Energy+Environmental Economics

2020 ACC Workshop

Transmission and Distribution Avoided Capacity Costs

5/6/2020

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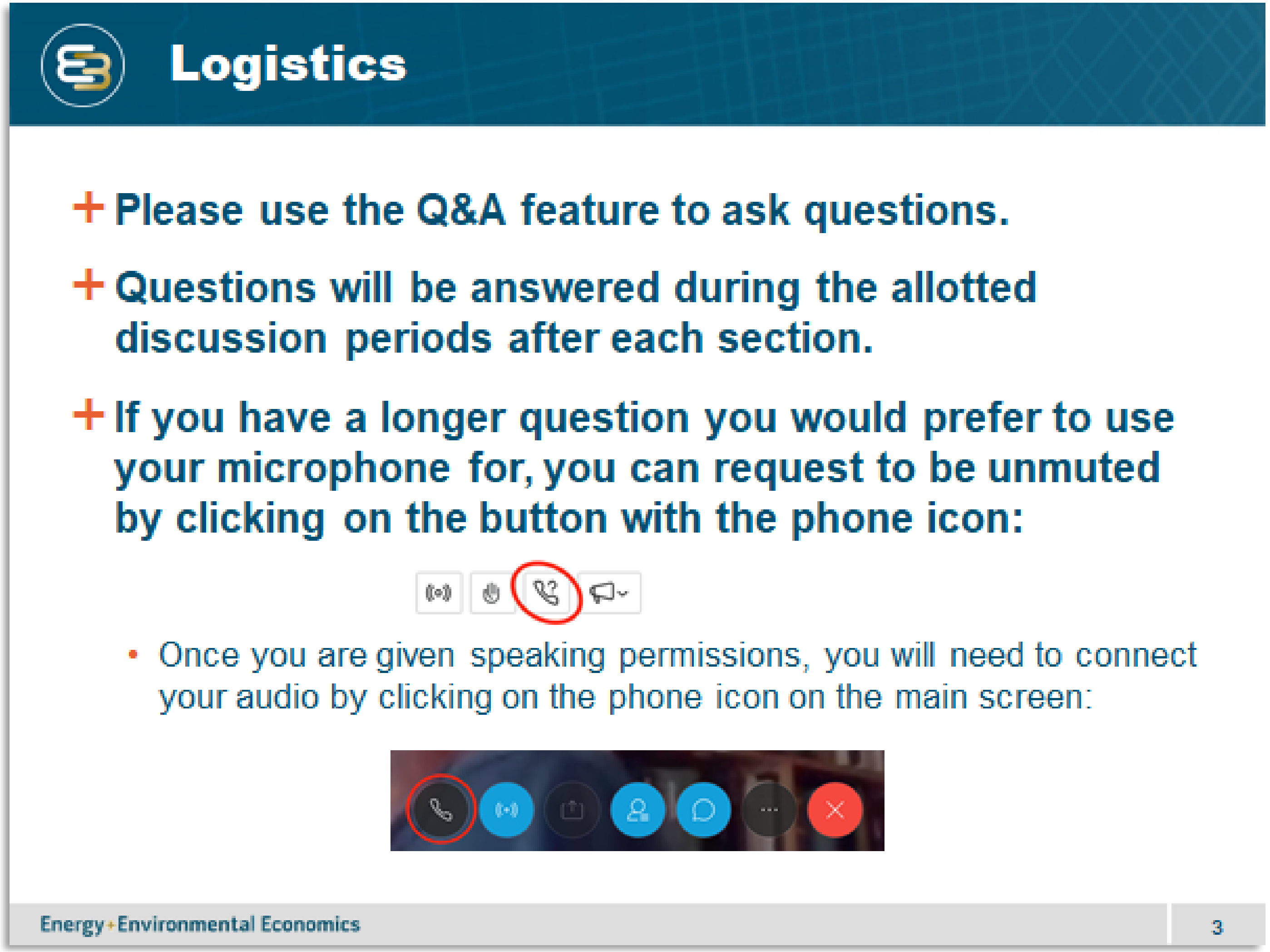
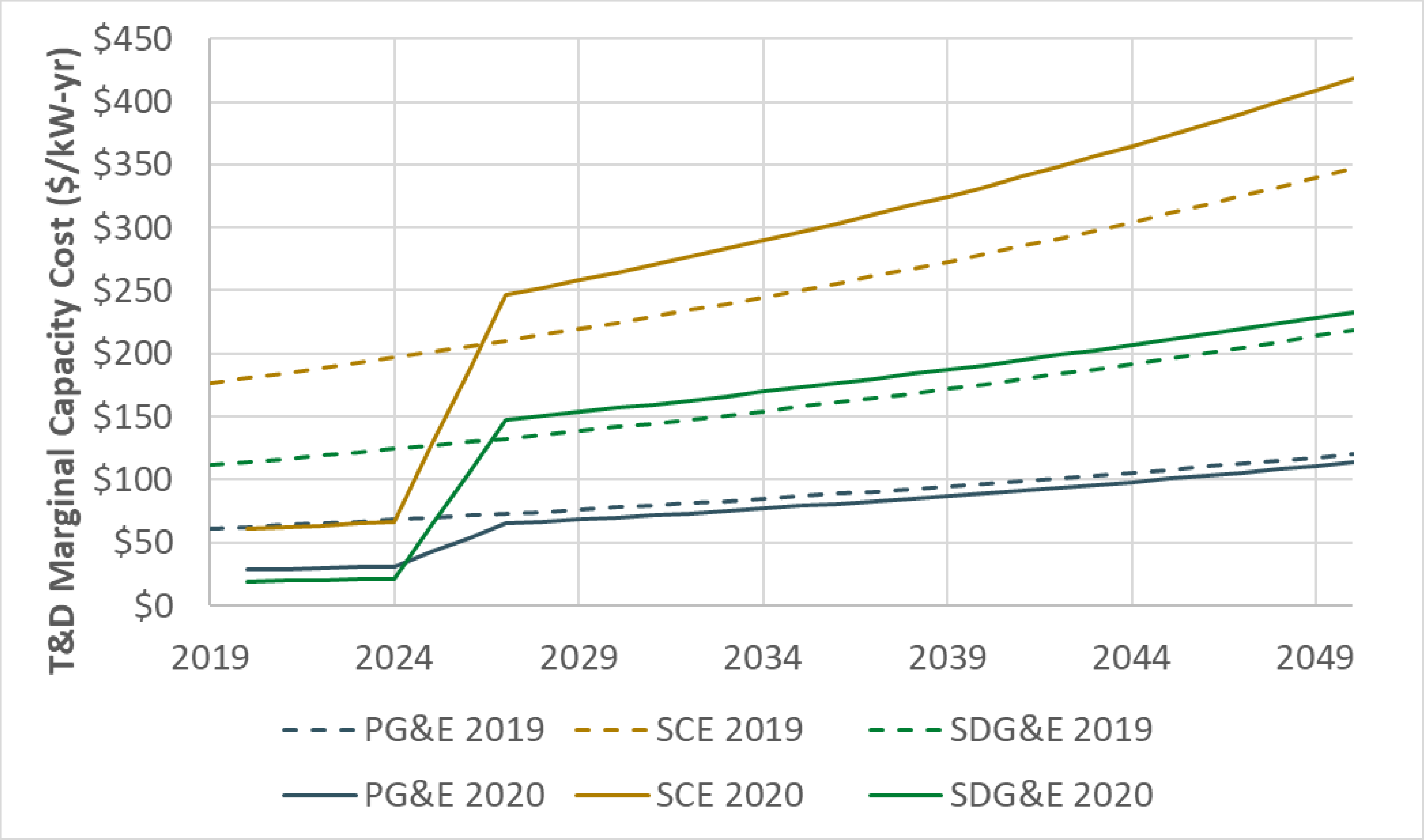
Agenda

