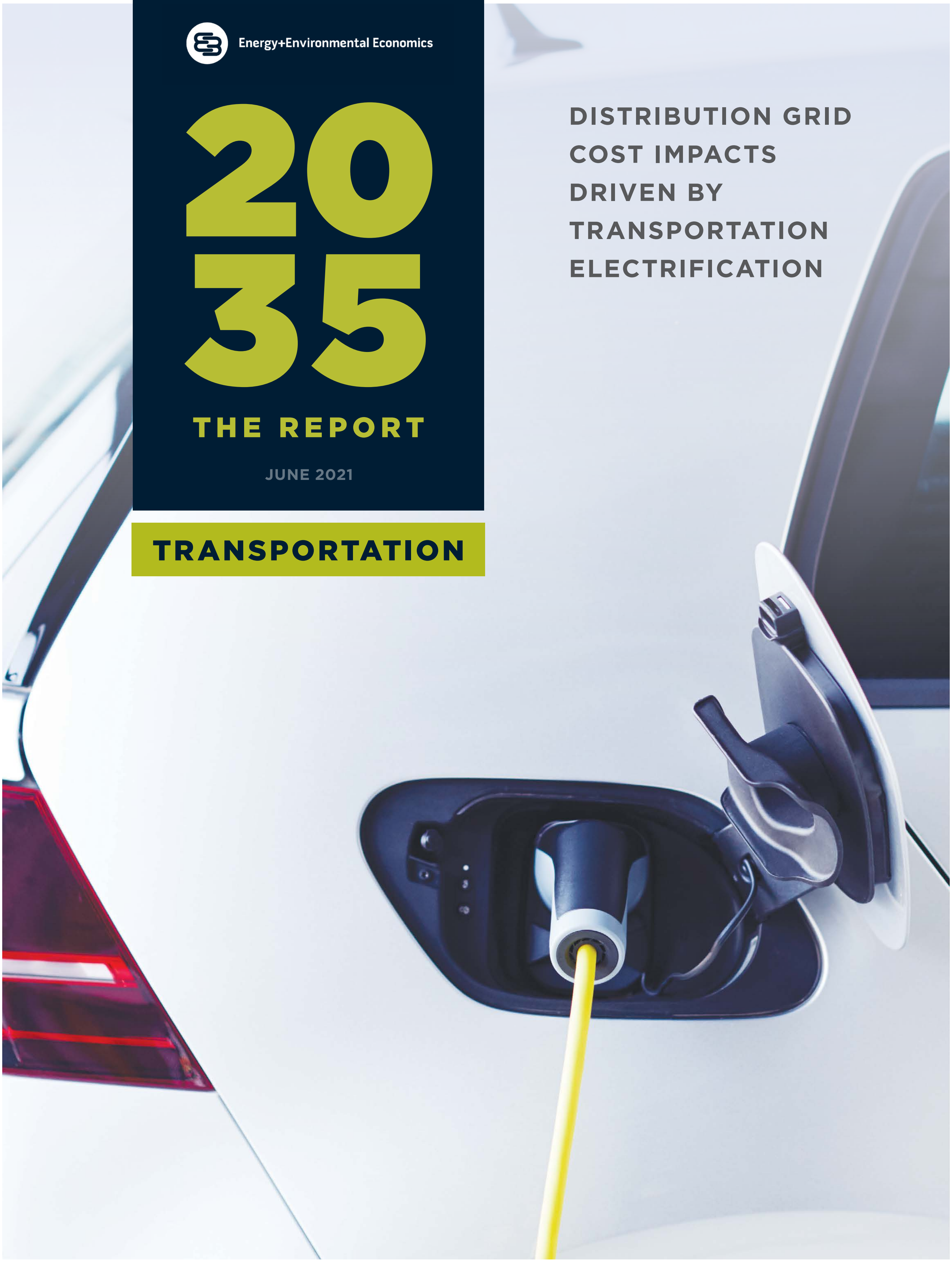
Energy+Environmental Economics

2035 THE REPORT

JUNE 2021

TRANSPORTATION

DISTRIBUTION GRID COST IMPACTS DRIVEN BY TRANSPORTATION ELECTRIFICATION



ABSTRACT

This analysis estimates the U.S. national electric utility distribution upgrade costs that will be driven by EV charging for the No New Policy and DRIVE Clean (100% LDEV Sales by 2030) adoption scenarios in the 2035 Report 2.0. We estimate costs for two categories of upgrades: primary distribution costs driven by coincident peak EV charging (coincident peak load) and secondary distribution costs driven by the interconnection of EV chargers (connected load). Key drivers of distribution upgrade costs vary widely and are location specific making any nationwide estimate necessarily approximate. For the DRIVE Clean scenario we estimate 2050 annual revenue requirements for distribution upgrades that range from $2.8 to $20 billion. Even at the high end, this is a fraction of the $162 billion of annual distribution revenue requirement projected for 2050 by the 2021 Annual Energy Outlook and would actually reduce average $/kWh distribution rates due to added EV charging load. Furthermore, simple managed charging solutions such as time of use (TOU) rates could reduce distribution costs by 50% or more.

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EXECUTIVE SUMMARY

This analysis estimates the U.S. national electric utility distribution upgrade costs that will be driven by EV charging for the No New Policy and DRIVE Clean adoption scenarios in the 2035 Report 2.0. The DRIVE Clean adoption scenario assumes all light duty vehicles (LDV) sold in 2030 and later are electric. A novel contribution of this analysis is to estimate costs for two categories of upgrades: primary distribution costs driven by coincident peak EV charging (coincident peak load) and secondary distribution costs driven by the interconnection of EV chargers (connected load). Secondary distribution upgrade costs are a fraction of primary costs on a $/kW basis, but the connected load of EV chargers is an order of magnitude higher than coincident peak EV charging load.

For the No New Policy scenario, coincident peak load reaches 30 GW by 2035 and 95 GW by 2050 (Figure 1). Connected load for the EV chargers is more than 10 times the coincident peak load at 402 GW in 2035 and 1,282 GW in 2050. In the DRIVE Clean scenario EV adoption is accelerated, and the coincident peak load is 113 GW in 2035 and 167 GW in 2050. The connected load is 804 GW by 2035 (about twice that of the No New Policy scenario) and 1,269 in 2050 (essentially the same as in the No New Policy scenario).

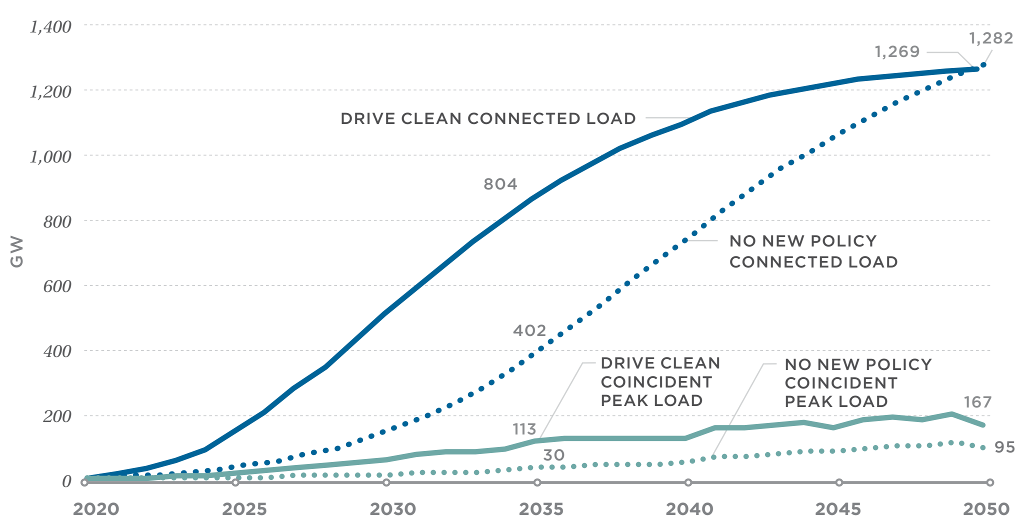


FIGURE 1.

Connected EV Charger Load and Coincident Peak Charging Load for the No New Policy and DRIVE Clean Scenarios

We apply two methods to estimate distribution investment costs driven by EV load growth. The first is based on a survey of marginal cost approaches commonly used to estimate load growth related distribution costs in utility rate cases and regulatory proceedings in the U.S. The second is a more detailed evaluation of all forecasted needs on the distribution system and planned upgrades, which is based on approach used in the California Distribution Resource Planning (DRP) Proceeding. For each method we develop a low-cost case keeping current cost assumptions constant, and a high-cost case, assuming cost and number of upgrades driven by EV load will increase over time (in real dollars) with increased penetration and clustering.

The marginal cost low case, based on a survey of utility distribution cost studies for distributed energy resources (DER) results in 2050 cumulative distribution investment costs of $76 million for the No New Policy scenario and $116 billion for the DRIVE Clean scenario (Figure 2, in $2020). The marginal cost high case increases the 2050 cumulative investment cost by over 200% in the No New Policy scenario and 175% in the DRIVE Clean scenario. The highest cost estimates in both scenarios are around $200 billion where the DRIVE Clean scenario investment occurs earlier when the presumed increases in upgrade costs are lower in the high-cost cases. The California DRP low-cost case produces 2050 cumulative costs of $28 billion, about 25% of the marginal cost low case.

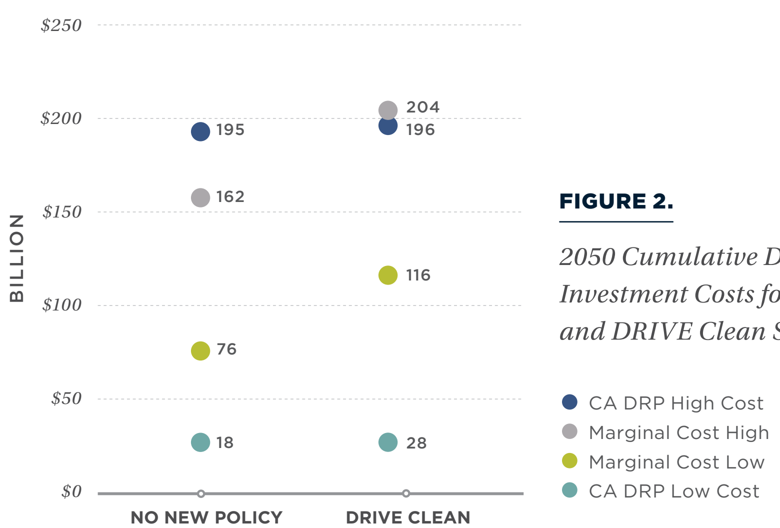


FIGURE 2.

