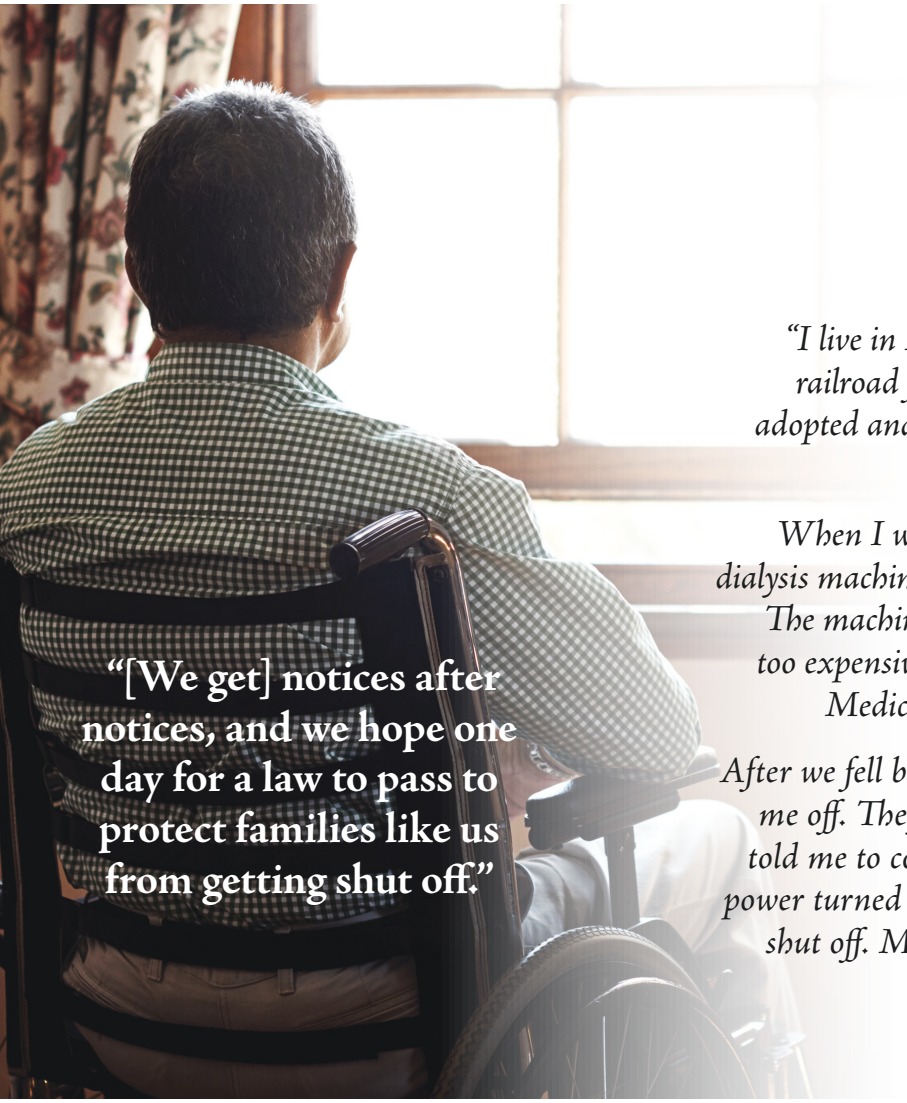
- PG&E conducted 72,365 multiple shutoffs in 2016.
- Edison shut off electric service 129,377 times in homes that had already been shut off at least once before in 2016.
- SoCal Gas conducted 62,537 shutoffs in homes that had had at least one shutoff already in 2016.
- SDG&E shutoff 15,489 homes that had already experienced at least one shutoff in 2016.

"I have 2 children who are bedridden and connected to medical devices. This makes our bills very high. We are constantly in danger of being shut off. It happens at least once every year, usually during the summer. It's so stressful."

~ Gabriel, San Diego

Utility Customers' Health Threatened by Multiple Shutoffs

Each of the utilities disconnects some of their customers multiple times throughout the course of a year. While we cannot tell from the data if a person was shut off 2 times or 5 times, we do know that nearly 280,000 shutoffs took place in homes that had already experienced one shutoff in 2016. The mental and emotional toll of anticipating one's family's next shutoff less than 12 months after the last and the actual physical consequences of multiple shutoffs merit serious consideration by policymakers and utility staff.



"[We get] notices after notices, and we hope one day for a law to pass to protect families like us from getting shut off."



"I live in Madera. I'm retired after working for the local railroad for many, many years. When I was younger, I adopted and raised eight children. They were brothers and sisters and I didn't want them to be separated.

When I was diagnosed with kidney failure, I got a home dialysis machine so that my family could care for me at home. The machine uses a lot of electricity and our bills got to be too expensive. Even though we are enrolled in CARE and Medical Baseline, we struggle to pay our PG&E bill.