- 2019 vs. 2020 T&D Value Comparison
- Transmission Value Updates and Methodology
- Distribution Value Updates and Methodology
- PCAFs and Day mapping



Comparison between 2019 and 2020 T&D Values



** PG&E numbers reflect Climate Zone 11*

Transmission Avoided Capacity Cost Background

+ **Potential cost impacts on utility transmission investments from changes in peak loadings on the utility systems**
+ **Does not address whether particular technology, measure, or installation could provide transmission avoided cost savings.**
+ **Simple system averages for each IOU**
+ **Transmission capacity in the prior ACC**
  - PG&E GRC Filing: $7.54/kW-yr ($2019, without losses)
  - SCE: $0
  - SDG&E: $0

Transmission Capacity ($/kW-yr) (2020)

PG&E	SCE	SDG&E
$11.75	$28.82	$14.44

PG&E Transmission

+ **Discounted Total Investment Method (DTIM)**
  - Present value of peak demand-driven transmission investments divided by the present value of the peak demand growth.
  - This unit cost is then annualized using a **marginal cost factor** that consists of the RECC with adjustments for other costs, such as A&G and O&M
+ **DTIM has a long history of use for marginal cost estimation in California**
+ **See section 9.1.1 for more detail**

$$TCap = \frac{PV(Demand\text{–}Driven\ Invests)}{PV(Load\ Growth)} * Annual\ MC\ Factor$$

Table 3: Marginal Transmission Capacity Cost (2021 $) at 5-Year Time Horizon

[A]		[B]
PV of Investment ($)	[1]	$206,142,713
PV of Load Growth (MW)	[2]	1,793
PV of Load Growth (kW)	[3]	1,793,203
Marginal Investment ($/MW)	[4]	$114,958
Marginal Investment ($/kW)	[5]	$115
Annual MC Factor	[6]	10.46%
Marginal Transmission Capacity Cost ($/MW-Yr)	[7]	$12,022
Marginal Transmission Capacity Cost ($/kW-Yr)	[8]	$12.02

SDG&E

- **DTIM method**
- **SDG&E load forecast could not be used (was negative growth)**
  - Replaced with IEPR without DER forecast
- **Analysis used 2021-2024**

Discount rate	7.14%	Dec 2020 after-tax WACC
Inflation	2.35%	
Real Discount Rate	4.68%	

Year	SDG&E Capital Expenditures ($M)	IEPR without DER based forecast: IEPR without DER Peak Load (MW)	IEPR without DER based forecast: Annual Peak Demand Growth (MW)
		4,571	
2020	46.28	4,540	(31)
2021	9.78	4,579	38
2022	5.82	4,636	58
2023	4.96	4,695	58
2024	3.44	4,749	54
2025	0	4,800	50
2026	0	4,845	45
2027	0	4,892	47
2028	0	4,938	46
NPV(2021-2024)	$21.85		185.63

SDG&E Transmission Calculation

+ **See section 9.1.3 for more detail**

PV of Investment ($M)	[1]	$21.85
PV of Load Growth (MW)	[2]	186
PV of Load Growth (kW)	[3]	185,629
Marginal Investment ($/MW)	[4]	$117,706
Marginal Investment ($/kW)	[5]	$117.71
Annual MC Factor	[6]	12.27%
Marginal Transmission Capacity Cost ($/kW-Yr)	[8]	$14.44

SCE Transmission Avoided Costs

+ **Combination of two methods**
  - DTIM for system-driven projects
    - Big Creek and Sylmar
  - LNBA for local-driven project, Alberhill

SCE Transmission Avoided Capacity Costs

	Marginal Cost ($/kW-yr)
System-wide projects	$5.07 / kW-yr
Alberhill project averaged over SCE system	$16.75 / kW-yr
Transmission O&M	$ 6.70 / kW-yr
Total	$28.52 / kW-yr

SCE DTIM Transmission Avoided Costs

+ **DTIM**
  - SCE load forecast showed negative growth
  - Replaced with median peak load growth from IEPR without DER forecast
  - DTIM covers five year period (2020-2024)
  - SCE MC Factor = 10.96%
    - Does not include O&M
  - DTIM = $17.68M/382.34MW * 1000 * 10.96% = $5.07/kW-yr