2050 Cumulative Distribution Investment Costs for the No New Policy and DRIVE Clean Scenarios ($2020)

The 2050 annual revenue requirement for the marginal cost low case is $7.6 billion for the No New Policy scenario and $11.6 billion for the DRIVE Clean scenario (Figure 3). The highest annual revenue requirement for all the cases is $20 billion in 2050.

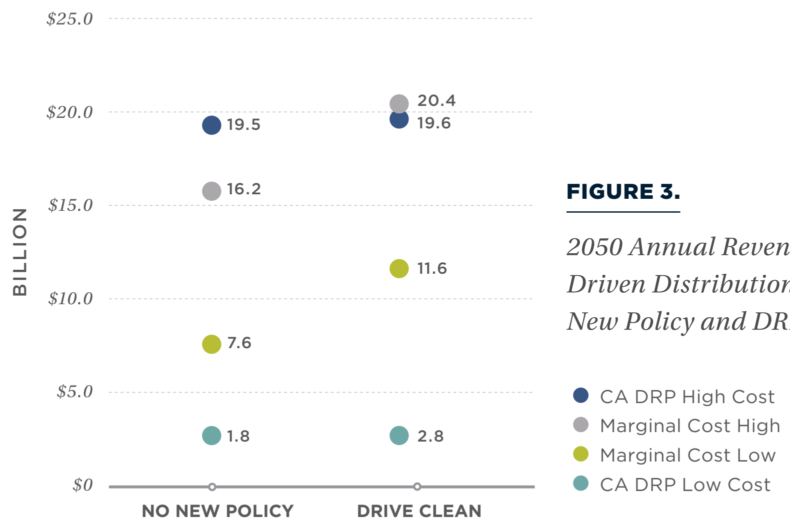


FIGURE 3.

2050 Annual Revenue Requirement for EV Driven Distribution Upgrades for the No New Policy and DRIVE Clean Scenarios

The annual revenue requirements calculated for EV driven distribution costs are a comparatively small portion of total utility distribution annual revenue requirement, which the 2021 Annual Energy Outlook (2021 AEO) projects to be $162 billion in 2050 (in $2020) (U.S. Energy Information Administration, 2021). More importantly our calculations suggest that adding EV load will reduce average distribution rates. The 2021 AEO projects a national average distribution cost of $0.03397/kWh based on retail sales of 4,748 TWh in 2050. Our highest cost estimates adds $20 billion in annual revenue requirement for the distribution system, and a total of 882 TWh of EV charging load. This results in an average distribution rate of $0.03221/kWh, a reduction of $0.0018/kWh or 5%.

Furthermore, this analysis did not evaluate Time-of-Use (TOU) rates and simple load management strategies, which have been shown to be quite effective at shifting EV charging off-peak. If 80% of coincident peak load is successfully shifted off-peak, reducing primary, but not secondary, distribution costs, cumulative investment costs in marginal high-cost case for the DRIVE Clean scenario could be reduced by just over 50% from $204 to $99 billion.

Any nationwide estimate of distribution upgrade costs is necessarily approximate and comes with many qualifications. Key drivers of distribution upgrade costs are both highly uncertain and location specific; primary distribution cost estimates vary by a factor of ten even within one utility. Furthermore, as compared to the primary distribution costs, the cost of upgrades on the secondary distribution system driven by the connected load of EV chargers is less widely studied and well understood. How the number, size and cost of upgrades driven by a given GW of EV load will change over time with increased EV penetration and clustering is highly uncertain.

With these caveats, important conclusions can nevertheless be drawn from our analysis. Transportation electrification (TE) increases system utilization and reduces average distribution rates even in our high-cost estimates and without managed charging. The less well studied secondary distribution costs driven by connected EV charging load are an important consideration, reaching as high as 50% of total distribution upgrade costs in our scenarios. Managed charging solutions have the potential to significantly reduce distribution costs, especially if they can reduce connected load driven secondary upgrade costs as well as coincident peak EV charging load.

2

DISTRIBUTION COSTS AND COST DRIVERS

2.1 LOAD GROWTH DRIVEN DISTRIBUTION COSTS

Utilities routinely perform marginal cost studies to quantify distribution investment costs for rate setting and 'avoided' cost studies to estimate distribution upgrade costs that can be avoided with DER. **Marginal costs** are all the incremental distribution costs required to serve additional load. **Avoided costs** are the distribution costs that can be avoided by reducing or shifting load.

For marginal cost studies, distribution costs are divided into three categories; 1) costs that vary with the number of customers, 2) costs related to the diversified load of customers that is coincident with the distribution peak and 3) costs related to the total non-coincident connected load of customers served by the distribution system. Individual planned distribution upgrades may also be driven by other needs such as voltage support, reliability or resiliency but these are not generally considered separately in marginal or avoided cost studies for forecasted growth in customer load or DER. Distribution investment driven by the number of customers (as opposed to customer loads) includes land, poles, right of ways and meters to serve new customers and sub-divisions. For DER in general and TE specifically, analysis is focused on the latter two load-growth driven cost categories.

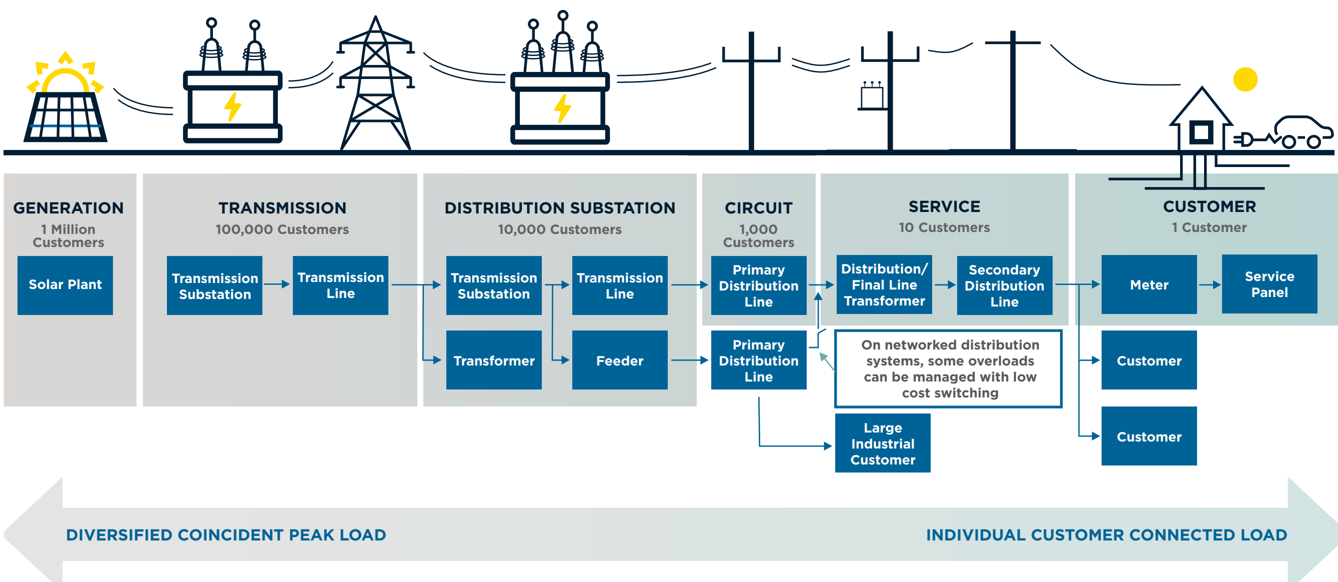
- **Diversified Coincident Peak Load** is the aggregated coincident peak load of a large number of customers. It is the primary driver of generation, transmission and distribution substation costs. Across such a large group of customers, utility planners can safely assume diversity in the timing of customer loads and that only a subset of all EVs will be plugged in and charging coincident with the system peak.

- **Non-coincident Connected Load** is the total maximum load of the customers connected to the distribution system. The number of customers connected decreases as you move further down the distribution system to the circuit, service or line section level. Here load diversity cannot be safely assumed — all customer loads may be near their maximum level at the same time. If 5 out of 10 customers at the service level own EVs, planners will design the system to accommodate the maximum charging of all five EVs at the same time.

Figure 4 illustrates the components of the electric grid and the different number of customers served from each. The diversified load of thousands of customers that is coincident with the utility system peak drives distribution substation, bank and feeder costs on the primary distribution system. Circuit, transformer and service level capacity costs at the secondary level are driven primarily by the long-term maximum non-coincident connected load of the customers served by the specific circuit (Nieto, 2019). To date, marginal and avoided cost studies for DER and TE have focused exclusively on diversified coincident-peak load driven costs at the primary feeder, bank and distribution substation level. High electrification scenarios for transportation and buildings are driving policy makers and planners to also give more careful consideration to the connected load driven costs at the secondary, circuit and service level as well.

FIGURE 4.

Cost Drivers of EV Charging on the Utility Distribution System



2.2 VARIATION IN DISTRIBUTION MARGINAL COSTS

Distribution investments are highly location specific and a variety of different approaches are used in marginal and avoided cost studies. This leads to a wide variation in estimates of marginal or avoided distribution costs, typically expressed in an annual $/kW-Yr. value. A 2014 review of 25 distribution avoided cost studies across the U.S. found values ranging from $0 to $171/kW-Yr. with an average of $48/kW-Yr. and 8 of the 25 studies falling in the $21-$40/kW-Yr. range (The Mendota Group, 2014).

FREQUENCY OF DISTRIBUTION AVOIDED COST RANGES ($/KW-YR.)

