The Los Angeles 100% Renewable Energy Study

Chapter 7. Distribution System Analysis

FINAL REPORT: LA100—The Los Angeles 100% Renewable Energy Study

March 2021

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Los Angeles Department of Water & Power

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The Los Angeles 100% Renewable Energy Study

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Context

The Los Angeles 100% Renewable Energy Study (LA100) is presented as a collection of 12 chapters and an executive summary, each of which is available as an individual download.

- The **Executive Summary** describes the study and scenarios, explores the high-level findings that span the study, and summarizes key findings from each chapter.
- **Chapter 1: Introduction** introduces the study and acknowledges those who contributed to it.
- **Chapter 2: Study Approach** describes the study approach, including the modeling framework and scenarios.
- **Chapter 3: Electricity Demand Projections** explores how electricity is consumed by customers now, how that might change through 2045, and potential opportunities to better align electricity demand and supply.
- **Chapter 4: Customer-Adopted Rooftop Solar and Storage** explores the technical and economic potential for rooftop solar in LA, and how much solar and storage might be adopted by customers.
- **Chapter 5: Utility Options for Local Solar and Storage** identifies and ranks locations for utility-scale solar (ground-mount, parking canopy, and floating) and storage, and associated costs for integrating these assets into the distribution system.
- **Chapter 6: Renewable Energy Investments and Operations** explores pathways to 100% renewable electricity, describing the types of generation resources added, their costs, and how the systems maintain sufficient resources to serve customer demand, including resource adequacy and transmission reliability.
- **Chapter 7: Distribution System Analysis (**this chapter) summarizes the growth in distribution-connected energy resources and provides a detailed review of impacts to the distribution grid of growth in customer electricity demand, solar, and storage, as well as required distribution grid upgrades and associated costs.
- **Chapter 8: Greenhouse Gas Emissions** summarizes greenhouse gas emissions from power, buildings, and transportation sectors, along with the potential costs of those emissions.
- **Chapter 9: Air Quality and Public Health** summarizes changes to air quality (fine particulate matter and ozone) and public health (premature mortality, emergency room visits due to asthma, and hospital admissions due to cardiovascular diseases), and the potential value of public health benefits.
- **Chapter 10: Environmental Justice** explores implications for environmental justice, including procedural and distributional justice, with an in-depth review of how projections for customer rooftop solar and health benefits vary by census tract.
- **Chapter 11: Economic Impacts and Jobs** reviews economic impacts, including local net economic impacts and gross workforce impacts.
- **Chapter 12: Synthesis** reviews high-level findings, costs, benefits, and lessons learned from integrating this diverse suite of models and conducting a high-fidelity 100% renewable energy study.

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Key Findings

Deployment of Distribution-Connected Resources

- All 100% renewable energy pathways examined in the LA100 study include significant quantities of solar and storage connected to the distribution system, including:
  - 2,800–3,900 MW_{PV} and 1,400–1,700 $MW_{Battery}$[1] of customer-adopted rooftop solar and storage. Roughly 90% of this customer-adopted capacity is connected to the 4.8kV distribution network.
  - 300–1,000 MW of utility-driven non-rooftop local solar deployment and 200–700 MW of battery storage connected to the 34.5kV subtransmission network.
- All scenarios modeled in LA100 exceed the local solar targets of the Los Angeles Green New Deal by about 1.5–2.4 times. Most of this capacity is customer-driven rooftop solar, although the mix of customer- versus utility-driven solar deployments will be strongly influenced by rate structures and incentive programs.
- The greatest amount of non-rooftop solar is built in the Early & No Biofuels – High Load Electrification scenario (1,000 MW) with the smallest amount built in the Transmission Focus – Moderate Load Electrification scenario (300 MW). In all cases, either very high loads or limits on building new transmission drive the development of additional in-basin capacity. Local solar deployment is not strongly impacted by distribution upgrade needs.
- The spatial deployment of non-rooftop distribution-connected in-basin solar shows significant regional variation. Overall, the LA100 scenarios build 6%–18% of the systemwide technical potential capacity for non-rooftop sources (see Chapter 6);[2] however, many receiving station (RS) regions have zero deployment, some consistently have 10%–80% of technical potential deployed across all scenarios, and other regions have 60%–99% of capacity deployed in only a few scenarios.
- Non-rooftop solar regional variation is influenced by in-basin transmission congestion as well as small differences in electric losses across regions that make particular regions closer to high load areas more attractive for siting. As a result, we find parking canopy solar an attractive solution for serving demand in denser regions of the city.
- To a lesser degree, the spatial deployment of rooftop in-basin solar also varies by RS region, mostly as a function of incentive level (see Chapter 4). Specifically, rooftop adoption varies from 5%–31% of technical potential capacity with moderate rooftop adoption and up to 11%–39% with high rooftop adoption, with similar patterns among RS regions.

Distribution Grid

- Distribution grid equipment upgrades are required on most (90%) of feeders/circuits to address overloads and voltage challenges caused by combined load, solar, and storage changes associated with 100% renewable electricity pathways. However:
  - For the 4.8kV system, the majority of challenges are limited to a fraction of feeders (1.4%–3.4% for 2021–2030, and 4%–23% for 2031–2040) where the maximum power flow is high enough to require splitting into multiple feeders.

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[1] MW for local solar and storage reported in MW_{DC}.
[2] This amount is partially driven by the higher costs assumed for in-basin non-rooftop solar due to higher land and labor costs.

  - The remaining problems can be addressed using existing technology—the most common upgrade is increasing the size of service transformers—those that connect the distribution system at 4.8kV or 34.5kV to the lower voltages used by customers.
  - Beyond feeder splitting, there are typically only a modest number of upgrades required per feeder/region (cumulative average [median] of 8–14 per feeder and 22–33 per larger 34.5kV region, depending on scenario). This represents only a fraction of the hundreds to thousands of pieces of equipment on each feeder/region.
- The total cumulative additional cost (through 2045, after correcting existing challenges) of distribution upgrades due to changes modeled in the LA100 study ranges from $472 million (SB100 – Moderate Load Electrification and Transmission Focus – Moderate Load Electrification) to $1,550 million (SB100 – Stress Load Electrification). These costs are about 1%–2% of bulk system costs and are also relatively minor compared to the equipment costs for corresponding distributed solar and storage resources. *However, these costs do not include a number of additional distribution system costs that are required through 2045. Specifically, these costs do not include substantial investments required to address current distribution upgrade needs, routine maintenance of the distribution system, distribution operations costs, or land acquisition and other costs that may be required for distribution upgrades, notably for substation upgrades. Collectively these other costs are likely much higher than these **additional** costs required as a result of load changes and distributed energy resource (DER) adoption.*
  - The total cumulative costs for LA100-driven distribution system upgrades through 2045 can be seen in Figure 1.

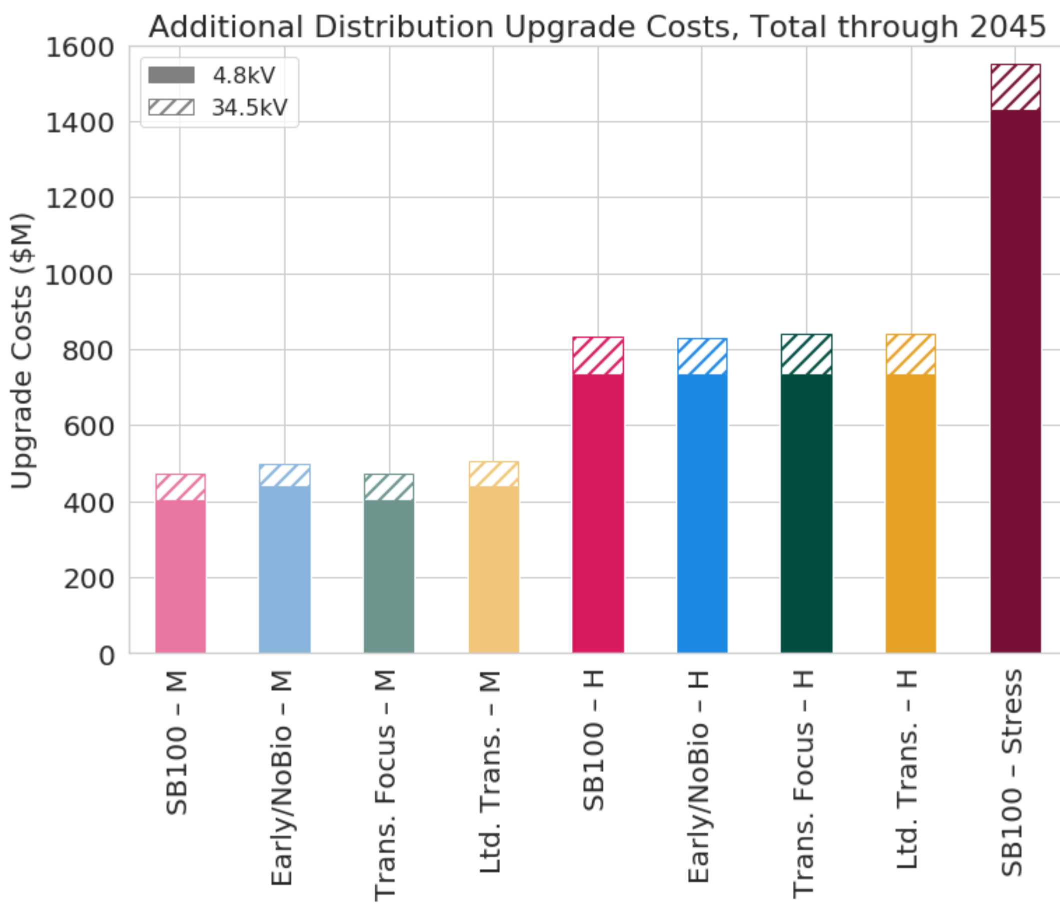

Figure 1. Total distribution system upgrade costs associated with changes modeled in the study, by scenario (2019$)

These costs are in addition to upgrades required to manage existing challenges on the distribution system. The distribution system costs presented here were updated after other chapters of the study were completed. These are the final distribution system costs.

- The vast majority of these upgrades and costs (85%–92%, depending on the scenario) are incurred on the 4.8kV distribution system, rather than the 34.5kV system.
- Solar and storage can help reduce maximum net loads (load minus solar and storage) and hence avoid some substation upgrades. This is true even though the storage in this study was dispatched to reduce systemwide operation costs, not to defer distribution upgrades. Modifying the storage dispatch to account for distribution needs could further avoid substation upgrades.
- When distribution upgrades are designed considering load needs simultaneously with customer-adopted rooftop solar and battery storage, the total upgrade costs are reduced compared to making upgrades sequentially for load and then DERs. This was observed on 8%–24% of feeders on the 4.8kV system and accounted for a total savings of 12%–15% systemwide depending on scenario.
- Although the specific locations of solar and storage integration can have a localized impact on distribution upgrades required, in aggregate the total systemwide upgrade costs were consistent (within 4%–12%) across five randomized samples of customer solar deployment patterns.
- There are a number of key questions that require additional analysis to answer, including:
    - Might it be better to upgrade the 4.8kV system to 12–13kV?

- To what extent might coordinated control[3] help?
- What is the value of optimizing distributed resources for the grid?
- To what extent could resiliency and other value streams change DER deployment and distribution needs?

Important Caveats

1. The quality of any study's results is limited by the quality of the data. For LA100, we endeavored to obtain and verify the best data available, but these data are still not perfect. Some specific challenges for distribution include inaccuracies in the electrical model itself and challenges and unknowns with disaggregated loads and high spatial resolutions of solar and storage deployment. Still, our estimates should reflect the overall direction of trends and systemwide impacts and opportunities.
2. Distribution analysis only estimates infrastructure upgrades needed for the 100% renewable pathways for the years 2030 and 2045 due in part to intensive computational and data needs. In actuality, infrastructure upgrades are continuously needed as loads change and distributed energy resources come online. This will undoubtedly change LADWP's actual upgrade deployment, and the changes in timing may result in different overall results. However, one clear outcome of this work is that simultaneously considering load growth and distributed solar and storage when upgrading the distribution system can save costs compared to sequentially upgrading for one followed by the other.
3. These results also only consider infrastructure upgrades needed to address system violations introduced due to load growth, electrification, and solar and storage deployments. They do not include other routine maintenance or capital costs like component replacement due to aging. They also do not include potential additional costs due to extreme weather, cyber, or other disasters. In some cases, these routine upgrades could also introduce opportunities for preemptive upgrades that could save LADWP and its customers money overall.
4. The results do not include some considerations beyond techno-economic drivers. For example, with any substation upgrades—such as transformer size increase, the addition of a new transformer/bank, or other reconfiguration—there may also be a need to expand the footprint of the substation, which can be difficult in dense portions of LA. In this case, our study does include equipment costs, labor, and some additional costs for reconfiguration and engineering work; however, we do not include land acquisition, community resistance, or other practical factors that could greatly complicate such a project in reality.
5. We do not include a number of technical analyses such as protection, voltage flicker, coordinated controls, and system reconfiguration. It is expected that these will be secondary considerations to the main thrusts of this analysis. However, some of them—notably considerations around reverse power flow—may require updated practices and

[3] Such as an advanced distribution management system (ADMS), DER management system (DERMS), or advanced distributed control schemes.

perceptions in planning and operations that might otherwise present challenges in the transition to 100% renewable energy.

6. In short, long-term studies like this one can never perfectly predict the future of load changes, customer adoption, community support/resistance, equipment costs, disruptive technologies, regulations, and other factors. Still, we expect the results presented here accurately capture the trade-offs among various options and scenarios.

1 Introduction

The electric distribution system provides a vital link for connecting not only loads but also distributed solar, distributed storage, electrified transportation, and responsive loads. In addition, distributed energy resources (DERs) provide key in-basin capacity in support of 100% renewable energy. Depending on the LA100 scenarios, a total of 2,800–3,900 MW of rooftop local solar (see Chapter 4) plus 313–1,046 MW of non-rooftop local solar (see Chapters 5 and 6 and Section 3) is estimated to be connected to LADWP's distribution system. This accounts for approximately 14%–19% of the total generating capacity for the LA100 scenarios in 2045. When combined with distributed storage, electrified transportation, and responsive loads, these resources make the electric distribution system a vital link for 100% renewable futures. The resulting impacts on the distribution grid require upgrades to support these technologies without overloading and while maintaining or enhancing power quality (notably voltage control).

This chapter first summarizes the growth in distribution-connected resources and then provides a detailed look at the impacts of both customer electricity demand growth and local solar and storage, required upgrades, and associated costs for the distribution grid. The impacts and upgrade analysis were performed running in-depth power flow for approximately 80% of the distribution system feeders and circuits at 13 different timepoints, for dozens of scenarios, representing a first-of-a-kind level of depth and coverage for this class of analysis.[4]

The LADWP Distribution System

The LADWP electric distribution system contains two utility voltage levels: 1) relatively large 34.5kV subtransmission circuits that serve the dual purpose of connecting the transmission system to the local distribution substations and directly serving larger customers (generally >300 kW); and 2) the shorter 4.8kV local distribution system to service most smaller loads. In addition to these, customers have a third secondary or service voltage typically in the 120–480V range that are not captured in detail in this analysis. The two-voltage-level distribution design somewhat complicates distribution-level analysis given the tight coupling between the systems and the large diversity in system behavior. A simplified schematic of these systems and their relation to the transmission system is shown in Figure 2.

[4] Most similar past efforts use only few representative feeders that may fail to capture the wide range of feeder diversity and location-specific factors.