SCE Costs and Loads used for DTIM

	Project Cost ($M)			SCE Forecast		IEPR without DER based forecast		
Year	Big Creek	Pardee Sylmar	Total	Peak Demand (MW)	Peak Demand Growth (MW)	IEPR without DER Peak Load (MW)	Annual Peak Demand Growth (MW)	Median Growth (2020-2028)
				23825		25,137		
2020	5	0	5	23744	-81	24,970	(166)	91
2021	0	0	0	23806	62	24,919	(51)	91
2022	0	6	6	23795	-11	24,871	(48)	91
2023	0	10	10	23805	10	25,017	145	91
2024	0	0	0	23743	-62	25,093	76	91
2025	0	0	0	23671	-72	25,184	91	91
2026	0	0	0	23544	-127	25,295	112	91
2027	0	0	0	23460	-84	25,462	167	91
2028	0	0	0	23311	-149	25,650	188	91
NPV (2020 - 2024)			**$17.68**		**(68.90)**			**382.34**

Note:

IEPR Source: https://efiling.energy.ca.gov/Lists/DocketLog.aspx?docketnumber=19-IEPR-03

Real Discount Rate Used: 5.99%

SCE LNBA Transmission Avoided Capacity Cost

- LNBA method developed in the DRP proceeding to evaluate individual projects
- Alberhill is a high cost project driven by 7MW/yr of load growth
- LNBA applied assuming a one-year deferral due to a 7MW reduction in area peak net loads.
- The deferral value is then spread across the entire SCE service territory based on the Alberhill area's share of total SCE peak load.
- System average marginal cost = $17.05/kW-yr

1	Discount Rate	8.46%	
2	Inflation Rate	2.33%	
3	Real Discount Rate	5.99%	*(1+[1])/(1+[2]) - 1*
4	Planning Horizon (yrs)	10	
5	RECC	12.81%	*([1]-[2])/(1+[1])*((1+[1])^[3]/((1+[1])^[3]-(1+[2])^[3]))*

	Year	Project Cost ($M)	Peak Demand Growth (MW)	1 Yr Deferral Value ($M)	Deferral Value ($/kW)		
6	2020	50	7	2.83	403.70		
7	2021	1	7	0.06	8.07		
8	2022	1	7	0.06	8.07		
9	2023	9	7	0.51	72.67		
10	2024	69	7	3.90	557.11		
11	2025	85	7	4.80	686.30		
12	2026		7	0.00	0.00		
13	2027		7	0.00	0.00		
14	2028		7	0.00	0.00		
15	NPV using Real Discount Rate			12.15	1735.93		
16	RECC (From Above) [5]					0.13	
17	Present Value Revenue Requirement Factor (ED-SCE-001)					1.549	
18	LNBA Value ($/kW-yr) [15] * [16] * [17]						$344.63
19							
20	A&G (1.1%)					1.10%	$3.79
21	General Plant (6.9%)					6.90%	$23.78
22	Franchise Fees (1.1%% of all items above)					1.12%	$4.17
23	Plus O&M ($/kW-yr from ED-SCE-001)						$6.70
24	Total Project Marginal Cost ($/kW-yr)						$383.06
25	Percent of system load						4.45%
26	**Project Marginal Cost spread across the system**						**$17.05**

Other Transmission Capacity Cost Info

Allocation Factors

- 2019 ACC used the distribution allocation factors for PG&E transmission
- 2010 ACC updated to use generation allocation factors

Annual Transmission Escalation Factors

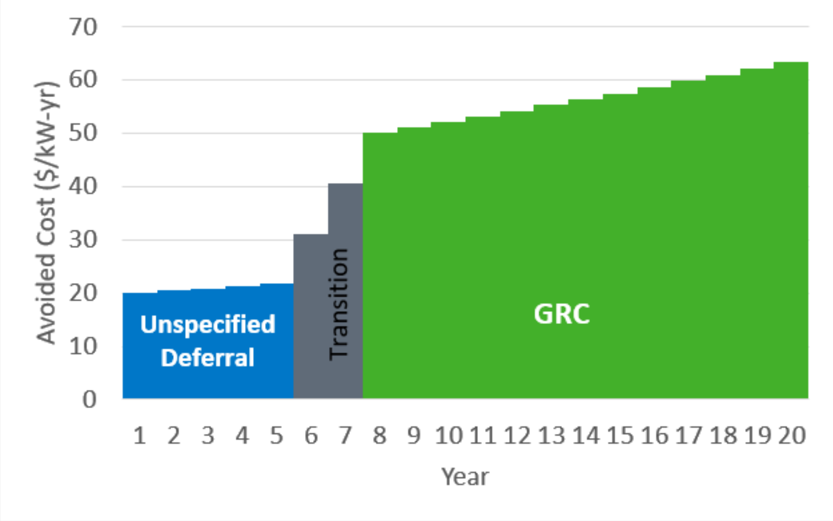
PG&E	SCE	SDG&E
2.34%	2.33%	2.06%

Transmission Capacity Loss Factors

PG&E	SCE	SDG&E
1.083	1.054	1.071

Distribution Capacity Costs

- **Three parts to the distribution capacity avoided costs**
  - GNA/DRP for the near term 2020 – 2024
  - GRC for 2027 and beyond
  - Linear transition for 2025-2026



		PG&E										SCE	SDG&E
	Climate Zone:	1	2	3A	3B	4	5	11	12	13	16	All	All
2020	Near Term	$14.85	$14.85	$14.85	$14.85	$14.85	$14.85	$14.85	$14.85	$14.85	$14.85	$29.81	$3.73
2021	Near Term	$15.22	$15.22	$15.22	$15.22	$15.22	$15.22	$15.22	$15.22	$15.22	$15.22	$30.51	$3.81
2022	Near Term	$15.60	$15.60	$15.60	$15.60	$15.60	$15.60	$15.60	$15.60	$15.60	$15.60	$31.22	$3.88
2023	Near Term	$15.99	$15.99	$15.99	$15.99	$15.99	$15.99	$15.99	$15.99	$15.99	$15.99	$31.94	$3.96
2024	Near Term	$16.39	$16.39	$16.39	$16.39	$16.39	$16.39	$16.39	$16.39	$16.39	$16.39	$32.69	$4.04
2025	Transition	$43.69	$42.85	$25.38	$17.42	$31.84	$35.99	$26.81	$22.66	$30.00	$34.67	$90.65	$44.15
2026	Transition	$70.99	$69.31	$34.37	$18.45	$47.29	$55.59	$37.23	$28.93	$43.60	$52.95	$148.61	$84.26
2027	Long Term	$98.29	$95.77	$43.36	$19.48	$62.74	$75.18	$47.65	$35.20	$57.21	$71.24	$206.57	$124.36
2028	Long Term	$100.75	$98.16	$44.44	$19.97	$64.30	$77.06	$48.84	$36.08	$58.64	$73.02	$211.39	$126.85