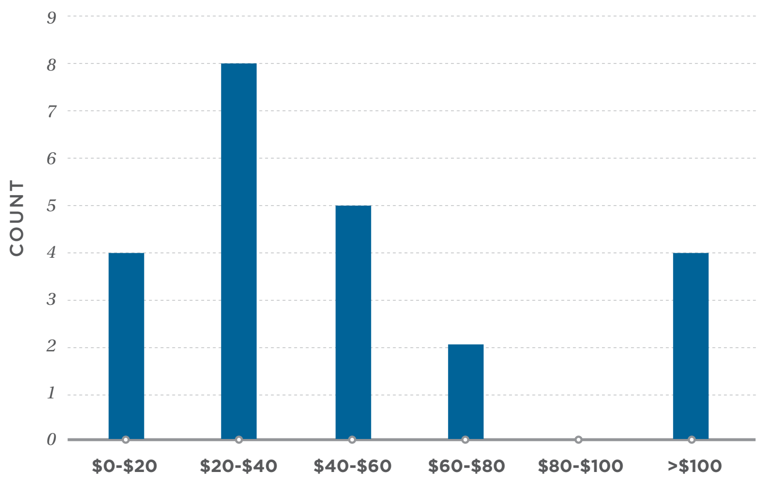


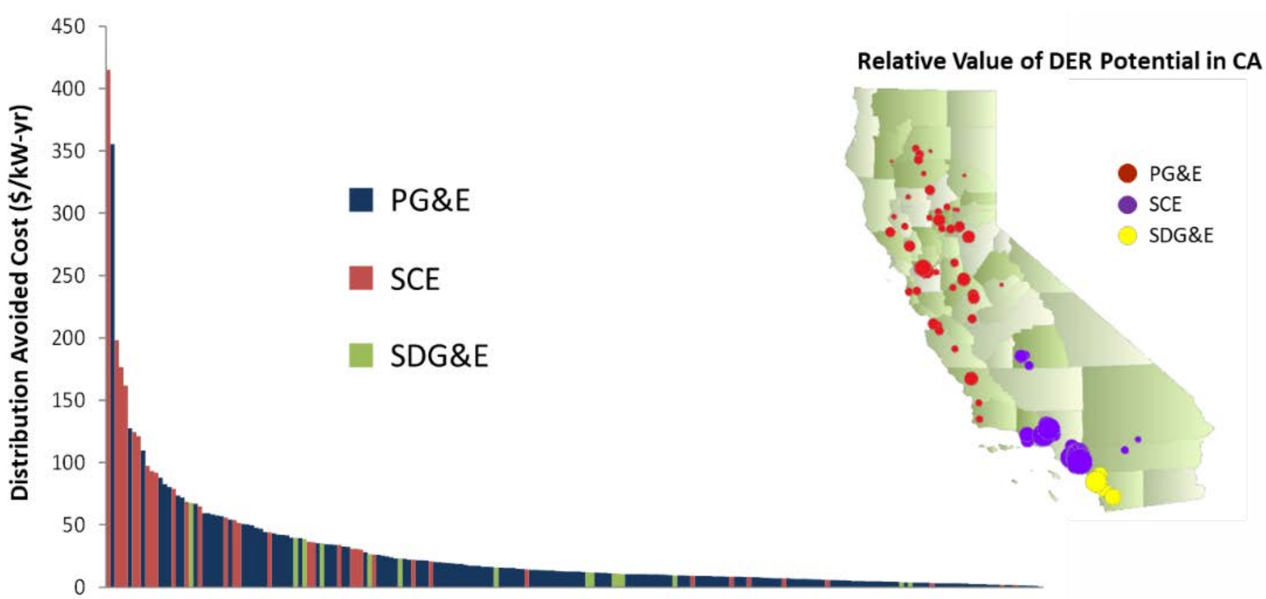
FIGURE 5.

The Mendota Group Survey of Distribution Avoided Cost Studies

Even within a single state or utility using a consistent methodology, marginal costs for distribution upgrades vary widely. The figure below shows the range of annualized local distribution avoided costs by area using California utility distribution planning information from 2011 (E3, 2011a). There is a small number of upgrades with high avoided costs above $100/kW-Yr. and a somewhat larger, but still a modest percentage, of upgrades above $50/kW-Yr. The vast majority of upgrades have an avoided cost below $50/kW-Yr.

FIGURE 6.

Avoided Cost Value for Distribution Upgrades by Area in California (2011)



More recent data in California shows a similar pattern. In 2014, the CPUC instituted a rulemaking (R.14-08-013) to develop Distribution Resource Plans (DRPs) (CPUC 2014a), resulting in a requirement for regulated utilities to file DRPs that systematically evaluate potential distribution system investments. The CPUC requires the utilities to annually perform a grid needs assessments (GNA) and issue a distribution deferral opportunity report (DDOR).1 Each utility performs a GNA that provides the available capacity, projected baseline DER deployment, and forecasted load growth for the next five years at every distribution feeder and substation bank. The DDOR summarizes all the planned investments needed to address deficiencies identified in the GNA (CPUC 2016). A Local Net Benefits Analysis (LNBA) is performed for each identified upgrade to quantify the avoided cost value on a $/kW-Yr. basis.

In 2019 PG&E evaluated 4,269 circuits in its GNA and found 6,994 "needs" for upgrades (PG&E 2019d). With respect to projects to meet these needs, 797 were related to distribution capacity, 6,153 to voltage support, and 44 for reliability. The GNA finds that the vast majority of needs can be addressed with planned load transfers and switching operations without additional upgrades. After load transfers, PG&E identified 215 planned investments for substation, feeder, and distribution line sections to mitigate the remaining needs (one project can mitigate multiple needs) (PG&E 2019c). Figure 7 and Figure 8 below show the LNBA deferral value for 165 of the identified upgrades that are capacity related and driven by coincident peak load growth. Here again a small number of upgrades have a high avoided cost value and the vast majority of upgrades have a low avoided cost value.

1 D.18-02-004 initially directed the IOUs to file annual GNAs and DDORs by June 1 and September 1, respectively. This was modified in May 2019 (in response to IOU motions), consolidating the requirement into a combined annual GNA/DDOR filing to be submitted by August 15 each year. See http://docs.cpuc.ca.gov/PublishedDocs/Efile/G000/M288/K311/288311944.PDF.

PG&E LNBA DISTRIBUTION DEFERRAL VALUES ($/KW-YR.)

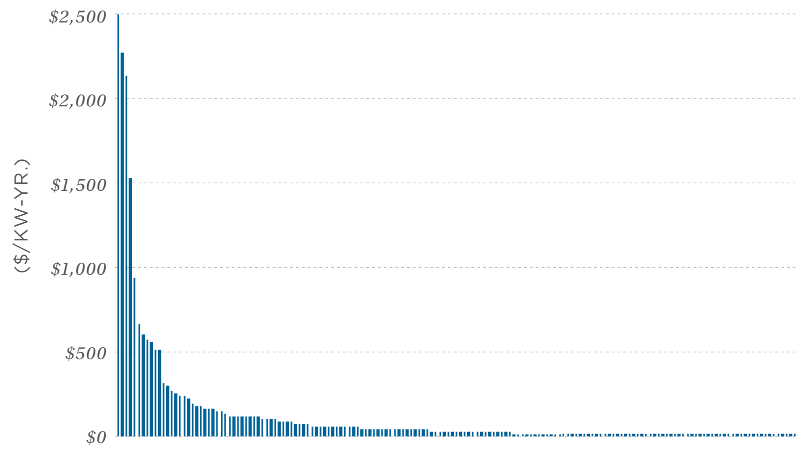


FIGURE 7.

Local Net Benefits Analysis (LNBA) Deferral Value for Identified Upgrades in PG&E's Service Territory (2019)

PG&E LNBA DISTRIBUTION DEFERRAL VALUE RANGE ($/KW-YR.)

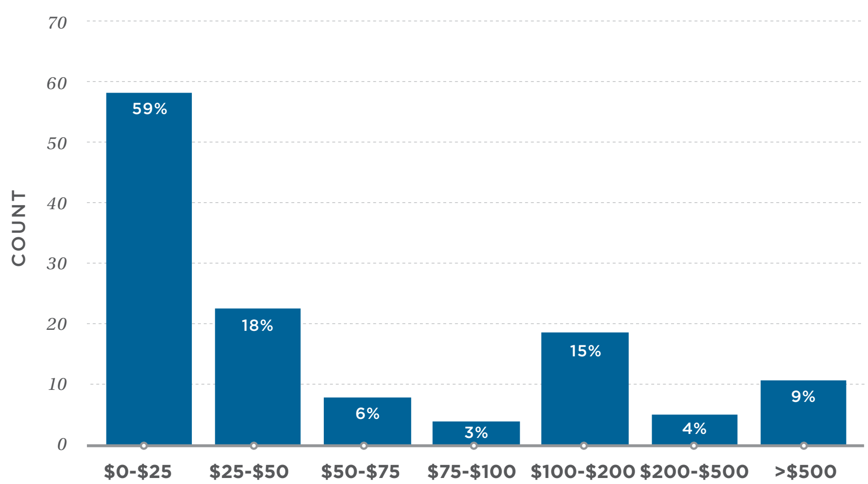


FIGURE 8.

PG&E Percentage of Upgrades by Avoided Cost Value

2.3 COINCIDENT PEAK LOAD GROWTH DRIVEN DISTRIBUTION COSTS

Marginal cost studies first calculate an average $/kW cost for capital investment in the distribution system that is driven by diversified, coincident peak load. Table 1 below shows $/kW marginal distribution costs for five utilities. PG&E estimates marginal costs by distribution planning area, ranging from $139 to $1,246/kW within a single utility in Northern California. Estimates for the two other major investor owned utilities in California are on the high end, above $1,300/kW. Marginal cost studies filed by Otter Tail Power Co (Nieto, 2018) in the Midwest and Eversource Energy (Nieto, 2019) in New Hampshire have lower marginal distribution costs in the $200/kW range.

TABLE 1.

Cost Drivers of EV Charging on the Utility

UTILITY		PG&E		SCE	SDG&E	OTTER TAIL	EVERSOURCE
Distribution Planning Area		Mission	Sonoma				
$/kW		$139	$1,246	$1,461	$1,307	$237	$183
$/kW-Yr		$14	$122	$168	$100	$21	$25
2020 Values	$/kW	$148	$1,322	$1,520	$1,415	$246	$186
	$/kW-Yr	$14	$129	$175	$108	$22	$25
RECC		9.8%	9.8%	11.5%	7.7%	9.0%	13.5%
Base Year		2017	2017	2018	2016	2018	2019

The upfront capital investment costs in $/kW are translated into an annual $/kW-Yr. revenue requirement using a Real Economic Carrying Charge (RECC) calculation. The RECC accounts for the useful life of the distribution investment (typically ~40 years), a rate of return earned by investor owned utilities on capital investments, a revenue requirement gross-up for utility administrative and overhead costs, and annual operations and maintenance expenses. Table 1 shows a range of RECC values from 7.7% for SDG&E to 13.5% for Eversource. Escalating values to a common 2020 base year using at 2% inflation rate yields annual $/kW-Yr. revenue requirements that range from a low of $14/kW-Yr. for PG&E's Mission distribution planning area to a high of $175/kW-Yr. for SCE.

It bears emphasizing that the sources cited in Table 1 and from the Mendota Group Report illustrate the wide range in values for distribution costs driven by coincident peak load but are not necessarily a representative sample for the U.S..