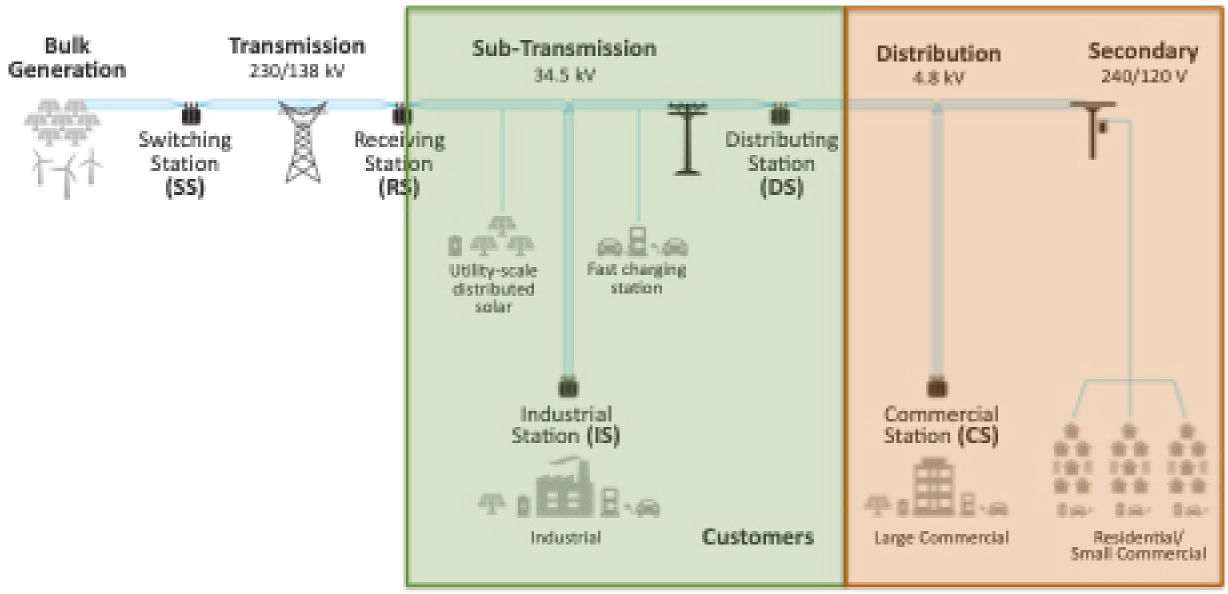

Figure 2. Simplified schematic of the LADWP electric grid, highlighting the 34.5kV subtransmission (green) and the 4.8kV local distribution (brown) systems and the nomenclature for substations

In the LA Basin, the 34.5kV subtransmission system is broken up into 19 different regions, each corresponding to a receiving station (RS). A map showing the approximate location of these RS stations can be found in Appendix B. These connect to a total of 638 34.5kV circuits that connect to the larger loads and distributing stations (DSs). There are 158 DSs that serve a total of 1,670 4.8kV feeders. As described in detail below, we conducted detailed electrical engineering simulations for the majority of this combined system and used these to drive automated upgrade and cost estimates.

Context within LA100

This chapter is part of the Los Angeles 100% Renewable Energy Study (LA100), a first-of-its-kind power systems analysis to determine what investments could be made to achieve LA's 100% renewable energy goals. Figure 3 provides a high-level view of how the analysis presented here relates to other components of the study. See Chapter 1 for additional background on LA100, and Chapter 1, Section 1.9, for more detail on the report structure.

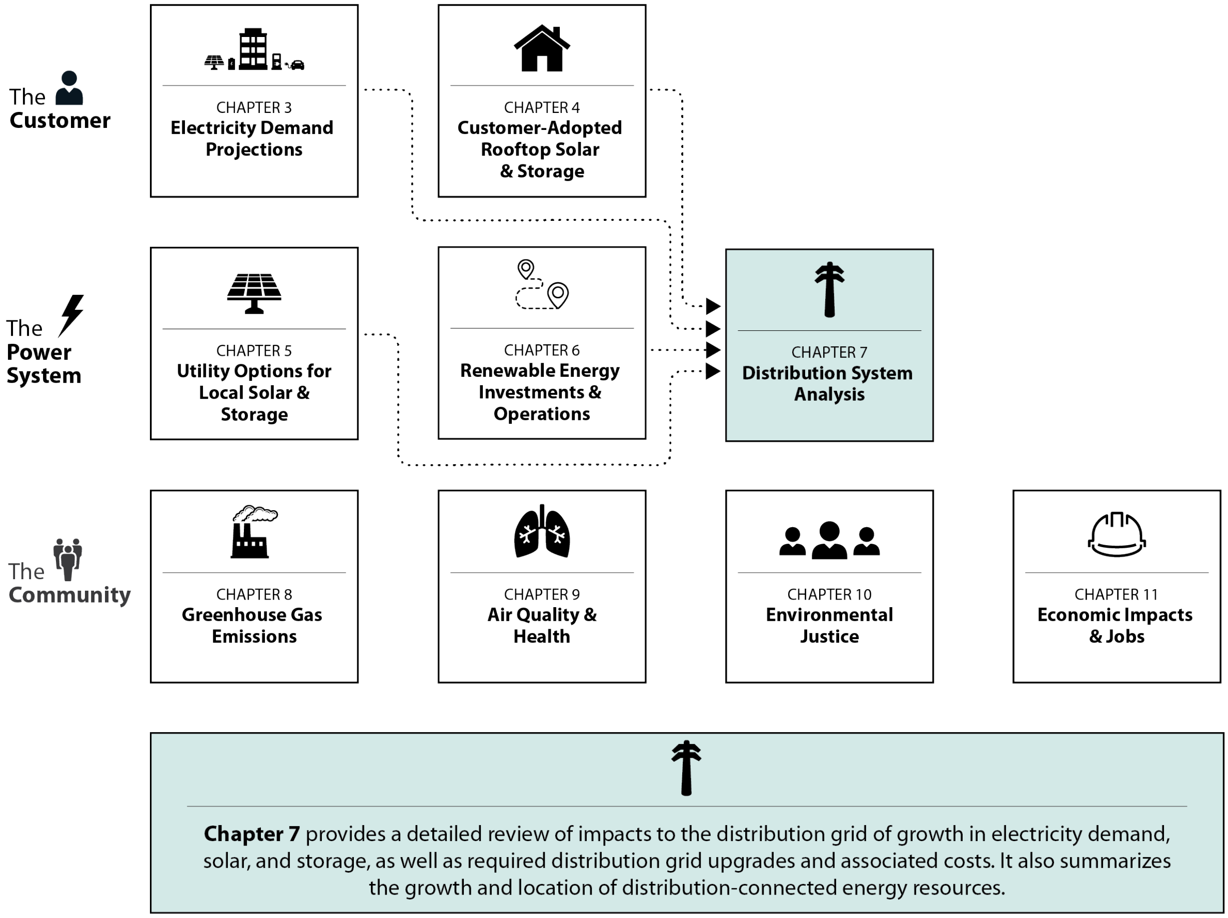

Figure 3. Overview of how this chapter, Chapter 7, relates to other components of LA100

Chapters 3, 4, 5, and 6 provide data and analysis that serve as inputs to the distribution system analysis in this chapter.

2 Methodology and Assumptions

The methods and assumptions for determining the amount of load and DERs in the future LADWP system were presented in earlier chapters. This section focuses on the methods used for the various electric distribution system analyses.

2.1 Distribution System Modeling Overview

We studied how the distribution grid can support the load changes and DERs required for each of the pathways to 100% renewables without overloading and with appropriate voltage management, as well as estimate the cost of any upgrades needed to achieve these ends. We did this using power flow modeling and bottom-up engineering cost assessment. There are three key components to this analysis:

7. **Core distribution impact and upgrade cost analysis**, which considers the overall distribution system impact and cost of changes in load, solar, and storage. This analysis covered two phases: 1) between 2020[5] and 2030 and 2) between 2030 and 2045.
8. **Simultaneous upgrade benefit analysis**, in which we examine how upgrading the distribution system while simultaneously considering both load and DERs can potentially provide cost savings relative to sequentially upgrading for load and then DERs. This is referred to as "value of simultaneous upgrade analysis," rather than non-wires alternatives analysis, because the placement and sizing of the solar and storage is based on customer choices or driven by overall system needs through the capacity expansion model and is not designed or sited specifically to defer upgrades as it would be in a non-wires alternatives program.
9. **Upgrade cost curves** for non-rooftop solar that look at the cost of integrating these resources relative to penetration level in order to inform deployment of these resources in different 100% renewable energy scenarios. The methodology and results of the upgrade cost curve analysis were discussed in Chapter 5 but share many of the mechanics described here.

All these analyses rely on the same general steps shown in Figure 4 and described in more detail in this section. In short, we started by building up electric models for the system (which did not previously exist) and attaching the loads and DERs corresponding to each scenario. Then we conducted detailed engineering simulations using three-phase unbalanced distribution power flow simulation to identify challenges. This power flow analysis was iterated with automated upgrade analysis to identify the set of upgrades required to manage any challenges. Finally, the corresponding costs for these upgrades were computed.

[5] Assumed to be after existing challenges with the distribution system are addressed.

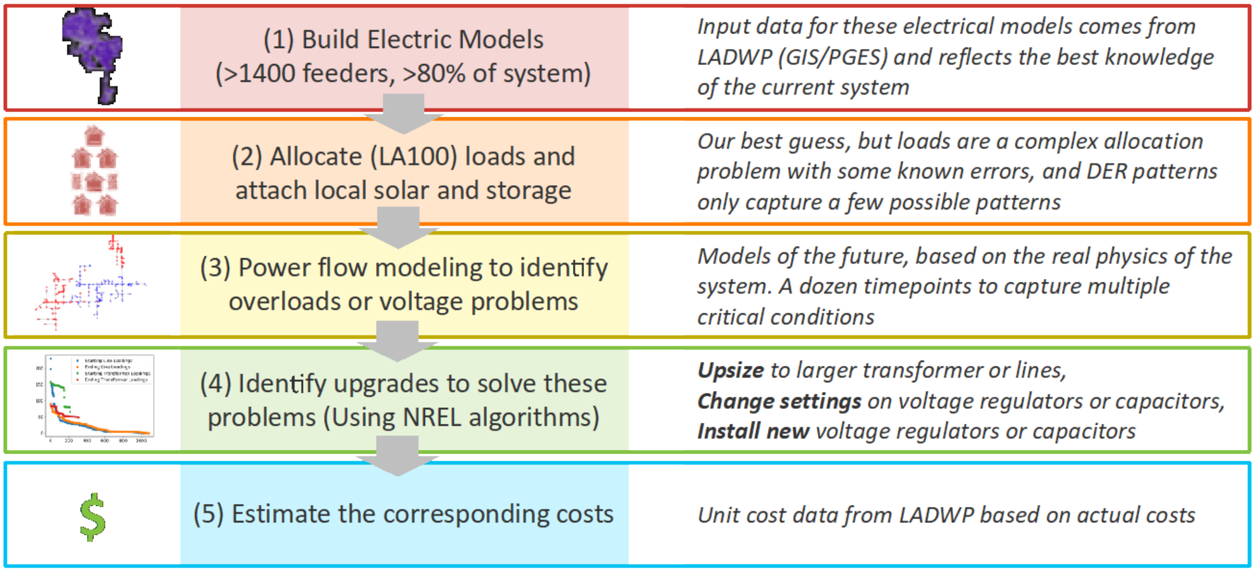

Figure 4. Sequence of steps used in the distribution analyses

As summarized in Figure 5, each of the upgrade-based analyses—core analysis, simultaneous upgrade, and cost curves—followed a specific sequence of cumulative upgrades in order to distinguish the upgrade drivers of interest. For the core analysis used in computing the overall scenario technical impacts and upgrade costs, this involved first upgrading “today’s” system to correct known existing challenges and lingering modeling errors, resulting in a clean 2020 system for “tomorrow”—with existing overload and voltage challenges fixed—before identifying the impacts and upgrades needed with load and DER changes. This approach allows the analysis to focus on additional costs (or savings) associated with the pathways to 100% renewable energy.

From this foundation, the combined upgrades required for load, local solar, and local storage were computed in two steps, first for 2030 and then from 2030 for 2045. The sequence for evaluating simultaneous upgrades isolates the relative upgrade needs in 2045 when conducted sequentially for loads-only first and then adding solar and storage versus directly upgrading to support all changes at once. The cost curve analysis (described in Chapter 5) goes straight from the raw 2020 system of today, which allowed comparing the costs or savings with the addition of the non-rooftop local solar and utility-driven storage in comparison to without.

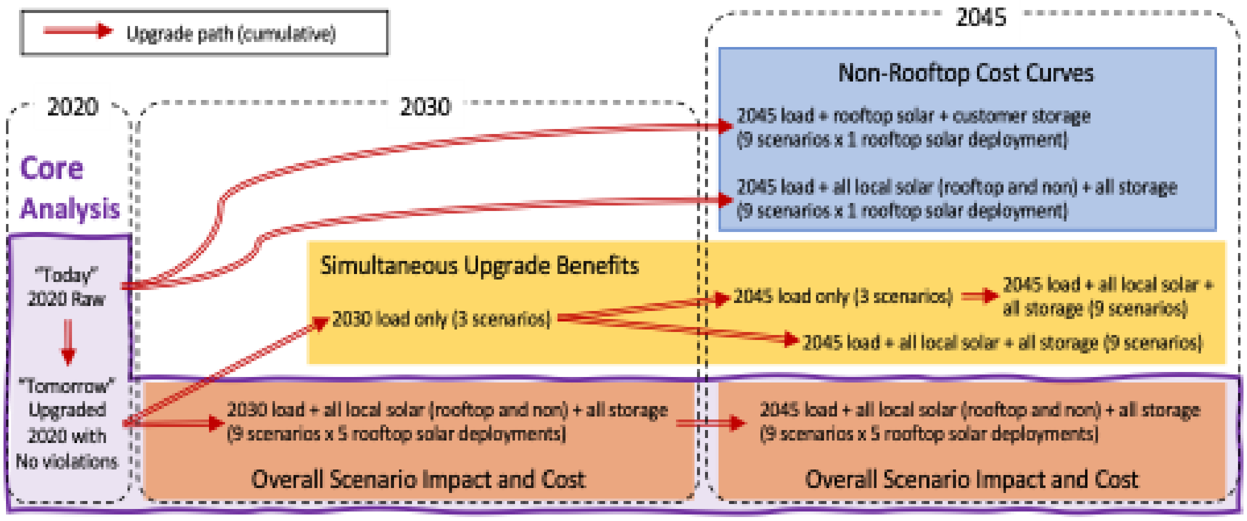

Figure 5. Graphical illustration of the upgrade analysis workflows

2.2 Building a Model of the LADWP Electric Distribution System

Because detailed electrical engineering models of the LADWP distribution system did not exist, the first step in the LA100 distribution modeling effort was to create such electrical models using existing GIS data from LADWP. To do so, as seen in Figure 6, we first extracted data from LADWP's legacy geospatial database (PGES[6]) and substation one-line diagrams while also developing a table of typical technical parameters for corresponding types of equipment, using specifications provided by LADWP. The data were then fed into a custom LADWP-specific input parser for NREL's open-source Distribution Transformation Tool (DiTTo) that combined these data and exported the results to OpenDSS models for detailed simulation. While data for these models are drawn directly from the PGES database wherever possible, in some cases data were missing. The assumptions used to address these data gaps can be found in Appendix A.

[6] PGES is an internal, semi-custom geospatial database used at LADWP that combines information from two other internal databases: FRAMME and FM.

