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APPENDIX A

Staff Proposal

Energy Division Staff Proposal for 2020 Avoided Cost Calculator Update

Integrated Distributed Energy Resources Rulemaking (R.14-10-003)

Updated March 13, 2020

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1. Introduction

The Integrated Distributed Energy Resources (IDER) proceeding, R.14-10-003, recently commenced a process, as outlined in Decision (D.)19-05-019, to determine major changes to be made to the Distributed Energy Resource (DER) Avoided Cost Calculator (ACC) in 2020. The ACC determines the benefits of DERs such as energy efficiency and demand response. Those programs that undergo cost-effectiveness analysis depend on the ACC to accurately determine the benefits they provide to the electric grid. The ACC determines several types of benefits including avoided generation capacity, energy, ancillary services, GHG emissions, and transmission and distribution capacity.

Historically, the value of the generation capacity and energy that a DER could avoid is determined by estimating the hourly marginal cost of a natural gas generator, for every hour of the year over a 30-year period. However, Renewable Portfolio Standard (RPS) requirements and greenhouse gas (GHG) reduction goals have resulted in profound changes to the electric grid, so that natural gas generators are less likely to represent the marginal unit of capacity (since they are unlikely to be built in California in the future) or energy (since renewable units are more and more likely to be the marginal unit during many hours of the day).

Therefore, Energy Division staff (Staff) believes that the Commission needs to change the basis of the ACC. One possible change would be to simply replace the natural gas generator with another technology (or technologies), such as a storage battery. This would more closely align the ACC with Integrated Resource Planning (IRP) modeling results.[1] In fact, the Joint IOUs, in their October 7, 2019 IDER testimony, have proposed this. However, Staff proposes that a better approach would be to align the ACC even more closely with IRP, by using IRP modeling outputs as inputs to the ACC.

The Commission has clearly expressed its intent that all electricity resource procurement be guided by the IRP process. Following this direction Staff proposes that in line with that effort, we align the data, models and methods used for IDER cost-effectiveness with the data, models and methods used in IRP. Staff sees alignment between the ACC and IRP as inevitable, with the main questions being timing and feasibility. Thus, the main question left regarding IRP-ACC alignment over the short term is whether it is feasible to implement this proposal in time for the 2020 Avoided Cost Calculator update.

Staff turned to its consultants, Energy + Environmental Economics (E3) to answer these questions. E3 and Staff have prepared this proposal to examine the details of aligning IDER and IRP, so that stakeholders and the Commission can judge whether it is reasonable to make the major changes to the Avoided Cost Calculator described in this proposal in 2020.

1.1. Overview of Proposed Avoided Cost Calculator Update

The existing Avoided Cost Calculator is a product of the time in which it was developed and the priorities that existed in the post-California Energy Crisis period of 2003 and 2004. At the time, the approach was innovative and led the nation in decomposing area- and time-specific avoided costs for the evaluation of California's robust energy efficiency program. Since the original avoided cost framework was developed,

[1] CPUC Integrated Resource Planning Proceeding (R.16-02-007)

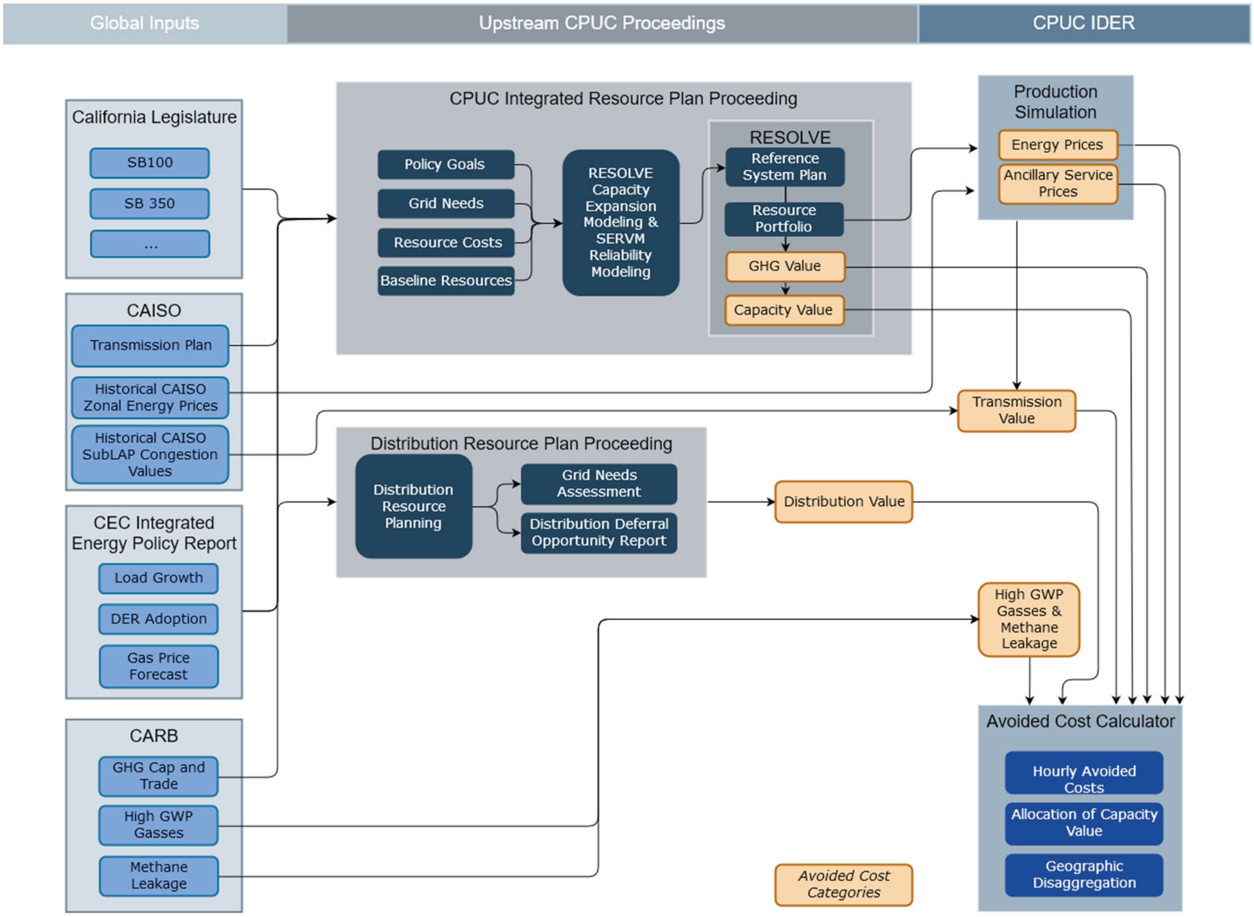
significant updates to the model to more closely reflect actual avoided costs have been adopted. The largest among these is the update to include avoided renewable generation and to incorporate the various GHG Adders, including the current one which was developed as part of the IRP process. In addition, many other smaller adjustments have been made as a response to evolving markets.

Nevertheless, the current approach does not reflect the value of DERs in this period of high renewable and clean generation capacity expansion in the state's plans required by SB 100, nor the wholly different operational regime of a highly intermittent renewable system, nor does it have a strong focus on GHG emission reductions. The "avoided" supply-side resource is now much more complicated than the fixed and fuel costs of a new combined cycle or combustion gas turbine. Therefore, to appropriately capture this value, Staff proposes a fully new approach that has a tight link to the IRP process where the costs and modeling of the avoided supply-side resources are being calculated and the least cost renewable portfolio is being selected for the system plan.

To appropriately value distributed energy resources a shift is needed, from avoided costs that are based on natural gas generation and utility transmission and distribution investment plans to a new framework focusing on avoided renewable generation, transmission and distribution planning with non-wires alternatives, flexibility, and resiliency. In addition, a central policy focus in California on reducing greenhouse gas (GHG) emissions will mean that it will be essential for any new framework to provide an accurate estimate of GHG impacts for all distributed energy resource types and include the value of reduced GHG emissions as a core component.

A high-level flow chart of the proposed 2020 ACC update process is shown in Figure 1. Policy directives are adopted by the state legislature and implemented through several state agencies, including the California Independent System Operator (CAISO), California Energy Commission (CEC) and California Air Resources Board (CARB) as well as the CPUC. A variety of information from these agencies provide inputs into the CPUC Integrated Resource Planning (IRP) and Distribution Resource Planning proceedings to guide electricity sector planning that supports the states policy objectives. For the 2020 ACC update Staff proposes to coordinate more closely with the IRP and DRP processes to support consistency in the evaluation of supply and demand side resources in the electric sector planning. The proposed process for translating CPUC IRP results into ACC inputs is covered in Sections 2-4 and for the DRP in Sections 5-6. The IRP will provide values for developing GHG and system capacity avoided costs, and the resource portfolio that will be used to develop energy and ancillary service avoided costs. The DRP will provide inputs for developing distribution avoided costs and Staff proposes to use CAISO congestion prices to develop transmission avoided costs. Finally, new avoided costs for high global warming potential (GWP) gas and methane leakage, using inputs from CARB.

Figure 1: Overview of Proposed 2020 ACC Update Process



2. IRP Coordination

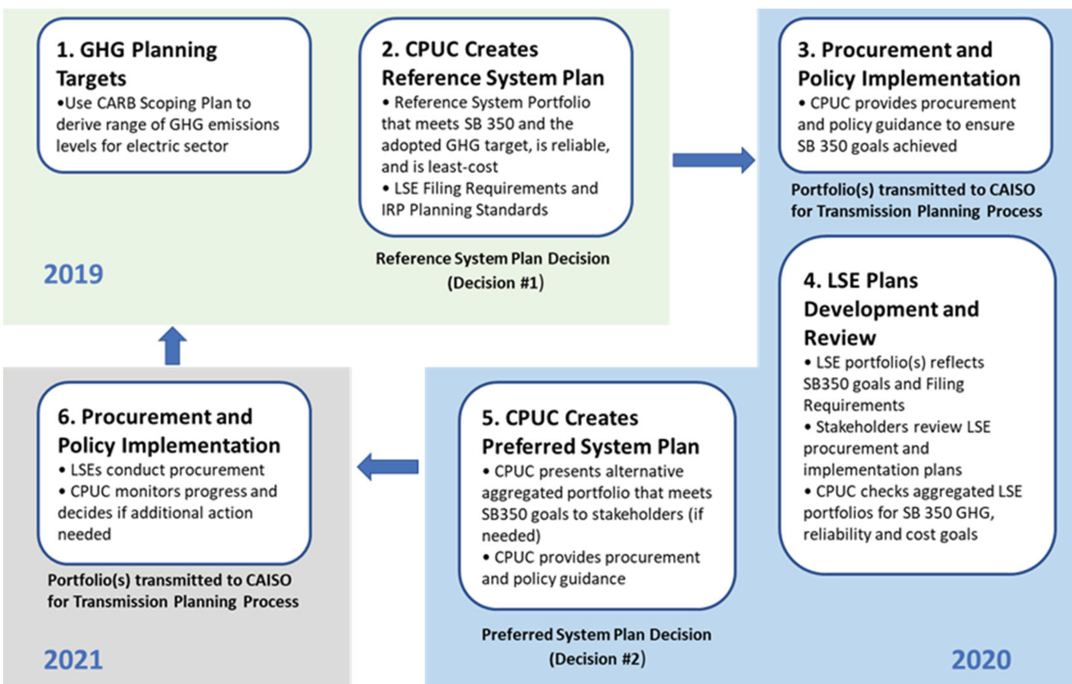
Generally speaking, the avoided costs developed for evaluating DER cost-effectiveness have always had a close relationship with supply-side resource planning. Utility resource planning typically involves lengthy and detailed modeling and stakeholder processes to develop a resource plan for investing in supply and demand side resources to meet anticipated needs. This resource plan represents the best thinking on how to reliably meet anticipated system needs at the lowest cost.

Avoided costs for DER are developed based on that resource plan to evaluate which DERs can meet system needs at a lower cost. System level planning over long time horizons necessarily requires that DERs be evaluated in aggregate with a high level of abstraction. Avoided costs provide a simpler and more transparent analysis and facilitate the evaluation of individual DER measures and programs in greater detail than is possible in supply side resource planning. This section describes the plan to more specifically coordinate the development of avoided costs with the CPUC IRP proceeding.

2.1. CPUC IRP Proceeding

The CPUC IRP proceeding (R.16-02-007) has established a biennial process to 1) Identify a diverse and balanced portfolio of resources needed to ensure a reliable electricity supply that provides optimal integration of renewable energy in a cost-effective manner and 2) have LSEs file integrated resource plans with the CPUC that accomplish specific goals, including meeting GHG, RPS, and reliability targets at least cost[2]. CPUC staff and consultants have been working in 2019 to develop a Proposed Reference System Plan (RSP) that will provide a safe, reliable and cost-effective electricity portfolio that meets California's GHG emission goals. A Reference System Plan is expected to be adopted by the CPUC in early 2020. This RSP is then passed to Load Serving Entities (LSEs) for use in development of their individual integrated resource plans. LSEs will then submit their individual integrated resource plans to the CPUC, which CPUC staff will review, potentially amend, and aggregate into a final Preferred System Plan (PSP) that is expected to guide resource procurement in the state beginning in 2021.

Figure 2: 2019-2020 CPUC IRP Process



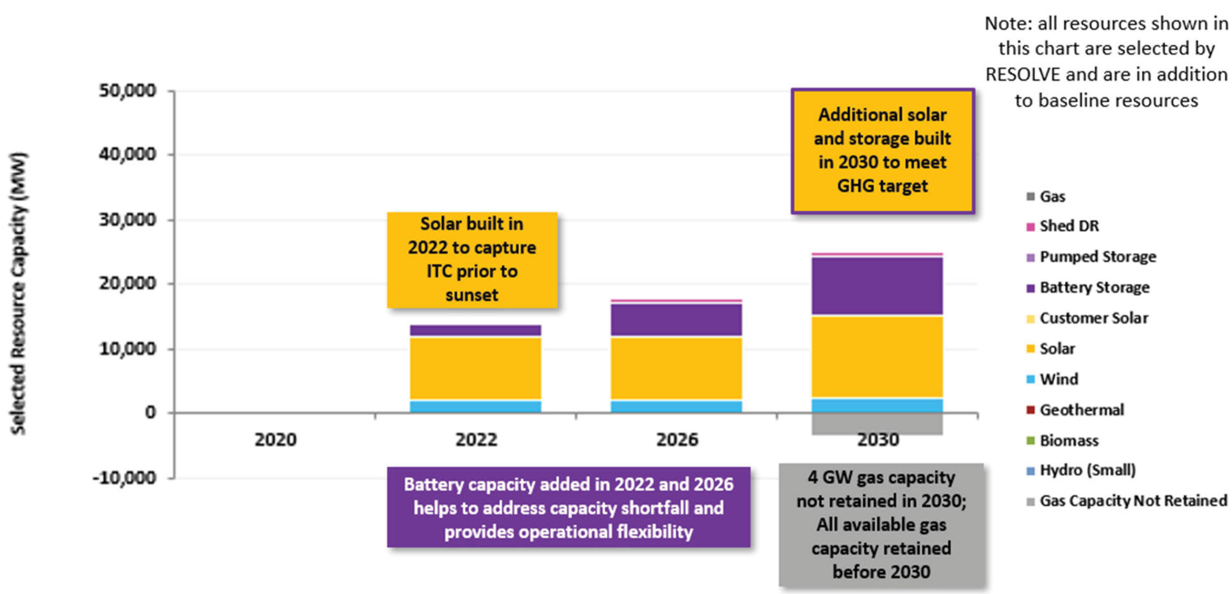
The 2019-2020 IRP Preliminary Results were presented at an informal workshop on October 8, 2019. They contained descriptions of the input and methodological updates from the previous IRP cycle, as well as preliminary results for the core policy cases and a variety several sensitivities.[3] The Preliminary Results will inform selection of the 2019 IRP Proposed RSP, expected to be issued in November 2019,

[2] For more information see the CPUC IRP webpage at: https://www.cpuc.ca.gov/irp/
[3] See CPUC 2019-20 IRP Events and Materials at: https://www.cpuc.ca.gov/General.aspx?id=6442459770 and the Preliminary Results Presentation at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/2019%20IRP%20Preliminary%20Results%2020191004.pdf

which is proposed to serve as the basis for developing inputs for this proposed 2020 Avoided Cost Calculator update.

The IRP uses the RESOLVE and Strategic Energy Risk Valuation Model (SERVM) models to identify least-cost portfolios of resources to meet California's electricity sector GHG emission targets under different assumptions. The RESOLVE model, a capacity expansion model developed by Energy Division's consultant E3, is used to select a least-cost portfolio of generation resources to meet future grid needs. The SERVM model is a probabilistic reliability planning model developed by Astrape that evaluates the loss of load probability for portfolios of generation and transmission resources generated by RESOLVE. The resources included in the 2019 IRP Preliminary Results 46 MMT case are summarized in Figure 2. This case includes 2.4 GW of wind and 12.6 GW of solar PV with 9.3 GW of battery storage and 440 MW of shed demand response (DR) in 2030.[4] This portfolio is considered adopted policy in the IRP proceeding, as it most closely resembles the 2017-18 IRP Preferred System Plan (PSP) 42 MMT case adopted in D.19-04-040.

Figure 3: New Resources Selected in 2019-20 Preliminary Results 46 MMT Case[5]



In the 2019-2020 IRP cycle, DERs are characterized by RESOLVE in two different ways. Generally, DER adoption is projected by California Energy Commission (CEC) Integrated Energy Policy Report (IEPR) demand forecast modeling and included as baseline resources in the Reference System Plan. A summary of the CEC IEPR mid case DER adoption projections for EE, PV, EVs and BTM storage are shown in Table 1. In addition to baseline resources, some DER are also provided to RESOLVE as candidate resources, including BTM PV, BTM storage, and shed DR, should the baseline resources in RESOLVE not be sufficient to meet future grid needs.

[4] Shed DR is the traditional type of DR that reduces load during peak system hours.
[5] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 52.

Table 1: DER resources included in 2019 Preliminary Results 46 MMT case[6]

Planning Area	PG&E		SCE		SDG&E	
Electric Demand Component [1]	2020	2030	2020	2030	2020	2030
Consumption, MW peak	22,838	25,760	25,353	28,753	4,825	5,517
Consumption, GWh load	111,274	123,640	110,047	123,337	22,123	24,691
Light-duty electric vehicles, GWh load	2,528	7,531	1,851	5,398	562	1,662
Time of use rate effects, GWh load [2]	-	23	-	13	0.03	2
Additional Achievable EE, GWh savings	2,939	12,949	2,881	14,108	572	3,029
Committed BTM PV installed cap MW	5,493	10,269	3,476	7,292	1,504	2,458
Additional Achievable PV installed cap MW	63	720	67	740	14	168
BTM storage installed cap MW [3]	122	469	167	566	65	198

2.2. No New DER Case

To quantify the avoided cost value of the DERs that are included in the RSP, Staff proposes that the IRP modeling include a "No New DER" sensitivity case of the RSP. Without the planned DER, RESOLVE will select more supply side resources to meet reliability and GHG targets, which will result in higher capital investment and annual operating costs. The difference in total revenue requirement between the Proposed RSP and No New DER case will provide a measure of the costs avoided with the DER included in the RSP portfolio.