Near Term Distribution Avoided Capacity Costs

- **Based on the Energy Division White Paper**
  - Calculate the counterfactual forecast
  - Identify counterfactual capacity projects
    - Remove low cost/no cost solutions
  - Calculate the average marginal cost of remaining counterfactual projects
  - Calculate system level avoided costs *based on benefits from DER in project areas. but spread over all DER*

Near-Term Distribution Marginal Capacity Costs

	PG&E	SCE	SDG&E
Circuits only		$12.24	
B-Bank Substations		$12.30	
A-Bank Substations		$3.07	
Subtransmission		$0.86	
Total Distribution Capacity ($/kW-yr)	$14.49 ($2019)	$28.47 ($2018)	$3.66 ($2019)

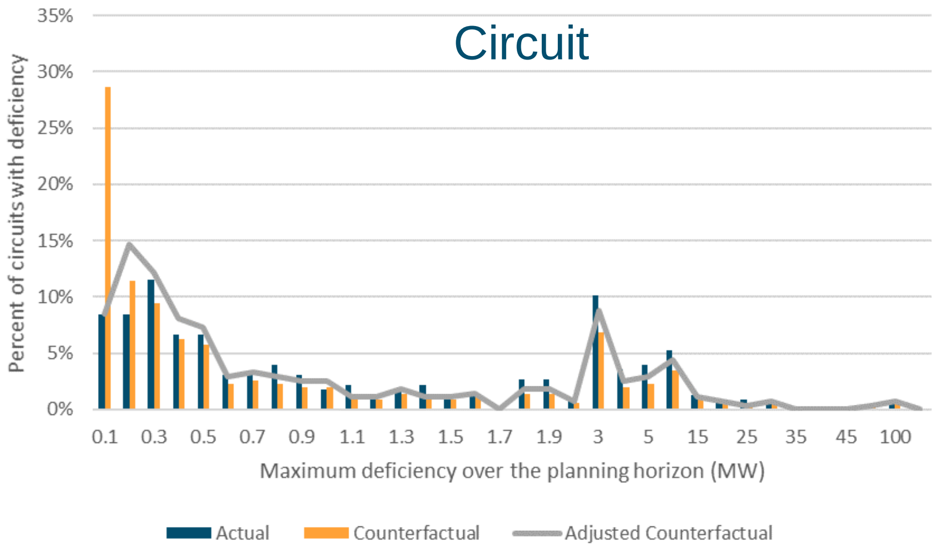
Near Term Distribution Calculations

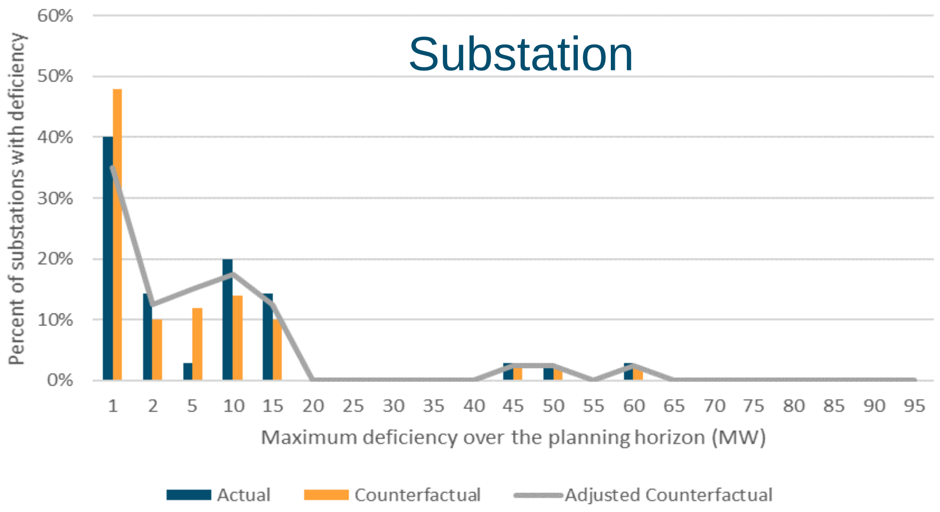
- [10] Unit cost
- [11] "Deferrable capital" is Unit Cost * Counterfactual overloads
  - Overloads are reduced by estimated low cost / no cost projects [4]
- [13] Deferral value per kW of DER is Line 11 divided by the total DER 5 –yr forecast
- Remainder applies RECC and adders

Line	Number of Overloads	PG&E	SCE-Substations (B-Bank)	SCE-Circuits	SDG&E	Notes:
1	Actual Overloads	224	35	226	11	[1]
2	Counterfactual Overloads	271	50	349	25	[2]
3	Number of Proposed Projects	180	N/A	N/A	10	[3]
4	Percentage of Overloads addressed by Load Transfers	20%	20%	20%	9%	[4] = 100% - ([3]/[1])
	Overload Capacity					
5	Actual Overloads (kW)	289,880	269,140	634,702	10,039	[5]
6	Counterfactual Overloads (kW)	349,018	286,660	643,360	25,320	[6]
7	Deferrable Counterfactual Overloads (kW)	280,461	229,328	514,688	23,018	[7] = [6] x (100% - [4])
	Project & Planned Investment Costs					
8	Total Cost of Planned Investments in DDOR Filing ($)	$390,416,858	$350,016,877	$288,412,287	$17,800,000	[8]
9	Capacity Deficiency that Planned Investments Mitigate (kW)	323,844	269,140	634,702	17,178	[9]
10	Unit Cost of Deferred Distribution Upgrades ($/kW)	$1,205.57	$1,300.50	$454.41	$1,036.21	[10]* = [8] / [9]
	System Level Avoided Distribution Costs					
11	Deferrable Capital Investment	$338,114,662	$298,241,326	$233,877,317	$23,851,370	[11] = [10] x [7]
12	5 Year Total forecasted DER (kW)	2,285,003	2,911,430	3,113,110	625,460	[12]
13	Distribution Deferral Value ($/kW)	$147.97	$102.44	$75.13	$38.13	[13] = [11] / [12]
14	IOU Specific RECC	9.79%	11.49%	11.45%	7.65%	[14]
15	Capacity Deferral Value ($/kW of DER installed-yr)	$14.49	$11.77	$8.60	$2.92	[15] = [13] * [14]
	O&M Distribution Costs					
16	O&M Deferral Value ($/kW-yr)	$0.00	$6.74	$21.98	$20.26	[16]
17	O&M Deferral Value ($/kW of DER installed -yr)	$0.00	$0.53	$3.63	$0.75	[17] = [16] * [7] / [12]
18	**Unspecified Marginal Cost ($/kW of DER installed-yr)**	**$14.49**	**$12.30**	**$12.24**	**$3.66**	[18] = [15] + [17]