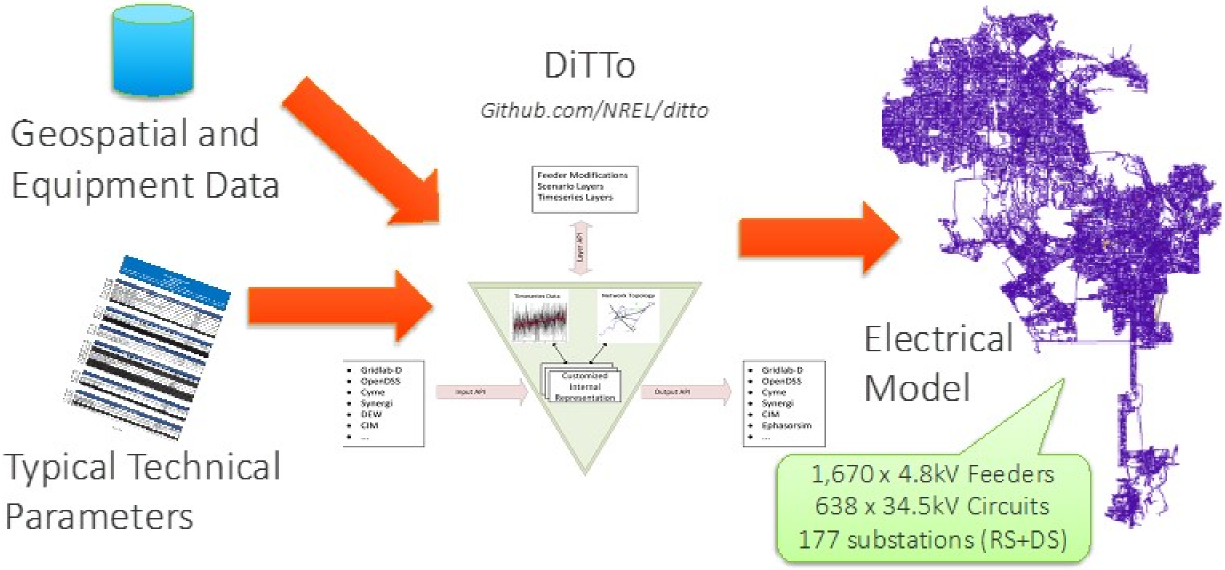

Figure 6. Workflow for creating detailed electric models of the entire LADWP distribution system

2.3 Allocating Customer-Level Load and Distributed Energy Resources

After the distribution electric models were created, we connected the corresponding load and DER projections developed for LA100 at the disaggregated scale needed to fully populate the electrical model. This included the following data sets, listed along with their corresponding chapters for in-depth discussion:

- Electric loads including energy efficiency and electrification measures in buildings, electric vehicle adoption, and DC fast charging (Chapter 3)
- Customer-driven rooftop solar and storage (Chapter 4)
- Non-rooftop "local solar" and corresponding storage at sites identified and ranked in a GIS siting and supply-curve analysis (Chapter 5) using scenario- and region-specific deployment quantities determined from bulk systemwide expansion planning (Chapter 6).

Matching these data sets to specific locations relies on and contributes to a comprehensive project-wide geospatial database of agents and other parcels of land. The term "agents" in LA100 is loosely defined as parcels or properties, and they are used to represent the base level of decision making and the finest geographic level for LA100 load and DER modeling. This project-wide agent database is holistic; it includes details about agents including their geographic locations and their defining attributes (e.g., sector, building type, building size), and it also captures agents' electrical geographies (i.e., transformer and feeder connections). This database was used to allocate modeled loads (Chapter 3) to agents (Chapter 3, Appendix J: Agent Load Allocation), to allocate agents to the distribution grid (Chapter 3, Appendix K: Agent to Grid Allocation), to define customer adoption agents (Chapter 3, Appendix I: Agent Generation) for the rooftop solar and storage adoption projections (Chapter 6), and to inform the GIS assessment of non-rooftop local solar potential (Chapter 5). As a result, the underlying load and DER data listed above use the same geographic units in a form that can be used for distribution analysis.

With this database ready, the DiTTo tool was again used to automatically connect agents to nodes in the electrical model. This included extracting the corresponding load and solar production data for the simulation timepoints of interest as described in the next section.

For the core analysis and simultaneous upgrade analysis, in each of the scenarios, five different potential randomized patterns, or deployments, of customer-owned PV adoption were simulated. The raw output from the customer adoption modeling (Chapter 4) is a premise-level estimate of probability of adoption. Hence, each of these deployment patterns correspond to different random seeds, which results in very different locational patterns of adoption between deployments, while still having similar systemwide totals of adoption. This allowed capturing the uncertainty in which customers might adopt solar and storage and computing the corresponding distribution system impacts for each. Unless otherwise noted, the corresponding results across deployments are presented as averages (arithmetic means) across these five deployments.

2.4 Power Flow, Upgrade, and Cost Computations

2.4.1 Tools and Workflow

The core part of the distribution system analysis is the tightly coupled use of power flow and upgrade analyses (Steps 3 and 4 in Figure 4) and then the post-processing to add cost estimates (Step 5 in Figure 4). Figure 7 expands on these steps to show the detailed workflow and tools involved in these computations.

Working through Figure 7 from left to right, we see that the first step is assembling the various components of the engineering models using DiTTo as described in Sections 2.2 and 2.3. This results in a collection of OpenDSS and supporting data files. Early on, a subset of these is used in pre-processing with PyDSS directly to identify any modeling challenges such as syntax errors, disconnected components, missing parameters, or unloaded transformers. This pre-processing stage also identifies any 4.8kV assigned loads that were too large (>500 kVA) to be connected to 4.8kV for relocation on the 34.5kV system. This could occur if, for example, a mid-sized low-rise office building were replaced with a larger multistory mid- or high-rise building. These loads are then removed from 4.8kV and replaced with a small load (assigned as 1% of connected transformer rating) to avoid voltage simulation errors with unloaded transformers. To avoid dropping any load, any removed loads are assumed to be connected directly to the corresponding DS substation.

Once corrected, corresponding Distribution Integration Cost Options (DISCO) configuration files for the specific analysis workflow of interest are created in the Analysis Setup step. The main computations are then orchestrated using DISCO to first link the appropriate electric models and supporting data and then create the various PyDSS and upgrade configuration files for each analysis step. DISCO then coordinates running the thousands of PyDSS/upgrade simulations on NREL's Eagle high-performance computer (HPC) for each analysis. Once completed, a post-processing step computes the corresponding upgrade costs and collects the large number of feeder simulation results into summary files for further analysis and visualization. Finally, synthesis, extreme upgrades, net load, and other analyses are conducted using a collection of custom Python scripts running in Jupyter notebooks, combined with spreadsheet, GIS, and other analyses.

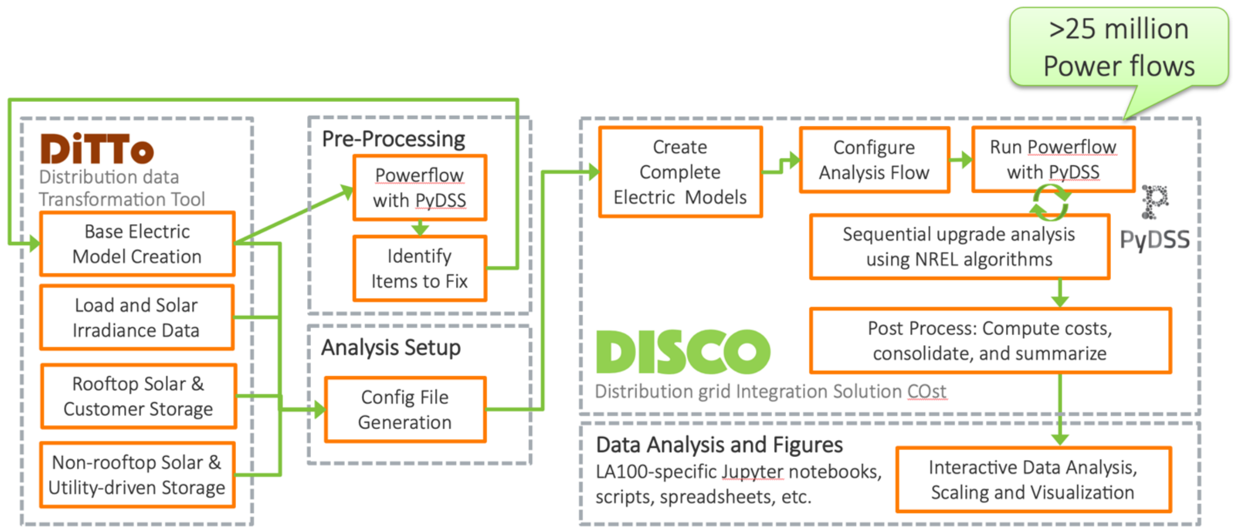

Figure 7. Detailed workflow for distribution system analysis

The set of tools used in this analysis were carefully chosen for capability, performance, and flexibility. Specifically:

- **DiTTo**[7] provides a many-to-one-to-many distribution electric model data conversion and manipulation utility. A custom "reader" for the LADWP PGES data formats was developed for LA100 and can be then linked with any of the existing "writers" to produce engineering models in most common formats for distribution simulation, including OpenDSS, as was used for this study. Once ingested into DiTTo, electric models can also be modified by mixing in data (such as missing technical parameters), combining models (such as the creation of a single RS region-wide electric model for each 34.5kV region), or attaching scenario data for load and DERs. The use of DiTTo across the large number of feeders, scenarios, timepoints, rooftop solar deployments, and more was automated in a consistent manner using and the closely related automation tool layerstack.[8] Both DiTTo and layerstack were developed by NREL and are available open source.
- **PyDSS**[9] provides a greatly enhanced, Python-based interface for OpenDSS[10]-based three-phase unbalanced distribution power flow simulations. For LA100, among its other features, PyDSS enabled accurately modeling the combination of Volt-VAR and Volt-Watt advanced inverter controls, provided significantly improved control convergence using a heavy-ball algorithm to manage oscillations with large quantities of advanced inverters, and provided automated upgrade algorithms. PyDSS connects to the cross-platform OpenDSS compute engine via the OpenDSS-Direct[11] library interface. This enables the use of PyDSS across platforms including on Windows and Mac laptops for debugging and on the Linux-based high-performance computer (HPC) used for large-scale production runs. PyDSS and OpendDSS-Direct were both developed at NREL, while OpenDSS was developed by the Electric Power Research Institute (EPRI). All these tools are available open source.

[7] "NREL/Ditto," https://github.com/NREL/ditto.
[8] "Smart-DS/Layerstack," https://github.com/Smart-DS/layerstack.
[9] "NREL/PyDSS," https://github.com/NREL/PyDSS.
[10] "OpenDSS,' EPRI, https://www.epri.com/pages/sa/opendss.
[11] "OpenDSSDirect.py," https://dss-extensions.org/OpenDSSDirect.py.

- **DISCO**[12] provides a Python-based software framework for conducting scalable, repeatable distribution analyses. While DISCO was originally developed to support solar PV grid hosting capacity analysis and provides a range of other capabilities, for LA100 it specifically used to run highly scalable simulations for impact analysis, sequence automated upgrade steps, and coordinate postprocessing. It uses the Job Automation and Deployment Engine (JADE)[13] to automate parallel execution of jobs including distributing work on HPC compute nodes, although it can also be run on a local laptop or other machine.

2.4.2 Power Flow-Based Impact Identification

The LA100 distribution power flow simulations are used to estimate the extent of violations in voltage or (over)loading with the addition of load, PV, and storage. Specifically, we considered the following types of violations that would trigger a need for distribution upgrades:

- Transformer overload, greater than 125% of the power rating[14]
- Line overload, greater than 125% of the power rating
- Overvoltage, greater than American National Standards Institute (ANSI) C84.1 Range B, "Acceptable"[15]
- Undervoltage, less than ANSI Range B
- Transformer overload, greater than 125% of the power rating
- Maximum net load[16] magnitude at the feeder or RS source higher than a specified threshold: greater than 600 Amps or 5 MW for 4.8kV feeders and greater than 600 MW for 34.5kV RS regions.

These definitions of violation thresholds are based on existing standards and were agreed upon in discussions with LADWP's distribution engineers. In addition to considering this set of five violations that would lead to upgrades, we also track the number of instances per circuit where ANSI Range A voltage limits ("Preferred")[17] are exceeded or loading of lines or transformers in excess of 100% of their rated power occur. These are less severe distribution violations that would not typically warrant upgrades unless they were widespread and/or occurred frequently but are still undesirable and reflect non-optimal grid performance.

These impacts are calculated using PyDSS. For the 4.8kV system, every feeder is simulated separately and commonly include the feeder-head voltage regulator, any capacitors, all lines, and all service/secondary transformers. The low-voltage secondary network is not modeled in detail; rather, all loads and customer DERs are attached to the low side of the corresponding service transformer. For the 34.5kV system, all the circuits within a region are assembled together along with substation internals for both RS and DS stations, including multiple transformers or "banks"

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[12] DISCO will be released as open source shortly and will be available at https://github.com/NREL/disco.
[13] "NREL/jade," https://github.com/NREL/jade.
[14] 125% overloading is considered acceptable because it typically only occurs for a limited number of hours and is generally in-line with the higher short-duration ratings for equipment.
[15] The ANSI C84.1 Range B limits are 91.7%-105.8% of the nominal voltage.
[16] Net load is the native load minus any distributed generation from solar or storage. When storage is charging, it also adds to the net load. Although this value is often positive, indicating a need to draw load from external generators, it can also be negative, indicating that DERs are generating more energy that is needed by local loads such that energy is provided back to the larger grid. Since we consider the absolute magnitude of net load, very large reverse power flow may also trigger this violation.
[17] The ANSI C84.1 Range A limits are 95%-105% of the nominal voltage.

per station. The corresponding loads for each feeder are aggregated as a large single load connected to the 4.8kV side of the appropriate DS transformer/bank. The sum of rooftop solar and customer storage is similarly aggregated and connected to the 4.8kV bus of the appropriate transformer/bank. Any oversized loads incorrectly assigned to the 4.8kV system and removed from 4.8kV are also added to the DS station total load. The 34.5kV customer industrial stations (IS) are simplified to capture only the corresponding transformers, with loads and customer DERs connected to their low side. This combined regional scale for 34.5kV simulations allows capturing the semi-meshed nominal configuration within the subtransmission system.

2.4.3 Upgrading to Correct Violations

For each feeder/region, scenario, and deployment, whenever the initial impact power flow simulation identifies voltage or overload violations, the model is then passed to the automated upgrade analysis workflow. Upgrade analysis for all distribution analysis workflows is also conducted using PyDSS and automated with DISCO. Specifically, this portion of the analysis uses a PyDSS module that executes an NREL-developed automated upgrade algorithm. An automated upgrade analysis approach is required due to the large number of circuits and scenarios under study. The set of possible upgrades include the following traditional utility upgrades:

- Upgrading existing transformers to increase their capacity
- Installing new transformers
- Reconductoring to increase the capacity of lines
- Adjusting the set points on voltage regulating devices, including line regulators, load tap changers (LTCs), and capacitor banks
- Adding new line voltage regulators (on 4.8kV networks).

The upgrade algorithm first detects any overloading violations for transformers and lines and implements upgrades to mitigate those issues. These overload-driven upgrades are conducted first since they often resolve some of the voltage issues. After these upgrades, our algorithm checks for any remaining voltage violations and implements additional upgrades to resolve those issues—starting with less expensive control settings changes before adding any additional equipment. Per LADWP guidance, our algorithm attempts to implement solutions that result in lines and transformers that are loaded at 75% or less of their rated power and voltages for all buses being within ANSI Range A after upgrading.

Figure 8 provides an example of how the automated upgrade code works on a circuit experiencing widespread voltage violations. Note that in this example the number of voltage violations was artificially increased by adjusting PV-to-load ratios to create challenging conditions to test the algorithm and are not representative of an actual LA100 scenario. In this case, the algorithm first adjusts the settings of existing capacitors. It iteratively tries several different settings for the capacitor switches and selects the setting that reduces the largest number of voltage violations. Then the algorithm adds a substation load tap changer and similarly adjusts to find the settings which result in the largest reduction in the number of voltage violations. Next, it clusters buses with remaining voltage challenges and adds voltage regulators at specific locations along those clusters (again based on heuristics) and simulates again. Finally, the lower left panel shows that all the original voltage violations are resolved.