For the No New DER case, Staff proposes to remove from the RSP portfolio all DERs in the RSP that are associated with utility incentive programs and incremental to the DERs installed up until 2018. Thus, EE, PV, BTM storage and other resources would remain at the 2018 level. All DR, which requires ongoing annual incentive payments, will be assumed to be zero. The same DER categories would also not be available as candidate resources for RESOLVE to select. The energy (GWh) and capacity (MW) assumptions for the RSP and the proposed No New DER case are summarized in Table 2 and Table 3. Given the IRP timeline for issuing the RSP, only one No New DER case may be possible in the IRP proceeding. If time and resources permit, additional sensitivities, for example running RESOLVE cases with and without just one specific type of DER (e.g., BTM PV), could in the future potentially be performed in the IDER proceeding.

[6] From IRP Modeling Advisory Group June 17, 2019 webinar presentation, slide 40, available at: https://www.cpuc.ca.gov/uploadedFiles/CPUCWebsite/Content/UtilitiesIndustries/Energy/EnergyPrograms/ElectPowerProcurementGeneration/irp/2018/IRP_MAG_20190617_CoreInputs.pdf

Table 2: Proposed DER Energy (GWh) Assumptions for No New DER Case

CAISO Sales Forecast Buildup	2018	2020	2025	2030
Energy Efficiency (GWh)				
CEC 2018 IEPR - Mid Mid AAEE	1,906	5,930	17,322	27,940
No New DER Case	1,906	1,906	1,906	1,906
Commited BTM PV				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	12,439	16,797	25,446	32,466
No New DER Case	12,439	12,439	12,439	12,439
Additional Achievable BTM PV				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	-	134	1,441	2,657
No New DER Case	-	-	-	-
Behind-the-Meter CHP (GWh)				
CEC 2018 IEPR - Mid Demand	13,594	13,637	13,648	13,595
No New DER Case	13,594	13,594	13,594	13,594
Non-PV Non-CHP Self Generation (includes storage losses) (GWh)				
CEC 2018 IEPR - Mid Demand	764	751	716	681
No New DER Case	764	751	716	681

Table 3: Proposed DER Capacity (MW) Assumptions for No New DER Case

BTM PV and BTM Storage Capacity from CEC 2018 IEPR	2018	2020	2025	2030
Commited BTM PV				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	7,269	9,694	14,387	18,555
No New DER Case	7,269	7,269	7,269	7,269
AAPV (Additional Achievable BTM PV)				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	-	134	843	1,511
No New DER Case	-	-	-	-
BTM Storage (MW)				
CEC 2018 IEPR - BTM Storage installed capacity	92	722	1,239	1,647
CEC 2018 IEPR - BTM Storage peak impact	(81)	(641)	(1,072)	(1,390)
No New DER Case	(81)	(81)	(81)	(81)
Load Modifying Demand Response				
Load-Modifying Demand Response: Mid Mid AAEE	(137)	(162)	(186)	(200)
No New DER Case	-	-	-	-
Capacity Contribution of BTM Resources Modeled as Supply-Side in RESOLVE				
BTM PV (MW peak reduction)				
CEC 2018 IEPR - Mid PV + Mid-Mid AAPV	3,532	4,408	5,859	5,641
No New DER Case	3,532	3,532	3,532	3,532
Baseline DR 1-in-2 Peak Load Impact (MW)				
DR 1-in-2 Load Impact (MW)				
Mid Case	1,617	1,617	1,617	1,617
No New DER Case	-	-	-	-

The No New DER case has not yet been run, but a high load sensitivity included in the October 8, 2019 workshop presentation illustrates the concept. Removing DER will have the effect of increasing load. The high load sensitivity does not remove DER, but does show the additional costs that would be incurred if load growth is higher than the forecast used in the Reference System Plan. The High IEPR baseline load trajectory in place of the Mid IEPR case in the Preliminary Results 46 MMT high load case results in an increased total cost of $793 million dollars per year.

Table 4: 2019-20 IRP Preliminary Results: Sensitivity Results[7]

"Incremental TRC" calculated relative to 46MMT Reference case (highlighted in orange)

	Incremental Cost ($MM/yr)		
Sensitivity	**46 MMT**	**38 MMT**	**30 MMT**
Reference	**$0**	**$589**	**$1,621**
Low RA Imports	$294	$840	$1,833
High RA Imports	-$141	$563	$1,579
Paired Battery Cost	-$461	$88	$1,008
High Battery Cost	$602	$1,451	$2,634
PV ITC Extension	-$330	$297	$1,152
High PV Cost	$614	$1,351	$2,441
Low OOS Tx Cost	-$37	$362	$1,125
New OOS Tx	-$32	$478	$1,268
High OOS Tx Cost	-$30	$513	$1,412
High Load	$793	$1,533	$2,608

The proposed 2019 RSP will be used as the basis for calculating avoided costs as described in the following sections. The avoided costs based on the proposed 2019 RSP will provide the marginal value for DERs that are in addition to those already included in the RSP portfolio.

The No New DER Case will provide two different measures of the avoided costs of the DER included in the proposed RSP. The increased revenue requirement of the No New DER Case is a measure of the supply side costs avoided by the proposed RSP DER portfolio. Staff propose to also calculate avoided costs based on the No New DER Case as a sensitivity. This information is included as an appendix in the 2019-20 IRP Proposed Reference System Plan, released on November 6, 2019 by an ALJ Ruling in the IRP proceeding (R.16-02-007).

2.3. RESOLVE IRP outputs for the ACC

This section describes the key IRP RESOLVE modeling outputs that will be used as inputs for the ACC. The charts below show the values for the 2019 Preliminary Results 46 MMT compared to the 2017-18 42 MMT reference case, as well as the values in the 2019 ACC. Note that the IRP results are provided in 2016 dollars whereas the ACC values are in nominal dollars. For the charts below we have converted the IRP results to nominal dollars. The 2019 preliminary results shown here may change substantially prior to the release of the Proposed RSP.

[7] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 85.

The 2019-20 IRP cycle includes several updates to inputs, models and methodology from the 2017-18 cycle. Energy Division's consultant E3 anticipates that in total, the 2019-2020 updates will result in lower modeled total system costs to achieve a given GHG emissions target, though the ultimate outcome will depend on final assumptions made for the proposed RSP. The primary updates resulting in lower costs are lower cost projections for solar and storage technologies. Other updates have increased the capacity value relative to the prior IRP cycle. The accelerated retirements of Once-through Cooling (OTC) plants as required by the State Water Resources Control Board to reduce the environmental impacts of high-volume water withdrawals has resulted in a need for new capacity. In addition, the quantity of imports allowed to count towards Resource Adequacy has been reduced from 10 to 5 GW in the preliminary 46 MMT case. Finally, the Effective Load Carrying Capacity (ELCC) for energy storage of a given duration is now modeled to decline over time as the quantity of solar generation increases.[8]

RESOLVE calculates a shadow price for GHG emissions, which reflects the incremental capital and operating cost per ton of GHG to procure the resources necessary to avoid an additional ton of emissions. As in the previous IRP cycle, the GHG shadow price for the 2019 Preliminary Results 46 MMT case remains relatively low until 2030 when it reaches $150/ton in nominal dollars ($109/ton in $2016). The 2030 GHG shadow price is lower than the $301/ton in nominal dollars ($219/ton in $2016) for the prior IRP cycle due primarily to lower capital costs for solar and storage and in part because renewable generation is procured earlier for reliability needs.

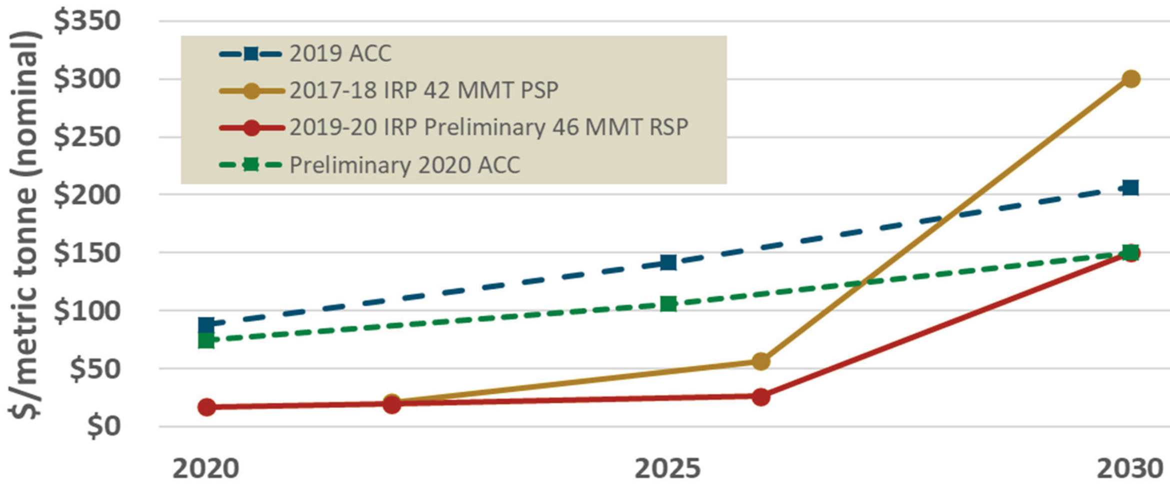
The 2019 ACC uses GHG costs set forth in Table 6 of D.18-02-018 (in $2016). These costs are developed from the RESOLVE GHG shadow price for the initial 42 MMT RSP trended back to a 2018 cap and trade price. The adopted 2017-18 42 MMT Preferred System Plan (PSP), however, incorporated an update to use forecasts from the 2017 CEC Integrated Energy Policy Report (IEPR) (whereas the Reference System Plan had used 2016 IEPR forecasts). This update changed the resulting GHG shadow prices in RESOLVE, as shown in Figure 4, below, in which the 2019 ACC (dashed blue line) and 2017-18 PSP (gold line) reflect different GHG cost trajectories and end points.

Figure 4 also reflects the GHG shadow price from the 2019 Preliminary Results 46 MMT case (red line), as well as preliminary 2020 ACC emissions costs (dashed green line). For the preliminary 2020 ACC trajectory, the Preliminary Results 46 MMT GHG shadow price in 2030 of $150/ton is discounted back to 2020 and 2025 using a nominal discount rate from the 2019 ACC (~7.3%). Note that this proposed 2019 Preliminary Results 46 MMT case may be updated prior to the adoption of the final RSP expected in early 2020. The 2020 ACC update proposes to use values from the final RSP to reflect emissions costs in the 2020 ACC.

The 2017-18 42 MMT PSP showed excess reserve margin for the full planning cycle, resulting in zero value for additional capacity resources. The 2019 ACC employs the current resource balance year approach for DER, assuming a capacity value at the Cost of New Entry for a combustion turbine starting at $112/kW-yr in 2020 and increasing to just over $150/kW-yr in 2030.

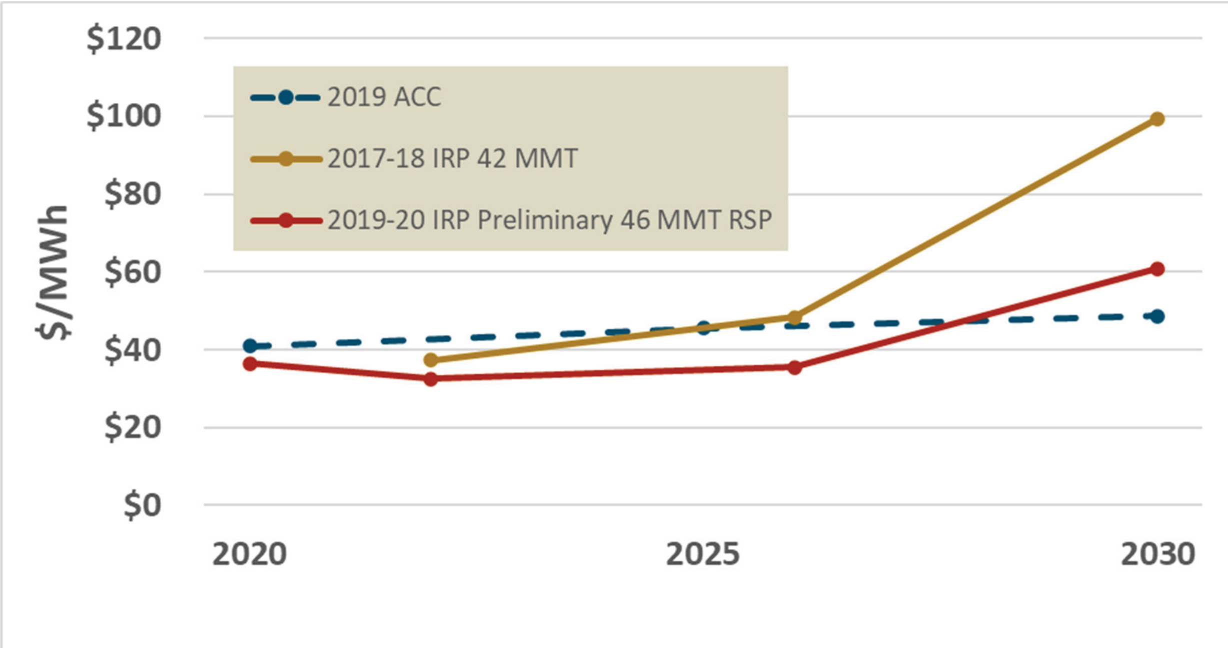
[8] See the IRP documentation referenced above for more detail on these and other IRP updates.

Figure 4: GHG Value ($ nominal)



The proposed energy value in the ACC is not a direct input from the IRP. Rather, Energy Division's consultant E3 recommends performing production simulation with the resource portfolio from the RSP to quantify energy values for DER (described in the next section). For purposes of comparison only, Figure 5 shows indicative annual energy values from 2017-18 and 2019-20 IRP modeling. Figure 5 shows the average annual energy value from RESOLVE, which are calculated as the hourly energy prices weighted by total load in each year. In 2022 the average annual energy price in RESOLVE modeling has decreased from $37/MWh to $32/MWh. In 2030 the reduction is much larger, from $99/MWh to $61/MWh. For comparison, the chart includes the average annual energy value from the 2019 ACC, which increases from $41/MWh in 2020 to $49/MWh in 2030. These preliminary RESOLVE results suggest that the energy prices produced with production simulation of the 2019 Preliminary Results 46 MMT case as described in the next section may be lower than those of the 2019 ACC, at least through 2026, and likely higher thereafter.

Figure 5: Energy Value ($ nominal)



Staff recognizes that implementing this proposal, which is a market-based approach to estimating avoided costs, is conceptually similar to returning to an older method of calculating avoided generation capacity costs, where the ACC included both short-run, market-based values, and long-run values, based on future construction costs. In 2016, the Commission decided to change to use only long-run avoided generation capacity costs in the Avoided Cost Calculator, thus eliminating the use of short-run avoided generation capacity costs. This means that the Resource Balance Year (RBY), which is defined as the point in time in which we switch from short-run to long-run avoided generation capacity costs, is currently always set at the current year. D.16-06-007 states:

> *We find that the current system omits Commission clean energy policies, such as the loading order and ignores grid planning processes. As discussed in detail below, this omission places distributed energy resources at a disadvantage to fossil fueled generation .*

Section 2.4 of the Decision goes on to explain in more detail why the generation capacity that DERs avoid is more appropriately represented by long-run, rather than short-run, capacity values.

Since that time, the question of alignment with other valuation methods, such as the Least Cost Best Fit (LCBF) method used for supply-side procurement and IRP models, has come up. Both IRP and LCBF consider both the short-run cost of generation, which is based on the current market price for capacity, and the long-run "cost of new entry (CONE)," which is based on the cost of building new generation facilities. If the Commission does decide to reconsider using only long-run costs it is important to consider the impact of any change in method on DERs and consider what can be done to alleviate the concerns raised in D.16-06-007. Staff welcomes party comment on this issue.

One of those concerns is that use of a valuation method which compares DERs to the short run value of capacity unfairly impacts demand response programs. Demand response cost-effectiveness analysis is done only over the lifetime of a demand response program, typically 3 years, which is generally well within the short-run timespan. Even the recent change from 3 to 5 years for demand response programs would not be likely to move much of the demand response value into the long-run period. Use of only short-run avoided capacity costs to value DR programs underestimates the value to the electric grid of having customers who are willing and able to reduce demand when needed, because once those customers are enrolled they are likely to continue in the program for more than 3 years, particularly if they invest in enabling technologies (which also will persist for more than 3 years).

Hence, this proposal requires a discussion of possible modifications to demand response cost-effectiveness analysis. For example, the Commission could consider if it is possible to develop a method for estimating demand response cost-effectiveness over an extended time period, such as the expected useful lifetime of enabling technologies. Questions that will be considered in a future update of the Demand Response Cost-effectiveness Protocols include:

- In the 10 or so years since the demand response cost-effectiveness methods were first developed, how have demand response programs, practices, and technologies changed?
- In that same time period, how much has the percentage of demand response participants using enabling technologies changed?
- Do technological changes require that we reconsider how we calculate demand response participant costs?
- Can we use the long-run supply costs of demand response developed in the demand response potential study and IRP modeling in the cost-effectiveness framework?

This will be taken up in the appropriate demand response proceeding.

2.4. RESOLVE Resource Portfolio for Production Simulation

RESOLVE selects a least-cost portfolio for the 2019 RSP. That portfolio would be used as an input in production simulation to generate hourly energy and ancillary services prices (described in next section). The resource portfolio from the 2019 Preliminary Results 46 MMT case is summarized below in

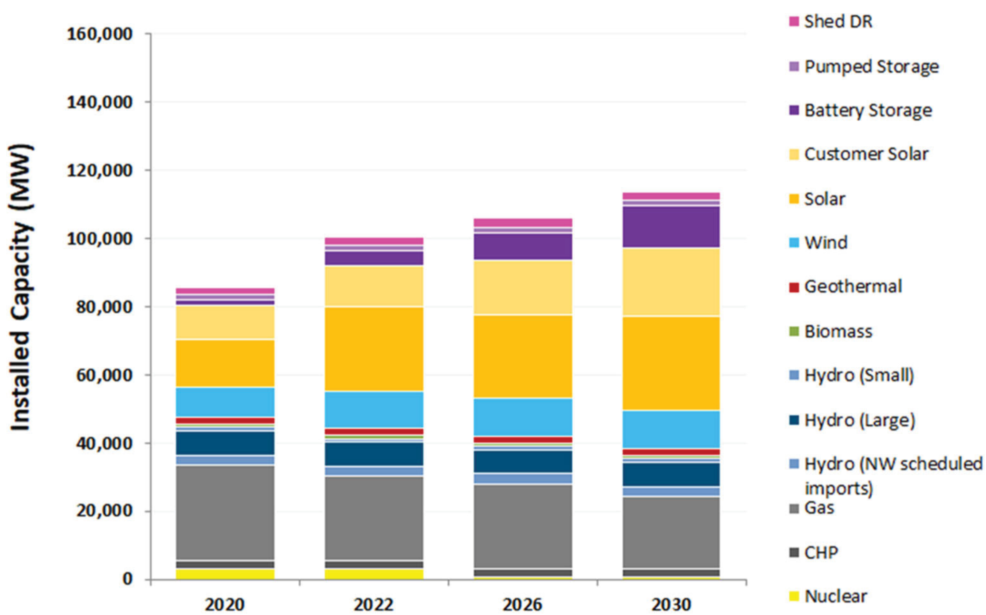
Table 5 and Figure 6. The energy balance from that resource portfolio is shown in Figure 7.