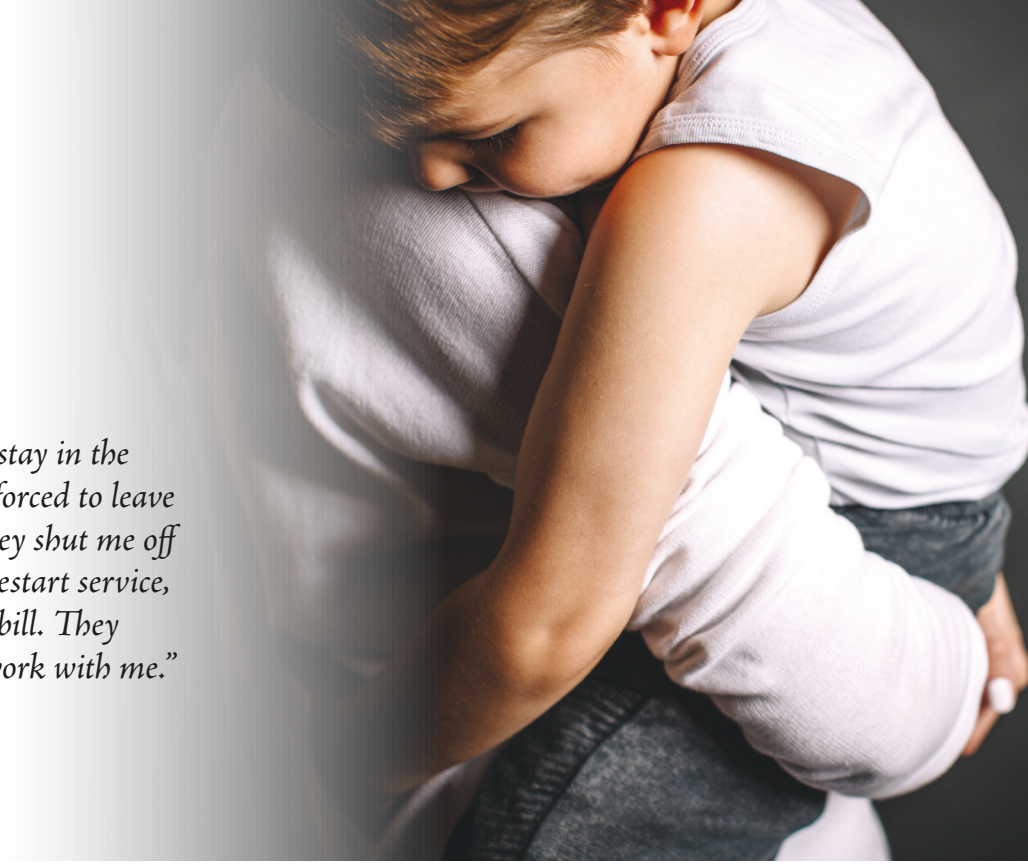
After we fell behind on payments the last time, PG&E shut me off. They didn't care about my medical condition and told me to come up with the money to pay if I wanted my power turned back on. I had to leave the house while it was shut off. My daughter took me in so that I could run the dialysis machine and stay cool."

~ Rubén, Madera



"Our landlord wouldn't let my family stay in the apartment without power so we were forced to leave and find a new place to live. When they shut me off Edison demanded a $500 deposit to restart service, in addition to paying my outstanding bill. They wouldn't give me a payment plan or work with me."

~ Teresa Colbert, Hemet



Shutoffs Are a Hidden Driver of Housing Displacement

Approximately 1 out of every 10 customers who has their electricity shut off is never reconnected, driving countless families from their homes. A home without utility service is not fit for habitation. While the data cannot tell exactly what happens to families and individuals who are never reconnected, we know that few people live for extended periods of time without service.

Data from community surveys and individual stories relate that many people end up moving, sometimes crowding in with other family members, couch surfing, or living on the streets. Community partner organizations have documented evictions from subsidized housing due to disconnections, because utility service is a condition of Section 8 and other subsidized and transitional housing leases.

	Total Disconnections	Reconnections	Never Reconnected	% Never Reconnected
PG&E	312,007	275,059	36,948	12%
Edison	402,761	358,403	44,358	11%
SoCal Gas	129,545	89170	40,375	31%
SDG&E	40,067	35,628	4,439	11%

Source: Disconnections Rulemaking Data





"Over the winter, the cold days caused me so much pain because of my rheumatoid arthritis. To keep warm and control the pain, I turned on the heat. I didn't realize that just keeping the house warm would make my utility bill so high. I try to keep my bills low by turning off lights and washing clothes in cold water. I cut back on food and other needs, but I'm still going to be shut off."