SCE's Low Cost / No Cost Percentage

- **SCE's GNA data did not allow direct derivation**
- **Developed a proxy based on distribution of deficiencies using 20% percentile cutoff**
  - Comparing the actual (blue) and the counterfactual (orange) distributions shows the counterfactual having a much higher percentage of projects in the lowest two deficiency levels
  - Removing the lowest 20% of deficiency projects (gray line) brings the distribution closer to the actual distribution.





SCE Near-Term Subtransmission and A-Banks

+ SCE circuit and substation marginal costs are based on the White Paper method.
+ Subtransmission and A-Banks do not fit well with that paradigm because of the contingency-driven nature of such projects.
+ To address this gap, we include a fraction of SCE's long-term GRC-based subtransmission and A-bank marginal capacity costs in the near-term costs.
+ The fraction is the ratio of SCE Substation B-Bank counterfactual overloads to total DER reduction forecast over the five-year planning horizon (2019-2023).

Line		SCE-Substations (A-Bank)	SCE Subtransmission	Notes
[1]	Distribution Deferral Value ($/kW-yr)	$ 31.17	$ 8.77	From SCE GRC
[2]	Deferrable Counterfactual Overloads (kW)*	286,660	286,660	* Using SCE Substation B-Bank Values
[3]	5 Year Total forecasted DER (kW)	2,911,430	2,911,430	* Using SCE Substation B-Bank Values
[4]	Distribution Deferral Value ($/kW of DER - yr)	**$ 3.07**	**$ 0.86**	[4] = [1] * [2] / [3]

Long Term Distribution Capacity Costs

+ **Based on the GRC Hierarchy**
  - PG&E 2017 GRC Phase II
  - SCE 2018 GRC Phase II
  - SDG&E 2019 GRC Phase II

PG&E Long Term Distribution

- Varies by climate zone
- Total of Primary and Secondary marginal costs
- Division-level costs converted to wtd average Climate zone costs

J	K
Climate Zone	Wtd Avg Capacity Cost $/PCAF-kW-yr (Col I wtd by Col F)
1	$76.79
2	$74.81
3A	$33.87
3B	$15.22
4	$49.01
5	$58.73
11	$37.22
12	$27.50
13	$44.69
16	$55.65

A	B	C	D	E	F	G	H	I
Line No.	Division	Climate Zone	Primary Capacity $/PCAF-kW-yr /1/	Secondary $/FLT-kW-yr /1/	Total PCAF Loads (PCAF kW) /2/	Total FLT Loads (FLT kW) /2/	Secondary $/PCAF-kW-yr (E*G/F)	Total Distribution Capacity $/PCAF kW-yr (D+H)
1	Central Coast	4	$69.09	$1.04	823,510	1,759,256	2.22	$71.31
2	De Anza	4	$35.65	$1.01	741,675	1,234,311	1.68	$37.33
3	Diablo	12	$17.78	$1.56	1,265,169	1,524,487	1.88	$19.66
4	East Bay	3A	$19.99	$0.88	627,862	1,338,170	1.88	$21.87
5	Fresno	13	$39.52	$1.36	2,164,629	3,575,125	2.25	$41.77
6	Humboldt	1	$73.97	$1.12	292,803	736,437	2.82	$76.79
7	Kern	13	$34.07	$1.23	1,585,454	2,449,767	1.90	$35.97
8	Los Padres	5	$56.49	$1.06	492,381	1,041,742	2.24	$58.73
9	Mission	3B	$13.63	$0.97	1,233,354	2,022,915	1.59	$15.22
10	North Bay	2	$29.42	$1.75	647,540	1,283,383	3.47	$32.89
11	North Valley	16	$53.40	$1.26	742,213	1,324,624	2.25	$55.65
12	Peninsula	3A	$31.79	$1.06	766,475	1,436,434	1.99	$33.78
13	Sacramento	11	$40.91	$1.22	970,943	1,589,591	2.00	$42.91
14	San Francisco	3A	$40.41	$1.52	829,544	1,435,075	2.63	$43.04
15	San Jose	4	$40.12	$1.16	1,369,868	2,130,431	1.80	$41.92
16	Sierra	11	$30.65	$1.25	1,187,910	1,833,534	1.93	$32.58
17	Sonoma	2	$121.98	$1.28	544,454	1,147,401	2.70	$124.68
18	Stockton	12	$33.36	$1.34	1,207,506	2,114,747	2.35	$35.71
19	Yosemite	13	$60.18	$1.56	1,090,280	2,098,437	3.00	$63.18

/1/ From PG&E 2017 GRC Phase II, MCRev_GRC.xlsx. IN-Dist-Capacity MC tab

/2/ From PG&E 2017 GRC Phase II, MCRev_GRC.xlsx.OUT)PCAF-FLT Factors tab

SCE Long Term Distribution

- From 2018 GRC Phase II proceeding
- SCE also proposes the functionalization of its distribution marginal capacity costs into a peak component and a grid component.
- We are not making a distinction between peak and grid distribution capacity costs for SCE in this ACC update.
- This is consistent with avoided distribution capacity costs that have been used for SCE in prior ACCs.