Table 5: Summary of 2030 Portfolio for 2018 Preferred System Plan and 2019 Preliminary Results 46 MMT case[9]

[9] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 82.

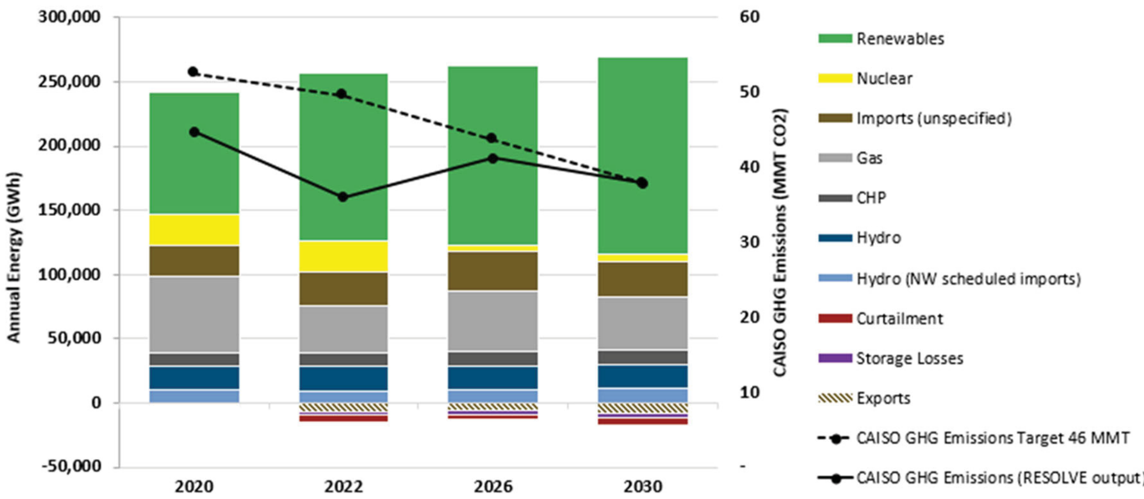
Metric	2017-18 IRP Preferred System Plan	2019 Preliminary Results 46 MMT
CAISO GHGs	34 MMT	37.9 MMT
Selected Resources (by 2030)	2.2 GW wind 5.9 GW solar PV 2.1 GW battery storage 1.7 GW geothermal	2.4 GW wind 12.6 GW solar PV 9.3 GW battery storage 440 MW shed DR
Selected Renewables *(on existing Tx)*	9.8 GW	15 GW
Levelized Total Resource Cost	$44.5 billion/yr	$46.3 billion/yr
Marginal GHG Abatement Cost	$219/metric ton ($2016) $301/metric ton (2030 nominal)	$109/metric ton ($2016) $150/metric ton (2030 nominal)
Planning Reserve Margin	22%	15%

Figure 6: Total Resource Portfolio for 2019 Preliminary Results 46 MMT case[10]



[10] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 61.

Figure 7: CAISO Energy Balance for Preliminary Results 46 MMT case[11]



3. Production Simulation

Prior ACC cycles have relied upon historical CAISO day-ahead hourly energy prices to provide shapes for forecasted 8,760 hourly energy prices. With the forecasted increase of renewable generation in California, historical prices are no longer a reliable indicator of future price shapes. Staff therefore recommend shifting to production simulation to develop forecasts of energy prices and hourly energy price shapes.

Production simulation is a widely used method of modeling the operation and associated costs of the power system, including the interaction between generators and transmission constraints. Users specify different combinations of assumptions and inputs that describe the electric grid and power needs, such as generator characteristics, fuel prices, load forecasts, weather, and dispatch constraints. Based on these inputs, production simulation models produce the least-cost operational outcomes that ensure sufficient supply to meet demand for all modeled time periods, while satisfying all constraints. Different scenarios and sensitivities can be designed to investigate the impact of different input assumptions on system operation and prices.

The CEC uses production simulation in developing time-dependent valuation (TDV) for evaluating cost-effective energy efficiency for California Title 24 building standards (Section 3.1). The process is quite similar in intent, though different in approach, to this proposed update to the ACC. In both cases, state policy makers are developing a set of avoided costs to evaluate and implementing programs to require/promote DER measures that are found cost-effective. Using production simulation for the 2020 ACC update will facilitate alignment and consistency in these two processes.

To highlight the importance of updating the ACC methodology to better reflect expectations of future price shapes, Figure 8 below shows the increase in spring solar generation on the CAISO system, and the impact on system operations. Years 2017-2019 show pronounced changes in system operation and price shapes with increased solar generation. Each dot represents a single hour for each day in March, April

[11] From 2019-20 IRP Preliminary Results Presentation, October 8, 2019, slide 65.

and May across hours of the day (from left to right). As solar generation increases, the 'duck curve' shape emerges in the net loads for 2017-2019. Thermal generation decreases overall, with a dual morning and evening peak in 2018 and 2019. Imports are significantly reduced mid-day, with exports of excess solar out of the state in 2018 and 2019. Most importantly, for purposes of developing avoided costs, the price shapes are dramatically different beginning in 2017. These changes illustrate the importance of capturing anticipated changes in the generation resource mix over time when developing avoided costs.

An additional advantage of employing production simulation is that it can also provide real-time energy and ancillary service prices, which have not been outputs of previous ACCs. Real-time energy and ancillary service values will reflect the value that dispatchable DERs can have in providing grid services.

There are a variety of production simulation models available, each with advantages and disadvantages. The CEC uses the PLEXOS model for its IEPR and Title 24 building standards. The CAISO is also using PLEXOS in developing transmission plans, so use of the PLEXOS model could provide some consistency across state agencies, although due to difference in the timing and purpose of each proceeding, it is not necessarily feasible for the Commission to use precisely the same PLEXOS model and cases as the CEC and CAISO. Energy Division staff use the SERVM production simulation model as part of the IRP process. Using the SERVM model would have the advantage that it is already fully integrated with the IRP modeling. Staff and its consultants E3, will determine in the near future which production simulation model is the most appropriate and feasible to use.

Note, while the proposed ACC would leverage RESOLVE outputs and assumptions to remain aligned and consistent with the IRP, RESOLVE is not a production simulation model and therefore does not directly produce the data needed to develop forecasts of future energy prices and hourly price shapes. A production simulation model will provide a useful complement to the resource portfolio outputs from RESOLVE.

Figure 8: CAISO Spring Solar Generation with Impacts on Net Load, Thermal Generation, Imports and Prices (X axis represents average of hours 01 – 24 for the months of March-May in each year)

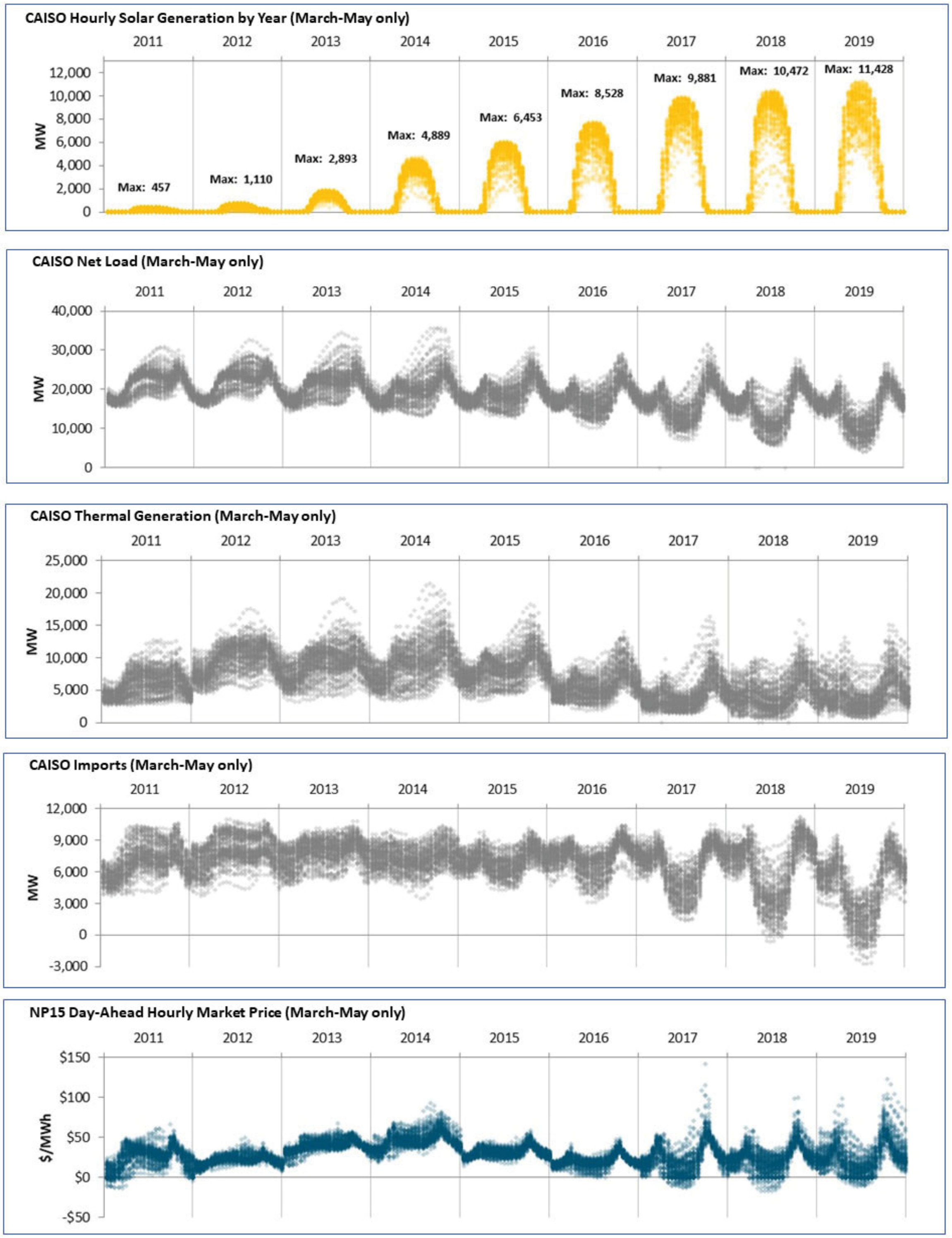
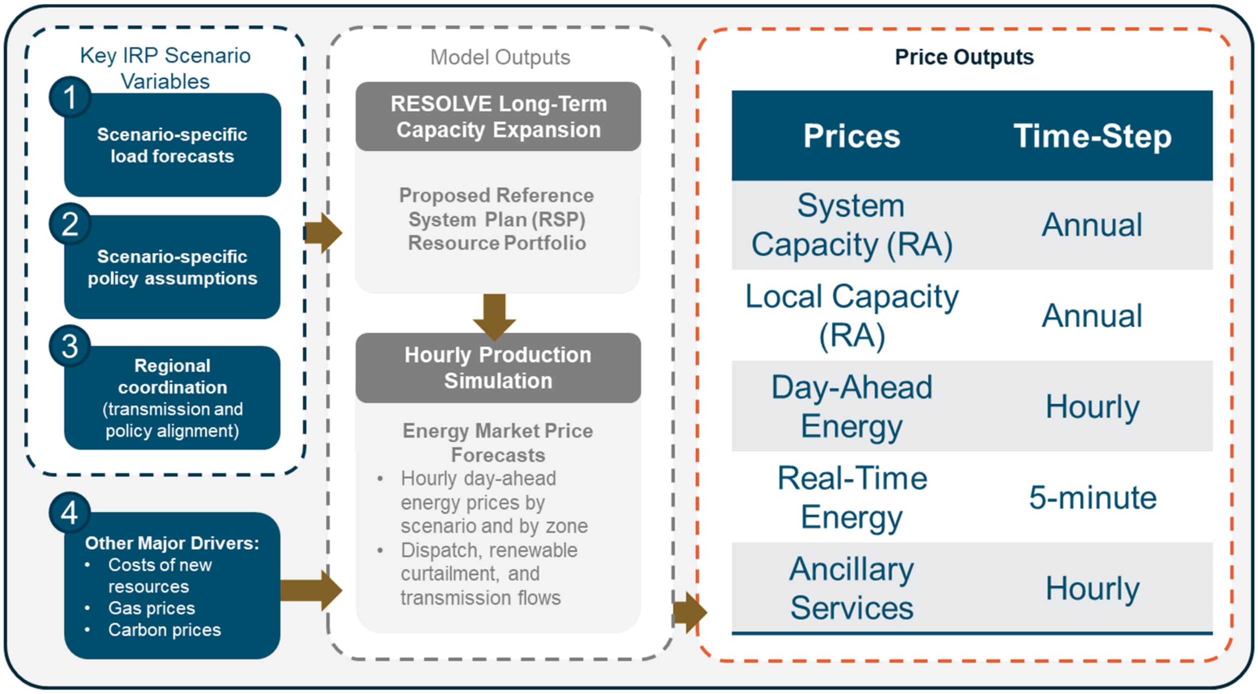


Figure 9: Overview of Proposed Production Simulation Process



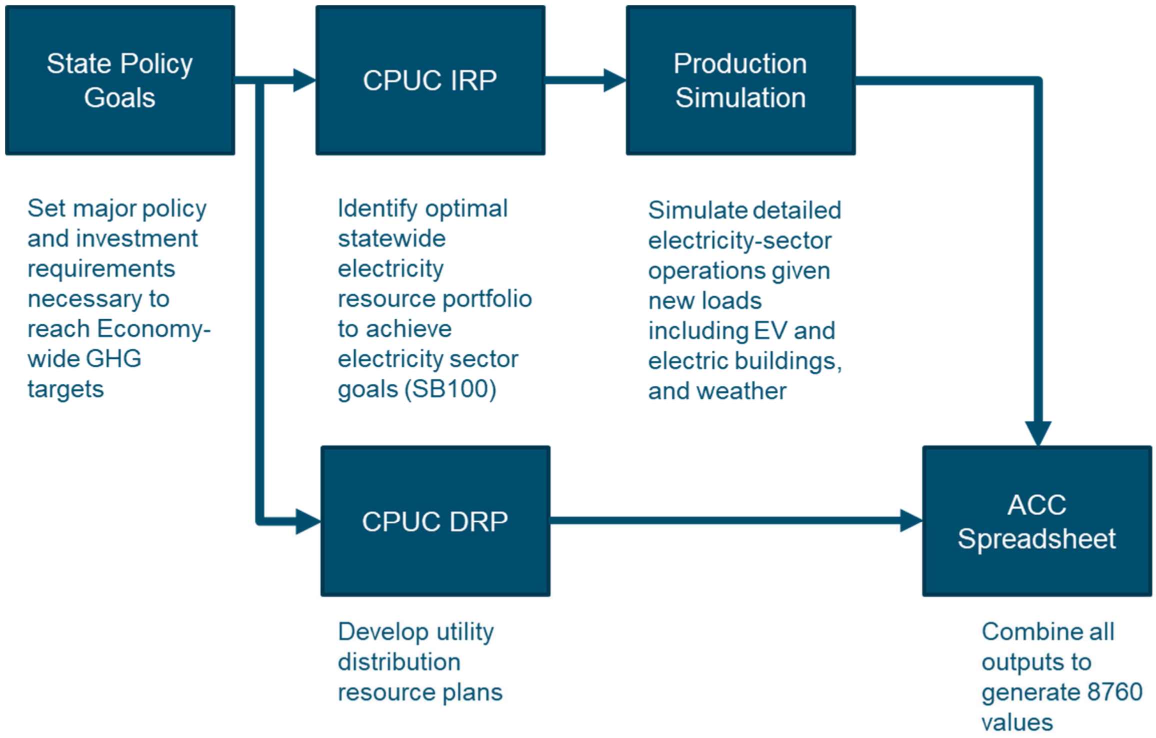
3.1. Example Production Simulation for Title 24 Building Standards

Every three years the CEC undertakes an update to the cost-effectiveness methods and calculator for time-dependent valuation (TDV) that is used to evaluate cost-effective energy efficiency for California Title 24 building. Both the CEC and CPUC are focused on developing policies to update their respective analytical approaches to appropriately and consistently evaluate load increasing (such as building and transportation electrification) and load reducing DER. Staff proposes that aligning the inputs, assumptions and approaches of the CEC ACC and the CEC Title 24 TDV proceedings will promote consistency in cost-effectiveness evaluation and efficient allocation of public funds to the most effective DER programs and measures. This alignment can be achieved while fully supporting the goals and policies adopted in the CPUC IDER proceeding.

Figure 10 shows the proposed CPUC avoided cost process, which is similar in concept to the CEC TDV process:

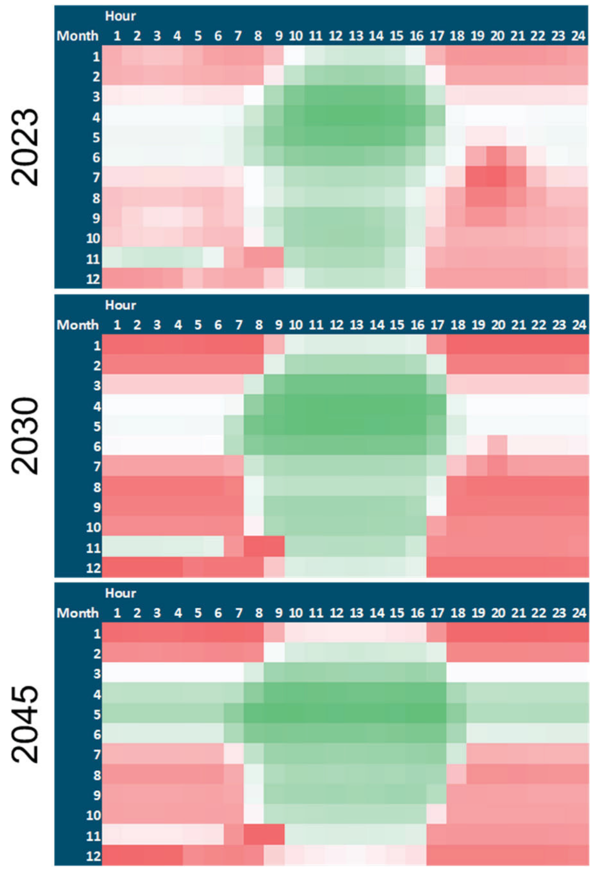
1. California state level policy goals guide the development of electricity sector resource plans.
2. RESOLVE capacity expansion modeling identifies least-cost resource portfolios for the electric section.
3. The selected resource plans are uses as the basis for production simulation modeling.
4. Production simulation modeling results feed into an Excel based TDV/ACC model that provides hourly values for DER for multiple categories.

Figure 10: Proposed CPUC Process for Developing Avoided Costs



Illustrative results from the CEC production simulation modeling are presented below for reference. The CEC ran production simulation for 2023-2030 and for 2045, interpolating results in between for the years 2023 – 2052. Illustrative heat maps of average hourly prices are shown in Figure 11 with lower priced hours in green and higher prices hours in red. This heat map shows how production simulation can produce price shapes base on changing electric generation portfolios over time.

Figure 11: CEC Production Simulation Modeling Energy Price Shapes Evolve with Changing Loads and Generation Mix



3.2. CEC Weather Year Matching

In this update of the ACC, Energy Division's consultant E3 recommends another step towards aligning California evaluation of DER cost-effectiveness, namely using the CEC's new California Thermal Zone 2022 (CTZ22) typical meteorological year (TMY) as the weather underlying the Avoided Costs. This CTZ22 TMY weather, adopted for the 2022 TDVs, will be used for the avoided cost components for which weather-driven load or generation affects the hourly variation of electricity costs.