2.4 CONNECTED LOAD GROWTH DRIVEN DISTRIBUTION COSTS

Marginal cost estimates for distribution costs at the secondary, circuit and service level driven by connected load are less commonly available. The most detailed source we were able to find is from PG&E's 2017 rate case (Table 2). The first column shows the primary capacity costs, including the $14 and $122/kW-Yr. shown for the Mission and Sonoma distribution planning areas in Table 1 above. The next column shows much lower $/kW-Yr. costs at the secondary level. The primary capacity costs are driven by diversified peak loads (labeled here a Peak Capacity Allocation Factor or PCAF load) and the secondary costs are driven by higher (less diversified) loads measured at the final line transformer.

Using these results, we estimate connected load upgrade costs at secondary level as being 5% of the diversified load costs at the primary level.

TABLE 2.

PG&E 2017 Rate Case Distribution Costs by Distribution Planning Area

DISTRIBUTION PLANNING AREA	PRIMARY CAPACITY $/KW-YR	SECONDARY $/KW-YR	SECONDARY/ PRIMARY COST	TOTAL PEAK CAPACITY ALLOCATION FACTOR LOADS (PCAF KW)	TOTAL FINAL LINE TRANSFORMER LOADS (FLT KW)	FLT/PCAF LOAD
Central Coast	$69.09	$1.04	2%	823,510	1,759,256	214%
De Anza	$35.65	$1.01	3%	741,675	1,234,311	166%
Diablo	$17.78	$1.56	9%	1,265,169	1,524,487	120%
East Bay	$19.99	$0.88	4%	627,862	1,338,170	213%
Fresno	$39.52	$1.36	3%	2,164,629	3,575,125	165%
Humboldt	$73.97	$1.12	2%	292,803	736,437	252%
Kern	$34.07	$1.23	4%	1,585,454	2,449,767	155%
Los Padres	$56.49	$1.06	2%	492,381	1,041,742	212%
Mission	$13.63	$0.97	7%	1,233,354	2,022,915	164%
North Bay	$29.42	$1.75	6%	647,540	1,283,383	198%
North Valley	$53.40	$1.26	2%	742,213	1,324,624	178%
Peninsula	$31.79	$1.06	3%	766,475	1,436,434	187%
Sacramento	$40.91	$1.22	3%	970,943	1,589,591	164%
San Francisco	$40.41	$1.52	4%	829,544	1,435,075	173%
San Jose	$40.12	$1.16	3%	1,369,868	2,130,431	156%
Sierra	$30.65	$1.25	4%	1,187,910	1,833,534	154%
Sonoma	$121.98	$1.28	1%	544,454	1,147,401	211%
Stockton	$33.36	$1.34	4%	1,207,506	2,114,747	175%
Yosemite	$60.18	$1.56	3%	1,090,280	2,098,437	192%

3

ESTIMATES OF MARGINAL DISTRIBUTION COSTS

The studies summarized in Section 2 illustrate two fundamentally different approaches to quantifying capacity related avoided costs for the distribution system. The most common is an aggregated marginal cost approach that looks at all capacity related distribution investments made or planned by the utility and the load growth that is driving those investments. The sources for investment costs are usually high-level aggregated costs by category from general rate cases or FERC reports. There are different methods we will not delve into here, but essentially the total investment divided by the total load growth yields a $/kW or $/kW-Yr. marginal or avoided cost value. In this aggregated marginal cost approach, every kW of increased (or decreased) load growth drives a $/kW distribution capital investment cost.

A second more detailed approach is used in the California DRP process in which specific needs by location are identified in the distribution planning process, typically identifying individual distribution upgrades needed in the next five years. Many needs can be addressed with low-cost load transfers and switching operations. Of the remaining upgrades, some are identified as deferrable with DER. Once again, dispensing with the details, the total deferred distribution investment divided by the forecasted DER contribution to peak load reduction yields a $/kW avoided cost value per kW of DER. Note that in this approach every ‘x’ kW of DER forecasted avoids a smaller ‘y’ kW of identified capacity related distribution upgrades.

3.1 MARGINAL COST APPROACH

For our marginal approach, we developed an estimate of $40/kW-Yr. to be close to the modal value of the 2014 Mendota Group survey. We assume a small percentage of high and mid-value upgrades at $1,400 and $600/kW respectively, and a larger percentage of low-cost upgrades at $200/kW (Table 3). This results in a weighted average cost of $400/kW which translates to $40/kW-Yr. with an assumed RECC value of 10% (see Table 1).

TABLE 3.

Distribution Upgrade Costs for Marginal Cost Approach

AVG.	HIGH	MID	LOW	
	10%	20%	70%	
$400	1,400	600	200	$/kW
$40	140	60	20	$/kW-Yr.
RECC	10.0%			

For the base value case we keep the assumptions constant with no increase over time in the percentage of deficiencies or connected load upgrades driven by EV load or in the proportion of upgrade costs that are in the high or mid cost categories (Table 4).

TABLE 4.

Low Value Case for Marginal Cost Approach — Escalation of Marginal Cost

	2020	2030	2040	2050
Deficiencies driven by EV Load	100%	100%	100%	100%
Connected load upgrades driven by EV Load	100%	100%	100%	100%
High	10%	10%	10%	10%
Mid	20%	20%	20%	20%
Low	70%	70%	70%	70%
Secondary as Percent of Primary Distribution Upgrade Costs	5%			

For the high-cost case we assume that the proportion of high and mid cost upgrades increases over time. This reflects a presumption that with higher EV penetrations and with higher concentrations of EVs in specific areas that the required upgrades will gradually become more expensive over time. (Table 5).

TABLE 5.

High Value Case for Marginal Cost Approach — Escalation of Marginal Cost

	2020	2030	2040	2050
Deficiencies driven by EV Load	100%	100%	100%	100%
Connected load upgrades driven by EV Load	100%	100%	100%	100%
High	10%	18%	25%	33%
Mid	20%	27%	35%	42%
Low	70%	55%	40%	25%
Secondary as Percent of Primary Distribution Upgrade Costs	10%			

3.2 CALIFORNIA DISTRIBUTION RESOURCE PLANNING APPROACH

For our California DRP approach, we develop an estimate from the GNA reports of each California investor owned utility, PG&E, SCE and SDG&E. The average cost of deferred upgrades ranges from $1,036/kW for SDG&E to $1,301/kW for SCE. The total forecasted DER peak load reduction and associated deferrable overloads that are identified are shown for each utility. Note that there is a large difference in the overloads as a percentage of the DER forecast, from a low of 4% for SDG&E to a high of 12% for PG&E. This results in avoided costs ranging from $38/kW for SDG&E to $148/kW for PG&E. Using each utilities' specified RECC value and adjusting to a 2020 base year shows avoided cost values ranging from $3 - $15/kW-Yr.

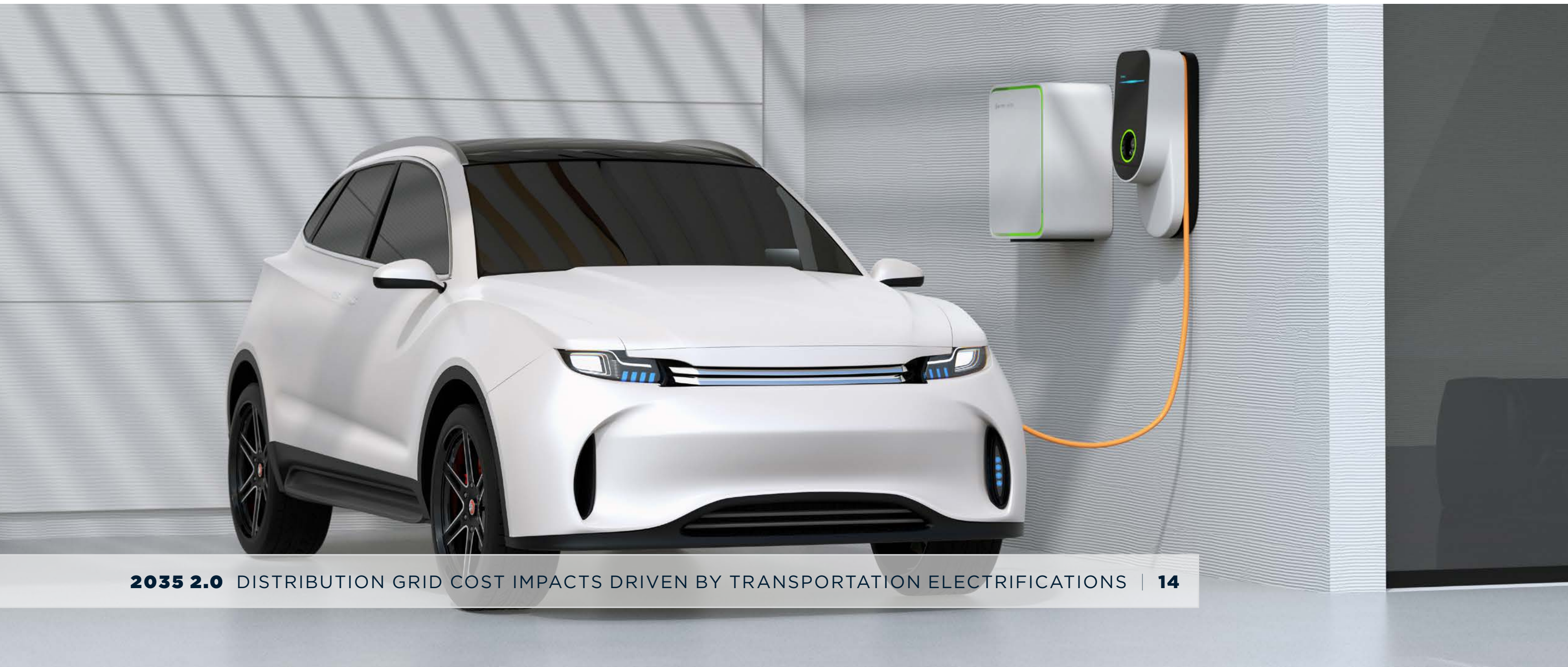


TABLE 6.

Inputs for Distribution Upgrade Costs for California DRP Approach

	PG&E	SCE	SDG&E	UNITS
Unit Cost of Deferred Upgrades	$1,206	$1,301	$1,036	$/kW
Deferrable Overloads	280,461	229,328	23,018	MW
DER Forecast	2,285,003	2,911,430	625,460	MW
Deferred Overloads as % of DER Forecast	12%	8%	4%	%
Distribution Deferral Value	$148	$102	$38	$/kW
	$14	$12	$3	$/kW-Yr.
2020 Distribution Deferral Value	$151	$107	$40	$/kW
	$15	$12	$3	$/kW-Yr.
RECC	9.79%	11.49%	7.65%	%
Base Year	2019	2018	2018	

We generalize the above results by creating a weighted average avoided cost of $1,190/kW and $119/kW-Yr. We pick the middle of the 4-12% range for the three utilities and assume that on average 8% of load growth from EVs drives deficiencies requiring upgrades, resulting in an upgrade cost of $95/kW (again using a 10% RECC). Applying a California cost adjustment of 1.23 from the U.S. Army Corp of Engineers yields national average cost of $77/kW and $8/kW-Yr.