~ Sheila Clark, Oakland

Medical Baseline Customers Have the Worst Reconnection Rates

Customers enrolled in the Medical Baseline program experience dismal reconnection rates. Medical Baseline is a program administered by the utilities that helps people who have serious medical conditions and/or use medical equipment that make it hard to afford their monthly bill. Customers who qualify for Medical Baseline can get more of their gas and electricity at lower rates. Medical Baseline is not means-tested, so any customer, regardless of income, may qualify.

Too many Medical Baseline customers are never reconnected. They are up to 4 times more likely to never be reconnected than other customers. No one has documented what happens to them. As with regular customers, they may end up marginally housed, in a nursing home or—in the worst-case scenario—dead.

The range of customers never reconnected who are registered for the Medical Baseline program is about 1 in 3 for Edison, SoCal Gas and SDG&E. Most startlingly, PG&E never reconnected half of the Medical Baseline customers they disconnected in 2016.

	MB Disconnections	Reconnections	Never Reconnected	% Never Reconnected
PG&E	1,349	679	670	50%
Edison	1,917	1,261	656	34%
SoCal Gas	199	127	72	36%
SDG&E	197	126	71	36%

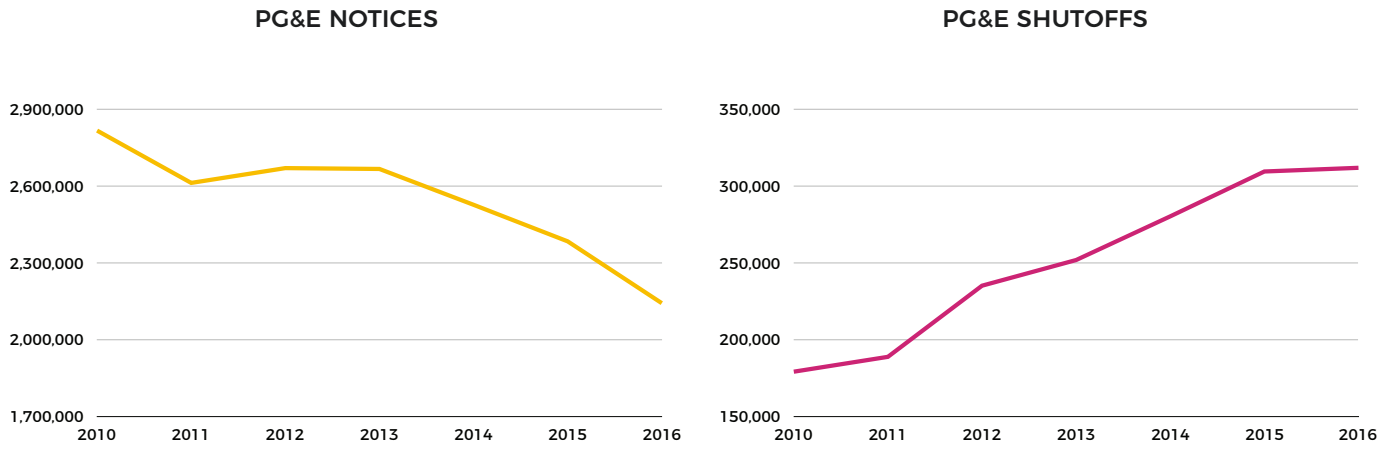
Source: Disconnections Rulemaking Data

Shutoffs are No Longer a Last Resort for Collections

Before Smart Meters were installed at a majority of residences, a crew had to take a truck out to a residence to manually disconnect, and again to reconnect, service at a customer's home. Since the mass installation of Smart Meters, remote disconnections have replaced virtually all field disconnections.