The CTZ22 weather year was developed by Whitebox Technologies and Bruce Wilcox for the 2022 Title 24 Building Codes update.[12] The development of this weather year shares much of the same methodology as the typical weather year used in previous code cycles. For each month, the year whose weather is most "typical" for California is selected. This selection is done for the state as a whole, instead of by climate zone so that weather is consistent across climate zones. The defining difference between CTZ22 and previous weather years is that the historical weather is sampled from more recent years to reflect impacts of climate change. For areas outside of California, historical weather data from

[12] See presentations from Oct 17, 2019 CEC Workshop and methodology reports (forthcoming) under Dockets #19-BSTD-03 and #19-BSTD-04: https://ww2.energy.ca.gov/title24/2022standards/prerulemaking/documents/

the same month-years in CTZ22 are used to maintain simultaneous, consistent weather across the entire WECC footprint.

Using CTZ22 TMY weather matching and production simulation will align three key components that impact the shape and magnitude of energy prices: weather, load and DER impact shapes, and long-term forecasts. Several of the data sources developed with a significant, CEC-funded effort that can be consistently aligned with this process include:

- System Load Balancing Authority Area (BAA) data for WECC[13]
- Annual hourly electricity consumption for all-electric residential and commercial building prototypes and for selected electric water heating, space heating, cooking, and clothes drying end use shapes generated in CBECC-Res[14] and CBECC-Com[15] building simulation software
- Hourly wind generation profiles from multiple sources including NREL Western Wind[16], NREL Wind Toolkit[17], and Renewables Ninja[18]
- Simulated utility-scale PV generation profiles and historical NREL National Solar Radiation Database (NSRDB) data[19]
- Constructed database of Distributed Generation (DG) Solar PV for every county in the WECC using LBNL's Tracking the Sun dataset[20]

Energy Division's consultant E3 recommends continued examination of how assumptions, inputs and methods from the CEC TDV update process can be productively used in the CPUC 2020 ACC update process, erring on the side of maintaining consistency with the CPUC IRP as a first preference.

Other weather year files are available that could be used if parties suggest they are more appropriate. White Box Technologies also developed the CALEE2018 weather year.[21] However, CALEE2018 is more similar to the old CZ2010 TMY in that historical weather was sampled to be typical by climate zone instead of statewide as in the CTZ22. This results in the use of different years for different climate zones, which complicates production simulation modeling. In contrast CTZ22 year was designed to maintain historically consistent weather across the entire state, while representing typical weather as best as possible. The advantage of the CAL EE2018 weather year is that it uses the most recent 12 years of data, rather than the 20 years used for CTZ22, which may be a better basis for future changes in weather due to climate change.

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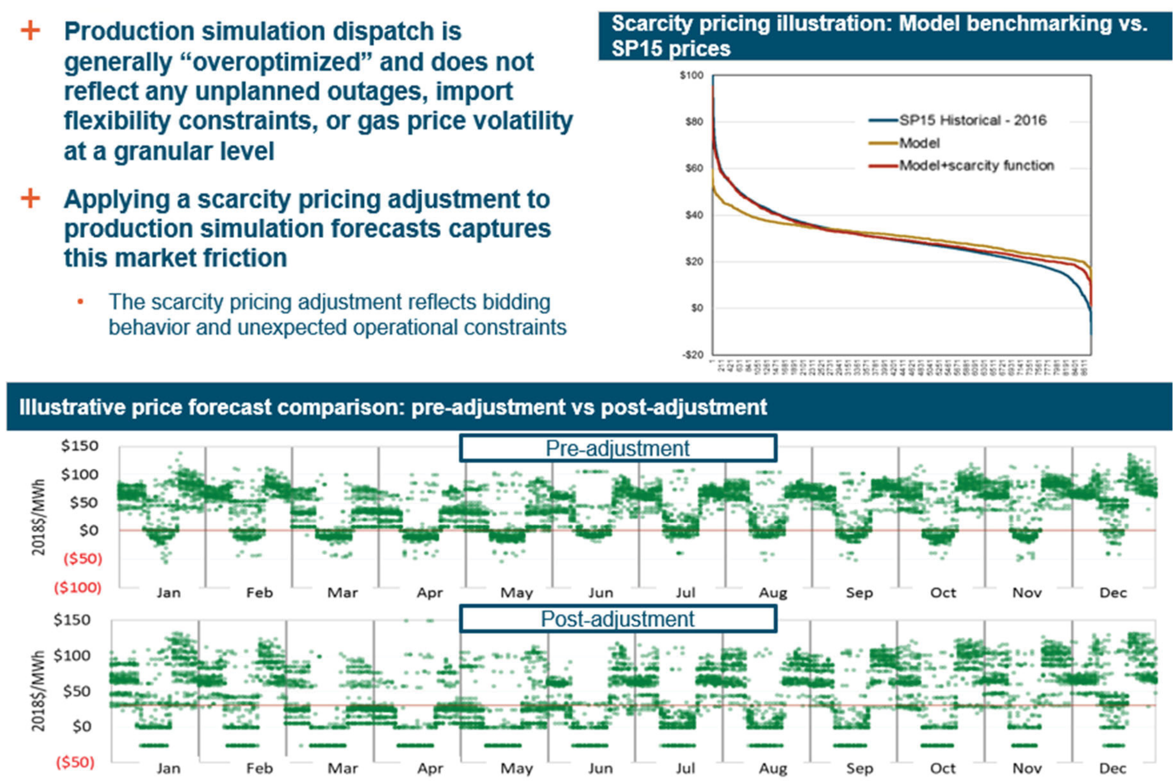
[13] Data requested from WECC: https://www.wecc.org/Pages/Contacts.aspx
[14] http://www.bwilcox.com/BEES/BEES.html
[15] http://bees.archenergy.com/index.html
[16] https://www.nrel.gov/grid/western-wind-data.html
[17] https://www.nrel.gov/grid/wind-toolkit.html
[18] https://www.renewables.ninja/
[19] https://nsrdb.nrel.gov/
[20] https://emp.lbl.gov/tracking-the-sun
[21] For more information on the differences between CTZ22 and CALEE2018 see: https://pda.energydataweb.com/api/view/2280/Weather webinar CALEE2018 7-12-2019.pptx

3.3. Introducing Volatility in Production Simulation

Production simulation tends to produce unrealistically smooth price shapes and the optimization does not reflect real-world market friction, imperfect information or operating constraints. Energy Division's consultant E3 therefore recommends introducing volatility with a scarcity pricing function. Incorporating volatility that better matches real-world prices will be important for valuing dispatchable and flexible DER that can respond to market conditions. The scarcity pricing function is designed to capture real-world bidding behavior and operational constraints, which mostly apply to extreme price hours. The first step is calculating the implied marginal heat rate for each hour based on prices generated through production simulation. Then a set of multipliers will be applied to implied heat rates that are on both high and low bookends and recalculate the corresponding energy prices based on the adjusted implied heat rates. The multipliers are derived through benchmarking simulated prices to actual prices for selected historical years. Although hourly price shapes will change with the evolving grid as described above, historical price volatility and day-ahead vs. real-time relationships are the best model we have for producing similarly volatile prices from production simulation.

Figure 12: Illustration of Introducing Volatility to Production Simulation with a Scarcity Pricing Function



4. GHG Emissions and Avoided Cost Value

4.1. GHG Emissions

Staff proposes to update the GHG emissions methodology used in the ACC to better reflect the evolution of California's electric grid as the state progresses towards its emissions reduction goals. The current GHG avoided cost approach does not incorporate the declining GHG intensity of the electric grid as planned in the IRP. The proposed new method will accurately account for the decreasing emissions intensity of the electric grid when considering the increasing adoption of electrification measures. Without an accurate reflection of their electric sector impact the emissions attributable to these technologies will be grossly overstated. For the 2020 ACC update, Staff proposes to use production simulation (described is Section 3) to calculate short run hourly marginal emissions in place of the current implied market heat rate method. With the proposed RSP portfolio from the IRP modeling, marginal GHG emissions from production simulation will accurately reflect the declining emissions intensity of the grid going forward.

In the current ACC, GHG impacts are based on hourly short run marginal emissions, calculated using an implied heat rate methodology that incorporates market price forecasts for electricity and natural gas, as well as gas generator operational characteristics.[22] The future market price shapes are currently adjusted using the RPS calculator to reflect increased renewable generation. This approach does result in lower implied market heat rates during periods of higher solar generation, but it does not account for the declining annual average GHG emissions intensity of the grid.

Measuring GHGs based on the short run marginal emissions rate, however, does not accurately account for the supply-side response that will need to be procured due to changes in load. Given the GHG emissions reduction goals that California has adopted, the carbon intensity of the state's electric sector will need to decrease significantly in the coming years, even as the state adds considerable new load through building and transportation electrification. Thus, as demand-side actions modify load, load serving entities will rebalance the supply portfolio to meet the required emissions targets.

Staff proposes to account for this supply-side response in the updated ACC through a methodological shift to using long run marginal emissions in evaluating the GHG impacts of demand-side load modifications. Given that California plans to meet the SB100 goal of 100% decarbonized electricity (as measured by retail sales) by 2045, long run marginal emissions can be calculated based on an assumed GHG reduction target aligned with the SB100 goal.[23] Staff believe it is most appropriate to structure the long run emissions calculations based on this electric sector emissions reduction target. To do so Staff

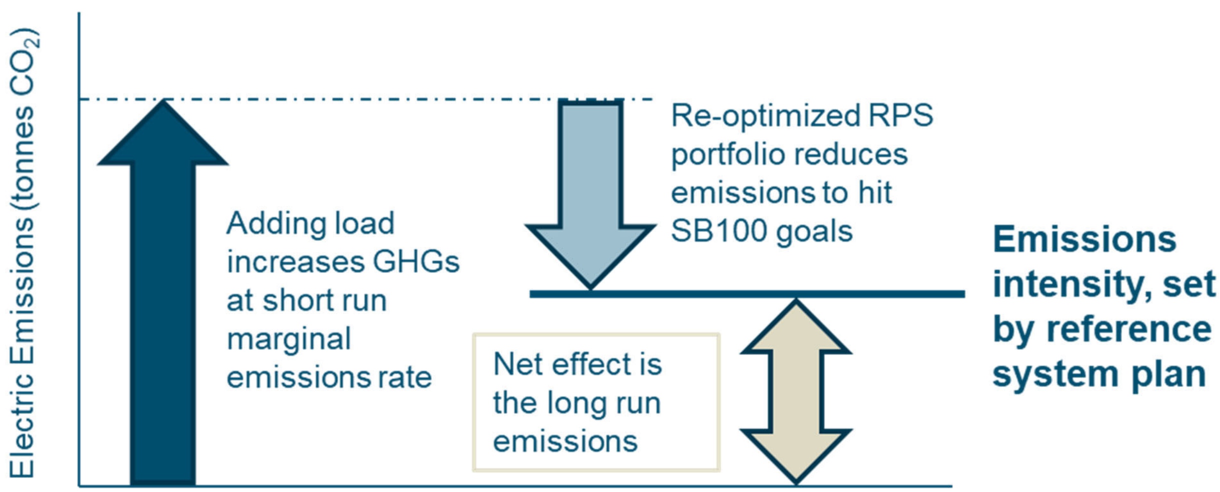
[22] See 2019 Avoided Cost Update Documentation available at: https://www.cpuc.ca.gov/General.aspx?id=5267

[23] A joint agency report process to assess an interpret SB 100 requirements is underway. Among the issues is an interpretation of how to define SB 100-eligible zero carbon resources. CPUC IRP inputs in the 2019 RSP modeling analysis were developed, of necessity, based on one possible interpretation of the SB100 goals. However, assumptions used for IRP modeling purposes by CPUC staff do not represent the Commission's dispositive view on SB 100 interpretation.

proposes to use the annual emissions intensity values derived from the IRP to reflect the emissions attributed to load-modifying demand-side actions.[24]

Figure 13 below provides an illustrative example of how long run emissions based on annual emissions intensity targets would be derived, and their relationship to the existing short run emissions calculated in the ACC.

Figure 13: Illustrative Long Run Emissions Calculation



The annual emissions intensity factors are calculated as follows, for year t:

$$Emissions\ Intensity_t(\frac{tCO_2}{MWh}) = \frac{Total\ CAISO\ Emissions_t(tCO_2)}{Total\ Retails\ Sales_t\ (MWh)}$$

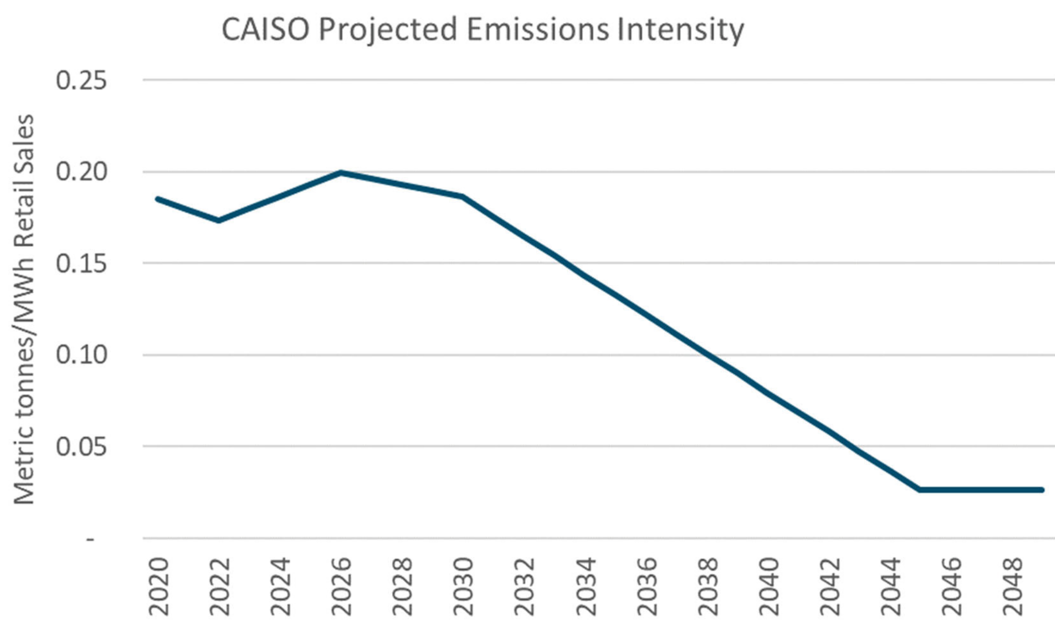
Table 6: and Figure 14 below depict the annual emissions intensity trajectory derived from the 2017-2018 Reference System Plan. Note that the rebound in emissions intensity between 2022 and 2026 is due to the planned retirement of Diablo Canyon. Emissions intensity is calculated as tonnes of GHG per MWh of retail sales to be consistent with SB100 language that zero-carbon resources supply 100% of retail sales of electricity to end-use customers in 2030.

Table 6: 2019 IRP Preliminary Results 46 MMT Case Load and Emissions

	Units	2020	2022	2026	2030
Load	*GWh*	242,188	247,401	253,790	257,010
Total Retail Sales	*GWh*	207,468	208,040	207,212	203,359
Total CAISO Emissions	*MMtCO2/Yr*	45	36	41	38
Emissions Intensity	*tCO2/MWh*	0.22	0.17	0.20	0.19

[24] The 2017-18 Reference System Plan adopted an electric sector goal of 42 MMt CO_2e by 2030, reflective of specific scenario assumptions. Energy Division's consultant E3 recommends using the implied annual emissions intensity – rather than the 42 MMt emissions goal itself or the updated 46 MMt goal in the proposed 2019-20 Reference System Plan – to reflect the electric sector target for that year.

Figure 14: CAISO Projected Emissions Intensity, 2019 IRP Preliminary Results 46 MMT Case



As the adopted 2017-2018 Reference System Plan provides retail sales and GHG emissions through 2030, a linear progression was assumed between these 2030 values and the 2045 SB100 goals to estimate emissions intensity at that end-year.[25] However, as the IRP process progresses it will be possible to more directly leverage outputs from that proceeding to inform annual emissions intensity values beyond 2030.

4.2. Avoided Cost Value

In addition to updating GHG accounting from short run marginal to long run marginal emissions, Staff further proposes to modify the valuation of these emissions to better align with the updated accounting approach.

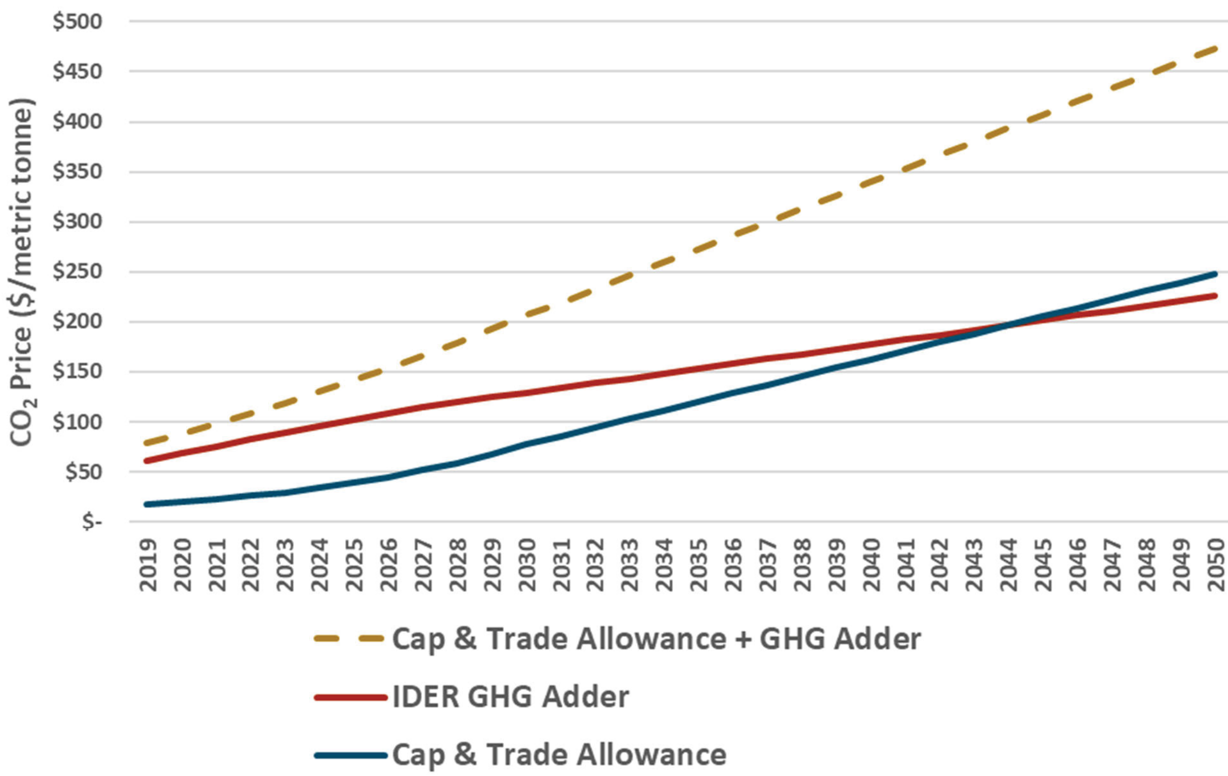
In the current ACC, the avoided cost of GHG emissions is represented by the sum of two values, 1) the monetized carbon cap and trade allowance cost embedded in energy prices, and 2) the non-monetized carbon price beyond the cost of cap and trade allowances (represented by the GHG Adder, as adopted

[25] To estimate the emissions intensity in 2045 it is assumed that SB100 goals will be met, requiring a minimum level of decarbonized generation equal to 100% of retail sales. With this assumption, up to approximately 7.25% of electric generation could be from natural gas generation (based on loss factor assumptions from the 2019 ACC v1b). Sector emissions in 2045 can be calculated using an assumption of the emissions intensity of a combined cycle gas turbine (with a heat rate of 7,000 Btu/kWh) and an assumed volume of fossil energy that could be used while still allowing the state to meet the SB100 target. The remaining energy on the system is assumed to have zero emissions.

by the CPUC).[26] The second of these values reflects the cost of further reducing carbon emissions from electricity supply, rather than the compliance cost represented by the cap and trade allowance price.