	SCE Distribution Marginal Capacity Costs (2018$)
Subtransmission ($/kW-yr)	$40.00
Substation ($/kW-yr)	$25.00
Local Distribution ($/kW-yr)	$102.90
Total ($/kW-yr)	$167.90

SDG&E

+ **SDG&E 2019 GRC Phase II**

	SDG&E Marginal Capacity Cost ($2016)
Substation ($/kW-yr)	$22.05
Local Distribution ($/kW-yr)	$77.97
Total	$100.02

Other Distribution Info

+ Annual Escalation Factors

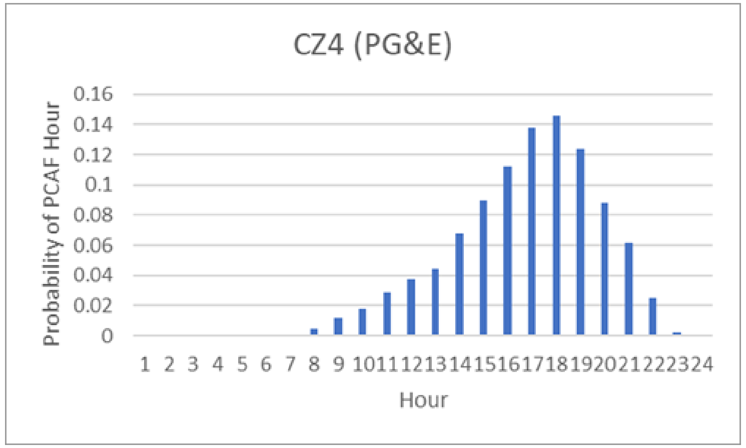
PG&E	SCE	SDG&E
2.50%	2.33%	2.00%

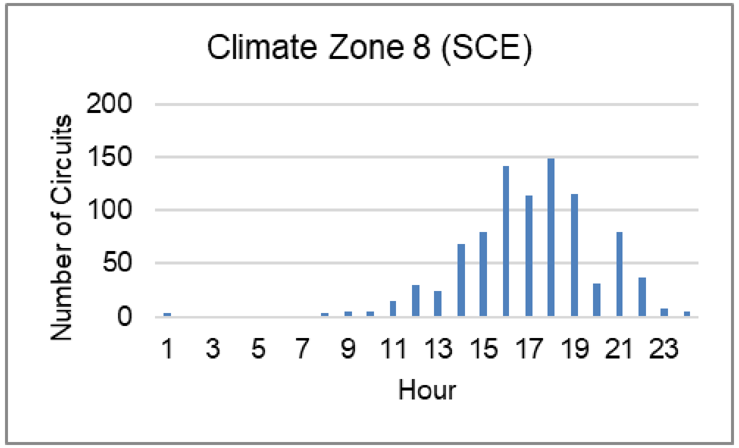
+ Loss Factors

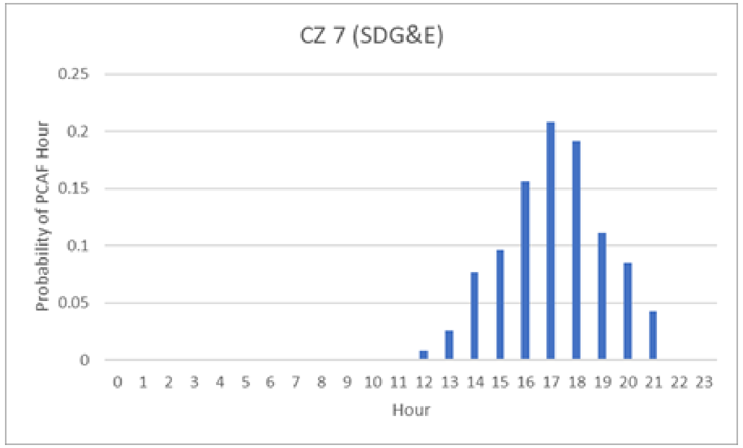
PG&E	SCE	SDG&E
1.048	1.022	1.043

Distribution PCAFs

- Annual capacity costs are allocated to hours of the year to allow the ACC to reflect the time varying need for capacity by using Peak Capacity Allocation Factors (PCAFs)
- Each IOU provided a set of allocation factors that were converted to normalized, hourly probability distributions
- Hourly PCAFs were then mapped to match the reference CTZ 22 Typical Meteorological Year using E3's daymapping routine



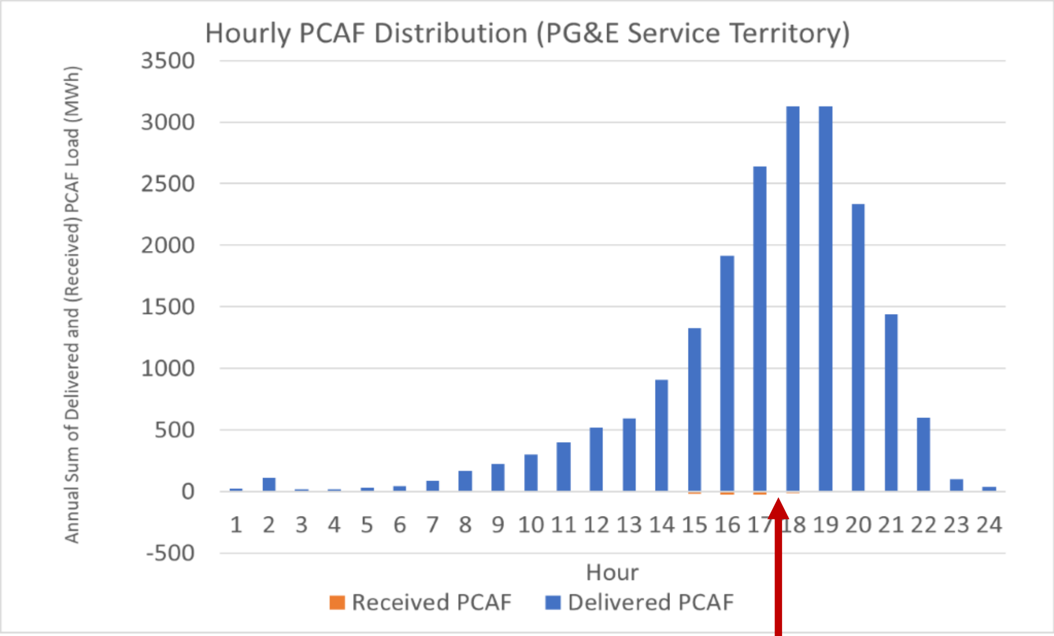




PG&E PCAF Normalization

- In its 2020 GRC Phase II proceeding, PG&E provided PCAFs by distribution area as well as a novel modification to its methodology which includes the impact of exports in the PCAF calculations
- While the concept of peak export hours has merit, the impact of exports on overall PCAF shapes were found to be negligibly small, and not included in the ACC for this cycle. In lieu of exports, E3 used the following formula to calculate normalized PCAF shapes, where h is each hour of the year