TABLE 7.

Distribution Upgrade Costs for Bottom-Up California DRP Approach

	HIGH	MID	LOW	
	10%	20%	70%	
$1,190	10,000	600	100	$/kW
$119	1,000	60	10	$/kW-Yr.
RECC	10.0%			

Investment Cost per kW of EV Load		
CA	National	
$95	$77	$/kW
$10	$8	$/kW-Yr.
Deficiencies Driven by EV load	8%	
California Cost adjustment	1.23	

For the low-cost case we assume no escalation in the upgrades driven as a percent of EV load or in the proportion of high and mid cost upgrades (same as for the top-down marginal cost approach) (Table 8).

TABLE 8.

Low Value Case for California DRP Approach - Escalation of Avoided Cost

	2020	2030	2040	2050
Deficiencies driven by EV Load	8%	8%	8%	8%
Connected load upgrades driven by EV Load	8%	8%	8%	8%
High	10%	10%	10%	10%
Mid	20%	20%	20%	20%
Low	70%	70%	70%	70%
Secondary as Percent of Primary Distribution Upgrade Costs	5%			

For the high-cost case, we assume that the percentage of upgrades driven by EV load will increase over time and that the proportion of upgrade costs in the high and mid cost categories will also increase over time. Similar to the marginal cost approach, this is to reflect a presumption that an increasing penetration and concentration of EVs is specific areas will gradually use up existing headroom on the distribution system and lead to more and more expensive upgrades being required.

TABLE 9.

High Value Case for California DRP Approach — Escalation of Avoidedl Cost

	2020	2030	2040	2050
Deficiencies driven by EV Load	8%	15%	25%	33%
Connected load upgrades driven by EV Load	15%	23%	30%	37%
High	10%	18%	25%	33%
Mid	20%	27%	35%	42%
Low	70%	55%	40%	25%
Secondary as Percent of Primary Distribution Upgrade Costs	10%			

4

ANALYTICAL APPROACH AND RESULTS

4.1 ANALYSIS OF EV LOAD IMPACTS

The analysis was performed for two scenarios, the “No New Policy” and “DRIVE Clean”. In the No New Policy scenario, EVs constitute 45% of new LDV sales, 38% of MDV sales, and 12% of HDT sales in 2035, and the clean electricity share reaches only 45% by 2035. The Drive Clean scenario represents a future in which EVs constitute 100% of new U.S. light-duty vehicle (LDV) sales by 2030 as well as 100% of medium-duty vehicle (MDV) and heavy-duty truck (HDT) sales by 2035 and the grid reaches 90% clean electricity by 2035.

Using EV charger and load data provided by UC Berkeley, we calculated the connected and coincident peak loads for 2020 to 2050. For each charger type, we calculated connected load by multiplying the number of chargers by their power. We assumed power levels for each charger type shown in the table below. We summed the connected load for each charger type to calculate total connected load.

TABLE 10.

Power Level by Charger Type

CHARGER TYPE	POWER (KW)
Level 1	1.4
Level 2	11
DCFC	50
DCFC 100 kW	100

To calculate coincident peak load, we first identified residential and public peak load times using the NREL ReEDS High Electrification Scenarios (NREL, 2020). We then identified residential and public EV charging occurring during the respective peak times to calculate residential and public coincident peak loads.

The figures below show the resulting connected and coincident peak loads for the No New Policy and DRIVE Clean scenarios. In the No New Policy Scenario, coincident peak load for EV charging reaches 30 GW by 2035 and 95 GW by 2050. The connected load of all EV chargers totals 402 GW by 2035 and 1,282 GW in 2050.

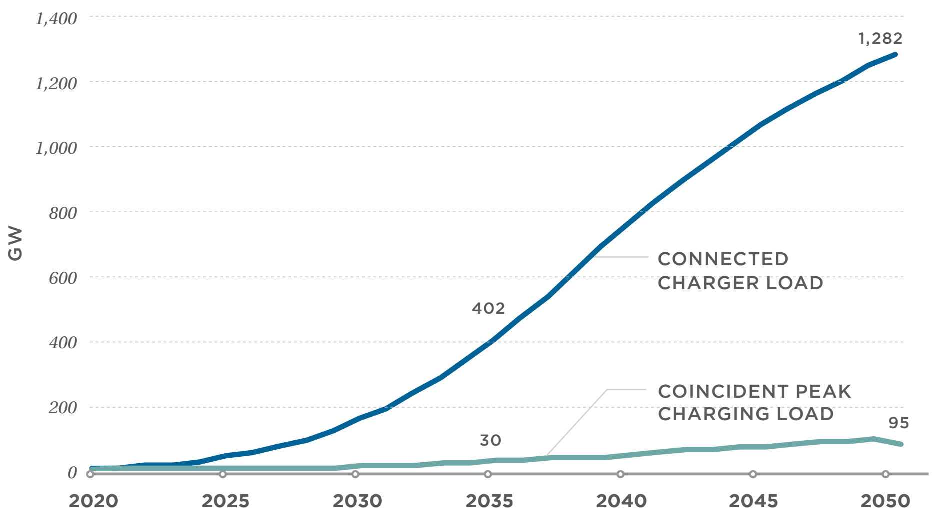


FIGURE 9.

No New Policy adoption case connected and coincident peak charging loads.

In the DRIVE Clean Scenario, coincident peak load for EV charging reaches 113 GW by 2035 and 167 GW by 2050. The connected load of all EV chargers totals 804 GW by 2035 and 1,269 GW in 2050.

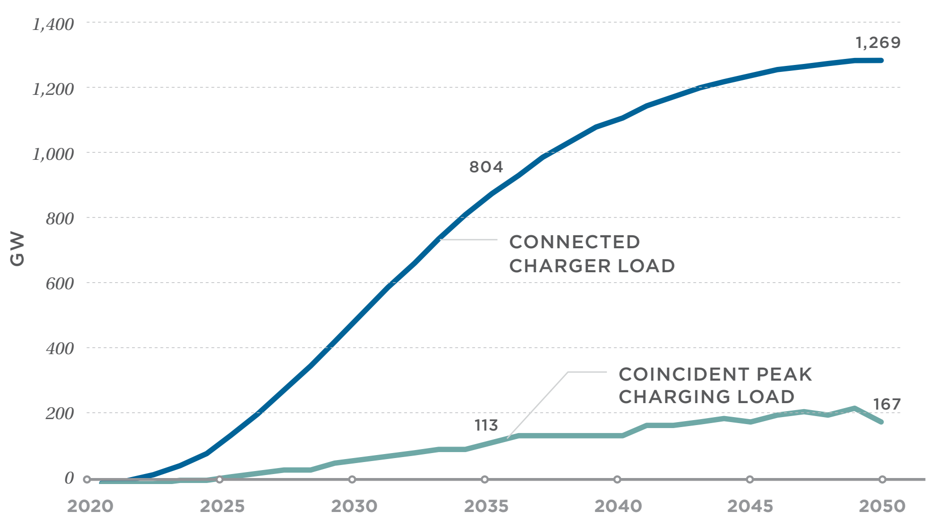


FIGURE 10.

DRIVE Clean adoption case connected and coincident peak charging loads.

Based on the figures above, total connected load reaches about 1,270 GW in 2050 for both the No New Policy and DRIVE Clean adoption scenarios. The DRIVE Clean scenario has a total connected load ramp that is steeper and begins earlier than the No New Policy scenario before tapering off in 2040. The DRIVE Clean scenario has a coincident peak load that is 3.8 times higher than the No New Policy scenario in 2035 and 1.8 times higher in 2050.

4.2 DISTRIBUTION COST SCENARIOS FOR NO NEW POLICY SCENARIO

4.2.1 MARGINAL COST APPROACH

The incremental annual coincident peak and connected loads are multiplied by their respective upgrade costs described in Section 3 to calculate the total distribution upgrade costs for the No New Policy and DRIVE Clean scenarios for each of the four cost cases. For the marginal cost low case, the coincident peak load is multiplied by the $400/kW upgrade cost ($2020) for the primary distribution system and the connected load is multiplied by $20/kW for the secondary distribution system (5% of the primary cost). The costs for each state are adjusted from the national average using the U.S. Army Corp of Engineers Construction Cost Index (USACOE, 2020).

The marginal cost low case is the most similar to the standard approach used today by utilities to calculate distribution costs driven by EV load. Under this case, the annual EV driven distribution costs total $1.5 billion (in $2020) in 2035 with a cumulative investment of $6 billion. By 2050 the cumulative investment is $76 billion, an average of $2.4 billion per year, with an annual revenue requirement in 2050 of $7.6 billion The total cost in 2050 are $562 per EV and $664 per charge point (note that these figures represent the total distribution costs divided by the number of EVs and number of charge points and are not additive).

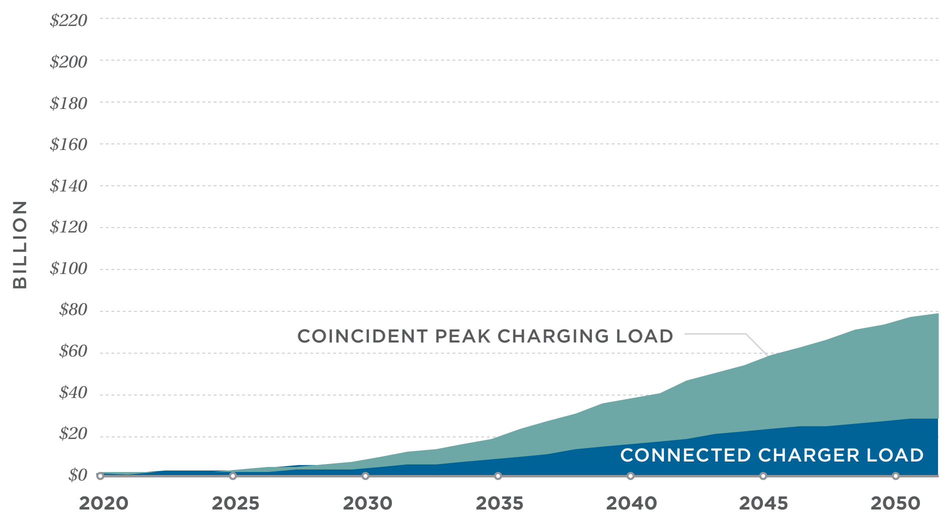


FIGURE 11.