Figure 15 below depicts the price forecasts for the cap and trade allowance price (solid blue line), the IDER GHG Adder (solid red line) and the allowance price plus the GHG Adder (dashed gold line) from the 2019 ACC v1b.

Figure 15: CO_2 Cap & Trade and GHG Adder Price Series



The proposal is to continue to calculate a GHG avoided cost value based on the shadow price of GHG emission reductions from RESOLVE modeling in the IRP. As described in Section 2 above, the GHG value in the 2019 proposed RSP is expected to be lower than the 2017-18 PSP. However, using the GHG valued developed in the most recent IRP provides consistency in the evaluation of supply and demand side cost-effectiveness. The GHG avoided cost value will continue to be used in total, but separated into a monetized cap and trade value and the residual non-monetized value that is the difference between the GHG shadow price and the cap and trade value.

A proposed change to the 2019 ACC methodology and the D. 18-02-018 GHG avoided cost value is to discount the 2030 GHG shadow price from the IRP at the utility WACC to calculate GHG avoided cost values for 2020 – 2029. This would be in place of trending the value back to the current cap and trade price. RESOLVE modeling for the IRP results in relatively low GHG shadow prices in earlier years. This is

[26] D.18-02-018, Table 6. Note that in Table 6 of this IRP Decision, the term "GHG Adder" is used, inconsistent with the usage in IDER, to represent the combined value of the monetized cap and trade allowance price and the non-monetized residual value (rather than only the residual, non-monetized value).

for a variety of reasons, but in part because renewable generation is procured prior to 2022 for reliability and to take advantage of the ITC before it steps down from 30% to 10%. This results in a generation portfolio that exceeds the GHG targets for 2022 and 2026, resulting in a low GHG shadow price for GHG. Energy Division's consultant E3 recommends that the long-term value of GHG reductions from DER is better reflected by discounting the 2030 value back to 2020 to calculate the annual GHG avoided cost value.

In current cost-effectiveness calculations, the direct, hourly short run marginal emissions for a given year are multiplied by the load shape (the hourly load increase or reduction) of a given DER program or measure, and the annual product of that multiplication represents that year's GHG emissions. This annual emissions figure is then multiplied by that year's total carbon value (cap and trade allowance value plus GHG Adder) to derive the avoided emissions cost (either positive or negative) of a given program or measure, which represents the value of additional supply-side investments to reduce emissions.

To be consistent with the methodological change to using an annual emissions intensity target the emissions valuation must also be updated. Rather than assuming *all* demand-side changes in emissions must be entirely offset by supply-side resources, the *difference* between the direct short run marginal emissions and the intensity target must be calculated. When multiplied by the GHG Adder this value reflects the avoided electric sector emissions cost of maintaining the annual intensity target, rather than the cost of completely offsetting the change in emissions due to the measure's load impact.

The remaining emissions – that is, the additional emissions which would need to be offset to result in a given measure having zero net emissions impact – should be valued differently, as these emissions no longer represent GHG that should only be valued at costs specific to the electric sector (as represented by the GHG Adder). Instead, it is more consistent with the state's economy-wide GHG reduction goals to value these residual emissions as emissions from other sectors are valued at the CARB cap and trade price.

The following equations illustrate the difference between the existing GHG calculation in the 2019 ACC and the proposed GHG calculation for the 2020 ACC. These equations reflect the net present value of the emissions attributable to a given measure or program, over its expected useful life.

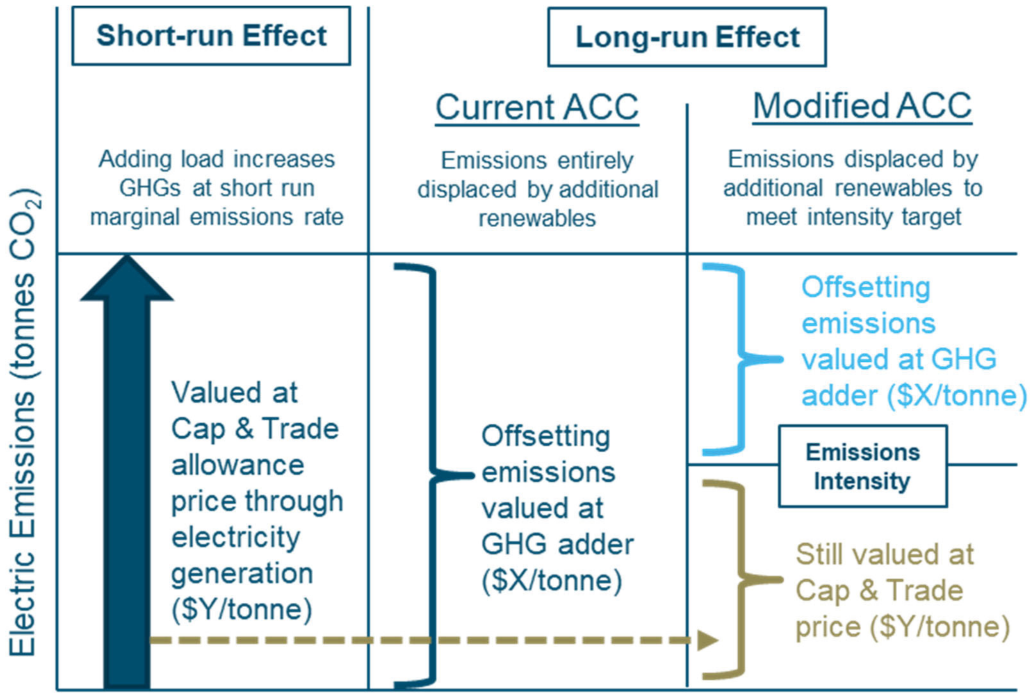
$$GHG\ Calculation_{2019\ ACC} = Load\ Shape\ (kWh)_h * Marginal\ Emissions\ (tCO_2e/kWh)_h * GHG\ Adder(\$/tCO_2e)_y$$

$$GHG\ Calculation_{2020\ ACC} = Load\ Shape\ (kWh)_h * [Marginal\ Emissions\ (tCO_2e/kWh)_h - Annual\ Emissions\ Intensity\ (tCO_2e/kWh)_y] * GHG\ Adder(\$/tCO_2e)_y + [Annual\ Load\ (kWh)_y * Annual\ Emissions\ Intensity\ (tCO_2e/kWh)_y * Cap\ and\ Trade\ Price\ (\$/tCO_2e)_y]$$

Note, in the above equations *h* represents an hourly dimension, while *y* represents a yearly dimension.

Figure 16 provides an illustrative example of the current ACC emissions valuation and the proposed update based on the long run emissions calculation. This example illustrates increased emissions due to a load-building measure, but the inverse relationship would hold true for a measure which instead reduces load.

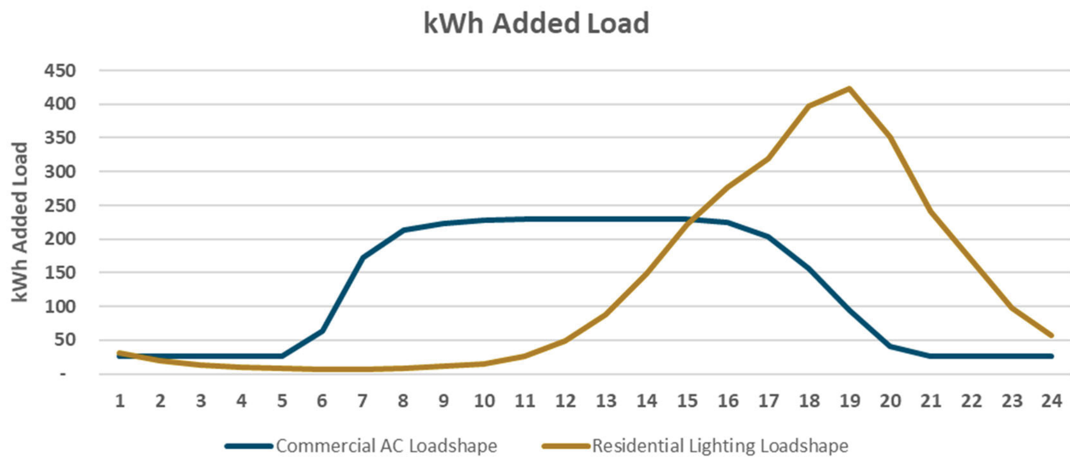
Figure 16: Current ACC GHG Valuation and Proposed Update (illustrative load increase example)



4.3. Example Calculation

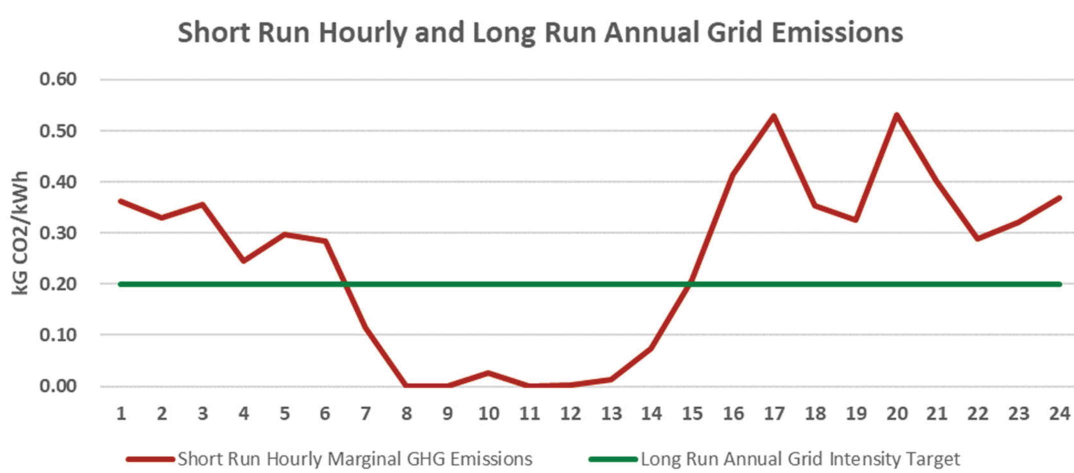
This section presents an example calculation for the GHG emissions impact and associated avoided costs. Using the methods described above, the example adds load to the electric grid and calculates the resulting increase in GHG emissions costs. To illustrate the combination of short run hourly and long run annual emissions, the example shows one day with two load shapes. The two load shapes are commercial air conditioning with load added predominately in the middle of the day, and residential lighting with load added predominately in the evening (Figure 17).

Figure 17: Illustrative Load Shapes for Example Day



For this example, a target long run annual grid intensity of 0.2 kg C02/kWh is assumed. The short-run hourly marginal emissions for the example day are higher than the long run intensity in the morning and the evening, but lower during the middle of the day, as shown in Figure 18. The commercial AC load shape adds load predominately during the middle of the day when the short run hourly marginal emissions are lower than the annual intensity, whereas the residential lighting measure adds load during evening hours when the short run emissions are higher.

Figure 18: Illustrative Short Run Hourly Marginal Emissions and Long Run Annual Grid Emissions Intensity



The hourly load shapes and GHG emissions illustrated in the above charts are shown below in Table 7. The first two columns list the hourly kWh load shape for the commercial AC and residential lighting load, both totaling 3,000 kWh for the day. At the long run annual grid emissions intensity of 0.2 kg/kWh both measures will each increase GHG emissions by 600 kg for this example day. Both the short run and the long run marginal GHG emissions are displayed for each measure, as is the difference between these values.

The commercial AC load is adding load during the middle of the day with lower marginal emissions such that the emissions intensity of the added load is lower than the 0.2 kg/kWh annual average. This additional load at lower emissions intensity creates headroom of 103 kg of CO2 in grid emissions that can be added while still meeting the 0.2 kg/kWh intensity target. For residential lighting the additional load is well above the annual average intensity, such that 435 kg of CO2 must be removed from the grid to meet the 0.2 kg/kWh intensity target. The differences between the short-run emissions intensity and the long-run emissions intensity target are valued at the GHG Adder which reflects the marginal cost of supply-side GHG reductions in RESOLVE and includes the costs of renewable generation and integration.

Table 7: Illustrative Short and Long Run GHG Emissions Calculations for an Example Day

	Added Load		GHG Emissions Rates		Short-run GHG Emissions		Long-run GHG Emissions		Marginal GHG Impact Relative to Intensity Target	
	Commercial AC Loadshape	Residential Lighting Loadshape	Short Run Hourly Marginal GHG Emissions	Long Run Annual Grid Intensity Target	AC	Lighting	AC	Lighting	AC	Lighting
Hour	kWh	kWh	kg/kWh	kg/kWh	kg	kg	kg	kg	kg	kg
1	26	32	0.36	0.2	9	12	5	6	4	5
2	26	19	0.33	0.2	9	6	5	4	3	2
3	26	14	0.35	0.2	9	5	5	3	4	2
4	26	10	0.25	0.2	6	2	5	2	1	0
5	27	8	0.30	0.2	8	2	5	2	3	1
6	64	7	0.28	0.2	18	2	13	1	5	1
7	173	7	0.12	0.2	20	1	35	1	(15)	(1)
8	213	8	0.00	0.2	-	-	43	2	(43)	(2)
9	224	12	0.00	0.2	-	-	45	2	(45)	(2)
10	229	15	0.03	0.2	6	0	46	3	(40)	(3)
11	229	27	0.00	0.2	-	-	46	5	(46)	(5)
12	229	50	0.00	0.2	0	0	46	10	(45)	(10)
13	229	89	0.01	0.2	3	1	46	18	(43)	(17)
14	229	148	0.07	0.2	17	11	46	30	(29)	(19)
15	229	222	0.21	0.2	48	46	46	44	2	2
16	224	277	0.41	0.2	93	115	45	55	48	59
17	203	318	0.53	0.2	107	168	41	64	67	105
18	156	397	0.35	0.2	55	140	31	79	24	61
19	95	423	0.32	0.2	31	137	19	85	12	53
20	42	351	0.53	0.2	22	186	8	70	14	116
21	26	241	0.40	0.2	10	97	5	48	5	49
22	26	169	0.29	0.2	7	49	5	34	2	15
23	26	98	0.32	0.2	8	32	5	20	3	12
24	26	57	0.37	0.2	10	21	5	11	4	10
Total	**3,000**	**3,000**			**497**	**1,035**	**600**	**600**	**(103)**	**435**
				Allowable kg/kWh of additional generation >>					**0.23**	**0.06**

The resulting sum of the short and long run GHG value calculations are shown in Table 7. In both cases the total added long run GHG emissions, after changes in the supply portfolio, for the illustrative day are the same at 600 kg CO2.

The short run emissions are valued at the cap and trade allowance price, in this case assumed to be $90/tonne. This results in a $45 cost for the commercial AC measure, and a $93 cost for the lighting measure given it adds load in hours with higher emissions. In addition to these values, the difference between each measures' short run emissions and the long run emissions calculated assuming an annual intensity target of 0.2 kg/kWh is multiplied by the GHG adder, here assumed to be $110/tonne. This results in a credit of $11 for the AC measure, given it is adding load in relatively low-emission hours, and a cost of $48 for the lighting measure given it is adding load in relatively high-emissions hours.

Table 8: Illustrative GHG Value Calculation

GHG Emissions Value ($/Tonne)			Commercial AC Load Shape		Residential Lighting Load Shape	
			kg GHG Impact	$ GHG Value	kg GHG Impact	$ GHG Value
Short run Emissions	Cap and Trade Value	$90	497	$45	1,035	$93
Incremental Emissions beyond Intensity Target	IRP GHG Shadow Price	$110	(103)	($11)	435	$48
		Total		**$33**		**$141**
			kWh Added	$/MWH GHG Value	kWh Added	$/MWH GHG Value
			3,000	$11.17	3,000	$46.97

For the sake of brevity, a similar example for load reductions is not included. However, the method and logic applies exactly the same in the opposite direction for load reductions. If the above examples of commercial AC and residential lighting were efficiency measures rather than load additions, they would result in GHG costs of -$33 and -$141, respectively. In that scenario, the residential lighting measure is more valuable from an emissions standpoint than the commercial AC measure, given that it is reducing load during hours with relatively high emissions rates.

5. Distribution Avoided Costs

Distribution avoided costs represent the value of deferring or avoiding investments in distribution infrastructure through reductions in distribution peak capacity needs. The ACC currently uses marginal cost values from IOU filings in their General Rate Case Phase II proceedings. Recently the Distributed Resources Planning (DRP) proceeding (R.14-06-013) has developed considerable insight and data related to the impact of DERs on the distribution system. Specifically, the Energy Division White paper attached to the DRP June 13, 2019 ALJ Ruling[27] (DRP Staff Paper) defines two types of avoided costs (Specified and Unspecified), and proposes to leverage information from utility Distribution Deferral Opportunity Report (DDOR) and Grid Needs Assessment (GNA) filings that contain detailed information about utility needs and investment plans. Therefore, for the 2020 update, Energy Division has asked our consultants E3 to examine how to use the DRP information to derive avoided costs that are more applicable to cost-effectiveness evaluations than the extant GRC marginal costs. The following section proposes a method for developing avoided distribution costs that is based on the recommendations in the DRP Staff Paper. The CPUC will determine in the DRP proceeding how to use the DRP Staff Paper's recommendations.

5.1. Distribution avoided costs from the DRP

5.1.1. Specified Deferrals

The utilities calculate distribution avoided costs as part of the annual DDOR process. These avoided costs are specific to a small number of utility capacity projects that could potentially be deferred via DER adoptions in the project areas. The DDOR avoided costs represent the value of deferring distribution investment projects through the addition of DER or other load reducing measures that are *above and beyond* the DER growth the utility expects to be adopted in the project area because of current DER policies, incentives and programs. The DRP report defines these DDOR costs as "**Specified deferrals**".

The Specified deferral costs are not included directly in the avoided costs for the ACC because new incremental DER in these areas would be implemented through a separate DDIF process. The Specified deferral avoided costs and underlying information, however, are used as inputs into the calculation of Unspecified deferrals discussed below.

5.1.2. Unspecified Deferrals

The second set of avoided costs, which will be used in the ACC, is derived using data from the DRP, but not a direct output of that process. Defined as "**Unspecified deferrals**" in the DRP Staff Paper, these avoided costs reflect the increased need for capacity projects that would have occurred if there were less DER growth embedded in the utility base forecasts. With less DER growth, the forecasted demand would be higher on each circuit which could lead to a circuit overloads that trigger the need for upgrade projects not identified in the GNA filings.