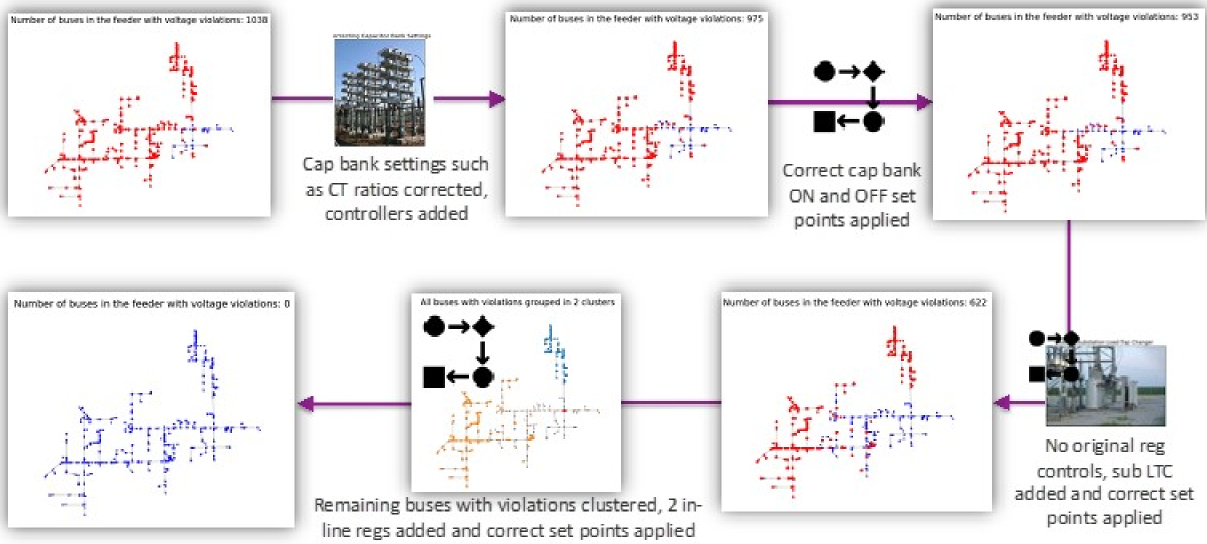

Figure 8. Example of the performance of NREL's automated upgrade selection algorithm on a non-LADWP feeder

When analyzing upgrades, impacts from a total of 13 different timepoints/loading conditions were simultaneously considered. For each feeder-deployment-scenario combination, upgrades were added until violations from all these timepoints were corrected. The specific timepoints considered corresponded to the following points, which generally varied by each scenario and each year of analysis:

- The system peak load
- The system minimum load
- The system maximum PV/load ratio
- The peak load for each individual RS
- The minimum load for each individual RS
- The maximum PV/load ratio for each RS
- The peak EV-only load for each RS
- 3 p.m. on Christmas Day
- A fall afternoon: November 1 at 3 p.m.
- A winter afternoon: January 18 at 3 p.m.
- A lightly loaded spring afternoon with high solar production: April 27 at 2 p.m.
- An additional summer afternoon: August 11 at 3 p.m.
- An additional summer evening: August 11 at 7 p.m.

As described in more detail in earlier chapters (notably Chapters 3 and 4), the weather conditions used to drive load and solar irradiance for all these timepoints were taken from 2012 historical data. For loads, these conditions were further refined to reflect predicted climate change impacts as described in Chapter 3. The use of time/weather-synchronized data was critical to capture correlations between weather conditions that may simultaneously drive load and solar production. For instance, a hot sunny day can result in high loading from air conditioners, combined with high solar production during the middle of the day.

2.4.4 Estimating Distribution Equipment Upgrade Costs

After the algorithm determines what upgrades are required, the results are then written out into a file and post-processed to calculate total costs. Total costs are equal to the count of each upgrade multiplied by the unit cost of that upgrade. The unit costs are derived from an LADWP-specific unit cost database developed by NREL for this project using sample cost data for different upgrades from LADWP. The data in this database was reviewed by LADWP's subject-matter experts prior to use. When LADWP-specific data was not available, we used additional cost data from NREL's publicly available Unit Cost Database (K. Horowitz 2019). A summary of the distribution cost assumptions used in LA100 can be found in Appendix G.

2.4.5 Treatment of Extreme Upgrade Needs

In certain scenarios we found that since the algorithms do not directly consider new feeders or circuits, our automated upgrade algorithm runs out of larger-sized in-place equipment options and instead installs multiple lines or transformers in parallel in order to provide sufficient capacity to incorporate load and DER growth without violations. In practice, detailed design practices by distribution engineering staff would likely identify alternate solutions on a case-by-case basis, but with a tremendous number of combinations of feeders, rooftop solar deployments, scenario, years, and time points to consider, we instead made the following assumptions:

- For the 4.8kV system, in some situations a very large number of transformers in parallel (>20) indicates an issue with the customer load allocation, prompting us to remove the corresponding feeder-deployment-scenario-year from the 4.8kV analysis (the loads are already captured on 34.5kV in aggregate). This condition occurs in <1% of the modeled feeder-deployment-scenario-feeder combinations. Dropping these feeders also corrects the most extreme examples of parallel lines.
- In remaining 4.8kV feeders, parallel lines indicate a challenging overload situation that might prompt a need to split the feeder into two parts and create a new feeder. Any number of lines in parallel indicates that the automated upgrade code was unable to find a large enough sized line/conductor as a drop-in replacement. This could be a true overloading that prompts a need for a new feeder, or it could also be a location where limitations of the current network topology artificially limit the capacity of available equipment. For instance, a load that was previously single phase and attached to a single-phase lateral may have grown large enough that it should really have three-phase service, which would prompt and that portion of the lateral to be upgraded to three phase. We assume this type of in-place upgrade, rather than a full new feeder, is needed when there are fewer than three line segments on a given feeder. In these cases, we assume the upgrade code costs for parallel lines provides a reasonable proxy for the cost of converting to multiphase lines. However, if three or more line segments indicated parallel lines, we assume that a reconfigured/new feeder is required and add in the estimated cost of $2.6 million per new feeder based on data provided by LADWP.
- For 34.5kV service transformers (a proxy for IS stations), the upgrade code already captures the cost of multiple transformers found in parallel, which we use directly, as this simply indicates a need to expand the IS station, which may already have multiple transformers. As a result, no additional cost adders are used.
- For substation transformers at the RS level, we consider that a parallel RS transformer likely requires additional substation configuration, so use the 4.8kV "new feeder" cost ($2.6 million) as a proxy for additional costs on top of the transformer installation itself. Additional costs, such as those for acquiring land to expand the physical footprint of a substation, are not included.

  - Additional RS substation transformers are only seen in RS-N for 2020, which as modeled requires five new transformers, suggesting a need for 1–2 new RS (consistent with LADWP plans). In 2045, RS-HAL requires a single additional transformer in all scenarios except the Early & No Biofuels ones. (See Appendix B for a simplified RS locator map.)

- No DS substation transformers are upgraded to need a parallel transformer in our analysis (but some do require increased capacity).
- For 34.5kV we treat excessive numbers of parallel lines as a proxy for the need for some form of additional circuit/substation rework in the corresponding RS regions. These regions represent multiple partially meshed circuits, which collectively include large numbers of line segments. As a result, we flag a need for RS rework for regions with more than three line segments that have equipment in parallel. This also helps ignore limited parallel line segments due to incomplete catalog data or algorithm glitches. In these cases where additional reconfiguration is required, we again use the 4.8kV "new feeder" cost ($2.6 million) as a proxy for additional costs on top of line segment upgrades.

  - Such reconfiguration occurred throughout the study. In 2020, such reconfiguration was needed in two regions (RS-B and RS-F). In 2030, RS-P and RS-Q required reconfiguration for all scenarios, while RS-A did so only for the Moderate load scenarios while RS-H did so only for the High load scenarios. In 2045, this was required in RS-RIN for all scenarios except SB100 – Stress, in RS-A for High and Stress load scenarios, in RS-T for the High load scenarios, and in RS-P and RS-J for a mix of other scenarios.

2.4.6 Summary of Assumptions—All Distribution System Analyses

- We analyze approximately 80% of LADWP's distribution system in full detail (specific coverage data included in the additional assumptions for each analysis). Simulating 100% of the distribution network is not possible due to missing or erroneous system data and numeric/computational challenges. For circuits we are not able to directly analyze, we estimate total systemwide values by scaling up from those circuits that were successfully modeled.

  - For 4.8kV, scaling for missing results is based on the count of successfully simulated feeders versus the total number of feeders.

  - For 34.5kV, we filled missing results for each RS region to ensure full spatial coverage. For the core upgrade and cost analysis, we used linear regression as described in Section 2.5.1. For the non-rooftop solar integration cost curves (Chapter 5) we filled data using results for the same region for the most similar scenario that successfully ran. For example, SB100 – Moderate loads were used to fill results for missing regions in the Transmission Focus – Moderate scenario. The simultaneous upgrade analysis did not include the 34.5kV system.

- The study considers the existing network layout, and any upgrades are assumed to maintain the current topology (line paths, substation locations, overhead vs. underground, etc.). The analysis does not consider the construction of new substations or circuits, except additional lines required to connect new resources (e.g., distribution-connected front-of-the-meter PV) or large electric vehicle charging stations (e.g., fleets or fast charging stations).

  - See Section 2.4.5 for the approach used to partially estimate the costs for more extreme upgrade needs, which can be interpreted as substation expansion, new feeder creation, or a suggested need for a new substation. For the core impact and upgrade analysis, the high net load adjustments described in Section 2.5.2 provided some additional partial estimates of these costs.

- Although service transformers that step down the distribution voltage to the low-voltage service (120–480V in most cases) used by customers are included, the low voltage, or secondary, lines are not modeled.
- Costs for routine maintenance and to replace equipment due to aging are not included.
- Analysis is only conducted in the nominal operating configuration. Switch/breaker-based reconfiguration for maintenance, alternate circuit-transformer-line connections, or non-radial operations, or other reasons are not included.
- The electric models for distribution are built using data from existing non-electrical geographic representations (FRAMME/PGES). As such, these models rely on representative electrical parameters and control settings derived by a combination of specified equipment matched to standard LADWP procurement requirements, representative equipment specifications, discussions with LADWP, and in some cases expert judgement.
- Distribution electrical modeling uses the OpenDSS power flow engine, with advanced inverter controls, improved convergence, automated upgrades, and other enhancements modeled with NREL's open-source PyDSS, and automated using NREL's DISCO tool suite.
- The study assumes two-way power flow is allowed at all levels of the distribution network. The forward and reverse ratings for lines and equipment are considered to be equal.
- Simulations were conducted for 13 timepoints in the year, corresponding to both system and local peaks, max solar-to-load ratio, and other key design points in order to ensure acceptable grid operations under a wide range of conditions (see Appendix E for specific timepoints).
- All new solar and storage installations are assumed to use "smart inverters" consistent with California Rule 21 and IEEE 1547-2018. Specifically, they are modeled as using a combination of Volt-VAR[18] plus Volt-Watt[19] inverter controls, consistent with LADWP's planned requirements (see Appendix A for specific curves). The relatively few existing solar inverters are assumed to operate with unity power factor (no advanced controls).
- We assume upgrades are required if nodes are outside ANSI Range B voltage limits and/or overloading in excess of 125% of equipment ratings occurs for any of the timepoints modeled. After upgrades, equipment is configured to keep voltage within ANSI Range A and sized to limit loading on upgraded equipment to ≤75% of rated capacity.
- System protection impacts are not directly included. These costs are relatively small percent of the total distribution upgrade costs. Getting precise numbers for protection-related impacts of DERs is complex, since the corresponding analyses require faster time-step modeling approaches and considerably more data. In addition, the suite of upgrades that are required for coordinating protection is still a topic of active discussion and research.
    - Protection upgrade costs are, however, partially included, as engineering analysis and system configuration costs are included in equipment upgrades, and part of the premium for creating a new feeder or introducing a new transformer bank at a substation accounts for protection equipment and design.

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[18] Volt-VAR control uses the power electronics that already are built into inverters help manage the local voltage impacts of distributed generation. It does so by adjusting the phase differences between injected current and system voltage which produces or consumes "reactive power". If the local voltage is getting too high, Volt-VAR control works to absorb reactive power and reduce the voltage. If it is too low, the system injects reactive power to help boost the voltage. The term VAR refers to the unit of reactive power, Volt-Ampere-Reactive.
[19] Volt-Watt control helps to correct extremely high voltages by reducing the (real) power production of solar.

  - Flicker and harmonic studies are also not included.

- A centralized distribution operations scheme such as an advanced distribution management system (ADMS) or distributed energy resource management system (DERMS) is not included, consistent with current LADWP's current distribution operations practices and the scope of this study.
- This study did not consider the time to implement upgrades, or the potential impact of any funding or regulatory challenges on executing needed upgrades by 2030 or 2045.
- Demand response is not included in the distribution analysis.
- When large loads are relocated from the 4.8kV system to 34.5kV, the additional costs to extend the 34.5kV lines are not included.
- Although detailed identification of new substation needs was not a focus of the LA100 study, we did include some additional costs to estimate such needs when simpler upgrade options were not sufficient, as described in Sections 2.4.5 and 2.5.2.

2.5 Analysis Approach: Core Impact and Upgrade Costs

As summarized in Figure 5, the core distribution impact and upgrade analysis followed three steps:

1. Upgrade the 2020 distribution system models to resolve any voltage or thermal overloading issues caused by existing deferred maintenance or data and model limitations. This is done in order to disambiguate the effects of implementing 100% renewable electricity pathways from the costs to address existing deferred maintenance as well as costs reflective of data and model limitations.
2. Add all projected load and DER changes through 2030 and then upgrade the system to estimate pre-upgrade impacts and corresponding upgrade costs to remedy.
3. Repeat Step 2 for 2045.

For this portion of the analysis, we also accounted for a few additional upgrade factors as described below.

2.5.1 Managing Missing 34.5kV Cost Estimates

For the core impact and upgrade analysis, we used linear regression to fill in an estimate of upgrade costs for regions that did not successfully solve power flow. This ensured full spatial coverage of results. Specifically, we used the statsmodels Python package[20] to estimate an ordinary least squares model for costs as a function of load DER deployment and scenario. The specific regression terms were adjusted until the aggregated sum of regression cost estimates matched the actual costs results within 10% or less.

For 2030, we used a combination of maximum native load, maximum net load, and scenario for the curve fit resulting in an average (mean) aggregated estimate error of <1% across scenarios. For 2045, we used a combination of maximum native load, maximum solar production, and load scenario resulting in an average error of 3.3%.

[20] https://www.statsmodels.org/

2.5.2 Treatment of High Net Loads

For the core impact and upgrade analysis, in addition to other upgrades, we also conducted a final upgrade step to ensure the system meets the LADWP design limits for each voltage class. For this effort, we consider the absolute net load at the source of each 4.8kV feeder or RS region by subtracting the total DER power production at each timepoint from the native load and assuming a unity power factor:

- For the 4.8kV system, the amperage limit of 600A translates into a maximum absolute net load magnitude of 5 MW.[21] When above this limit, the feeder will also require reconfiguration into two (or more) feeders. We therefore assigned an additional new feeder cost for any feeders over this limit that are not already flagged for reconfiguration by other parts of the workflow or prior years.
  - This was most common in 2045, where between 4% (Moderate load scenarios) and 21% (SB100 – Stress) require reconfiguration due to high net loads.
  - In 2030, 1.3% – 3.4% required reconfiguration with the same limiting scenarios.
- For the 34.5kV system, RS substations typically use 150 MVA transformers and range in capacity from about 300 MW to 800 MW, with 600 MW as the most common size. For simplicity, we use a net load limit of 600 MW to estimate when additional RS transformer banks are required. In these cases, we again use the 4.8kV feeder replacement cost as a proxy for RS reconfiguration and also assign a cost of $2.2 million for each new RS transformer required, if not previously accounted for.
  - This was required for 2045 where 1–3 RS substations required upgrades due to high net load for the High load scenarios and five RS substations required upgrades for SB100 – Stress. No such RS station upgrades were required for the Moderate load scenarios.

Summary of Assumptions—Core Impact Analysis and Upgrade Costs

In addition to the common assumptions for all distribution analysis listed in Section 2.4.5, the following additional assumptions apply to the core impact and upgrade analysis:

- Analysis is conducted for 2030 and 2045 for all nine LA100 scenarios and included all five deployment patterns for rooftop solar and customer storage.
- 81%–90% of LADWP's 4.8kV feeders are successfully modeled, depending on scenario and year. For 34.5kV, 79%–84% of LADWP's 34.5kV regions are successfully modeled in 2030 dropping to 53%–84% in 2045. The missing circuits/feeders encountered modeling, numeric, or computational errors[22] and are estimated using regression as described in Section 2.5.1.