Marginal Cost Low Case for No New Policy Scenario

TABLE 11.

Summary of Marginal Cost Low Case for No New Policy Scenario

	UNITS	2020	2035	2050
Total Annual Investment	$billion	$0.2	$1.5	$1.7
Cumulative Investment	$billion	$0.2	$6	$76
Annual Revenue Requirement	$billion	$0.0	$0.6	$7.6
Total Cost per EV	$/EV	$673	$537	$562
Total Cost per Charge Point	$/Charge Point	$444	$568	$664

The marginal cost high case is the highest of our four cost scenarios. Recall that the high-cost case assumes that a larger portion of upgrades will be in the high and mid cost categories and that the secondary distribution upgrade costs are 10% (rather than 5%) of primary distribution upgrade costs. In the marginal cost high case, cumulative distribution investment more than doubles, reaching $162 billion; an average annual investment of $5.2 billion and a 2050 revenue requirement of $16.2 billion. Note that the connected load costs are approximately 50% of the total (as compared to 35% in the marginal cost low case). In 2050 the total costs are $1,198 per EV and $1,415 per charge point.

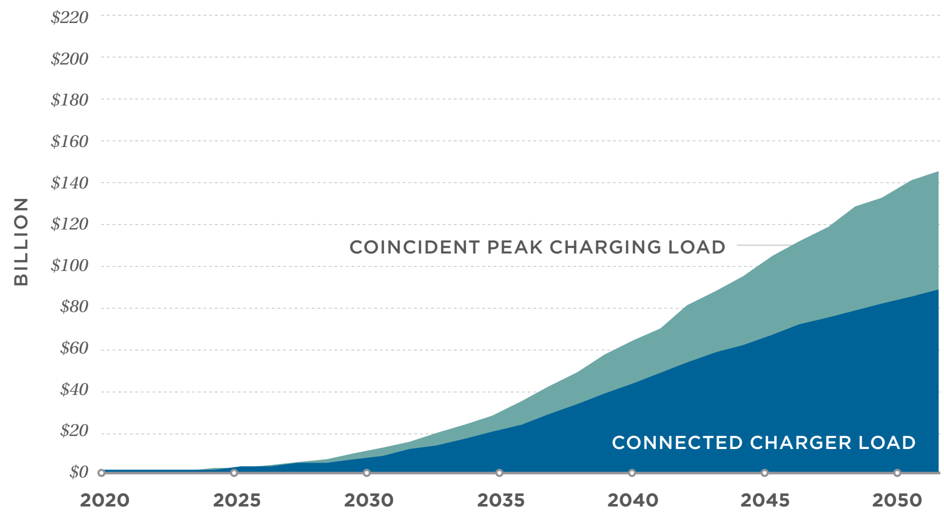


FIGURE 12.

Marginal Cost High Case for No New Policy Scenario

TABLE 12.

Summary of Marginal Cost High Case for No New Policy Scenario

	UNITS	2020	2035	2050
Total Annual Investment	$billion	$0.3	$2.6	$4.7
Cumulative Investment	$billion	$0.3	$10	$162
Annual Revenue Requirement	$billion	$0.0	$1.0	$16.2
Total Cost per EV	$/EV	$935	$1,000	$1,198
Total Cost per Charge Point	$/Charge Point	$618	$1,057	$1,415

4.2.2 CALIFORNIA DRP APPROACH

The California DRP Approach produces an even wider range of distribution investment costs. The California DRP low-cost case holds the costs and assumptions derived from 2019 DRP constant. If every 100 GW of EV coincident peak loads drives just 8 GW of upgrades and the majority of those upgrades are in the low-cost category, the cumulative investment is 24% of that in the marginal cost low case, just $18 billion by 2050. On the other hand, if the deficiencies driven by EV load increase from 8% to 33% by 2050 and the portion of upgrades that fall in the high and mid cost categories also increases, cumulative investment reaches $195 billion in 2050, more than 2.5 times the marginal cost low case.

4.2.3 NO NEW POLICY SCENARIO RESULTS SUMMARY

The results of the four cost cases for the No New Policy scenario are summarized below. In the No New Policy scenario the vast majority of EV adoption and associated distribution investment occurs after 2035. The California DRP low-cost case is relatively low at $18 billion in cumulative investment in 2050 with an annual revenue requirement of $1.8 billion. The more commonly used marginal cost approach yields a cumulative investment of $76 billion and an annual revenue requirement of $7.6 in 2050 in the marginal cost low case. Increasing upgrade costs over time in the marginal cost high case increases the cumulative investment over 50% to $162 billion by 2050. The California DRP high-cost case is our most pessimistic, with a cumulative cost of $195 billion, 2.5 times higher than the marginal low-cost case.

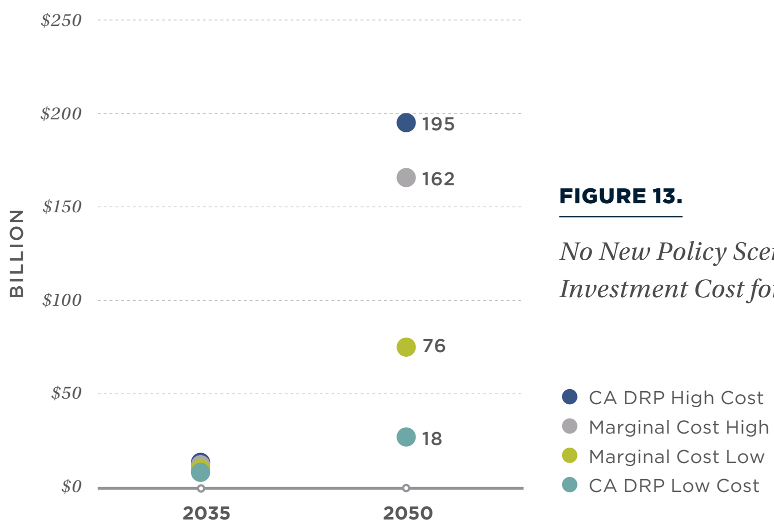


FIGURE 13.

No New Policy Scenario Cumulative Investment Cost for Four Cost Cases

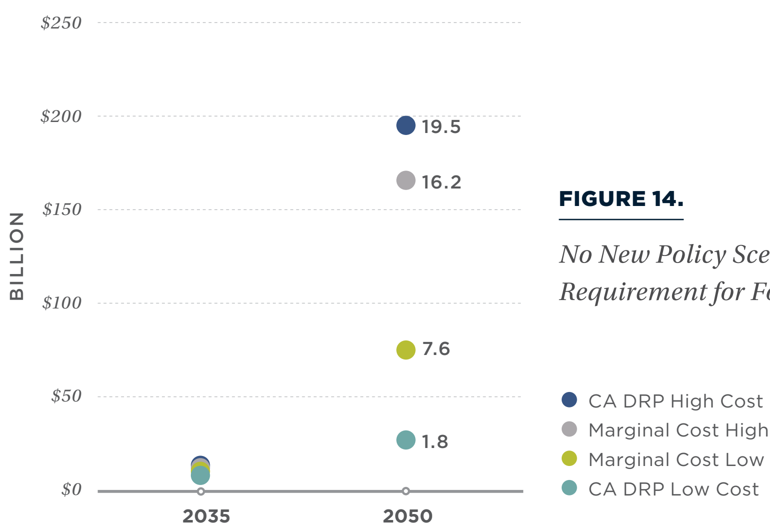


FIGURE 14.

No New Policy Scenario Annual Revenue Requirement for Four Cost Cases

4.3 DISTRIBUTION COST SCENARIOS FOR DRIVE CLEAN SCENARIO

4.3.1 MARGINAL COST APPROACH

For the DRIVE Clean scenario, the cost cases are the same as those used for the No New Policy scenario, but applied to the higher coincident peak and connected loads. As compared to the No New Policy scenario, EV adoption and associated distribution investment occurs earlier. By 2050 the coincident peak EV load is 1.7 times higher than the No New Policy scenario, but the connected charger load is similar as the build out of EV chargers occurs earlier in the DRIVE clean scenario but is similar for both scenarios by 2050. For the marginal cost low case, cumulative investment is $116 billion in 2050, an average annual investment of $3.7 billion and an annual revenue requirement in 2050 of $11.6 billion. This is 1.5 times higher than in the No New Policy scenario. The total costs of $489 per EV in 2050 are lower than the No New Policy scenario, but the total costs of $1,009 per charge point are higher. This is because there is a larger number of EVs but a similar number of charge points in the DRIVE clean scenario relative to the No New Policy scenario.

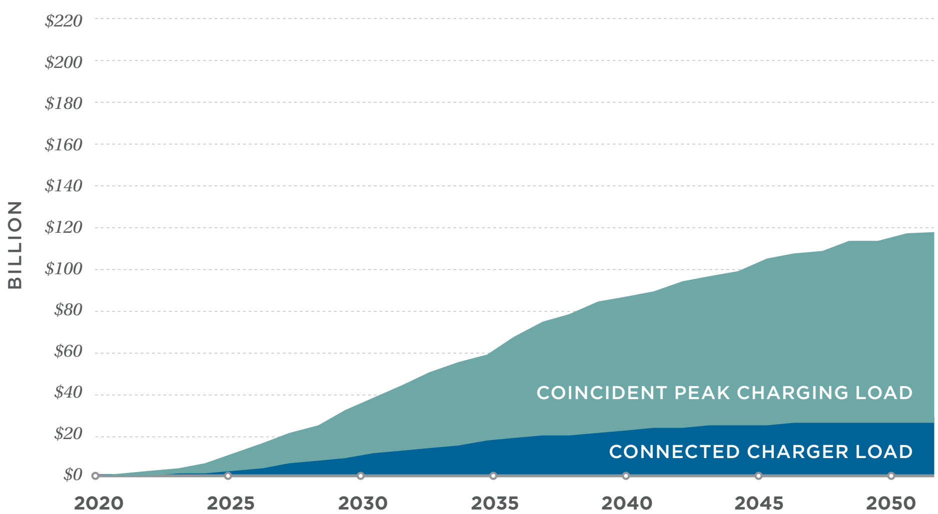


FIGURE 15.

Marginal Cost Low Case for DRIVE Clean Scenario

TABLE 13.