Unspecified deferrals are represented in Figure 19 as the lower right quadrant. The table summarizes the differences between the Specified and Unspecified deferrals. Specifically, the Specified deferrals are for a limited set of utility projects and based on load forecasts that reflect all projected new DER growth, while the Unspecified deferrals are based on the rest of the utility system and reflect capacity needs under a counterfactual load forecast.

[27] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 13, 2019

Figure 19: Distribution avoided costs

	Base Load Forecast (reflects expected new DER)	Counterfactual Load Forecast (reflects limited new DER)
DDOR Subset of Projects	**Specified** Deferrals (Not included in ACC)	
Rest of System **(GNA data)**		**Unspecified** Deferrals (Included in ACC)

5.1.3. Counterfactual Load Forecast

To estimate the Unspecified deferrals, a counterfactual load forecast is developed for each circuit. The counterfactual forecast is conceptually similar to the No New DER case discussed above, in that it a method of forecasting how the future would be different without new DERs, so as to determine the impact of DERs on load (in the case of the counterfactual forecast) or system costs (in the case of the No New DER case).

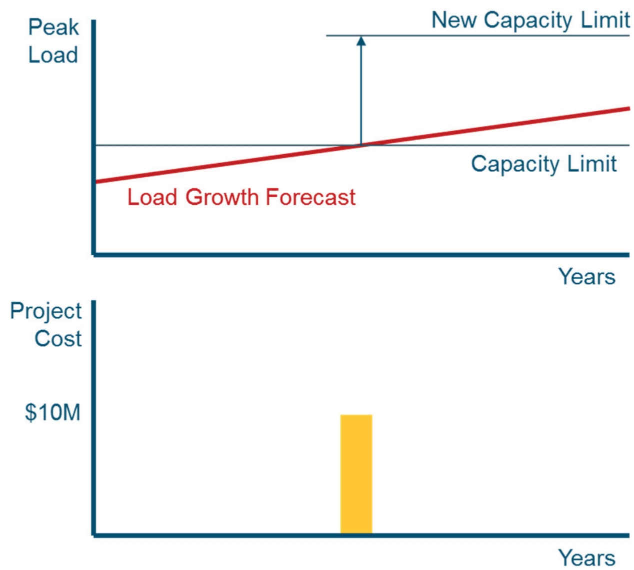
The counterfactual forecast, as defined in the DRP Staff Paper, is the load forecast from which forecasts of the adoption of load-modifying distributed energy resources, such as energy efficiency, demand response, battery storage, rooftop photovoltaic (PV), and electric vehicles, have been removed, for the most part. This counterfactual forecast reflects the removal of those DER load impacts that are the result of Commission policies, including tariffs like Net Energy Metering (NEM). As the CPUC does not have jurisdiction over Federal or State Codes and Standards, such as the California Title-24 Building Energy Efficiency Standards, those load reductions are not removed from the counterfactual load forecasts. The difference between the utility base forecast and the counterfactual forecast is also referred to as the **embedded DER**.

5.2. Distribution Deferral Background

The Specified deferral value calculates avoided costs using the Distribution Deferral methodology. Similarly, the Unspecified deferral value seeks to calculate what the Distribution Deferral avoided costs would have been under the counterfactual load forecasts. The essence of the Deferral Value is the present value revenue requirement cost savings from deferring a local expansion plan for a specific period of time. More details on the methodology can be found at the California IDER and DRP Working Group site.[28]

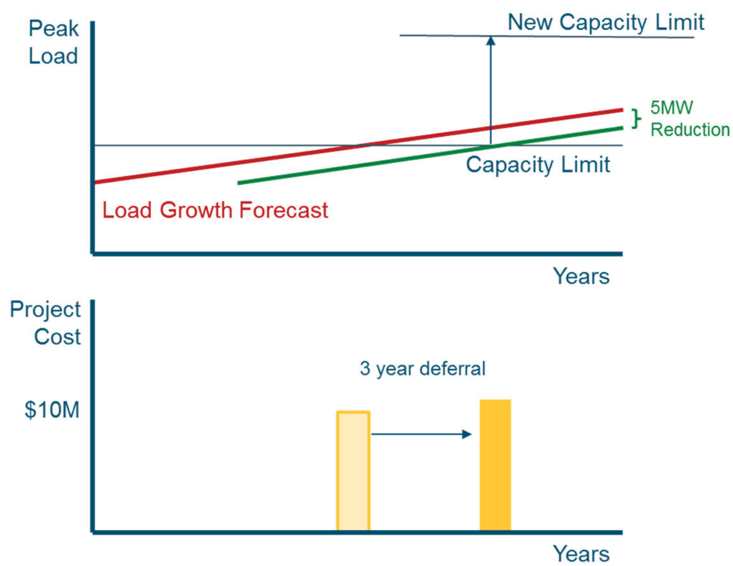
Figure 20 illustrates a situation where a network T&D investment is needed and the project cost. The project is needed to prevent the load growth (net of naturally occurring DER) from exceeding the T&D facility's load carrying capability and allows time for project deployment prior to the actual overload. In Figure 21, the utility is targeting incremental load reduction from the red line to the green line to allow the investment to be deferred by 3 years. The deferred project's cost is slightly higher due to equipment and labor inflation costs, but this would be more than offset by the financial savings from being able to defer the project.

Figure 20: Investment in a typical distribution project due to load growth



[28] https://drpwg.org/sample-page/drp/ and http://drpwg.org/wp-content/uploads/2016/07/R1408013-PGE-Demo-Projects-A-B-Final-Reports.pdf

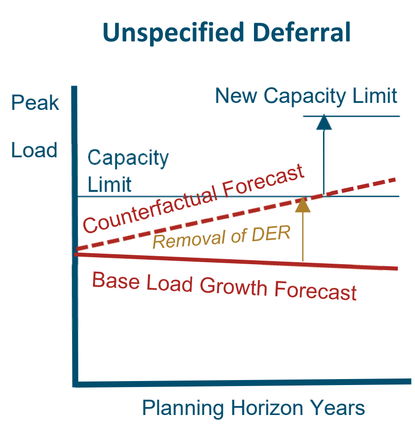
Figure 21. Project deferral of a typical distribution investment



5.3. Unspecified Deferral Value Method

As shown in the prior figures, the need for a capacity-driven distribution project is determined by the intersection of the capacity limit with the load growth forecast. In some cases, the load growth forecast may not intersect the capacity limit because of the expected peak load reductions from new DER. However, if that new DER were removed from the forecast, there could have been a need for a capacity project. This is illustrated in Figure 22 where the chart on the left represents the GNA analysis for a circuit that shows no need for a capacity project within the five-year planning horizon. The chart on the right shows the effect of the removal of the new DER growth from the load forecast. The counterfactual forecast is higher than the utility's base forecast and indicates the need for a capacity project within the five-year planning horizon.

Figure 22: Project need from counterfactual forecast



The Unspecified deferral avoided cost represents the potential capacity benefits for those circuits where there is no identified need for a project in the GNA's five-year planning horizon, but there is an indicated need if the utility base load forecast is replaced with the higher counterfactual forecast.

Below is a summary of the five-step process to calculate unspecified deferral avoided costs. For a more detailed description, please refer to pg. 11 of the DRP White Paper[29].

1. *Calculate the counterfactual forecast from the GNA:* For each listed circuit, the counterfactual load can be derived by removing the circuit level DER forecast from the circuit level load.

2. *Identify potential new capacity projects under the counterfactual forecast:* Circuits overloaded in the counterfactual forecast and not overloaded in the actual planning GNA forecast are considered deferrable. Projects that showed an overload in the GNA are not included.

3. *Estimate the percentage of distribution capacity overloads that lead to a deferred distribution upgrade:* Calculate a system level quantity for deferred distribution capacity by using a ratio between capacity overloads identified in the GNA to capacity overloads deferrable in the DDOR. The resulting percentage is a proxy for the percentage of distribution capacity upgrades that can be deferred by DER. Multiplying this percentage with the number of deferrable projects from Step 2 determines the subset of counterfactual capacity projects that could potentially be deferred via DER.

4. *Calculate the average marginal cost of the deferred distribution upgrades:* The average DDOR marginal cost is the sum of the DDOR avoided distribution cost ($/kW-yr) for each project from the DDOR filing, multiplied by its total deficiency need over the planning horizon, and the sum then divided by the total deficiency need for all DDOR projects.

5. *Calculate system level avoided costs:* Multiply the average DDOR marginal cost found in step 4 by the total quantity of deferred capacity by DERs for each circuit. This product is then divided by the sum of forecasted level of DERs for all areas (not just DDOR areas) to obtain a single, system level distribution deferral value in $/kW-yr.

5.4. Near-term and long-term avoided distribution costs

As stated in the DRP Staff Paper, "the impact of DERs to defer distribution upgrades accrue over the long term, while the GNA is limited to the forecast horizon that is necessary for distribution planning." The avoided costs estimates discussed above are based on DDOR and GNA filings that use a 5 year planning horizon. To extrapolate these estimates into long-term forecasts, Energy Division's consultant E3 recommends two options:

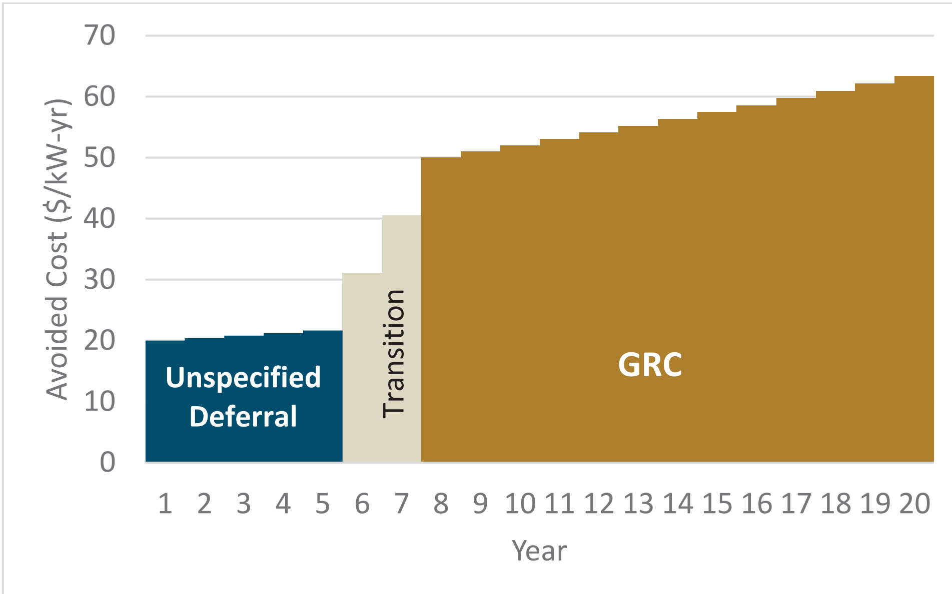
A. Escalate the short-term avoided cost estimates at a deemed rate per year.
B. Transition to marginal costs from each utility's most recent GRC Phase II proceeding

Of the two options, Energy Division' consultant E3 recommends transitioning to the GRC levels over a three-year period. The avoided costs in years 1-5 would be the Unspecified deferral values held constant on a real dollar basis. Years 8 and beyond would be the GRC level held constant on a real dollar

[29] ADMINISTRATIVE LAW JUDGE'S AMENDED RULING REQUESTING COMMENTS ON THE ENERGY DIVISION WHITE PAPER ON AVOIDED COSTS AND LOCATIONAL GRANULARITY OF TRANSMISSION AND DISTRIBUTION DEFERRAL VALUES, June 2019, Attachment A, p. 11

basis. Years 6 and 7 would linearly transition between the two end points of years 5 and 8. This method is depicted in the figure below.

Figure 23: Illustrative Distribution Avoided Cost Transition



5.4.1. Distribution avoided cost area granularity

PG&E estimates marginal distribution costs by area (division). Therefore, the extrapolation of the marginal costs into the future requires an assumption of if and when the area-specific distribution avoided costs should revert to a utility-wide average or continue to escalate separately. We recommend that the area differences be maintained in the forecasts, based on detailed work originally conducted as part of the 2004 avoided cost methodology prepared by Energy Division's consultant E3 and adopted for use in the cost effectiveness evaluation of California IOU energy efficiency programs[30]. Staff welcomes input from PG&E to update and amend these assumptions as needed.

5.5. GRC-based marginal costs

The California IOUs have used a wide variety of methods for estimating distribution marginal costs in their GRC filings[31]. The long-standing purpose of the marginal costs in a GRC filing is to guide the allocation of the utility revenue requirement to customer classes and the design of marginal-cost based rates. The GRC filing therefore provides a useful source for marginal costs that are estimated on regular three-year cycle. However, the GRC marginal costs might not be completely appropriate for use in DER

[30] PG&E's territory in 2004 comprised 18 planning areas across 9 climate zones. Given such diversity, the utility indicated to E3 that fundamental differences in population density and climate imply that its area-specific avoided T&D costs should not converge to the system average over the long run. Rather, high density areas with mild temperatures such as San Francisco, the Peninsula and the coastal East Bay would remain low cost due to economies of scale and flatter peak demand. On the other hand, hotter and less populated planning divisions such as North Valley, Stockton and Sacramento would retain relatively high avoided T&D costs.

[31] Methodology and Forecast of Long Term Avoided Costs for the Evaluation of California Energy Efficiency Programs, Prepared for the CPUC, October 2004, p. 102

cost effectiveness evaluations. They are not location-specific, and they are not necessarily avoidable costs. Therefore, Staff recommends that the GRC values be the source for long-run marginal costs, with the recognition that they may need to be modified for DER cost effectiveness and the ACC.

Specifically, this proposal uses GRC total distribution capacity costs for all utilities and does not make a distinction between peak and grid distribution capacity. Energy Division's consultant E3 has examined SCE's proposed separation of peak and grid-related distribution marginal costs, and has concluded that it was not supported by sufficient estimation rigor. Use of the total distribution capacity cost as estimated by SCE's regression analysis of cumulative distribution capacity-related investments and cumulative peak loads is consistent with avoided distribution capacity costs that have been used for SCE in prior avoided cost updates.

Should SCE adequately revise its methods in a subsequent GRC proceeding, those revisions should be evaluated on their merits and not rejected based on the current findings herein.

5.5.1. GRC Data Hierarchy

In selecting data to use for the long term avoided costs, Staff proposes the following hierarchy of GRC Phase II data sources, presented in descending order of preference.

1. Values adopted for revenue allocation from most recently completed proceeding.
2. Values adopted for rate design purposes from most recently completed proceeding.
3. Values agreed to by majority of parties for revenue allocation in settlement agreement from most recently completed proceeding.
4. Values agreed to by majority of parties for rate design purposes in settlement agreement from most recently completed proceeding.
5. Utility-proposed values for revenue allocation from most recently completed proceeding.

Note that some parties have recommended using averages of party positions when there are no adopted or settlement values. Staff has concerns that such an approach would encourage the gaming of party positions in order to skew the resulting averages. Given that GRC Phase II issues have been largely managed through settlement agreements rather than hearings, the risk of gaming is particularly high for California.

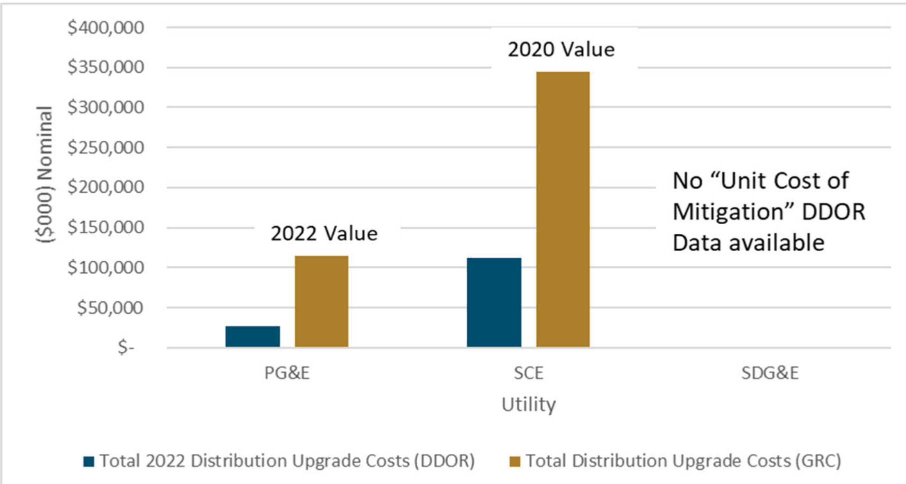
5.5.2. Gap Analysis

Using the GNA filing as the basis for distribution avoided costs is a new untested approach. Because of this, there is value in comparing the DDOR and GNA information that use the utility base load forecasts to the information that utilities have traditionally used in their GRC estimations of distribution avoided costs.

Initial investigations show that there is a large gap between the amount of annual investment represented by the DDOR projects and the annual capacity-related investments used to derive distribution marginal capacity costs in the utility GRC filings.

Figure 24 shows the difference between distribution upgrade costs from the utility DDOR and the forecasted distribution upgrade costs listed in the utility GRC. The total distribution upgrade costs from the PG&E and SCE DDORs were calculated by summing the "Unit Cost of Traditional Mitigation" for all Distribution Service projects coming online in 2022. The year selection was based on the fact that most distribution upgrade projects in SCE and PG&E came online in 2022. SDG&E did not report a unit cost of traditional mitigation in it's DDOR filing. The forecasted GRC Distribution Upgrade Costs from were taken from the 2018 SCE Workpapers[32] and the 2020 PG&E Workpapers[33].

Figure 24: Total Forecasted Utility Distribution Upgrade Costs



The gap analysis looks to identify and quantify the causes of the differences. For example, one cause would be that only a subset of capacity projects are included in the DDOR due to unlikely DER deferral success. Another cause could be the inclusion of projects in the GRC filings that are not captured in the GNA process. For example, PG&E had traditionally developed marginal costs for distribution as a sum of marginal costs for a) large identified projects over $1M and b) smaller capacity-related projects that are needed every year but are not specifically forecast by planners. If there were a large number of capacity-related projects that are not captured in the GNA process, then the distribution avoided costs based on the GNA would be incomplete.

The gap analysis would be useful from an information perspective, but could also affect the avoided distribution costs included in the ACC. For example, some of the reasons for excluding projects from DDOR, such as minimum project lead times, may not be applicable to Unspecified deferral values. Unlike DDOR projects that would require a minimum amount of load reduction by a specific date to allow deferral or avoidance of a specific project, the Unspecified deferral values are meant to be more general, and not tied to the amount of load reduction that could be provided.

For example, if it were determined that there were $30/kW-yr of missing non-GNA avoided distribution costs, then it might be appropriate to add $30/kW-yr to the unspecified avoided costs in the ACC.

Staff looks to the utilities for their insights on the reasons for the differences in investment levels from the two sources and will welcome recommendations for any avoided costs adders accordingly.

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[32] Southern California Edison 2018 General Rate Case - Transmission & Distribution (T&D) Volume 3 – System Planning

[33] PACIFIC GAS AND ELECTRIC COMPANY 2020 GENERAL RATE CASE EXHIBIT (PG&E-4) ELECTRIC DISTRIBUTION WORKPAPERS SUPPORTING CHAPTERS 11-19

5.6. Determining DER measure coincidence with distribution peak load hours

In evaluating the capacity value provided by a resource, there are five basic approaches for estimating the coincidence of the resource with the timing of the capacity need:

1. Simple Peak Method. Peak reduction is calculated as the resource output or load reduction at the time of the defined system peak. Typically a single hour is deemed to the peak, although in some cases a small number of hours are designated as peak hours and the peak reduction contribution is the simple average of resource performance across those hours.