2.6 Analysis Approach: Simultaneous Upgrade Benefits

Figure 5 illustrates (in yellow) the flow of the simultaneous upgrade benefit analysis. This flow involves comparing upgrade costs if load and customer-adopted solar and battery storage are

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[21] For a three-phase system, apparent power, S, is computed as $\sqrt{(3)} \times \mathrm{pf} \times \mathrm{I} \times \mathrm{V}$. With a power factor, $pf = 1$, and a current limit of $I = 600A$, this becomes $\sqrt{(3)} \times 1.0 \times 600 \times 600\mathrm{k}V \approx 5MVA$, which for simplicity we refer to as 5 MW.

[22] These errors are largely driven by data errors and while we corrected most of these challenges, getting to 100% coverage was beyond the project scope, which relied on semi-automated approaches. Full coverage could be achieved with additional in-depth attention from distribution engineering staff.

deployed simultaneously versus solar and battery storage being installed after loads have grown and the distribution system has already been upgraded to accommodate that load growth. This allows us to identify any potential synergies associated with upgrades, potentially pre-emptive, to support load and solar simultaneously.

We compute the relative numbers of violations and cost of upgrades for designing for loads then solar and storage vs. designing for both simultaneously by subtracting the corresponding violation counts and upgrade costs. For instance, to estimate the cost savings from simultaneously designing for load, solar, and storage, we subtract the sequential results (loads, then adding solar and storage) from the results for the simultaneous design.

We focused on the 4.8kV system because this system requires significantly more distribution upgrades than the higher-voltage, higher-capacity 34.5kV network. The primary goal of this analysis was to understand any synergies and cost savings from upgrading the distribution system to simultaneously support customer-adopted rooftop solar and battery storage and load growth. This analysis explored all the load and customer-adopted rooftop solar and battery storage scenarios.

Summary of Assumptions—Simultaneous Upgrade Benefit Analysis

In addition to the common assumptions for all distribution analysis listed in Section 2.4.5, the following additional assumptions apply to the incidental deferment analysis:

- Only the 4.8kV system in 2045 is modeled.
- 82% to 90% (depending on scenario) of the 4.8kV feeders are successfully modeled for simultaneous upgrades.
- Additional upgrade costs for high net loads are not included.

3 Summary of Distribution-Connected Resources

As seen in Figure 9, the LA100 study considers three categories of in-basin resources:

1. LADWP-procured solar and storage directly connected to the transmission system at existing in-basin generation sites.
2. LADWP-procured non-rooftop solar and storage connected to the distribution grid
3. Customer-adopted rooftop solar and storage, connected to the distribution system.

This chapter focuses on the latter two, which are connected to the distribution system. The resources at the existing thermal generator sites have existing infrastructure to tie into transmission and are thus a low-cost option for grid integration, within the limits of available land. The analysis for these sites is discussed in Chapter 6.

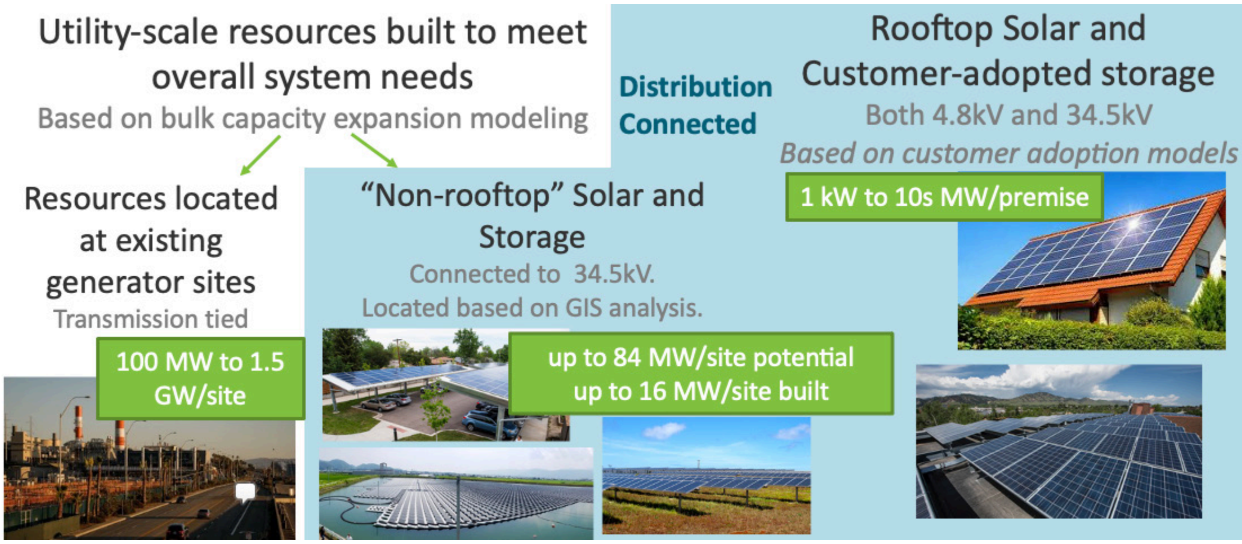

Figure 9. Three categories of in-basin distributed solar and storage considered in the LA100 study

The two remaining categories of in-basin resources—LADWP-procured non-rooftop solar and storage and customer-adopted rooftop solar and storage—are distribution-connected and are considered in detail below. These resources are estimated through 1) the non-rooftop local solar GIS siting and supply-curve analysis (Chapter 5) together with the systemwide capacity expansion results (Chapter 6) and 2) NREL's customer adoption model (Chapter 4). These chapters describe the overall methodology of selecting local solar and storage sites and modeling adoption in detail. Here, we provide a brief summary and synthesize some of the results with a focus on distribution-connected resources.

3.1 How Much Rooftop Solar and Customer Storage Is Adopted?

As discussed in detail in Chapter 4, and as summarized in Table 1, the LA100 study projects between 2.8 and 3.9 GW of customer rooftop solar and 1.1 and 1.5 GW of distributed storage to be adopted in LA by 2045.[23] Stratified by voltage class, we project an average of 90% (or roughly 2.5–3.6 GW_{PV} and 1.4–1.6 $GW_{Battery}$) of customer rooftop solar and storage to be connected to the 4.8kV distribution grid. Meanwhile, an average of 10% of customer-adopted rooftop PV and storage is connected directly to the 34.5kV subtransmission network. Across scenarios, behind-the-meter distributed solar ranges by 1.3 GW, with the highest 4.8kV demands in the Early & No Biofuels – High and Limited New Transmission – High scenarios.

Table 1. Summary of Customer Rooftop Solar and Storage Adoption in 2045 by Scenario and by Distribution Voltage Class

Scenario	Rooftop Solar (MW)			Customer Storage (MW)		
	4.8kV	34.5kV	Total MW	4.8kV	34.5kV	Total
EarlyNoBio – H and Ltd Trans. – H	3,559	340	3,899	1,641	96	1,737
EarlyNoBio – M and Ltd Trans. – M	3,282	335	3,617	1,478	96	1,574
SB100 – S	2,955	299	3,254	1,536	93	1,629
SB100 – H and Trans. Focus – H	2,826	297	3,122	1,468	92	1,560
SB100 – M and Trans. Focus – M	2,534	288	2,822	1,287	91	1,378

3.2 Deployment Projections for Non-Rooftop Solar

Depending on the various constraints of each scenario, our capacity expansion model determines the cost-optimal mix of generation resource needed (including local solar) across the city to ensure a reliable system (see Chapter 6). In addition to rooftop local solar deployments, we find that between 313 and 1,046 MW of non-rooftop local solar deployment and between 213 and 715 MW of 34.5kV-connected battery storage is built by the LA100 capacity expansion model in 2045 to meet LA's future 100% renewable energy grid. These non-rooftop solar and storage requirements are illustrated in Figure 10, where solar capacity is represented by the vertical bar and storage capacity is represented by a horizontal gray line. These 34.5kV-connected solar and storage capacities are largely driven by capacity expansion scenarios instead of future electricity demand scenarios. The Early & No Biofuels scenarios place the highest demands on in-basin non-rooftop local solar and storage, followed by the Limited Transmission scenarios and SB100 – Stress.

[23] Compare these values to 22–27 GW of total generation capacity for the different LA100 2045 scenarios.

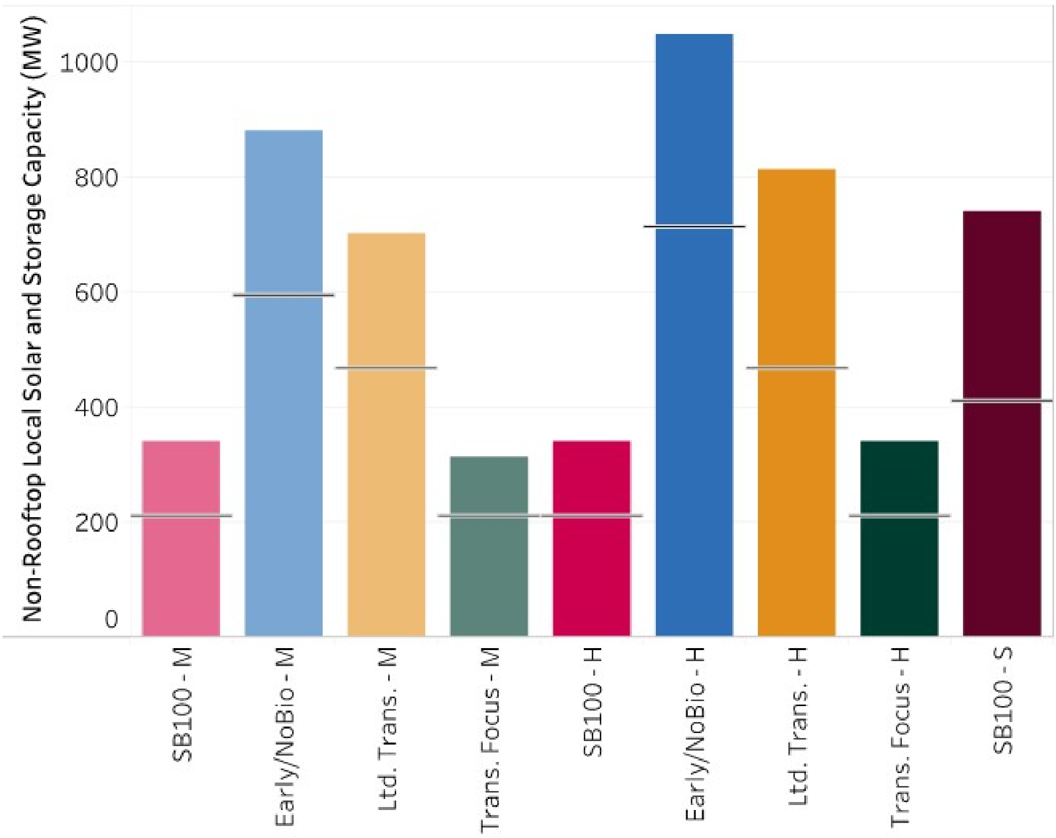

Figure 10. Summary of non-rooftop local solar and storage capacity connected to the 34.5kV system

Storage capacity is represented as the horizontal line.

Based on these total non-rooftop solar and storage capacity requirements in Figure 10, a GIS-based economic ranking (developed in Chapter 5) is used to site deployments on actual parcels within the city based on lowest cost and land-use ranking. Figure 11 maps the spatial placement of these non-rooftop solar deployments in 2045 sized by capacity for the Transmission Focus – Moderate (left) and Early & No Biofuels – High scenarios (right). In both scenarios, we find that these non-rooftop capacities are somewhat scattered about the city on the 34.5kV system, clustered around particularly transmission-constrained RS nodes that benefit from this generation capacity. Similar trends are found across the remaining LA100 scenarios; non-rooftop deployment maps for all scenarios can be found in Appendix C, Section C.1.

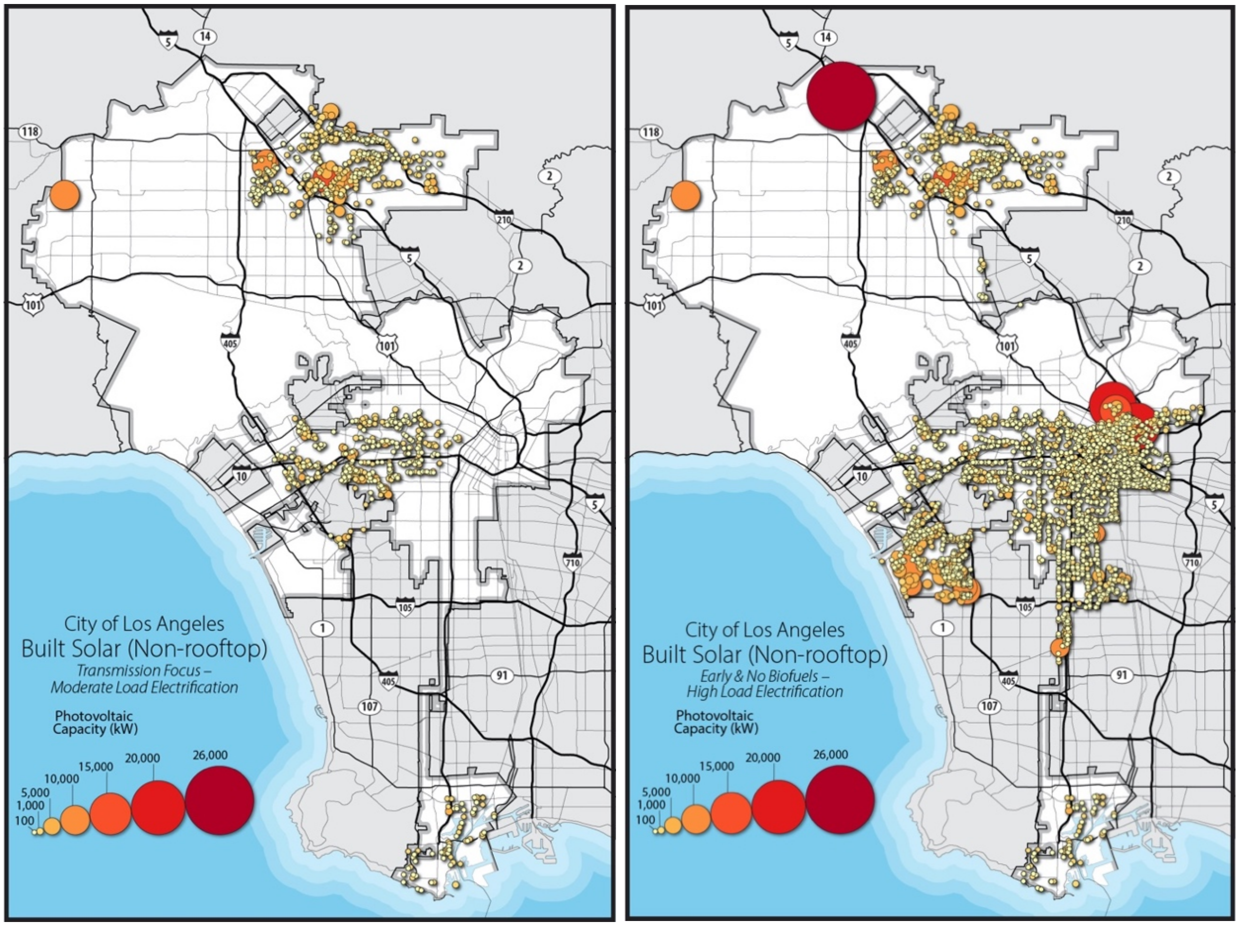

Figure 11. Capacities of non-rooftop solar on the distribution grid in 2045

Transmission Focus – Moderate (left) and Early & No Biofuels – High (right).

Figure 12 depicts the non-rooftop deployments across RS nodes, technology types, and scenarios. At this RS region level, we find RS-M and RS-D 34.5kV network serving the bulk of the capacity in each scenario, with RS-F and RS-N also playing significant roles in some scenarios (see Appendix B for map of RS stations). In more urban or densely populated parts of the LA network (e.g., RS-D, RS-B, RS-F, RS-N, RS-P), we find a mix of parking canopy and ground-mount solar being deployed, while some of the less-dense outer edges of the 34.5kV network (e.g., RS-M, RS-RIN) are dominated by larger multimegawatt ground-mount installations. For all scenarios, we find that the capacity expansion modeling finds significant value in solar+storage technologies, that combine solar PV and battery storage at the same sites, versus stand-alone solar, resulting in virtually all ground-mount solar installations being built with storage.[24]

[24] An important note here is that we site solar plus storage installations as being co-located on the same land parcel; however, in reality, RPM does not place restrictions on co-location as long as solar and storage are connected to the same 34.5 kV subtransmission network. This means it would be comparable from a system perspective to locate the solar and storage at different sites within the RS region. Such split/alternate siting could also be used to help manage challenges on the distribution system.