$$PCAF\ weight[h] = \frac{Delivered\ PCAF\ Load[h]}{\sum_{h=0}^{h=8760} Delivered\ PCAF\ Load[h]}$$



Exports have a negligible impact on total PCAF load hours

SCE PCAF Normalization

- The ACC utilizes the Peak Load Risk Factor (PLRF) analysis done by SCE in its 2018 GRC Phase II proceeding as a basis to generate normalized PCAFs
- SCE provided counts of circuits exceeding their planning threshold value by Climate Zone, and Date. For example, on Hour 21 of August 8th, there were 44 circuits over the threshold value in CZ6
- E3 then normalized each climate zone using the following formula, where h is defined as an hour of the year:

$$PCAF\ weight[h] = \frac{number\ of\ circuits\ over\ threshold\ [h]}{\sum_{h=0}^{h=8760} number\ of\ circuits\ over\ threshold\ [h]}$$

Raw Data from SCE PLRF analysis

Climate Zone	Peak Date	Peak Hour	Number Of Circuits
5	6Dec2018	22	1
5	2Jan2018	20	1
5	15Aug2018	16	1
5	29Dec2018	7	1
6	8Aug2018	21	44
6	6Jul2018	18	44
6	6Jul2018	19	33
6	6Jul2018	21	25

Heatmap from SCE PLRF Analysis

Hour / Climate Zone	5	6	8	9	10	13	14	15	16
1	0	3	4	6	6	2	1	1	2
2	0	0	1	0	1	2	0	0	0
3	0	1	0	1	0	0	1	1	1
4	0	0	0	1	0	0	1	0	0
5	0	0	1	1	0	1	0	0	0
6	0	1	0	2	0	2	0	0	1
7	1	1	1	1	2	2	4	0	0
8	0	4	4	2	4	9	3	0	5
9	0	5	5	3	4	3	4	1	5
10	0	9	5	4	7	3	1	0	6
11	0	7	14	13	4	3	4	1	3
12	0	16	30	8	8	5	3	0	2
13	0	17	24	16	33	2	9	1	2
14	0	34	69	49	59	6	7	3	3
15	0	52	79	80	62	12	24	10	6
16	1	59	142	119	130	17	19	32	9
17	0	72	114	213	179	28	49	41	7
18	0	71	148	141	184	36	56	60	14
19	0	69	115	87	90	35	62	21	37
20	1	71	31	20	20	31	27	9	27
21	0	121	80	27	17	13	28	2	22
22	1	42	36	17	2	6	7	2	5
23	0	9	8	4	5	4	4	0	0
24	0	8	5	0	1	1	3	3	1

SDG&E PCAF Normalization

+ SDG&E provided distribution level power flow data by climate zone, but did not provide a PCAF calculation, so E3 calculated PCAFs using the methodology using the following formula from the prior ACC:

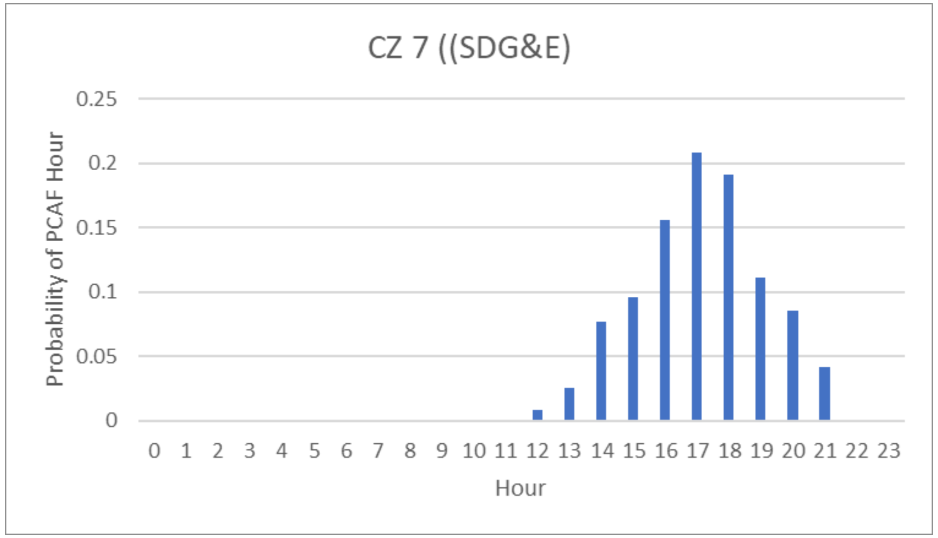
$$PCAF[a,h] = 1 + \frac{Load[a,h] - Threshold[a]}{\sum_{h=0}^{h=8760} |Load[a,h] - Threshold[a]|}$$

- a is the climate zone area,
- h is hour of the year,
- Load is the net distribution load, and
- Threshold is the area maximum demand less one standard deviation, or the closest value that satisfies the constraint of between 20 and 250 hours with loads above the threshold.
- Note that the denominator is an absolute value

Raw Data from SDG&E

CECClimateZone	LOAD_DATE	LOAD_HOUR	MW
7	1/1/2017 0:00	0	1066.86
7	1/1/2017 0:00	1	1091.04
7	1/1/2017 0:00	2	1039.16
7	1/1/2017 0:00	3	1003.04
7	1/1/2017 0:00	4	982.58
7	1/1/2017 0:00	5	986.47