2. Peak Clipping Method. Hourly loads for a project area are examined before and after installation of the resource(s). The change in the annual maximum net demand is the peak reduction provided by the resource(s).

3. Peak Capacity Allocation Factor (PCAF) Method. Peak reduction is the weighted average resource performance across hours in the peak period. The weights are relative to the project area demand in excess of a “peak threshold.” The higher the demand, the higher the weight assigned to the hour to approximate higher need for capacity in the higher demand hours.

4. Peak Load Reduction Factors (PLRF). Statistical representation of the timing of equipment peaks across the utility service territory

5. Convolution Methods. Peak capacity needs are based on both variations and uncertainty of customer demands as well as supply resources. These methods are typical of generation methods such as Loss of Load Expectation studies.

The distribution allocation factors should reflect current and future grid loadings, be flexible enough to allow modeling of alternate scenarios of DER and electrification penetration, match the underlying weather conditions assumed for the modeling of weather sensitive resources (which also entails modeling at the climate zone or finer geographic differentiation), and be applicable to cost effectiveness evaluations for individual resources (as opposed to being applicable only to entire portfolios).

Of the five methods, Energy Division’s consultant E3 recommends rejecting the Simple Peak method for being overly simplistic and dependent on a limited number of peak hours (often one). The limited hours are problematic because of the inherent uncertainty of when actual future peaks would occur. E3 also recommends rejecting the Peak Clipping method as its results are too dependent on the entire portfolio of DER that could be implemented in an area. While the method is useful for analysis of non-wires alternatives for a specific project, the method is not compatible with the use cases of the ACC model. Finally, E3 sees the Convolution methods as being overly complex and not well suited to the distribution capacity issue at this time. As customer generation continues to increase on the distribution system, it may be worthwhile to revisit convolution methods.

The two remaining methods, PCAF and PLRF, both are well matched to develop avoided costs for cost effectiveness evaluations. PCAF is used in the current ACC and by PG&E, and PLRF is used by SCE. Energy Division’s consultant E3 recommends the use of allocation factors developed by the utilities using their up-to-date demand information, provided that the allocation factors be estimated using both near term and future DER adoption levels, be performed at the climate zone or finer geographic level, and have accompanying weather information to allow mapping to the Typical Meteorological Year (TMY) data used to model efficiency measures in the Database for Energy Efficiency Resources (DEER).

As reliance on the utility allocation factors may require additional work by those utilities, Staff welcomes comments on this topic. Absent the utility allocation factors that reflect the needed conditions of 1) variation over years due to increased DER, and 2) geographic variation by climate zones or finer disaggregation, Energy Division's consultant E3 recommends that the current allocation method based on temperature-based hourly load estimates be continued.

5.6.1. Peak capacity allocation factors

Hourly allocation factors represent the relative need for capacity reductions during the peak periods specific to each distribution area. The concept is based on the Peak Capacity Allocation Factor (PCAF) method first developed by PG&E in their 1993 General Rate Case that has since been used in many applications in California planning[34].

The peak hours could be defined in three ways:

1. Specification of months and hours. For example, peak period is July and August hours between 4pm and 7pm on weekdays.
2. Specification of area peak threshold. The peak period would consist of all hours with forecasted demand above the specified threshold MW. The forecasted demand would be net of all existing and forecast naturally occurring generation (both behind the meter and in-front of the meter) located downstream from the planned distribution investment.
3. Statistical specification. The peak period would consist of all hours with demand within one standard deviation of the single hour maximum peak demand for the area. In other words, the area peak threshold is calculated by the LNBA Tool based on the variability of the area loads.

The relative importance of each hour is determined using weights assigned to each peak hour either 1) in proportion to their level above the threshold, or 2) on a uniform basis. Hours outside the peak period are assigned zero weight and zero value.

The formula for peak capacity allocation factors (PCAFs) using proportional weights is shown below.

$$PCAF[yr][hr] = \frac{Max(0, Load[yr][hr] - Thresh[yr])}{\sum_{hr=1}^{8760} Max(0, Load[yr][hr] - Thresh[yr])}$$

Where *Thresh[yr]* is the load in the threshold hour or the highest load outside of the peak period.

Once the PCAFs have been determined for each hour of the year, these are multiplied by the dependable output of each DER shape to determine the dependable MW contribution to peak load reductions. The following series of figures show an example of this process using the statistical peak period definition. One standard deviation from the top of the load duration curve above leaves the following hours with higher load than the threshold.

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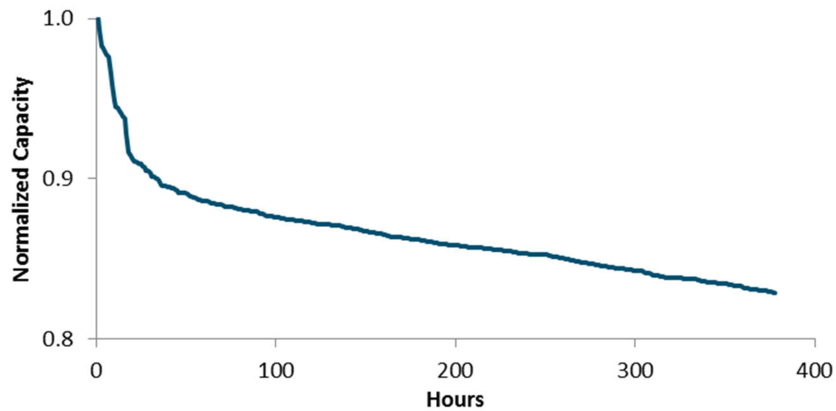
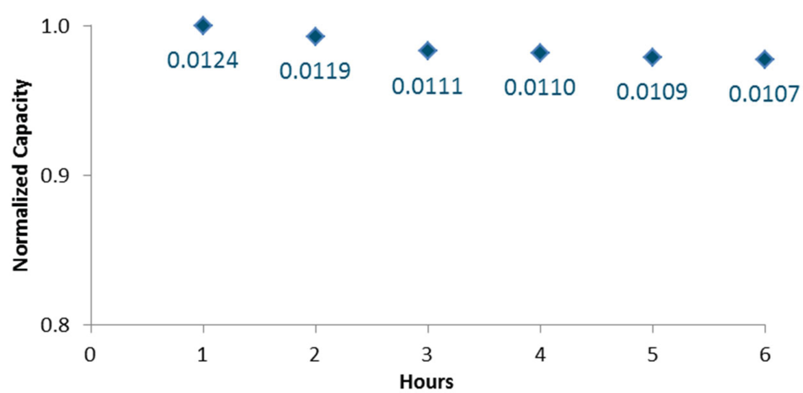
[34] For example, PCAfs were used recently in a CPUC report quantifying distributed PV potential in California: http://www.cpuc.ca.gov/NR/rdonlyres/8A822C08-A56C-4674-A5D2-099E48B41160/0/LDPVPotentialReportMarch2012.pdf

Figure25. Example of PCAF calculation



This relatively flat load duration curve has more hours above the threshold than other peakier load duration curves – in this case, there are 378 hours. A PCAF is assigned to each one of these hours using the formula above. The following chart shows the PCAFs for the top 6 hours of the load duration curve as an example. The number below each plotted hour's normalized load represents the PCAF relative importance to peak load reductions. They are unitless, sum to one over the hours above the threshold, and can be thought of as the weights in a weighted average calculation of a particular resource's capacity contribution.

Figure26. PCAFs for top 6 hours of load duration curve



5.6.2. Peak Load Reduction Factors (PLRF)

SCE uses a PLRF method to derive its distribution peak capacity factors. The method is similar in concept to the PCAF method, and is an equally valid method for use in DER valuation because, like the PCAF method, it allocates capacity value in proportion to the peak loadings in an area. In the recent GRC Phase II proceeding, SCE included a forecast of DER in 2021 to adjust the net circuit loads used for the PLRF, so in concept alternate forecasts could be incorporated to reflect DER forecasts farther in the future.

5.6.3. Effective Demand Factors (EDF)

SCE also developed Effective Demand Factors (EDF) that it uses as a measurement of peak load diversity and customer group contributions to gird-related costs. Should grid-related costs be separated out from peak-related costs for SCE, the EDF concept could be leveraged to quantify the contribution of DER to reducing grid-related costs. The EDF factors themselves would not be useful, but the distribution of the timing of the grid-related peaks could be used to create hourly allocation factors that equal that distribution. This would require the cooperation and assistance of SCE, but would not be needed for the 2020 update, given that this proposal has not accepted the use of their Grid-related costs as currently estimated.

6. Transmission Avoided Costs

For a long-term transmission value Staff proposes to use GRC transmission costs, as has been done in prior ACCs. This approach, similar to distribution value, would use annual \$/kW-yr values developed from GRC (or other sourced deemed appropriate), which is then allocated to individual hours using the PCAF method.

7. High GWP Gases

In 2017, the IDER proceeding issued an Energy Division Staff Proposal[35] that contained a proposal for a new avoided cost to estimate the value of DERs which decrease refrigerant leakage. This section expands upon that proposal by proposing a new avoided cost that encompasses a broader category of high Global Warming Potential (GWP) gasses, including refrigerants and methane. This new avoided cost would primarily apply to DER programs designed to replace natural gas appliances with electric appliances. However, it can also be used for DERs which results in changes in natural gas consumption, such as natural gas energy efficiency measures, and any future programs which focus on refrigerant replacement.

7.1. Background: Refrigerant leakage

As California pursues higher levels of building electrification, through SB 1477 programs, changes in building codes, energy efficiency measures, and other efforts, many more heat pumps will be purchased and used in the state. All heat pumps use refrigerants, and most refrigerants used today are very strong greenhouse gases— as much as 2,000 times stronger than CO_2. The ratio of global warming impact relative to that of CO_2 is known as Global Warming Potential, or GWP. Refrigerants only contribute to global warming when they leak, but leakage is inevitable given current practices. Emissions from refrigerant leakage in all-electric buildings can be a significant portion of a building's lifecycle GHG emissions.

[35] *Distributed Energy Resources Cost Effectiveness Evaluation: Societal Test, Greenhouse Gas Adder, and Greenhouse Gas Co-Benefits*. http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M175/K295/175295886.PDF

Figure 27: Annual emissions from a mixed fuel and all-electric building modeled as part of the CEC Title 24 2022 building code update.[36]

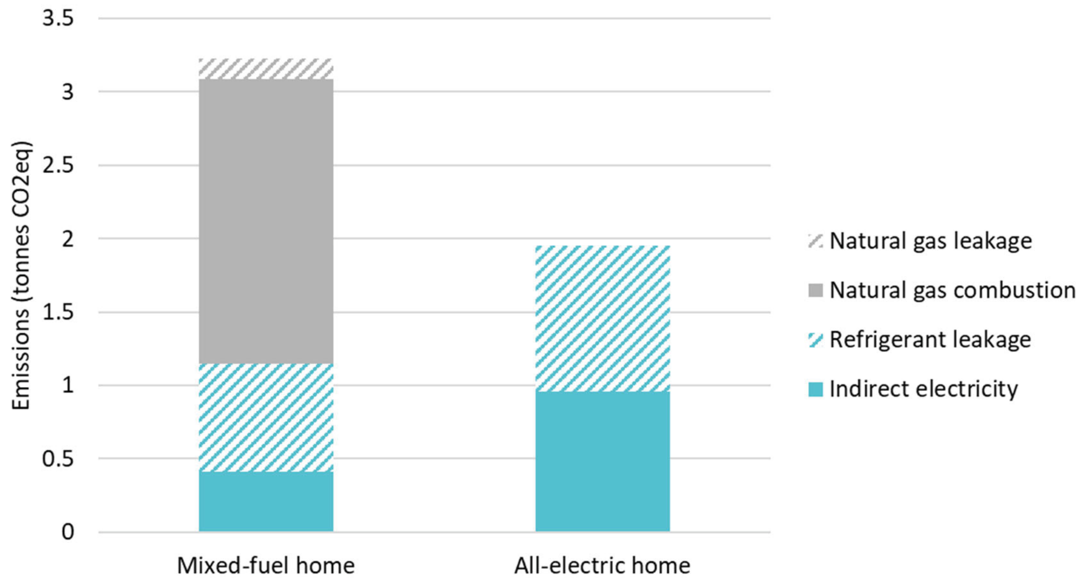
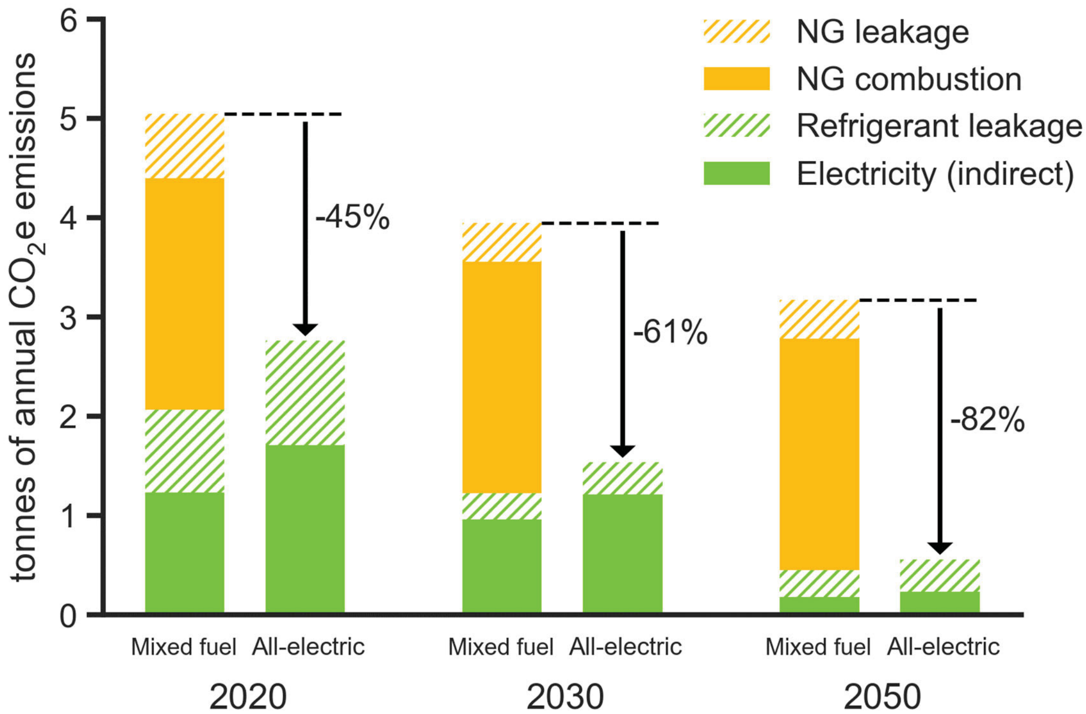


Figure 27 shows that when switching from a mixed fuel to an all-electric home, GHG emissions related to natural gas decrease, but GHG emissions from refrigerants *increase*. Also, switching from a device that uses a high-GWP refrigerant to one that uses a low-GWP refrigerant decreases refrigerant emissions. These types of equipment changes represent a significant change in avoided cost that has not yet been quantified in the IDER framework. This avoided cost also applies to a number of similar situations, such as where the alternative technology is a standard air conditioner. Air conditioners are very similar to heat pumps, and often use the same (high-GWP) refrigerants.

Figure 28 shows the CO2 equivalent emissions by source for a mixed fuel and electric home in 2020, 2030 and 2050 from the linked report on building electrification in California. This chart illustrates how declining GHG emission intensity of the electric grid over time will increase the proportion of global warming impacts attributed to refrigerant leakage, natural gas leakage and natural gas combustion. It will also increase over time the net GHG impact of electrification measures relative to the example shown above. Including an avoided cost category for GWP gasses will thus be increasingly important for DER cost-effectiveness evaluation.

[36] Energy and Environmental Economics (E3), "Title 24 2022 TDV Factors Background and Updates" presentation at the Lead Commissioner Workshop for the California Energy Commission 2022 Energy Code Pre-Rulemaking, October 17, 2019. https://ww2.energy.ca.gov/title24/2022standards/prerulemaking/documents/2019-10-17_workshop/2019-10-17_presentations.php

Figure 28: Annual GHG Emissions from a Mixed-fuel and All-electric 1990's Vintage Home in Sacramento[37]



The most common refrigerants found in new HVAC heat pumps and heat pump water heaters available today have GWPs in the range of 1,400-2,000. Lower GWP refrigerants are available and are actively being developed by refrigerant and heat pump manufacturers, but they often have slightly lower performance, require specially designed heat pumps that might be more expensive, and/or require special installation and maintenance practices to account for their mild flammability. With refrigerants trade-offs are inevitable. **However, it is important to account for the potential reduction in emissions from using low-GWP refrigerants, so that the benefits of using these refrigerants can be compared to their costs, and so that their use can be incentivized.**

[37] Energy and Environmental Economics (E3), "Residential Building Electrification in California: Consumer Economics, Greenhouse Gases and Grid Impacts". April 2019. Developed for Southern California Edison (SCE), Sacramento Municipal Utility District (SMUD), and the Los Angeles Department of Water and Power (LADWP)

Table 9: Common refrigerants in use today

Refrigerant	100-year Global Warming Potential (GWP)[38]	Common Uses
R-410A	2,088	New heat pumps and air conditioners
R-134A	1,430	New heat pump water heaters
R-22	1,810	Existing air conditioners (R-22 is mildly ozone-depleting and is being phased out in the US)

Table 10: Low-GWP refrigerant alternatives

Refrigerant	100-year Global Warming Potential (GWP)	Common Uses
R-32	675	Most promising near-term replacement for R-410A in residential HVAC heat pumps
R-1234yf	4	One of the more promising near-term replacements for R-134A in heat pump water heaters and clothes dryers
Propane (R-290)	4	Can be used in any heat pump, but high flammability means special installation and maintenance practices are required.
CO2 (R-744)	1	Some automobile air conditioners in Europe, some heat pump water heaters in Japan.

7.2. Background: Methane leakage

Another potentially significant avoided cost that has not yet been reflected in the IDER framework is the potential for avoided methane leakage when displacing a natural gas device. Global Warming Potential (GWP) is a measure of how much energy the emissions of 1 ton of a gas will absorb over a given period of time, usually 100 years, relative to the emissions of 1 ton of CO2. The larger the GWP, the more that a given gas warms the Earth compared to CO2 over that time period. Methane, the primary component of natural gas, has a 100-year GWP of 25[39], meaning it is 25 times stronger than CO2 over a 100-year time horizon, so any leakage of uncombusted methane has a disproportionately high impact on global

[38] GWPs listed are the same as those used by the CARB Refrigerant Management Program, which are IPCC AR4 (2007). See https://ww2.arb.ca.gov/resources/documents/high-gwp-refrigerants

[39] GWP is from IPCC AR4 (2017), and is the same as that used in the CARB GHG Inventory. See https://ww2.arb.ca.gov/ghg-gwps

warming compared to burning that same methane and emitting CO2 instead.[40] Methane has an even higher GWP if a shorter time horizon is used[41], as its lifetime in the atmosphere is only about 12 years, but a 100-year time horizon is assumed here to maintain consistency with refrigerant leakage GWPs and the CARB GHG inventory.