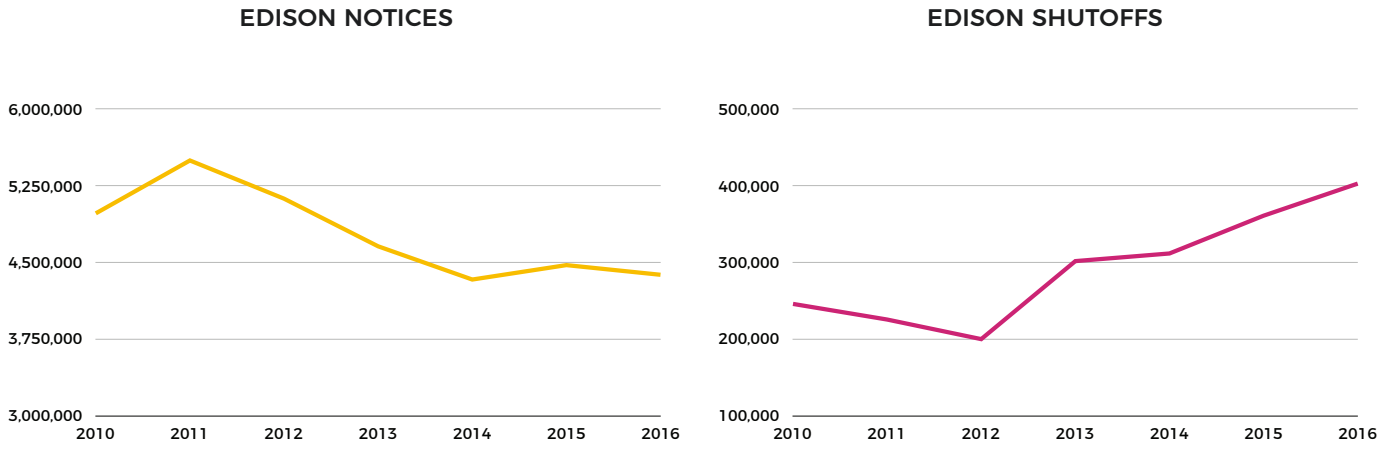
Ironically, as shutoffs have increased, the number of disconnection notices sent to customers has decreased. The data from all four utilities suggest that shutoffs are increasingly used by utility companies as a collection strategy and that they rely far less on disconnection notices.

Disconnection Notices and Shutoffs: PG&E



Source: Disconnections Rulemaking Data

Disconnection Notices and Shutoffs: Edison



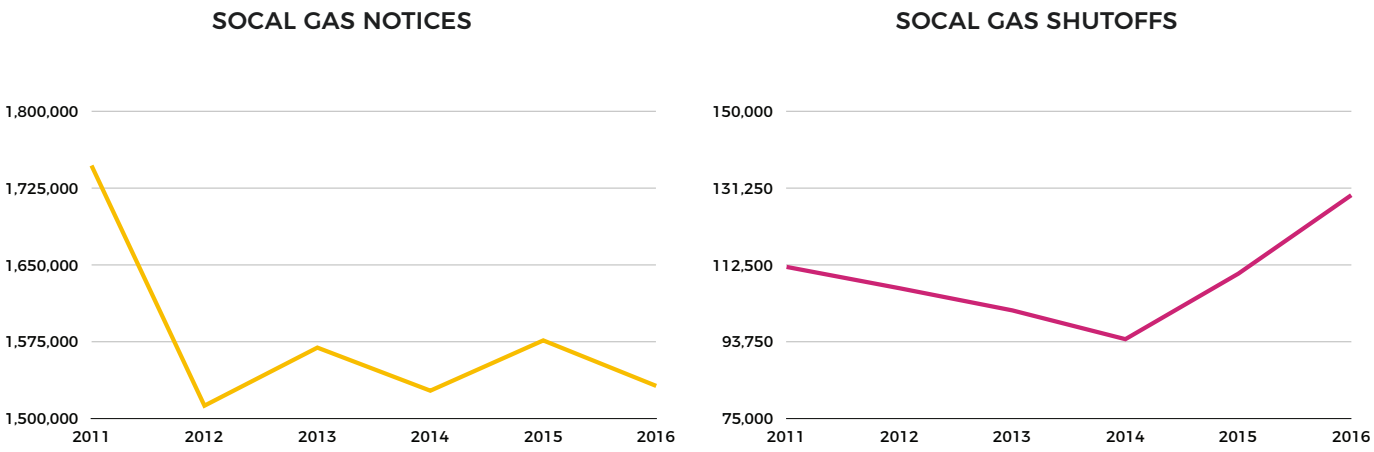
Source: Disconnections Rulemaking Data

Shutoffs Are Not Necessary for Revenue Collection

Southern California Edison had the highest disconnection rate in 2016. At 9.2%, Edison had almost 1 shutoff for every 10 customers. At 5.4%, PG&E had over 1 shutoff for every 20 customers. The Sempra Energy utilities (SDG&E and SoCal Gas) have the lowest rates of shutoffs. SDG&E reported one-third the number of shutoffs that Edison did. At 2.9%, SDG&E had 1 shutoff for every 30 customers. SoCal Gas had the lowest shutoff rate at 2.3%. However, SoCal Gas is unable to shut off their customers' natural gas service remotely. The increased difficulty involved in having to send out a crew to physically shut off natural gas service at customers' homes may be part of the reason SoCal Gas's disconnection rate is the lowest among the utilities.