Hourly PCAF Distribution



Day mapping Routine

- E3's Day mapping Routine was used to map PCAFs from an IOU provided weather year to the CTZ 22 index year
- The day mapping routine slotted each day of the year into season/workday "bucket" assigning each day a rank within each bucket based on its mean temperature
- For example, in the CTZ weather files shown to the right, 1/2/2020 was the 44th warmest winter workday
- For each bucket, the index date was matched to the corresponding (same-ranked) date in the IOU provided weather year

CTZ22 Temperature Metric Ranking (CZ4)

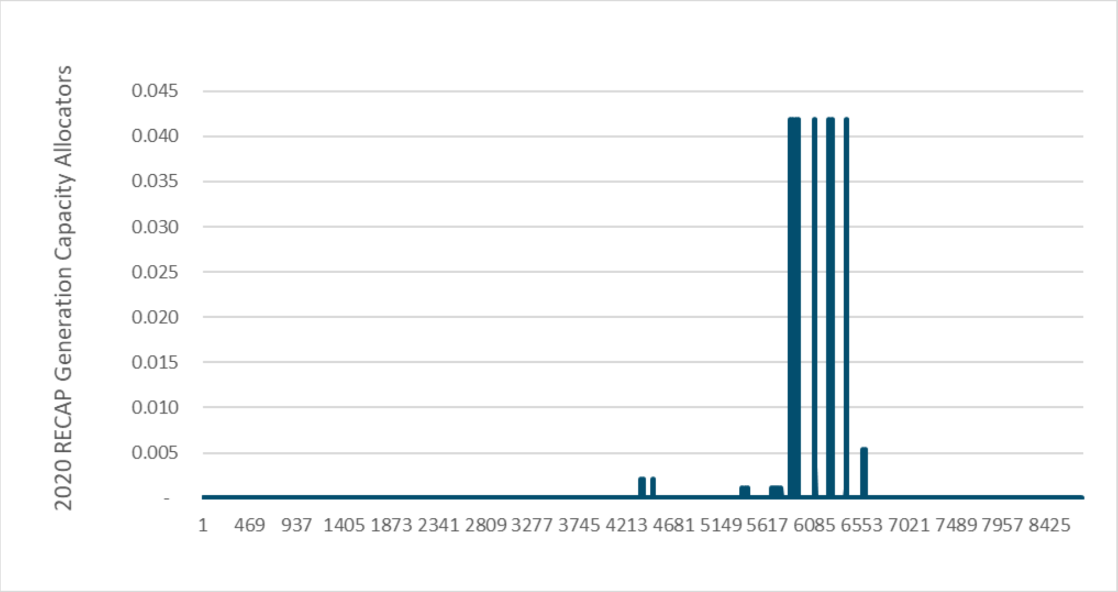
Index Date	Workday	Season	Rank
1/1/2020	0	Winter	10
1/2/2020	1	Winter	44
1/3/2020	1	Winter	59
1/4/2020	0	Winter	28
1/5/2020	0	Winter	27
1/6/2020	1	Winter	56
1/7/2020	1	Winter	16
1/8/2020	1	Winter	1
1/9/2020	1	Winter	13

Mapping Between Index and PG&E Data (CZ4)

Index Date	PG&E Weather Data	Classification	CTZ Rank	PG&E Rank
1/1/2020	2/18/2017	Winter Weekend	10	10
1/2/2020	12/7/2017	Winter Workday	44	44
1/3/2020	12/20/2017	Winter Workday	59	59
1/4/2020	1/28/2017	Winter Weekend	28	28
1/5/2020	12/17/2017	Winter Weekend	27	27
1/6/2020	2/23/2017	Winter Workday	56	56
1/7/2020	2/10/2017	Winter Workday	16	16
1/8/2020	2/8/2017	Winter Workday	1	1
1/9/2020	2/14/2017	Winter Workday	13	13

Transmission PCAFs

- **Transmission PCAFs were calculated using a three-step methodology**
  1. The E3 RECAP model uses 63 years of historical load and generation data to determine expected unserved energies (EUE) by month, hour, and weekday/ weekend
  2. A load-weighted daily maximum statewide temperature is calculated and EUE values are allocated to all hours in days where the system average temperature exceeds 90 degrees F
  3. EUE values are normalized into an 8760 profile, and day mapped to the CTZ22 temperature data and the 2020 calendar year for consistency with energy prices



Generation Capacity Allocation Factors

ay	jan	feb	mar	apr	may	jun	jul	aug	sep	oct	nov	dec
1	-	-	-	-	-	-	-	-	-	-	-	-
2	-	-	-	-	-	-	-	-	-	-	-	-
3	-	-	-	-	-	-	-	-	-	-	-	-
4	-	-	-	-	-	-	-	-	-	-	-	-
5	-	-	-	-	-	-	-	-	-	-	-	-
6	-	-	-	-	-	-	-	-	-	-	-	-
7	-	-	-	-	-	-	-	-	-	-	-	-
8	-	-	-	-	-	-	-	-	-	-	-	-
9	-	-	-	-	-	-	-	-	-	-	-	-
10	-	-	-	-	-	-	-	-	-	-	-	-
11	-	-	-	-	-	-	-	-	-	-	-	-
12	-	-	-	-	-	-	-	-	-	-	-	-
13	-	-	-	-	-	-	-	-	-	-	-	-
14	-	-	-	-	-	-	-	-	-	-	-	-
15	-	-	-	-	-	-	-	-	-	-	-	-
16	-	-	-	-	-	-	-	-	-	-	-	-
17	-	-	-	-	-	-	-	-	2.71	-	-	-
18	-	-	-	-	-	-	-	-	83.96	3.14	-	-
19	-	-	-	-	-	-	1.78	2.69	107.24	2.12	-	-
20	-	-	-	-	-	-	-	-	69.15	0.30	-	-
21	-	-	-	-	-	-	-	-	37.73	-	-	-
22	-	-	-	-	-	-	-	-	8.37	-	-	-
23	-	-	-	-	-	-	-	-	-	-	-	-
24	-	-	-	-	-	-	-	-	-	-	-	-

2020 EUE from RECAP