Methane leakage is inherently difficult to quantify, given that much of the leakage that occurs is due to abnormal, infrequent events, and even more difficult to quantify is the amount of methane leakage that is possible to avoid by displacing a natural gas device. California will continue to have a pressurized natural gas system for the foreseeable future, so any leakage associated with simply keeping this system pressurized is not likely to be avoided by decreasing throughput. However, there is certainly a nonzero quantity of methane leakage that will be avoided by displacing natural gas devices. At the least, behind-the-meter leakage will go to zero when switching from a mixed-fuel home to an all-electric home. At the most, leakage that happens during production and storage will also be reduced as a result of decreased throughput.

Methane leakage is quantified in official GHG inventories, such as the US EPA and California Air Resources Board inventories, but the leakage rates reported in these are widely accepted in the academic community to be significant underestimates[42] [43]. The leakage rate implied by the EPA GHG Inventory is 1.4%, but national leakage rates reported in academic literature range from 2.3% (see Alvarez 2018, previously cited) to 12% for certain shale gas developments[44]. These numbers all include lifecycle leakage emissions from well-to-meter, but not behind-the-meter leakage.

These academic studies reporting higher leakage rates than inventories generally note that the reasons for this discrepancy are likely to include abnormal events due to equipment malfunction (e.g., Aliso Canyon), and older emission factors that have since been updated. The distribution of methane leakage rates has a long “tail” (i.e., most facilities have low leakage, but a select few occasionally have very high leakage). Therefore, accounting for average leakage rates from normal usage, as is generally done in inventories, can lead to a significant underestimate of total leakage (see Alvarez 2018).

[40] Note that, when calculating GHG impacts from methane leakage (compared to burning the same methane), a factor of 9, not 25, must be used to account for the difference in molar mass between methane and CO2. For example, a 1% leakage rate for a home that consumes 100 tons of natural gas per year would result in 1 ton of leaked natural gas, leading to 25 tons of CO2-equivalent emissions. However, if that 1 ton of natural gas had been burned instead, it would lead to 44/16 = 2.75 tons of CO2 emissions (the ratio between the molar masses of CO2 and CH4). Thus it is the ratio between 25 and 2.75 that matters (25/2.75 = 9.1) in calculating the increased warming effect from leaking natural gas.

[41] https://unfccc.int/process/transparency-and-reporting/greenhouse-gas-data/greenhouse-gas-data-unfccc/global-warming-potentials

[42] Brandt, A. R., et al. “Methane Leaks from North American Natural Gas Systems.” Science, vol. 343, no. 6172, 2014, pp. 733–735., doi:10.1126/science.1247045.

[43] Alvarez, Ramón A., et al. “Assessment of Methane Emissions from the U.S. Oil and Gas Supply Chain.” Science, vol. 361, no. 6398, 13 July 2018, doi:10.1126/science.aar7204.

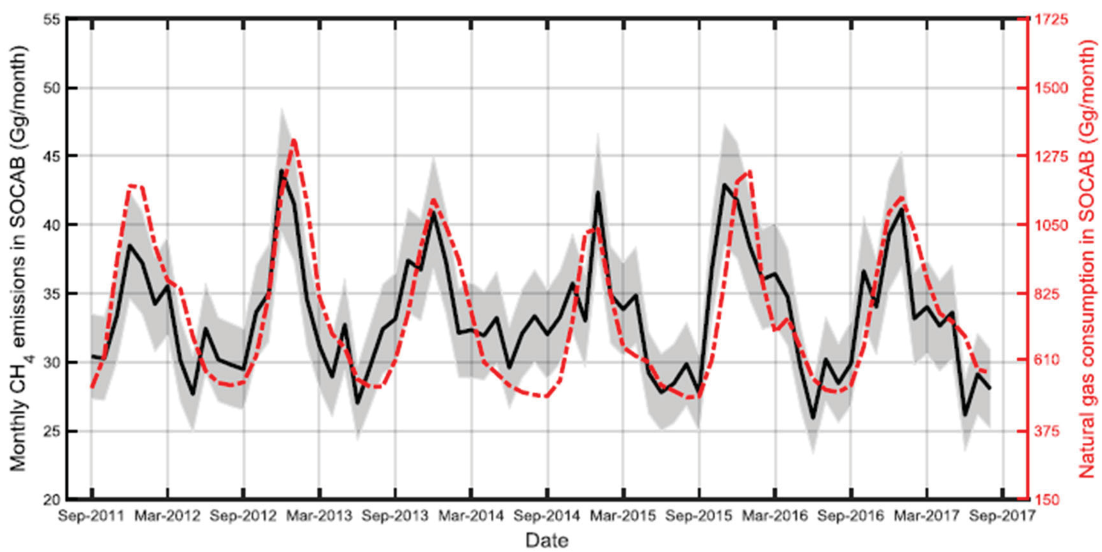
[44] Howarth, Robert. “Methane Emissions and Climatic Warming Risk from Hydraulic Fracturing and Shale Gas Development: Implications for Policy.” Energy and Emission Control Technologies, vol. 3, 8 Oct. 2015, pp. 45–54., doi:10.2147/eect.s61539.

The CARB inventory reports an even lower implied leakage rate of 0.7%[45], since it only quantifies in-state emissions, with the exception of electricity. California imports about 95% of its natural gas, so the leakage emissions that happen due to out-of-state production and storage are not included. Therefore, Staff proposes to not include these impacts in CPUC avoided costs. These emissions are likely significant, as production and storage is generally considered to be the leakiest part of the natural gas system (see Alvarez 2018). The CARB inventory includes behind-the-meter (BTM) leakage, a new addition for the 2017 inventory.

Also of note is that if the leakage rate were actually closer to 12%, as is reported by Howarth (2015, previously cited) for shale gas, then burning natural gas for electricity would be significantly worse for climate change than burning coal (see Howarth 2015).

As mentioned above, since at least for the near term the natural gas system will remain in place and stay pressurized, the key question for IDER is -- How much leakage could be avoided through displacing a natural gas device? Recent research attempted to quantify the degree to which natural gas throughput is correlated with methane leakage in the LA basin[46]. The study found that the two are highly correlated, meaning it is reasonable to assume that decreased throughput would result in decreased leakage, at least in the LA basin and likely in California more generally.

Figure 29: Methane emissions and natural gas consumption in the LA basin between 2011 and 2017.



7.3. Proposed methodology: Refrigerant leakage emissions

Staff proposes to quantify avoided refrigerant leakage emissions using detailed leakage data compiled by the California Air Resources Board (CARB). CARB maintains a database of typical refrigerant charge,

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[45] This number is obtained by dividing the total methane leakage reported in the ARB inventory for 2017 by the total natural gas consumption in CA in 2017, as reported by EIA.

[46] He, Liyin, et al. "Atmospheric Methane Emissions Correlate With Natural Gas Consumption From Residential and Commercial Sectors in Los Angeles." Geophysical Research Letters, vol. 46, no. 14, 2019, pp. 8563–8571., doi:10.1029/2019gl083400.

annual leakage rates, and end-of-life leakage rates for all major types of residential and non-residential equipment that uses refrigerants. The table below shows leakage data available from CARB for common residential equipment types.

Table 11: Refrigerant leakage data compiled by the California Air Resources Board.[47]

Appliance	Typical refrigerant	Refrigerant GWP	Average refrigerant charge	Average annual leakage	Average end-of-life leakage
Central A/C	R410A	2088	7.5 lbs	5%	80%
Air-source ducted heat pump	R410A	2088	8.2 lbs	5.3%	80%
Heat pump water heater	R134A	1430	2.4 lbs	1%	95%
Heat pump clothes dryer	R134A	1430	0.88 lbs	1%	100%

This leakage data can be converted into annualized leakage rates by adding the end-of-life leakage divided by the expected equipment lifetime, and subsequently to annualized emissions by multiplying by refrigerant charge and GWP:

$$\text{Annualized emissions} = \text{Refrigerant charge} * \text{GWP} * (\text{Annual leakage rate} + \frac{\text{End-of-life leakage rate}}{\text{lifetime}})$$

This equation in combination with the CARB data represents the proposed methodology for estimating refrigerant leakage emissions for IDER. This framework allows for the reduction in emissions from using lower-GWP refrigerants to be appropriately accounted for.

7.4. Proposed methodology: Methane leakage emissions

Energy Division's consultant E3 proposes to investigate and develop a methodology for calculating avoided costs for methane leakage. Proceedings at CARB on methane leakage are ongoing and final recommendations have not been adopted. Staff expects further direction from CARB to be finalized prior to the issuance of the 2020 ACC and will incorporate methane leakage rates accordingly into the new version of the ACC when it is proposed in 2020.

[47] Data obtained via email from CARB staff. Similar (but not exactly the same) data is available in the latest technical support document for the CARB HFC Inventory.

For the IDER workshop held in August 2019, Energy Division's consultant E3 presented two possible leakage rates (the CARB leakage rate of 0.7% and the Alvarez 2018 leakage rate of 2.4%, which reflects T&D emissions subtracted out but BTM added). Note that both of these leakage rates include behind-the-meter emissions (estimated at 0.5% of consumption[48]), which are the most certain to be eliminated through electrification. These two estimates represent likely bounds for any leakage rate that could be adopted. Energy Division's consultant E3 will perform a literature review to further examine the potential for decreased natural gas throughput to reduce methane leakage, including any values formally adopted in CEC or CARB proceedings. Avoided methane leakage emissions for natural gas devices will be quantified by multiplying lifetime natural gas consumption by the leakage rate which will be determined later. The proposed methodology for incorporating these emissions into the IDER framework is described further in the next section.

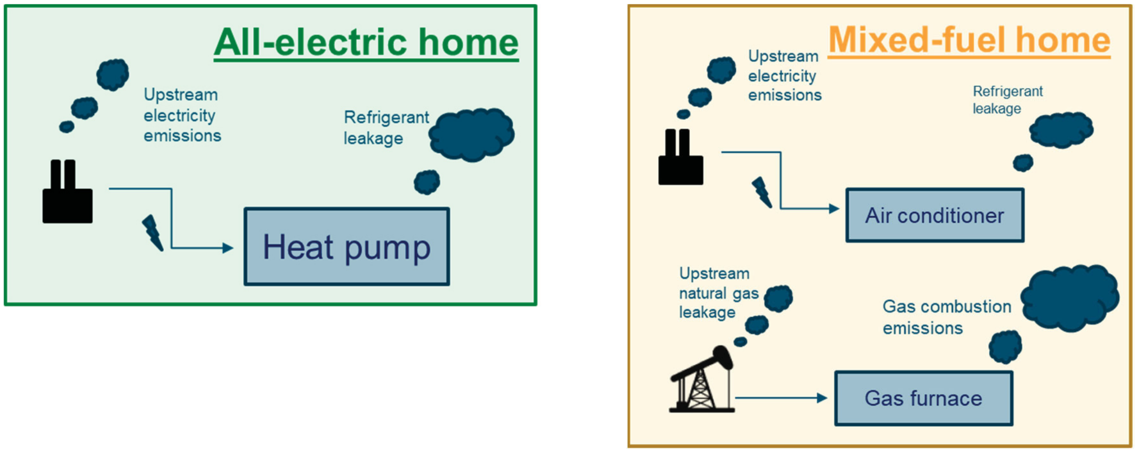
7.5. Example Calculation

To summarize, this section describes the method for calculating avoided costs for refrigerant gas and methane leakage, as shown in Figure 30. Staff anticipates that proceedings at CARB will produce additional findings and eventually adopt recommendations on refrigerant and methane leakage. We propose to determine the appropriate upstream leakage factors from the appropriate CARB findings for use in the 2020 ACC update. Upstream methane leakage factors will be multiplied by the annual volume of natural gas usage that is reduced to calculate CO_2-equivalent GHG impacts. Those impacts will be multiplied by the annual GHG value, in dollars, for the ACC. This methane leakage avoided cost will be applied to all measures increasing or decreasing natural gas consumption. The BTM leakage will be calculated in a similar manner, with annual leakage factors and annual natural gas impacts. BTM natural gas combustion emissions will be calculated as is currently done for natural gas measures in the 2019 ACC. The upstream and BTM methane leakage and BTM combustion avoided cost values will apply to all DER measures impacting natural gas consumption.

In addition, avoided costs for the global warming impacts of BTM refrigerant leakage will be calculated using the average annual leakage factor adopted for the appliance as described above. The BTM refrigerant leakage does not vary with annual electric or natural gas loads. Hourly load shapes are not a factor in calculating methane or refrigerant leakage.

[48] Estimated by a 2018 CEC study. The results of this study were included in the latest CARB inventory.

Figure 30: Comparison of All Electric and Mixed Fuel Home Leakage.



8. Geographic Resolution of the ACC

The proposed approached described above reference a range of possible geographic resolutions for the source data and for the resulting ACC categories. Distribution values are based on distribution planning areas for PG&E and the DDOR data could provide potentially finer resolution for PG&E and the other utilities. Transmission values refer to CAISO Sub-LAPs and CEC Title 24 TDV values, like CPUC avoided costs historically refer to climate zones. As part of the 2020 ACC update process Staff proposes to evaluate and propose a geographic resolution for avoided costs and for mapping inputs from different geographies consistently. Staff welcomes party input on the needed level of granularity.

9. Natural Gas Avoided Cost Calculator

Energy Division's consultant E3 recommends simplifying the current approach to developing natural gas price forecasts. The current method for natural gas price forecasts in the ACC evolved from a now obsolete Market Price Reference (MPR) methodology first established in 2004 to determine 'above-market prices' for renewable generation.[49] That the MPR methodology evolved over several years with stakeholder proposals and CPUC decisions made in the context of renewable procurement when prices for renewables were significantly higher than fossil generation. The core of the current MPR based method is using natural gas forward prices for the near-term (~5 years) and then transitioning to a long-term natural gas fundamentals price forecast. Energy Division consultant E3 proposes to retain this core concept, but simplify the approach. Whereas the current MPR based approach used Henry Hub fundamental forecasts, the proposed approach would instead transition to the long-term gas price forecasts used in the CPUC IRP, the CEC IEPR natural gas forecast.

As in the current ACC, the natural gas commodity avoided cost will be based on natural gas forward prices for NYMEX Henry Hub, and for and basis swaps for PG&E Citygate and the Southern California Border. Henry Hub forward prices typically trade for a future period of up to ten years whereas the basis

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[49] D.04-06-015

prices for California typically trade for up to 5 years. Staff proposes using forward based prices for 5 years and then transitioning to the CEC IEPR mid gas price forecast that is used in the CPUC IRP.

Whereas the current MPR based method transitions to the *escalation rate* of the Energy Information Administration (EIA) fundamentals forecast over a period of three years, we propose instead to transition to the actual *nominal $/MMBtu price* of the CEC IEPR forecast over the same three year period.

The MPR based method averaged forward prices for the prior 22 business days to avoid basing a long-term price forecast on a short-term aberration in market prices. In practice prices have varied by less than $0.10/MMBtu over the 22-day period. Furthermore, as the proposal is to transition to the nominal price forecast rather than the escalation rate, the impact of the last year of market price data is limited to that year and the 3 year transition period. That is, the last year of market price data is not escalated 25 years into the future. Instead, the proposal is to use an average of 5 business days of forward price data rather than 22.

In addition Energy Division's consultant E3 recommends continuing the approach of adding the relevant in-state transportation charges for PG&E, SoCal Gas and SDG&E, municipal franchise fees and an adder for natural gas hedging costs. The natural gas transportation cost allocation across seasons and customer classes has not been updated for some time. Staff proposes to direct its consultant E3 to continue investigating and implementing appropriate updates to those allocations.

Finally, given policy discussions on the future of natural gas in California, there is a question of how to forecast in-state natural gas transportation rates in an era of declining throughput. For the 2020 ACC update, the proposal is to continue to use a trend-based escalation of recent and currently proposed natural gas transportation rates. This would involve evaluating new methods or new transportation rate forecasts as may be adopted by the CEC or CPUC for the next ACC update cycle in 2021.

9.1. Natural Gas GHG Avoided Costs

For electricity sector GHG emissions below the grid intensity target, the proposal described in Section 4 is to use the projected cap and trade value for short run GHG avoided costs. Energy Division's consultants E3 recommend using the same cap and trade value for natural gas GHG emissions. This would provide a consistent metric for fuel substitution measures, so that the same value would apply for avoided GHG of both natural gas at the powerplant and at the customer premise.

Staff recognizes that there has been little research on this issue, and proposes that as an alternative, the current natural gas GHG adder could be retained until such time as additional research becomes available. In the future, targets for low carbon fuels in the natural gas system may drive sector specific investment and associated GHG emissions costs (analogous to the GHG shadow prices from IRP RESOLVE modeling). If specific targets are adopted by natural gas utilities for low carbon fuels in the portfolio, Staff recommends considering development of additional methods to reflect those costs in future ACC updates.

However, Staff also recognizes that either of the options above result in inconsistent valuation for DERs that reduce natural gas consumption and DERs that reduce electricity consumption, and in the extreme case would use different values for avoided GHGs resulting from dual fuel equipment or between fuels in a fuel substitution project. Therefore, Staff proposes as a third option to consider using the electric sector, IRP-based GHG Adder for natural gas, as a proxy value that indicates the approximate cost to ratepayers of the State's building decarbonization efforts. This would avoid what seems to be a problematic outcome of applying different avoided GHG values to the same avoided cost for projects or equipment that happen to involve two different fuels.

Staff welcomes party comment on these options.

10. Minor Updates to the ACC

This section proposes several minor updates to the ACC that do not entail substantial changes to methodology or results of the model. Note that the above major updates will entail significant changes and updates to the structure of the ACC that will need to be developed and implemented over several months. This section does not enumerate all possible changes that are proposed for the Avoided Cost Calculator. Rather, this section describes additional changes that are not related to the major updates described above.

One minor error has been found in 2019 Natural Gas Avoided Cost Calculator, which does not affect the 2019 ACC results. Staff proposes that this error be resolved in the next update. The issue was a mismatch in the start year, between the "Settings + Results" tab and the "Emissions" tab. The NOx and CO2 costs from the former were being pulled in beginning with 2019 data from the latter, regardless of the user-input "First year" value on the "Settings + results" tab. The same issue took place for the "Average T&D Cost" output on the "Settings + results" tab. Both issues have been resolved and will be incorporated in the next public version released."

Additional updates that are proposed to for development and incorporation in the 2020 ACC update are:

- **Expanding the Avoided Cost Calculator outputs used for demand response**: include 8760 values to value additional DR types. The DR outputs were designed to evaluate Shed DR that reduces load during peak load hours. More dynamic forms of DR are proposed to better support renewable generation. These include Shift DR to reduce load in some hours and increase load in hours, and Shimmy DR to provide flexible ramping and ancillary services like frequency regulation. Staff proposes expanding the ACC to provide the data needed to value these additional DR types.
- **Remove any remaining separate Avoided Cost Calculator outputs used for Permanent Load Shifting.** With the expansion of the DR evaluation described above, it will include all the results necessary to evaluate any load shifting programs.
- **One-year ACC back cast.** Evaluation, Measurement and Verification studies for DER in some cases want to perform ex-post cost-effectiveness or GHG impact evaluation of DER installed in prior years. For example, the Self-Generation Incentive Program evaluation reports include and evaluation of GHG impacts for the previous year. Staff proposes including one or more historical years in the ACC so such evaluations can be performed on a consistent basis, with aligned historical weather, loads and prices.

(END OF APPENDIX A)