Summary of Marginal Cost Low Case for DRIVE Clean Scenario

	UNITS	2020	2035	2050
Total Annual Investment	$billion	$0.2	$6.9	$0.5
Cumulative Investment	$billion	$0.2	$31	$116
Annual Revenue Requirement	$billion	$0.0	$3.1	$11.6
Total Cost per EV	$/EV	$537	$450	$489
Total Cost per Charge Point	$/Charge Point	$530	$827	$1,009

For the marginal cost high case, cumulative investment is just over $200 billion in 2050, an average annual investment of $6.6 billion and annual revenue requirement of $20.4 billion in 2050. Total costs in 2050 are $859 per EV and $1,773 per charge point.

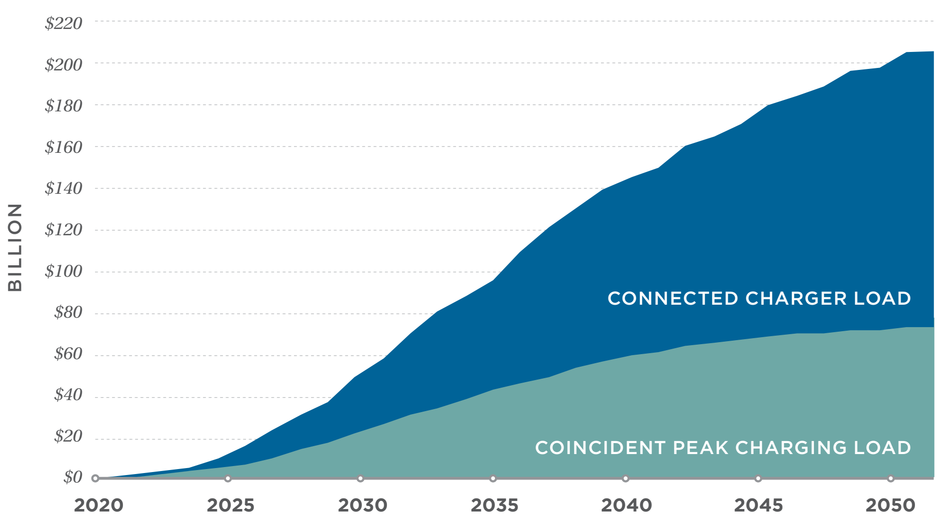


FIGURE 16.

Marginal Cost High Case for DRIVE Clean Scenario

TABLE 14.

Summary of Marginal Cost High Case for DRIVE Clean Scenario

	UNITS	2020	2035	2050
Total Annual Investment	$billion	$0.2	$10.8	$1.0
Cumulative Investment	$billion	$0.2	$47	$204
Annual Revenue Requirement	$billion	$0.0	$4.7	$20.4
Total Cost per EV	$/EV	$688	$735	$859
Total Cost per Charge Point	$/Charge Point	$679	$1,350	$1,773

4.3.2 CALIFORNIA DRP APPROACH

The California DRP low-cost case is again significantly lower than the marginal low-cost case, with a cumulative investment of $28 billion in 2050, $10 billion higher than the No New Policy scenario and 24% of the marginal low-cost case for the DRIVE Clean scenario. The California DRP high-cost case is very close to the marginal high-cost case for this scenario, with a cumulative investment of $196 billion in 2050. This is also very close to the California DRP high-cost case for the No New Policy scenario. This is because the distribution investment occurs earlier in the DRIVE Clean scenario, when the deficiencies caused as a percent of EV load is lower.

4.3.3 DRIVE CLEAN SCENARIO SUMMARY

In the No New Policy scenario, the 2035 cumulative investment is under $10 billion for all four cost scenarios. For the DRIVE Clean scenario, cumulative investment costs around $30 billion for the marginal cost low and California DRP high cases, and $47 billion for the marginal cost high case. The cumulative investment in 2050 for the marginal cost low case is $116 billion, 1.5 times the No New Policy scenario. The 2050 cumulative investment of $204 billion is 1.3 times the No New Policy scenario whereas the 2050 cumulative investment for the California DRP high-cost case essentially the same for both scenarios. This is because the EV adoption and distribution investment occur earlier when the assumed increase in distribution upgrade costs and deficiencies driven as a percent of EV load are lower in the high-cost cases.

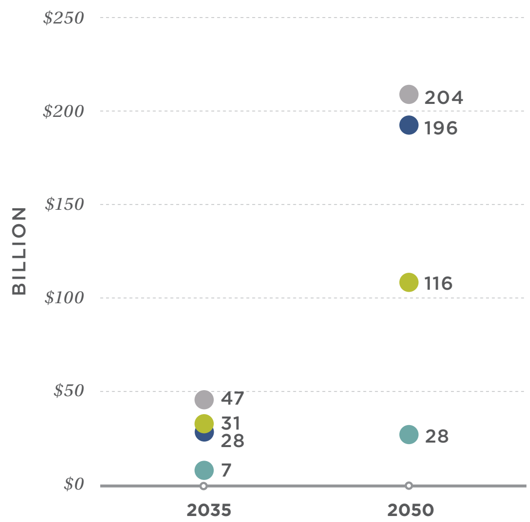


FIGURE 17.

DRIVE Clean Scenario Cumulative Investment Cost for Four Cost Cases

- CA DRP High Cost
- Marginal Cost High
- Marginal Cost Low
- CA DRP Low Cost

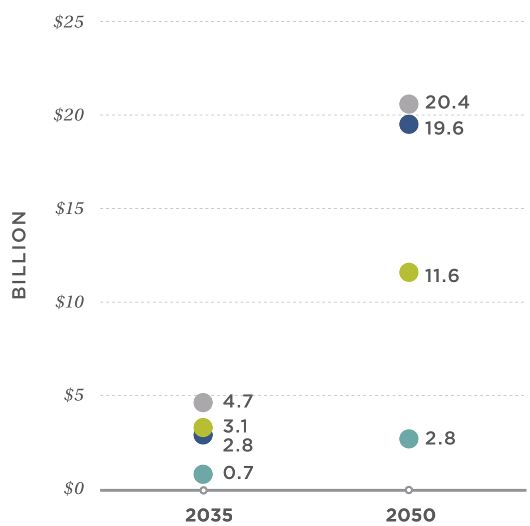


FIGURE 18.

DRIVE Clean Scenario Annual Revenue Requirement for Four Cost Cases

- CA DRP High Cost
- Marginal Cost High
- Marginal Cost Low
- CA DRP Low Cost

5

CONCLUSIONS

This analysis quantifies a wide range of potential distribution upgrade costs that will be driven by EV load growth in the U.S.. The low and high cost cases differ by a factor of 10. Any national estimate of distribution costs is necessarily approximate due to the wide range of upgrade costs that are very location specific and the uncertainty in how upgrade costs might change with increased adoption and clustering of EVs.

An important contribution of this analysis is to estimate secondary distribution costs driven by the connected load of EV chargers as well as the primary distribution costs driven by the coincident peak load of EV charging. Though we estimate secondary upgrade costs to be 5-10% of the primary costs, connected load can be higher than coincident peak load by a factor of 10 or more. Thus, connected load driven secondary upgrade costs range from 22 – 51% of the total in our cost scenarios.

Under the marginal cost low case, which is the most similar to how distribution costs are calculated today in utility regulatory proceedings, the cumulative distribution investment in 2050 for the No New Policy scenario is $76 billion and for the DRIVE Clean scenario is $116 billion (Figure 19), an increase of 53%. Using an assumed RECC of 10%, this translates to an annual revenue requirement of $7.6 billion and $11.6 billion respectively (Figure 20). For the highest cost cases, the cumulative investment by 2050 is around $200 billion, an annual revenue requirement of $20 billion.

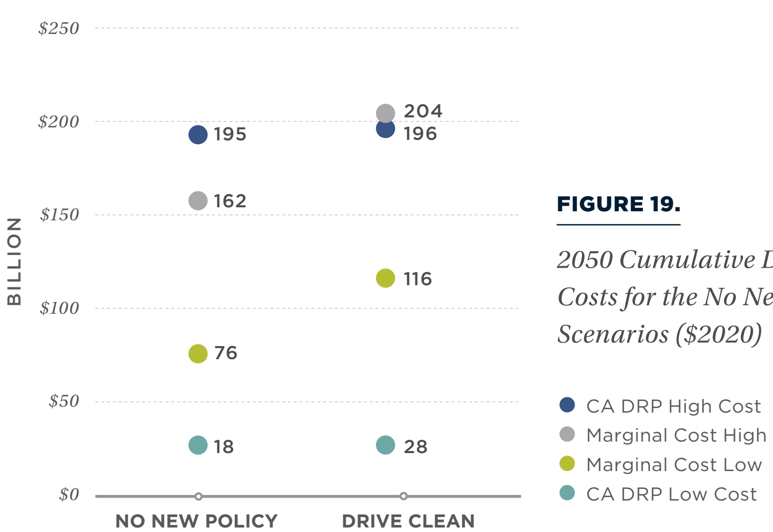


FIGURE 19.

2050 Cumulative Distribution Investment Costs for the No New Policy and DRIVE Clean Scenarios ($2020)

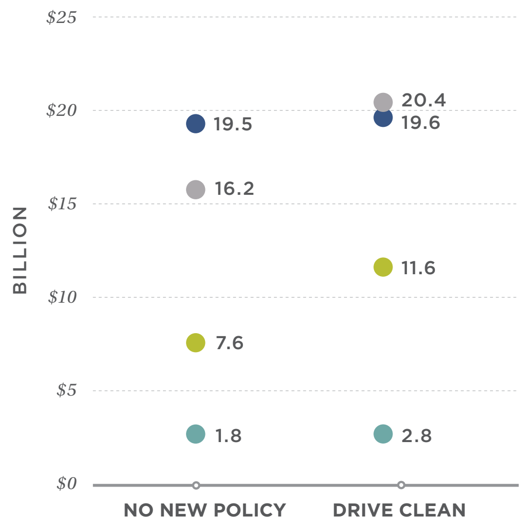


FIGURE 20.

2050 Annual Revenue Requirement for EV Driven Distribution Upgrades for the No New Policy and DRIVE Clean Scenarios

- CA DRP High Cost
- Marginal Cost High
- Marginal Cost Low
- CA DRP Low Cost

The annual revenue requirements calculated for EV driven distribution costs are a comparatively small portion of total utility distribution annual revenue requirement, which the 2021 Annual Energy Outlook (2021 AEO) projects to be $162 billion in 2050 (in $2020) (U.S. Energy Information Administration, 2021). In fact, our calculations suggest that adding EV load will reduce average distribution rates. The 2021 AEO projects a national average distribution cost of $0.03397/kWh based on retail sales of 4,748 TWh in 2050. Our highest cost estimates add $20 billion in annual revenue requirement for the distribution system, and a total of 882 TWh of EV charging load. This results in an average distribution rate of $0.03221/kWh, a reduction of $0.0018/kWh or 5%. Transportation electrification increases system utilization and reduces average distribution rates even in our high-cost estimates and without managed charging.