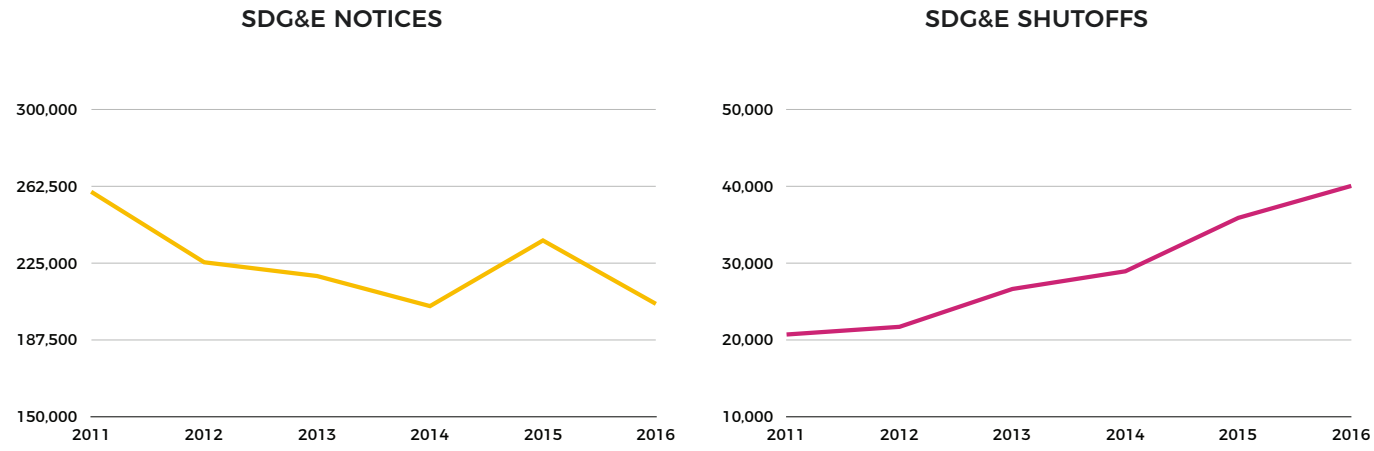
High shutoff rates are not necessary in order to manage customer back bills as evidenced by SDG&E and SoCal Gas's disconnection rates.