Figure 12. Total non-rooftop local solar deployments by RS, by technology type, and by scenario, sized by MW deployed

3.2.1 Looking Deeper: How Much Land Is Needed for Non-Rooftop Solar on the Distribution Grid in 2045?

The total land area required for ground-mount solar installations ranges between 4 and 8 km^2. Total development area, including for parking canopy solar, which does not compete for space and comprises 18%–77% of the total non-rooftop land area, is shown in Figure 13. The scenario with the least non-rooftop local solar, Transmission Focus – Moderate, is shown on the left; the scenario with the most is Early & No Biofuels – High, shown on the right.

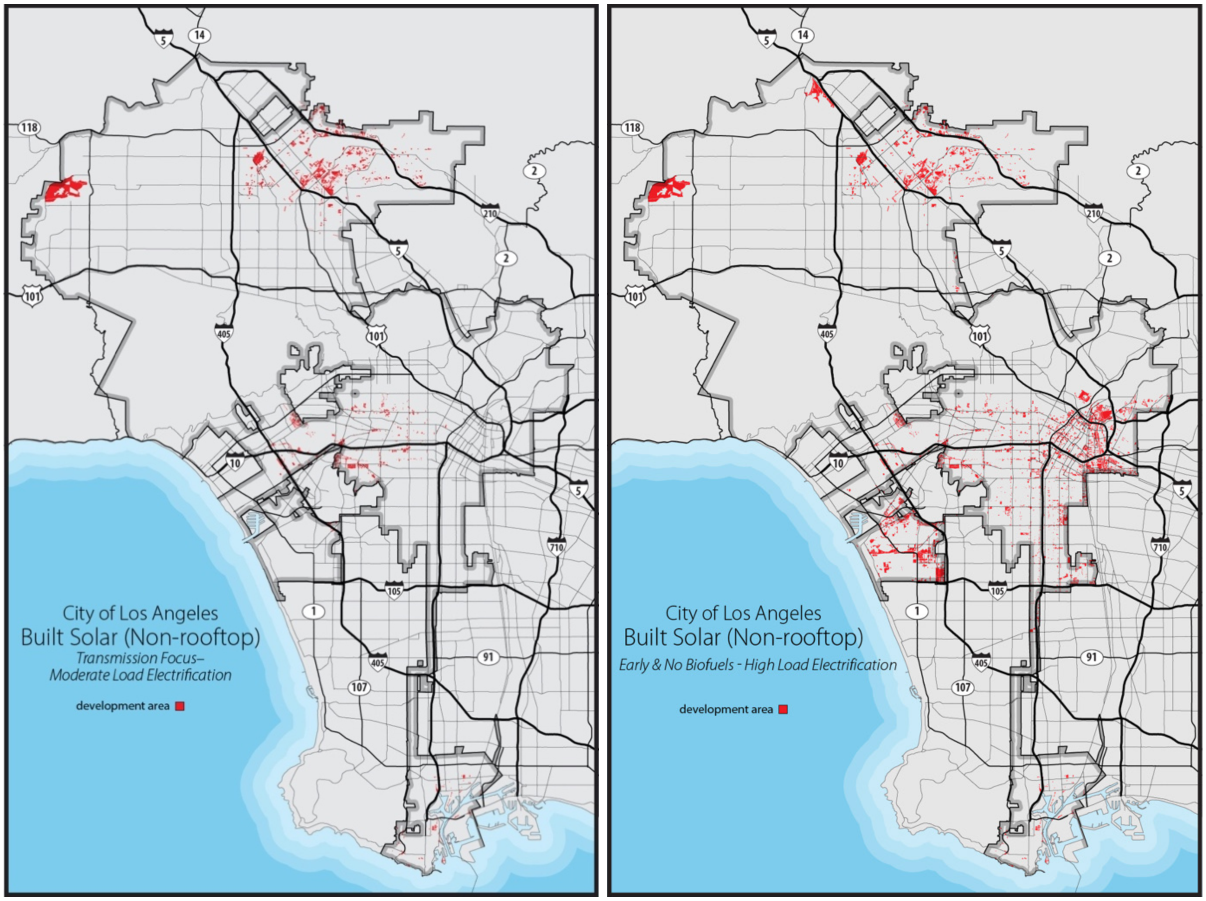

Figure 13. Land area required for non-rooftop solar on the distribution grid in 2045 for the Transmission Focus – Moderate (left) and Early & No Biofuels – High (right) scenarios

Parking canopy solar does not compete for space and it makes up 18%–77% of this development in these two scenarios.

3.3 Do the Scenarios Meet the 2019 pLAn's Local Solar Goals?

The Mayor's Los Angeles Green New Deal (pLAn 2019) goals for local solar in Los Angeles (as introduced in Chapter 5) include an increase of 1,950 MW in cumulative local solar capacity by 2045. All scenarios modeled in LA100 exceed these targets.

Figure 14 compares the pLAn goals with the LA100 rooftop and non-rooftop local solar capacity deployments. We find that the LA100 scenarios deploy 1.5 to 2.4 times more local solar than is required by the pLAn. We also find that the projected levels of customer rooftop solar adoption alone already exceed the pLAn targets and are a more significant quantity than the totals for non-rooftop solar (e.g., ground-mount or parking canopy systems).

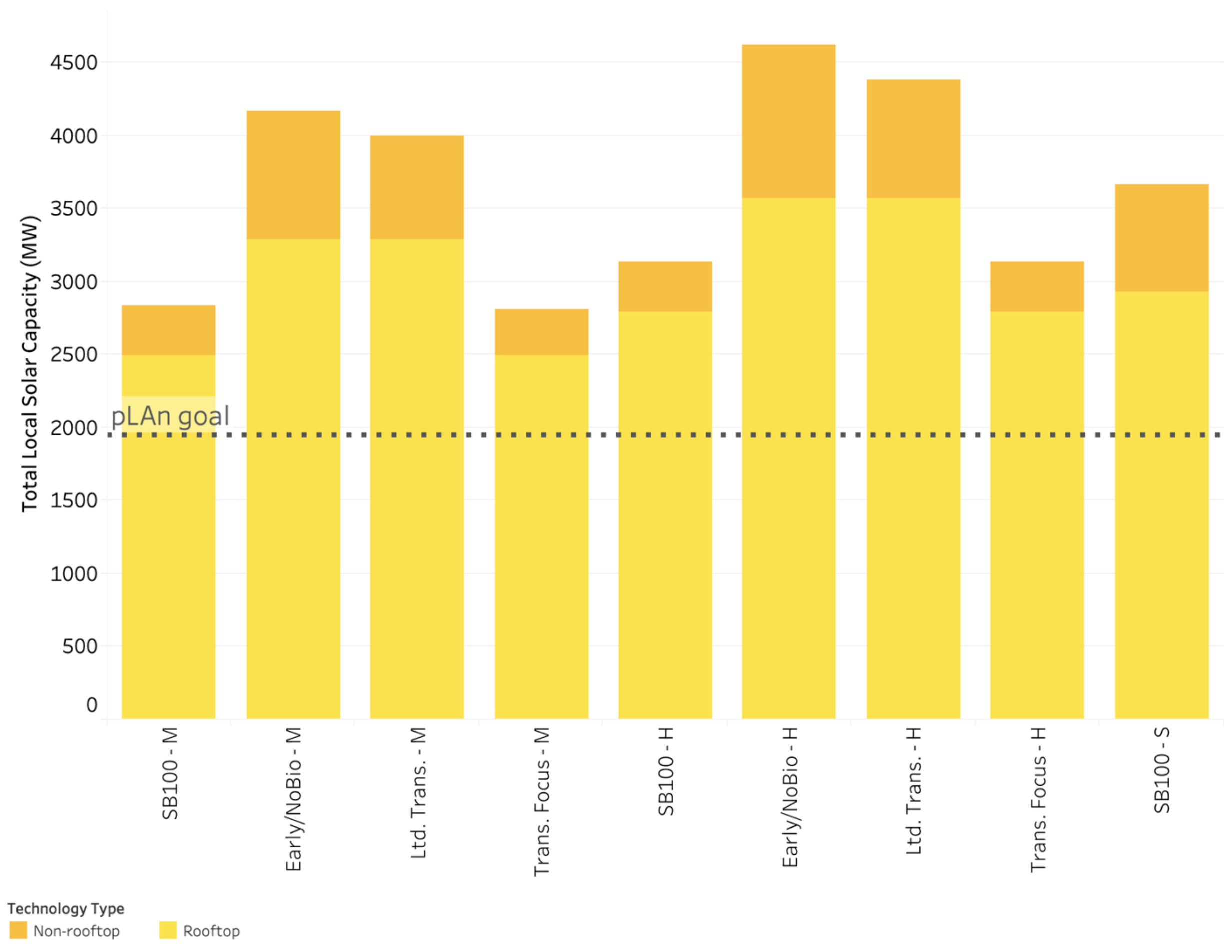

Figure 14. Total rooftop and non-rooftop local solar deployments by 2045 compared to 2019 pLAn goals, by scenario

3.4 Looking Deeper: How Do Non-Rooftop Deployments Compare to Techno-Economic Potential?

Despite these ambitious local solar deployments in 2045, there is still additional potential resource technically available for future development. In fact, depending on the scenario, we find that 6%–18% of non-rooftop local solar technical potential gets built in 2045, while 21%–29% of rooftop local solar technical potential is adopted. Figure 15 breaks down the total portion of rooftop and total portion of non-rooftop local solar technical potential built in 2045, by scenario. For rooftop solar, we find a relatively small difference in the fraction of rooftop potential deployed across the medium and high distributed generation scenarios. For non-rooftop systems, the fraction of potential sites varies more widely among scenarios. Both rooftop and non-rooftop percentages are highest in scenarios where limits on generation and/or transmission favor increased in-basin solar.

It is worth noting that the LA100 study first estimates rooftop adoption and later adds capacity for non-rooftop resources. This suggests that if rooftop adoption were lower than estimated here, we might see a corresponding increase in the amount of non-rooftop solar deployed.

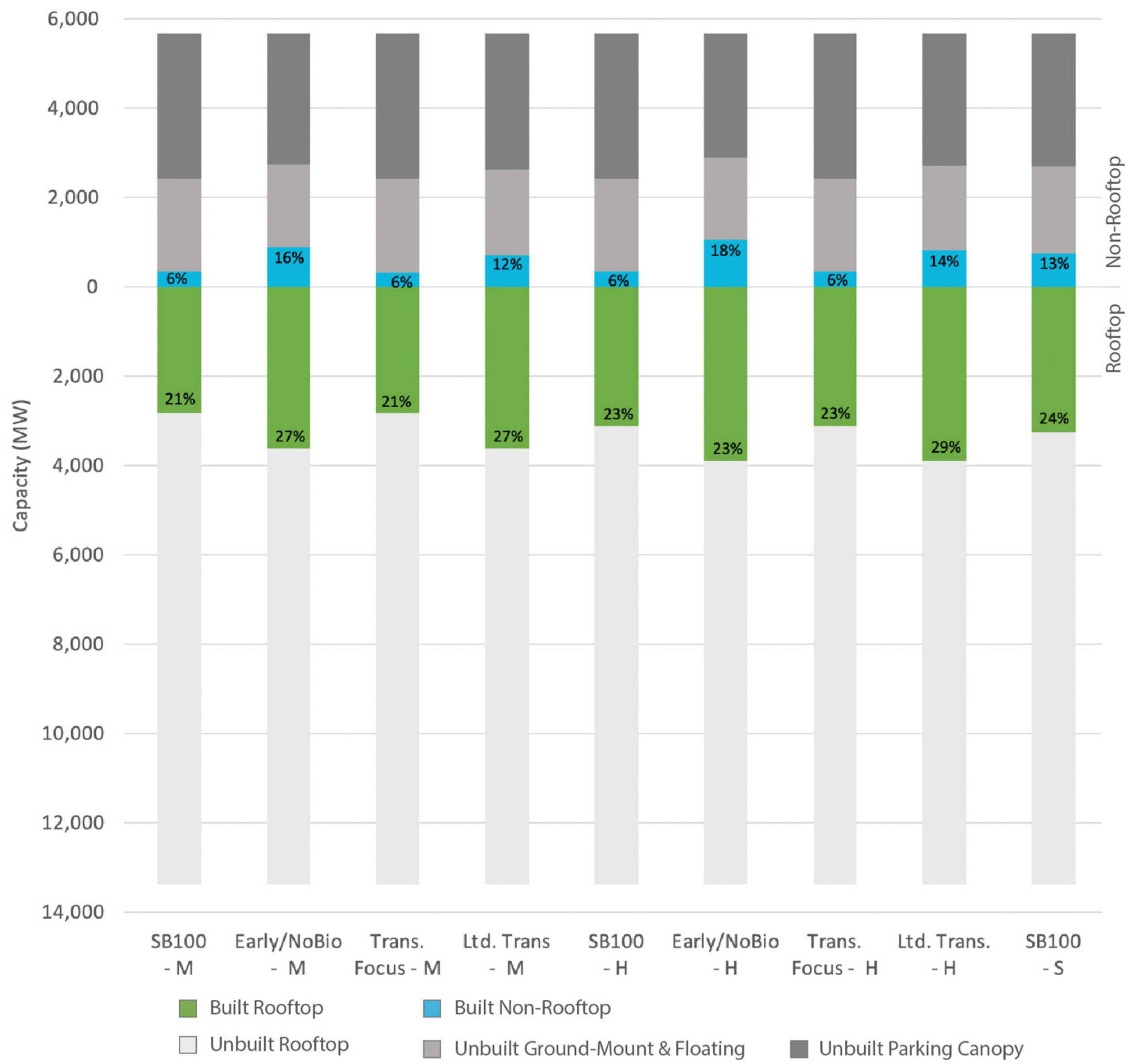

Figure 15. Portion of rooftop and non-rooftop local solar technical capacity built in 2045 by scenario

Digging deeper, we find that the deployment of non-rooftop local solar is non-uniform across scenarios and across RS regions, despite the fact that the technical potential is more uniformly distributed. This non-uniformity of deployment is driven primarily by the LA100 capacity expansion model, which optimizes transmission-level node deployments of non-rooftop local solar in order to balance demand and meet reliability. Specific decisions on capacity deployments are influenced by in-basin transmission congestion as well as small differences in electric losses across regions that make particular nodes closer to high load areas more attractive.

Figure 15 breaks down the deployed fraction of technical potential for each RS region across the city per scenario, and it shows how the spread and density of non-rooftop solar varies nonuniformly across regions. For example, we find that some regions always install non-rooftop solar (e.g., RS-N and RS-M), while others are never built at all (e.g., RS-S), despite having significant potential capacity. Likewise, some regions have only a small fraction of potential built (e.g., RS-J), while others are built to high percentages (~80%) of potential (e.g., RS-D), sometimes only for certain scenarios (e.g., RS-A for Early & No Biofuels and Limited New Transmission). In practice, the specific locations for this widespread deployment of non-rooftop solar and corresponding storage may vary due to many factors, but it is clear that from an overall system perspective, there are portions of the city that offer greater advantages than others.