Furthermore, we do not in this analysis evaluate Time-of-Use rates and simple load management strategies, which have been shown to be quite effective at shifting EV charging off-peak. If 80% of coincident peak load is successfully shifted off-peak, reducing primary but not secondary distribution costs, cumulative investment costs in marginal high-cost case for the DRIVE Clean scenario could be reduced by just over 50% from $204 to $99 billion. Managed charging solutions can lower costs even further if they can reduce connected load driven secondary upgrade costs as well.

APPENDIX A

US Army Corps of Engineers Civil Works Construction Cost Index System (CWCCIS) State Adjustment Factors

ALABAMA	0.91	MONTANA	0.97
ALASKA	1.17	NEBRASKA	0.96
ARIZONA	0.95	NEVADA	1.05
ARKANSAS	0.87	NEW HAMPSHIRE	1.04
CALIFORNIA	1.23	NEW JERSEY	1.23
COLORADO	0.94	NEW MEXICO	0.92
CONNECTICUT	1.15	NEW YORK	1.18
DELAWARE	1.10	NORTH CAROLINA	0.91
FLORIDA	0.91	NORTH DAKOTA	0.97
GEORGIA	0.92	OHIO	0.99
HAWAII	1.20	OKLAHOMA	0.88
IDAHO	0.99	OREGON	1.08
ILLINOIS	1.14	PENNSYLVANIA	1.08
INDIANA	0.98	RHODE ISLAND	1.14
IOWA	0.98	SOUTH CAROLINA	0.91
KANSAS	0.96	SOUTH DAKOTA	0.94
KENTUCKY	0.95	TENNESSEE	0.89
LOUISIANA	0.90	TEXAS	0.88
MAINE	1.01	UTAH	0.97
MARYLAND	0.99	VERMONT	1.01
MASSACHUSETTS	1.15	VIRGINIA	0.95
MICHIGAN	1.00	WASHINGTON STATE	1.07
MINNESOTA	1.10	WEST VIRGINIA	1.01
MISSISSIPPI	0.89	WISCONSIN	1.05
MISSOURI	1.00	WYOMING	0.94
		WASHINGTON D.C.	1.01

APPENDIX B

Lessons from Advanced Rate and Vehicle Grid Integration Pilots and Programs

We reviewed reports from over 20 smart charging pilots and programs in North America and Europe to summarize real world experiences with vehicle grid integration (VGI). EV charging has been shown to be highly responsive to TOU rates in a number of studies not shown here. We focus instead on programs that have successfully implemented and demonstrated more advanced VGI strategies.

Summaries for 13 of the most relevant indirect (passive) or direct (active) VGI programs are found below. Most of the programs described include between 100 and 500 participants and quantify actual cost savings across a range of categories. Some of the pilots find that incentives, customer engagement or technology costs exceed the benefits provided. This is to be expected for pilots of emerging technologies, but also demonstrates the need for scalable, cost-effective and customer friendly VGI solutions.

The pilots and programs summarized show that VGI is technically feasible and viewed positively by the participating customers. A variety of both 'passive' and 'active' VGI strategies are shown to be quite successful in shifting EV charging and reducing peak loads. Distribution System Operators (DSOs) in Europe are more advanced in trialing active VGI load management strategies for local distribution networks, but the strategies and results are equally viable in the US. Some of the pilots rely on price signals provided directly by the utility, whereas others are partnerships between the utility, an aggregator, and the customers.

Data collection and telematics have historically been a major challenge for executing active VGI pilots in the US. The 2018 update to the US national interconnection standard, IEEE 1547,[2] which standardizes interconnection and communication of DERs with the grid, will ease interconnection, dispatch, operational and M&V data collection and telematics for future pilots and programs. IEEE 1547-2018 will also make it easier to conduct full scale programs which gather data at larger scales, observe and dispatch broader driver populations, vehicle types, and geographies.

2 IEEE 1547 was revised to require DERs to include a SunSpec Modbus, IEEE 2030.5 (Smart Energy Profile, SEP 2.0), or IEEE 1815 (DNP3) communication interface (Narang, 2019)

FIGURE 21.

VGI Pilot Program Descriptions

PILOT OR PROGRAM	DESCRIPTION
HOURLY DYNAMIC RATES (INDIRECT/PASSIVE VGI)	
SDG&E Power Your Drive VGI Rate (San Diego Gas & Electric, 2020)	Customers are offered a pricing plan that changes hourly to encourage drivers to charge during grid-friendly times. Hourly dynamic rates are set day-ahead based on CAISO day-ahead energy prices, with dynamic adders for the top generation and distribution peak hours. Results from the first part of the program show that customers are modifying charging behavior to incorporate incentives from the hourly dynamic rate: 87% of charging through the Power Your Drive rate happened off-peak compared to 81% and 77% for regular TOU rates
New York Smart Home Rate Demonstration Projects (ConEdison, 2020) and (New York State Energy Research and Development Authority, 2015)	Designed to demonstrate how alternative rate structures with customer price signals can optimize value for the customer and the system. Customers with advanced metering infrastructure (AMI) enrolled in the program receive home energy management technologies and participate in a rate structure that reflect the day-ahead hourly locational based marginal prices (LMBP) set by the NYISO. In addition, the rate structures experiment with the effectiveness of daily demand charges (Rate I) and monthly demand subscriptions (Rate II).
Ameren Illinois Power Smart Pricing (Ameren Illinois, 2020)	Offered for whole house loads. An hourly dynamic rate based on day-ahead prices in the Midcontinent ISO is provided to enrolled customers. Research by the Citizens Utility Board finds that potential savings are most significant for electric vehicle owners enrolled in Power Smart Pricing: drivers can reduce their annual charging costs by 50% (Citizens Utility Board, 2020).
Agile Octopus, UK (Octopus Energy, 2019).	Energy prices for the following day are provided through the Octopus app, showing when the cheapest windows will be the next day. The program includes a price cap ensuring customers never pay more than 35p (~$0.45/kWh). The first results from the Agile program showed that program participants reduced peak consumption by 47% compared to 28% for non-EV drivers.
LOAD MANAGEMENT (DIRECT/ACTIVE VGI)	
Avista Electric Vehicle Supply Equipment Pilot (Avista Corporation, 2019)	439 networked charge ports allowed for load management experiments using DR technologies at home and at work. Customers accepted 75% of peak load reductions via remote utility controls, without negative effects on driving habits or overall satisfaction ratings. However, Avista found that the costs to implement DR must be dramatically reduced in order to provide net grid benefits.
BMW ChargeForward (BMW, 2020)	Enrolled 400 drivers in Northern California (PG&E) testing a variety of smart charging strategies, including CAISO day-ahead prices, demand response, excess supply signals, home energy storage systems, distribution deferral and transactive energy price signals. Found that smart charging can reduce GHG by 32% and that 83% of participants fully shifted load away from distribution system peak hours.

PILOT OR PROGRAM	DESCRIPTION
Exelon — Utility Managed Smart Charging, US (Exelon, 2020)	Exelon Utilities, along with partners Weave Grid, Argonne National Lab, and others, are launching a multi-year program to explore provision of grid services through managed EV charging. Funded by DOE's Vehicle Technology Office, this program aims to enroll 1,000 customer-owned EVs in a phased pilot to understand driver behavior, system impacts of EV charging, and modification of charging schedules for both bulk and local objectives.
Enexis/Elaad Home Energy Management System (HEMS), Netherlands (ElaadNL, 2019)	The DSO Enexis and an aggregator sent maximum capacity limits to manage EV charging for 138 EV-drivers with a home charging point and a HEMS. Half of the participants were given a financial incentive to provide flexibility to the DSO. The pilot achieved a 40% reduction in peak load on the low-voltage grid. Participants generally had a positive attitude towards charge management but indicated that an "override" function is important (though it was not often used).
Stromnetz/Siemens, Germany (IRENA, 2019)	Initiated a three-year controllable charge point pilot in 2019 allowing the utility to spread out EV charging load to avoid overloads and voltage issues. Estimates that setting up an infrastructure to control electric vehicle charging in Hamburg would cost roughly 10% of the costs associated with network upgrades
My Electric Avenue (EA Technology, 2016)	Enrolled 100 EV drivers in different clusters to be outfitted with "Esprit" technology that limited charging over 15-minute intervals when local network loads were high. Found thermal headroom benefits of up to 46% at the highest levels of EV uptake. The project also highlighted the potential for third-party involvement to accelerate innovation and deliver projects.
Schiphol Airport Electric Bus Charging, NL	Schiphol Airport operates a fleet of 100 Electric buses. The Mobility House ChargePilot system manages charging for 7 450 kW DCFC Pantograph chargers. Over 150 daily charge sessions are managed to a maximum load of 1 MW, 1/5th of the total 5 MW interconnection at the site.
Optimise Prime, Ofgen, UK (Optimise Prime, 2020)	"Profiled connection" provides a 48 half-hour maximum load profile rather than a single maximum charging limit that applies 24 hours a day. To date profiles have been developed for 20 Royal Mail Depots concretely demonstrating significant cost and time savings. Project also includes a home trial testing managing commercial EV charging at homes and testing commercial EV abilities to provide flexibility services.
UK Power Networks Waterloo Bus Garage (UK Power Networks, 2019)	UK Power Networks adopted a "timed connection" approach for the bus routes at Waterloo Garage, which allowed 51 buses to draw their maximum power requirement of 2.5 megawatts in the off peak hours and also draw a reduced capacity of 0.5 megawatts during the day for a smaller number of standby buses. Avoided upgrades on constrained low and high voltage network serving the garage.

FIGURE 22.

Summary of Elements Included in Each VGI Pilot

PILOT OR PROGRAM	HOURLY DYNAMIC RATES	DYNAMIC CAPACITY ADDERS	ACTIVE LOAD MGMT.	LOCAL NETWORK LOAD MGMT.	MAXIMUM DEMAND PROFILES
SDG&E Power Your Drive VGI Rate	✓	✓			
New York Smart Home Rate Demonstration Projects	✓				
Ameren Illinois Power Smart Pricing	✓				
Agile Octopus, UK	✓				
Avista Electric Vehicle Supply Equipment Pilot			✓		
BMW ChargeForward	✓		✓	✓	
Enexis/Elaad Home Energy Management System (HEMS), Netherlands			✓	✓	
Stromnetz/Siemens, Germany			✓	✓	
My Electric Avenue			✓	✓	
Optimise Prime, Ofgen, UK					✓
UK Power Networks Waterloo Bus Garage					✓

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