Disconnection Notices and Shutoffs: SoCal Gas



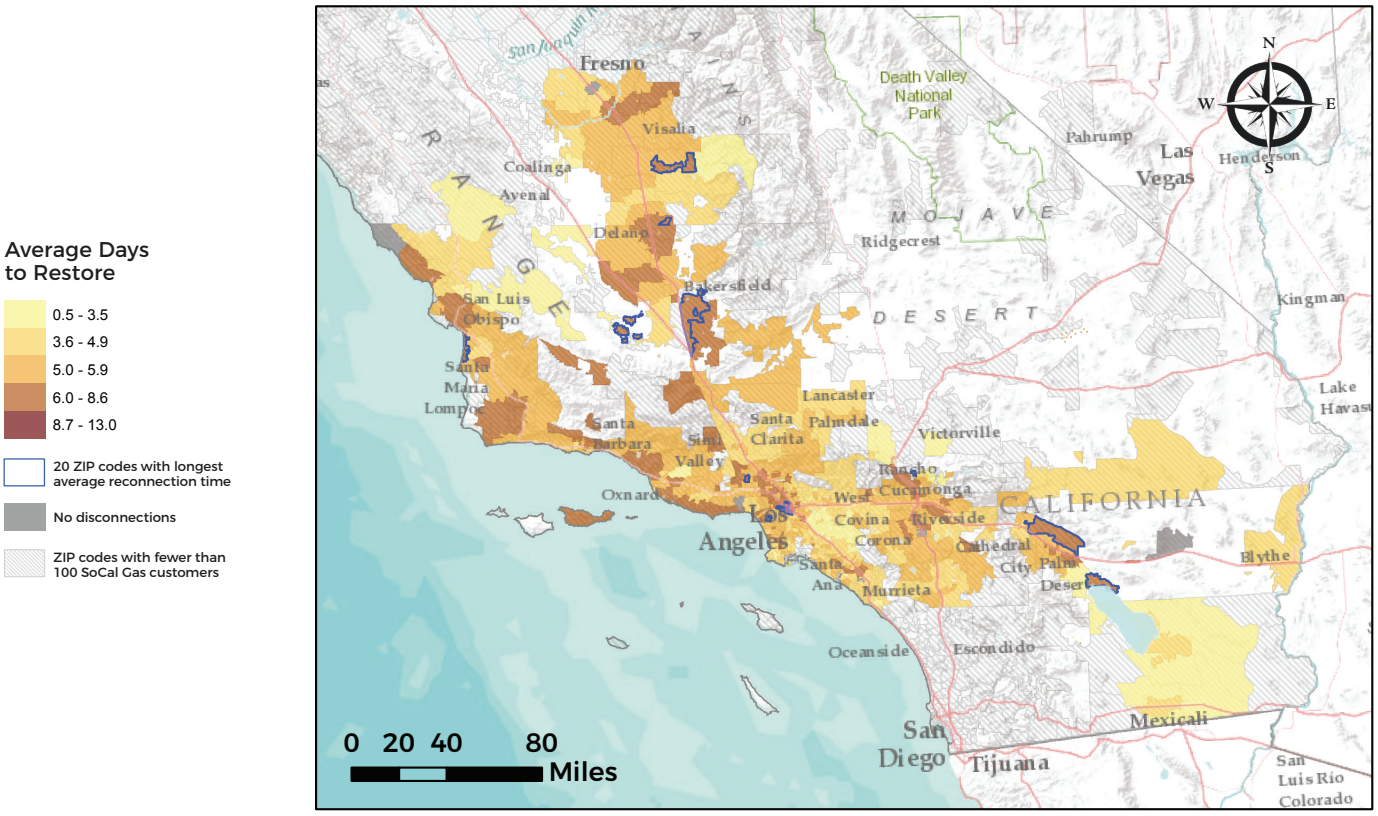
Source: Disconnections Rulemaking Data

Disconnection Notices and Shutoffs: SDG&E



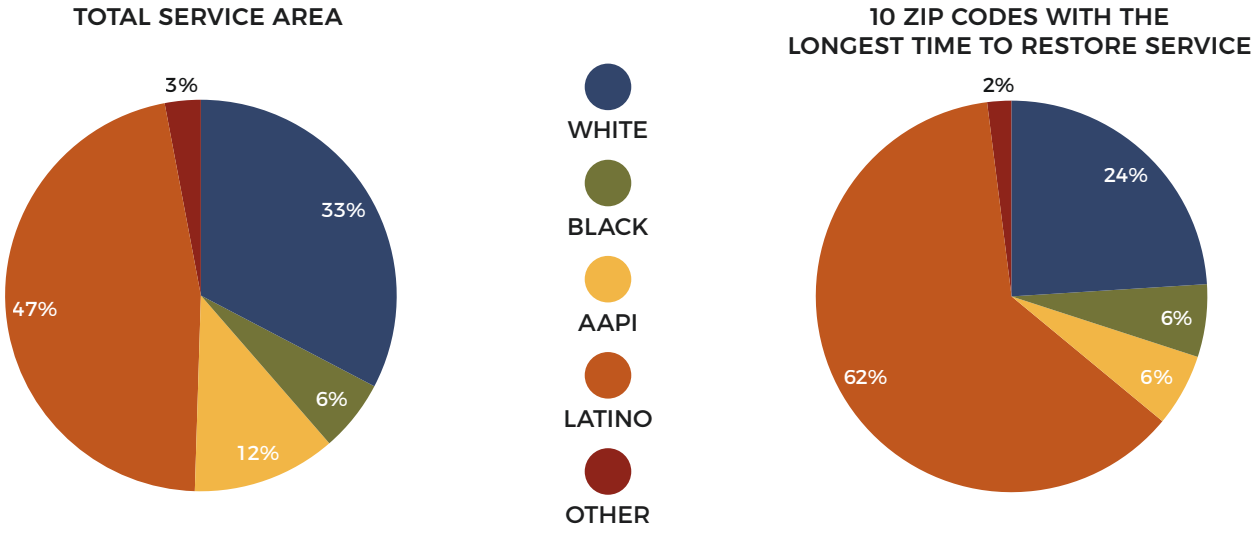
Source: Disconnections Rulemaking Data

Average Days to Restore Service: SoCal Gas



Source: SoCal Gas ZIP Code Data. Only ZIP codes with over 100 SoCal Gas customers in 2016 are displayed.

Time to Restore Service: SoCal Gas



Source: Utility ZIP Code Data and 2011-2015 American Community Survey, US Census Bureau

Restoring Gas Service Takes Longer for Low-Income Communities and Communities of Color

Reconnecting utility service for natural gas takes longer because it must be done in person, not remotely as with electricity.

ZIP code data indicate a trend that it may take longer for SoCal Gas to reconnect gas service in low-income communities and communities of color. As illustrated in the map below, the difference in the time it takes to be reconnected cannot be explained by location or geographic distance from a service center. In fact, in several instances ZIP codes with some of the longest times to reconnection (shown outlined in dark blue) are directly adjacent to ZIP codes with some of the shortest times to reconnection (shown in light yellow). The primary difference we found between these two pairs of ZIP codes is median household income.

The median household income throughout SoCal Gas's service territory is $59,539. The median household income of the ZIP codes with the longest time to reconnection is $34,648, almost $25,000 less than the median household income in the whole service territory.