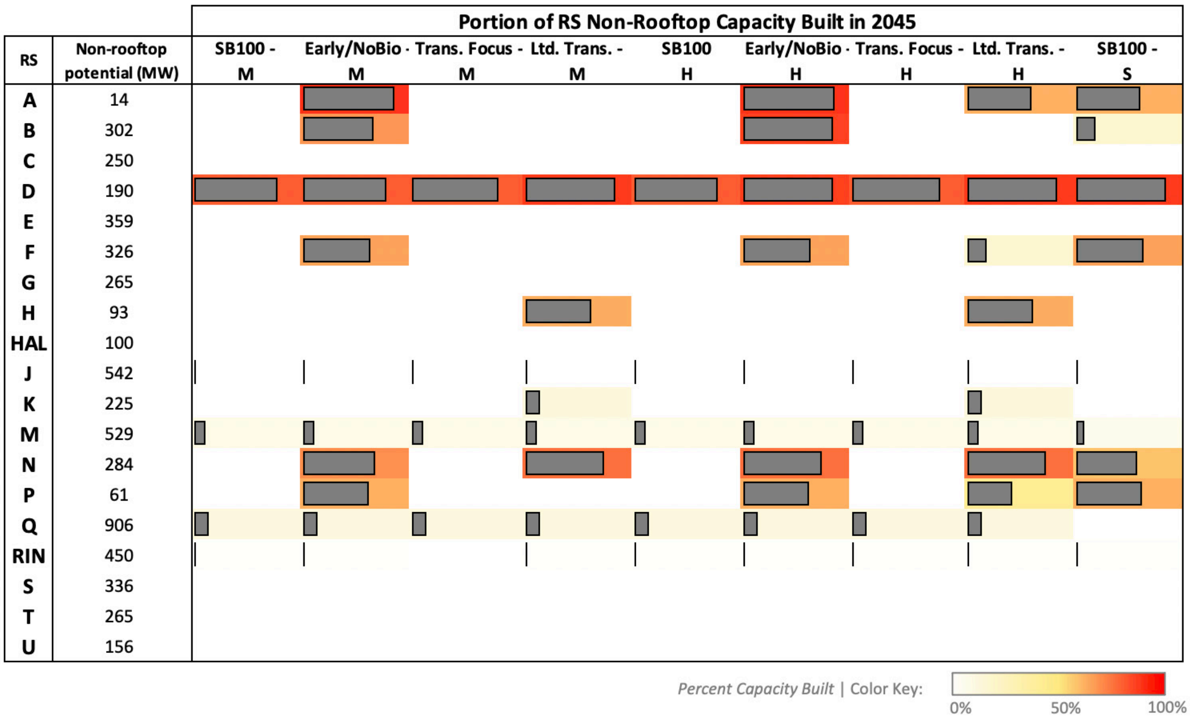

Figure 16. Portion of non-rooftop local solar technical capacity built in 2045 by RS region and scenario

Siting of non-rooftop local solar is influenced by two competing forces. First, the capacity expansion model determines in which 34.5kV regions in the city to deploy solar, as driven by a combination of costs and grid constraints. On the other hand, the more spatially resolved GIS siting based on land availability and location-influenced costs is used to identify suitable lands for non-rooftop solar and rank the best sites based on a least-cost prioritization ranking. In some cases, this creates a tension where the least-cost expansion planning may not select some of the sites where it is cheapest to build solar if they happen to be located in attractive regions.

An example of builds prioritized in our supply-curve analysis (discussed in detail in Chapter 5) that were ultimately not selected by capacity expansion planning includes the prioritized parking lots for parking canopy solar near the Port of Los Angeles and Port of Long Beach. Because the capacity expansion model chose exclusively ground-mount solar+storage at RS-Q (the RS that serves these ports), which cannot be located on parking canopies, the highly ranked and prioritized sites for parking canopy solar at the two ports were ultimately excluded. When it comes to actual deployment, it could be that the potentially small cost differences between such sites are overshadowed by practical siting needs and priorities, or that alternate storage locations are identified such that these and other sites do make sense to build out. Still, such differences should not detract from the overall takeaway: local solar of all types is a key asset in all pathways to 100% renewables in LA, and patterns of deployment are likely to vary across the city depending on how else the power system is evolving.

4 Distribution System Costs and Needs for 100% Renewable Energy Pathways

4.1 What Are the Costs for Distribution Upgrades?

The total costs for electric distribution system upgrades for the 100% renewable energy pathways through 2045 vary from $472 million (SB100 – Moderate and Transmission Focus – Moderate) to $1,550 million (SB100 – Stress). As described in Section 2.4, these costs are due to changes evaluated within the study and are in addition to the costs required to cover deferred maintenance and other upgrade needs that exist on today's system. The costs also do not include routine maintenance and operations of the system. As seen in Figure 17, these costs are strongly driven by upgrade needs on the 4.8kV local distribution system, which accounts for 85.6% (Early & No Biofuels – Moderate) to 92.1% (Early & No Biofuels – High) of the total.

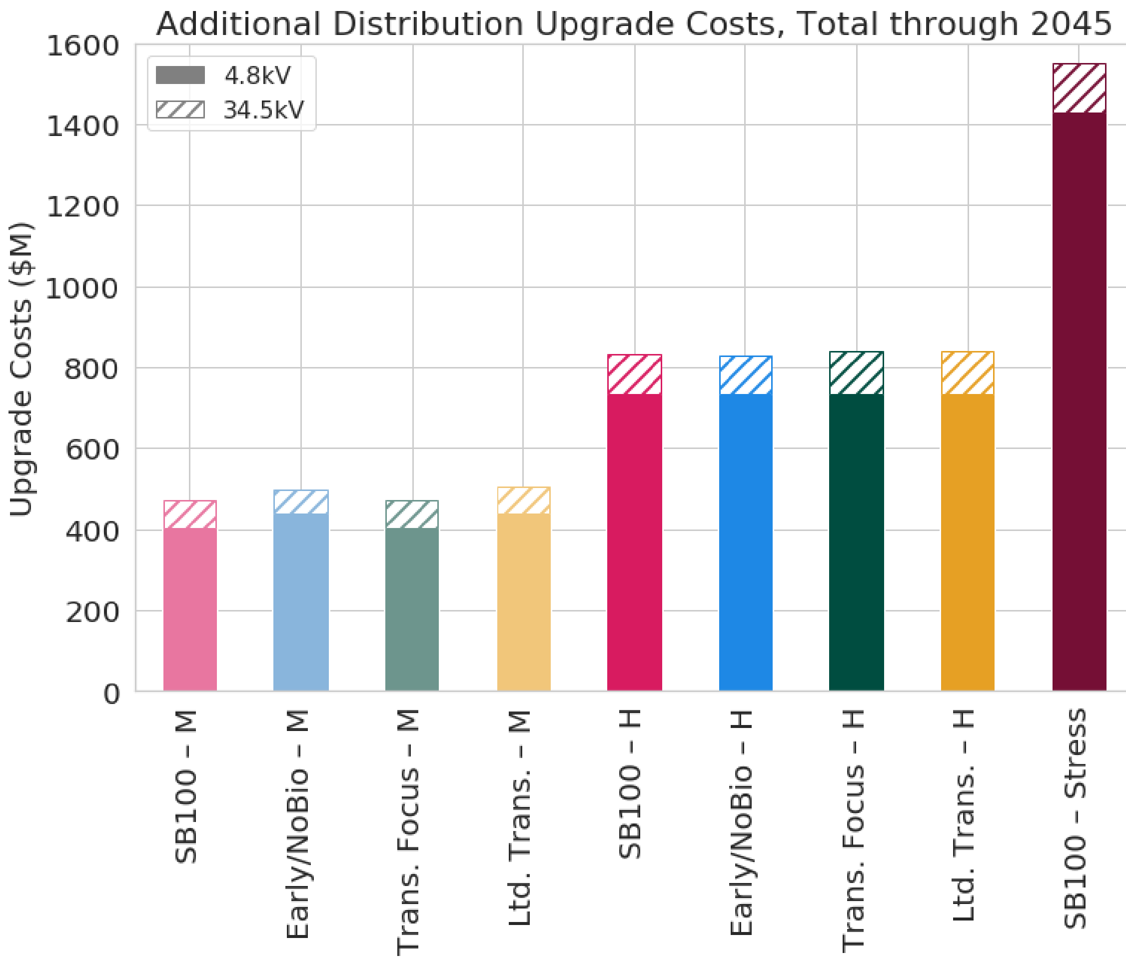

Figure 17. Cumulative distribution upgrade costs through 2045 by scenario (after addressing existing deferred maintenance) on the 4.8kV local distribution system and the 34.5kV subtransmission system (2019$)

The distribution system costs presented here were updated after other chapters of the study were completed. These are the final distribution system costs.

Comparing the Moderate to High to Stress load electrification scenarios shows how these total costs are strongly influenced by load electrification, with higher electrification corresponding to higher distribution upgrade costs. For the Moderate load scenarios, upgrade costs are also somewhat higher with higher levels of rooftop solar and customer storage. This can also be seen in Figure 17 by comparing the moderate rooftop solar scenarios (SB100 and Transmission Focus) with the corresponding high rooftop solar scenarios (Early & No Biofuels and Limited New Transmission).

To put these costs in perspective, these distribution upgrade costs are 1%–2% of the overall costs for the pathways to 100% (see Chapter 6). Distribution upgrade costs also only include the costs for grid upgrades and not the costs for efficiency measures, electrification, solar equipment, and storage, which are also collectively much higher. [25]

4.1.1 Timing and Location of Distribution Upgrades and Costs

Figure 18 breaks down the total distribution upgrade costs by timing. Our analysis only computed upgrade needs in two periods: 1) from 2020 (after existing deferred maintenance issues are resolved) through 2030 and 2) from 2030 through 2045. Most of the costs are incurred between 2030 and 2045. This is driven largely by the fact that, for all load scenarios, residential and transportation electricity demand increases more rapidly after 2030. The effect is even more pronounced for the High and Stress load scenarios, in which there is a sharper increase in plug-in electric vehicle adoption around 2027 compared to the Moderate load scenarios (see Chapter 3).

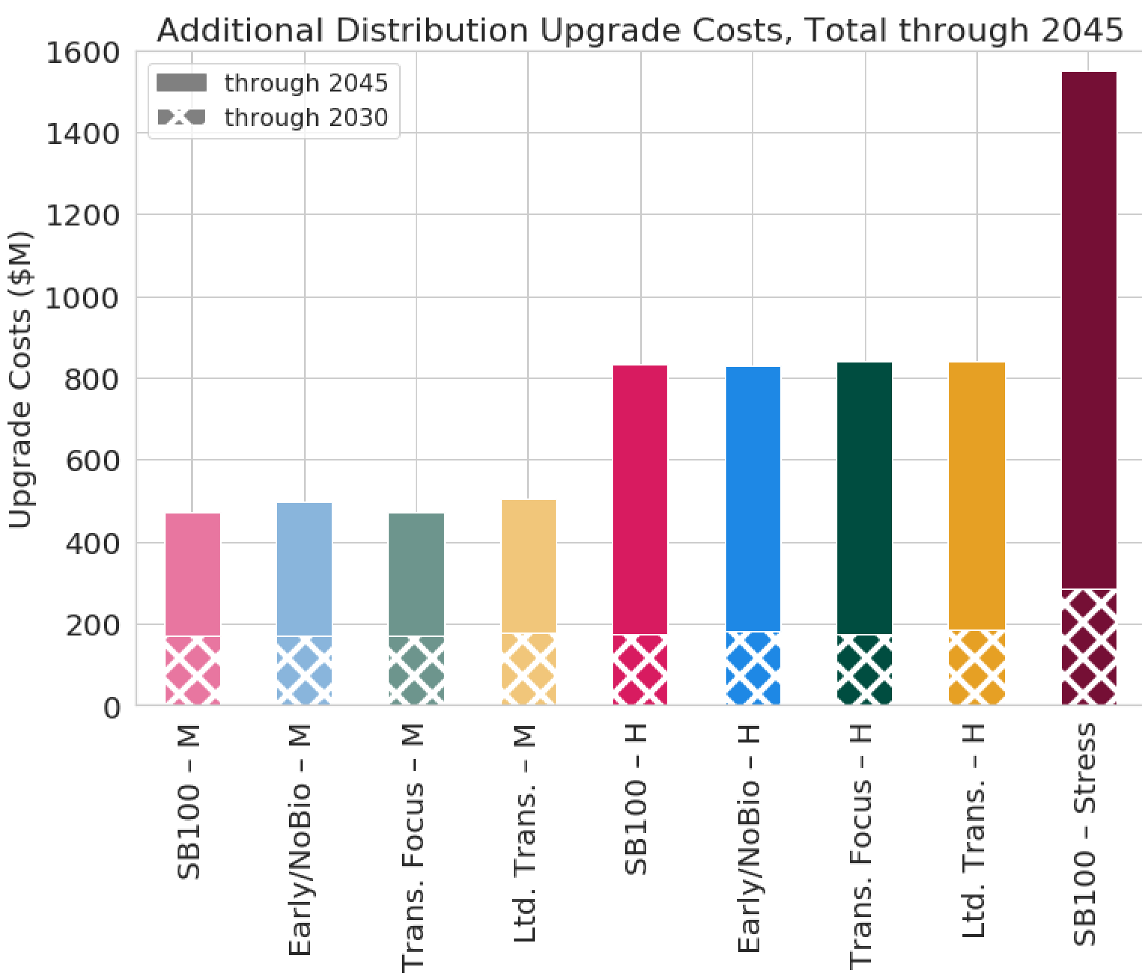

Figure 18. Breakdown of distribution upgrade costs incurred through 2030 (after fixing existing deferred maintenance) and through 2045

[25] Medium- and heavy-duty vehicle electrification was not modeled in detail, but Chapter 9, Appendix A provides a qualitative description of potential impacts, for charging, generation, the distribution grid, and air quality and health.

Figure 19 and Figure 20 show the spatial distribution of these upgrade investment patterns through 2030 (not including deferred maintenance) and from 2030 to 2045, respectively, for the SB100 – High scenario. These costs are spread throughout the LADWP distribution system, but some regions require more extensive upgrades than others based on the quantity of load, solar, and storage changes.

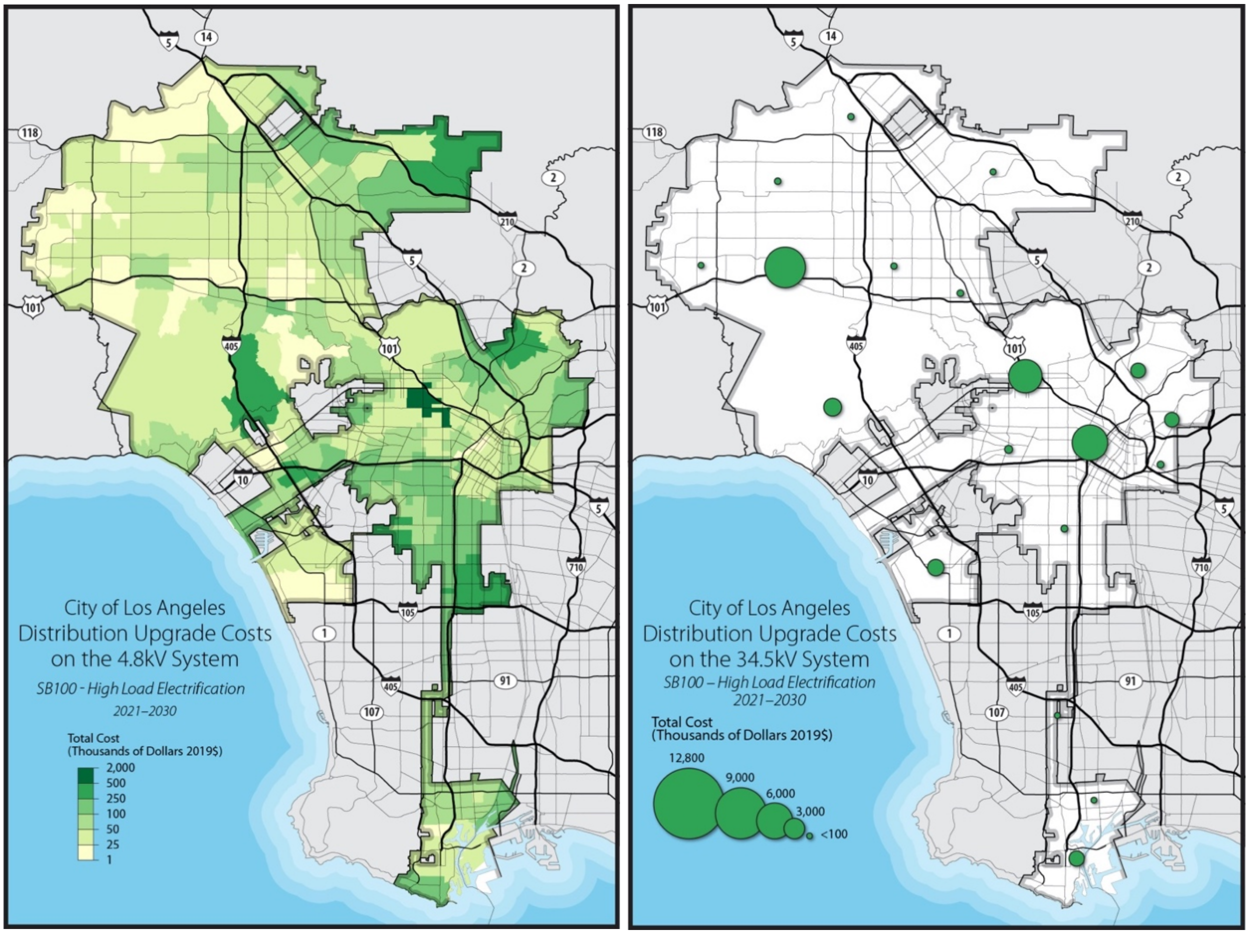

Figure 19. Map of distribution system upgrade investments for the 4.8kV system (left) and the 34.5kV system (right) through 2030, not including upgrades required for deferred maintenance and other needs on the system today