Time to Restore Service: SoCal Gas

Median Household Income	
Total Service Area	$59,539
10 ZIPS With Longest Time to Restore Service	$34,648

Source: Utility ZIP Code Data and 2011-2015 American Community Survey, US Census Bureau

The racial and class disparities in SoCal Gas's reconnections are also clear when we look at the racial makeup of the 10 ZIP codes with the longest time to reconnection. While 33% of the total service territory's population is white, the white population makes up only 24% of ZIP codes with the longest time to reconnect. The Latino population makes up about half (47%) of the service territory, yet Latinos comprise 62% of the population in ZIP codes with the longest time to reconnection.

Policy Challenges

There are several reasons a person's utility bill can become unmanageable. For the majority of people who fall behind on their bills, energy is simply priced beyond reach. However, there are other important factors that contribute to a person's inability to pay.

Bill volatility makes monthly budgeting difficult

No bill is subject to as much volatility as a utility bill. Unlike monthly payments for rent, car, phone, and cable service, utility bills can increase by hundreds of dollars from one month to the next, making it difficult to predict and budget for this expense.

Late and missed payments run up back bills

When faced with a larger-than-usual bill or when managing another unforeseen financial crisis—such as an illness, job loss, or a car breaking down—customers will sometimes miss a payment or pay less than the balance due with the hope of catching up in the future.

Health needs can increase energy usage

Sometimes additional energy usage is unavoidable, for example, when a family brings home a newborn baby, or when a family member becomes ill. Use of medical devices like nebulizers, dialysis machines or other equipment can dramatically increase monthly utility bills.

Deposits put people behind and keep them behind

Customers may be charged a deposit equal to two months of the home's average usage if they have bad credit, no credit, a past disconnection, or pay their bills late for multiple months.

Being forced to pay someone else's bill is unfair

Sometimes utilities will charge a customer for energy use that belongs to somebody else, such as forcing a new tenant to pay the bill left by the previous tenant. Investigations conducted by utilities are done in secret without due process to review or respond to the findings.

Meter or billing errors cause large back bills

Utilities will sometimes surprise customers with corrected bills covering several past months, without informing customers that they cannot be held responsible for more than 3 months of corrected bills due to a meter error or a billing error.

Utility bills are just too high for many people

The bottom line is that utility bills are unaffordable for an increasing number of California residents. For instance, between 2010 and 2017, the average monthly electricity bill for a PG&E customer skyrocketed 50% from $77 to $117.[11]

Legislation results in significant rate increases

Bills adopted by the legislature cause significant increases in monthly bills by requiring CPUC approval for utility ratepayer investments in electric vehicle charging stations, distributed generation, battery storage, "smart" grid equipment, etc.

Policy Solutions

Utility data must be accurate, standardized, accessible, and usable

Utility companies must report accurate data across the data points they are required to file each quarter with the CPUC. Data should be filed in a standardized format across utilities. It should be filed in a manipulable format in addition to PDF. Data should be easy to find and download.

Provide due process to customers accused of falsifying information

Require that customers have the right to see results of a utility investigation that concludes that they previously occupied a home where they are starting new utility service. Currently customers have no right to challenge any evidence collected by utility investigators that result in a large back bill being applied to their account.

Adopt short term goal of 50% reduction in utility disconnections

Greening the grid should not come at the expense of cutting off disadvantaged communities from the grid. CPUC should exercise its authority to require utilities to modify their collection policies to reduce disconnections by 50% by 2020.

Punish utility companies for violating consumer protections

Impose significant fines on utilities that charge customers for energy that was used by someone else, such as previous tenants at the same address or a current roommate at a different address, as well as utilities that charge customers for more than three months of a back bill due to meter or billing errors.

Require utilities to increase participation in Medical Baseline

Develop protocols for increasing participation of people who are seriously ill or dependent on medical equipment to 80% of those eligible for Medical Baseline by contracting with public health departments that serve medically vulnerable communities.

Adopt debt management programs to eliminate back bills

Create affordable debt management plans that forgive 1/12th of a low-income customer's back bills for each month they pay their current bill. This allows customers to focus on their obligation to pay the current bill and, at the same time, work toward a clean slate.

Improve various distributed clean energy programs to reduce utility bills

Reduce energy usage, carbon emissions, and monthly bills by improving existing energy efficiency, demand response and solar programs to more effectively help families threatened with disconnections or who have experienced utility shutoffs.

Cap utility rate increases to no more than inflation

Limit the combined impact of statutory and regulatory increases in utility rates in any year to no more than the Consumer Price Index, or rate of inflation, in order to keep monthly bills in line with increases in salaries and social security benefits.

Aspire to providing universal utility service as a human right

Develop minimum payment plans that guarantee continuous utility service for any household that makes a monthly payment that corresponds to how much they can afford, regardless of the size of their bill.

Endnotes

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7. Franklin, Marcus, et al. "Lights Out in the Cold: Reforming Utility Shut-Off Policies as If Human Rights Matter." NAACP (March 2017). http://www.naacp.org/wp-content/uploads/2017/12/Lights-Out-in-the-Cold_NAACP.pdf.

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9. Ishimaru, Heather. "Fairfield family had power shut off." ABC 7 News (April 30, 2010). http://abc7news.com/archive/7416709/, Murphy, Kate. "Three killed in Oakland apartment fire." The Mercury News (December 29, 2010). https://www.mercurynews.com/2010/12/29/three-killed-in-oakland-apartment-fire/ and Yuriar, Norma. "Vigil for Oakhurst Family Killed by Carbon Monoxide." Fox 26 (January 18th, 2011). http://kmph.com/archive/vigil-for-oakhurst-family-killed-by-carbon-monoxide.

10. Because SDG&E's service territory is significantly smaller and serves only a fraction of the customers the other utilities serve, we examined only the 10 ZIP codes with the highest shutoff rates.

11. PG&E External Communications. "PG&E Proposes Simplified System of Electric Rates: Forty Percent Cut in Top Rate Would Limit Summer Bill Shocks." (March 23, 2010). https://www.pge.com/about/newsroom/newsreleases/20100323/pge_proposes_simplified_system_of_electric_rates.shtml and Gallegos, Sami. "Statewide rate hike for PG&E customers gets approval." ABC 10 (May 12, 2017). http://www.abc10.com/article/news/local/california/statewide-rate-hike-for-pge-customers-gets-approval/103-439113476.



Grassroots Community Partners Convene in Sacramento

City Heights Community Development Corporation
Rickie Brown, Barbara Nevarez, Rosie Ulloa-Sanchez, Gianna Ulloa

Fathers and Families of San Joaquin
Nikki Chan, Gilbert Martinez

TURN
Ana Montes, Gabriela Sandoval, Mark Toney

Housing Long Beach
Josh Butler, Maria Lopez

Leadership Institute at Allen Temple
Servant Brian K. Woodson

Poverello House
Robert Huerta

Alameda County Public Health Department
Tram Nguyen

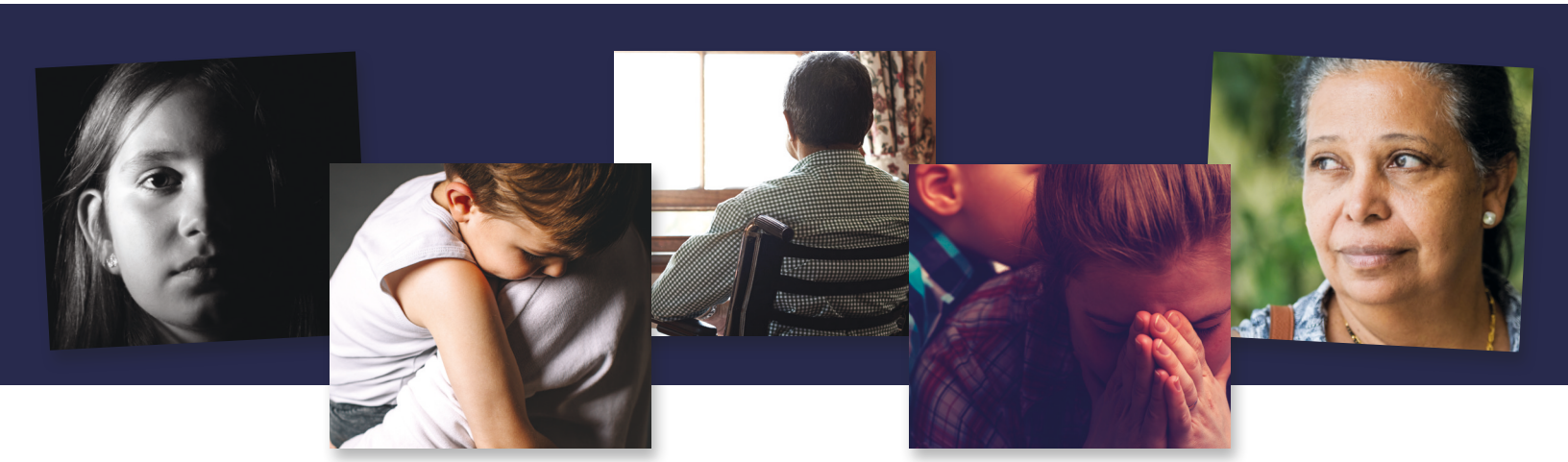
Congregations Organized for Prophetic Change (COPE)
Demita Burgess, Sky Smith

Spanish Language Interpreter
Norman Ospina

Centro La Familia
Lucio Avila, Victoria Santillan

Oakland Peace Center
Sandhya Jha

TURN believes no one should be cut off from essential electricity, gas or phone service. We hold utility corporations accountable by demanding fair rates, clean energy and strong consumer protections.



TURN

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