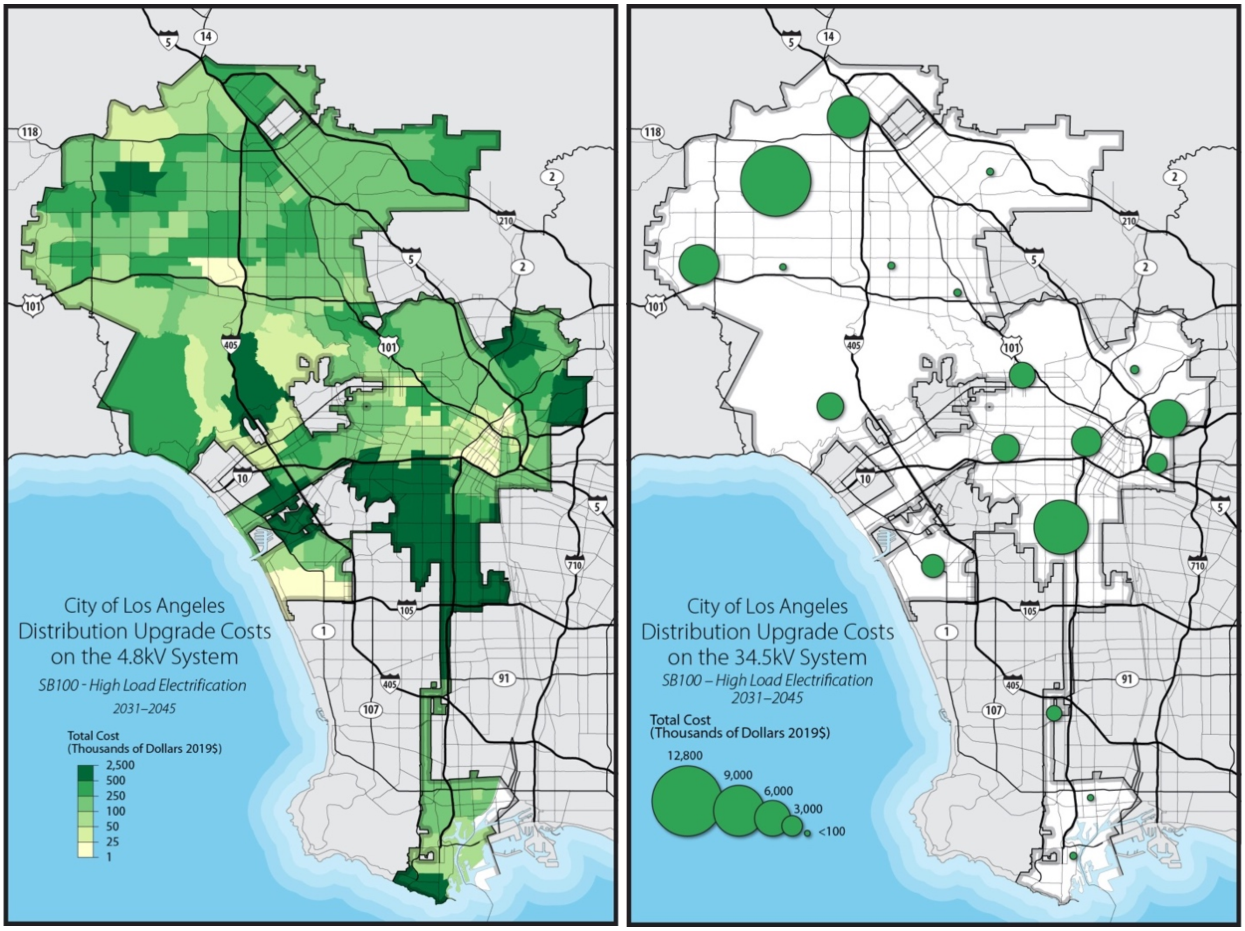

Figure 20. Map of distribution system upgrade investments for the 4.8kV (left) and the 34.5kV (right) system 2031–2045

4.1.2 Breakdown of Upgrade Costs by Type

As seen in Figure 21 and Figure 22, these costs for both 4.8kV and 34.5kV, respectively, are very strongly driven by a combination of feeder/RS reconfiguration and transformer upgrades. Both of these cost categories are partially due to the overloading seen with load electrification and DER additions, but also to the fact that the transformer installation and other feeder/substation reconfigurations have higher costs that those for setting changes.

For 4.8kV (Figure 21) new feeders account for 62% of the upgrade costs versus 29% for transformers. This split changes with time with the cost contributions of 47% and 44% for new feeders and transformers respectively in 2030 changing to 67% and 25% in 2045. These transformers are all service transformers that serve customer loads.

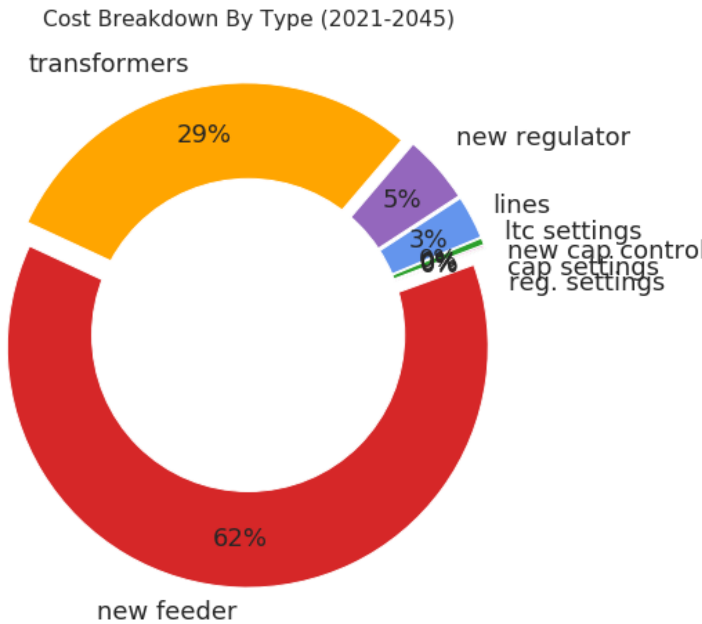

Figure 21. 4.8kV upgrade cost breakdown by type across all scenarios and years

For 34.5kV (Figure 22) the majority of costs are for transformers (51%) with RS substation reconfiguration (27%) and line upgrades (23%) accounting for nearly all of the rest. Here the transformer costs include a combination of RS substation transformers, DS substation transformers, and transformers that serve large customer loads (industrial station, or IS).

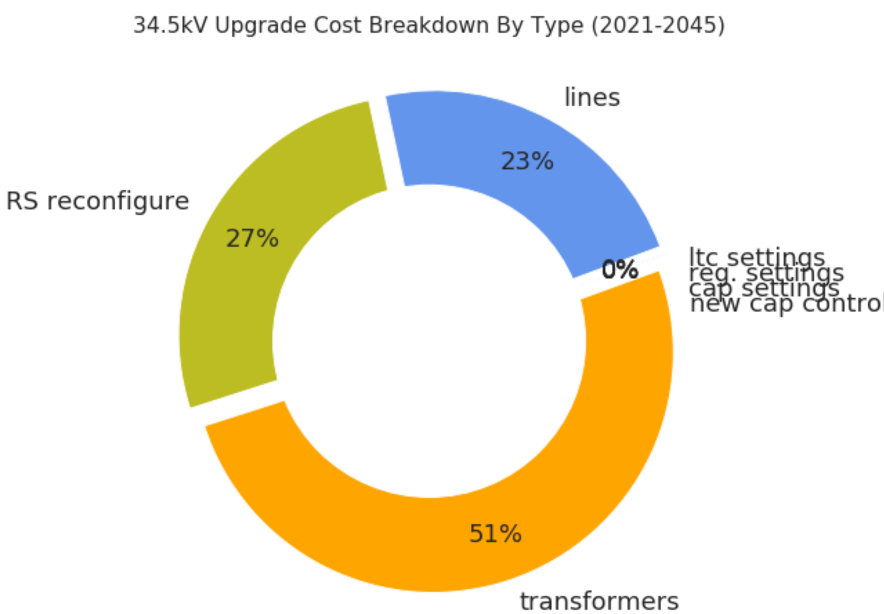

Figure 22. 34.5kV upgrade cost breakdown by type across all scenarios and years

The addition of new regulators accounts for the next largest portion (5%) of 4.8kV upgrade costs. These, along with the much smaller percentages of costs for load tap changer (LTC), capacitor, and regulator control and settings changes, indicate the prevalence of voltage regulation needs on the 4.8kV system. In contrast, the third largest expense for 34.5kV upgrades (23%) is in upgrading lines, which is partially due to the relatively more widespread need for line upgrades to address overloading on the subtransmission system, but also because of the considerably higher costs for lines at this voltage class. Such line upgrades only account for 3% of the cost of 4.8kV upgrades.

Although detailed identification of new substation needs was not a focus of the LA100 study, we did include some additional costs to estimate such needs when simpler upgrade options were not sufficient, as described in Section 2.4.5. At both voltage levels, there is also a noticeable amount of substation reconfiguration or expansion cost. Specifically, 9% of total 4.8kV upgrade costs are estimated for new feeders, which are indicated when the number of line segments that reach capacity becomes too high, suggesting a need to split the feeder into two. At the 34.5kV level, we see a similar amount (8%) for RS substation reconfiguration to manage similar overloads, plus 3% of costs to account for the need to add a new transformer/bank at one of the RS stations in many scenarios.

4.2 What Is the Value of Simultaneously Upgrading for Load and DERs?

As described in Section 2.6, LA100 did not include a detailed non-wires alternatives study that might optimize the location and installation level of these DERs to reduce the need for expansion/upgrades. However, we did explore how simultaneously upgrading to support load, solar, and storage can reduce the upgrade needs and costs compared to upgrading sequentially for loads and later for solar and storage. In addition to these results for the 4.8kV system, the non-rooftop solar integration cost curves in Chapter 5 highlight how some deployment levels of non-rooftop solar can result in a small upgrade cost savings and hence provide some incidental deferment value. Section 4.3 also highlights the impact of DERs on net load, which also demonstrates additional value from DERs.

This analysis finds that on 8%–24% of feeders on the 4.8kV system, depending on scenario, upgrading to simultaneously support load, solar, and storage reduces system upgrade costs. This analysis in 2045 compares upgrade costs between those needed when load, rooftop solar, and customer-adopted storage are deployed simultaneously versus solar and storage being installed after loads have grown and the distribution system has already been upgraded to accommodate that load growth. This analysis is shown for three scenarios in Figure 23 (SB100 – Stress Load), Figure 24 (SB100 – Moderate) and Figure 25 (Early & No Biofuels – Moderate). In these figures, a simultaneous upgrade benefit is observed (in orange) due to customer-adopted solar and storage.

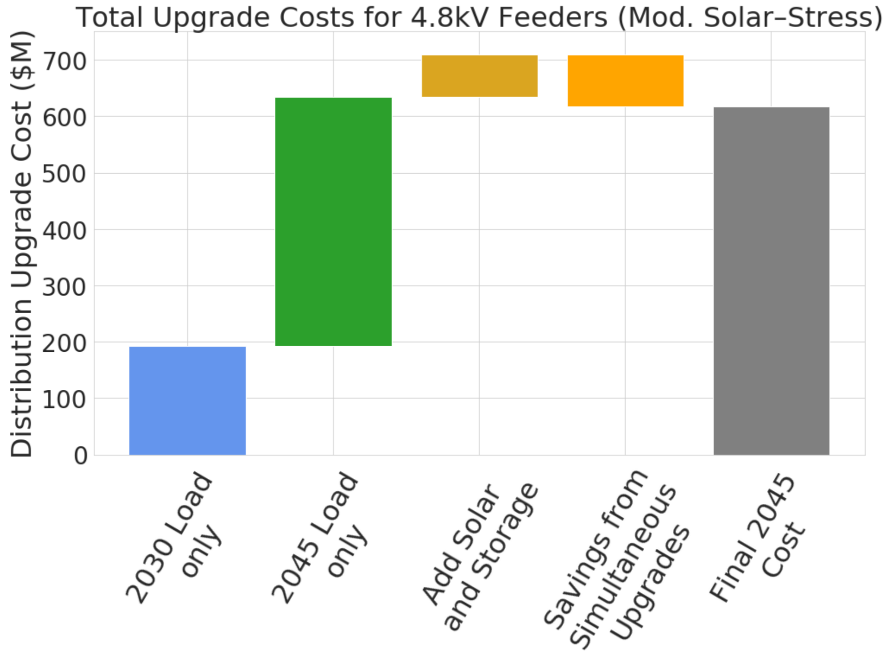

Figure 23. Sequential upgrade costs compared to simultaneous upgrade costs for 4.8kV feeders for SB100 – Stress, assuming existing deferred maintenance already addressed

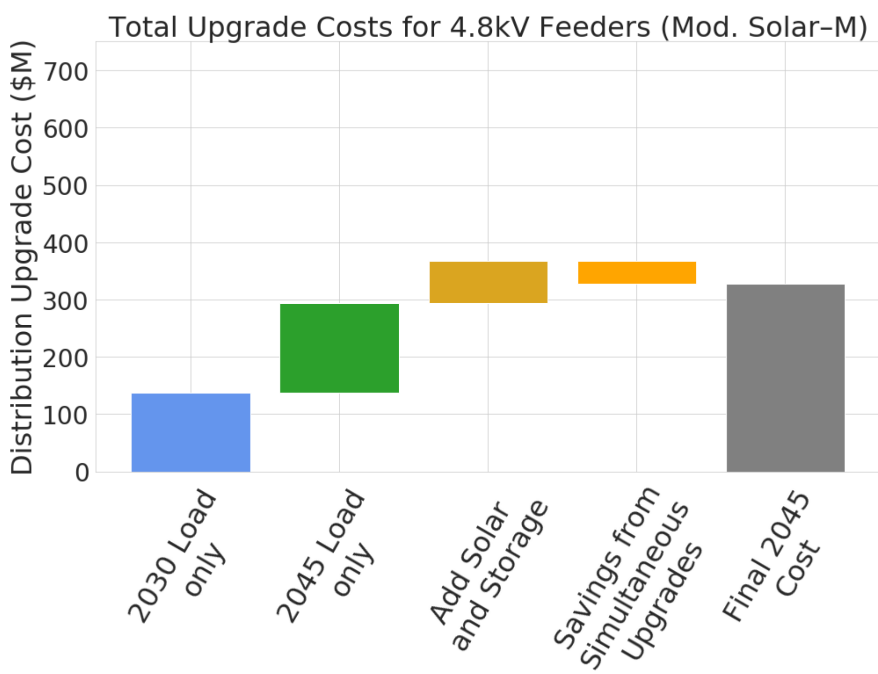

Figure 24. Sequential upgrade costs compared to simultaneous upgrade costs for 4.8kV system for SB100 – Moderate (= Transmission Focus – Moderate), assuming existing deferred maintenance already addressed

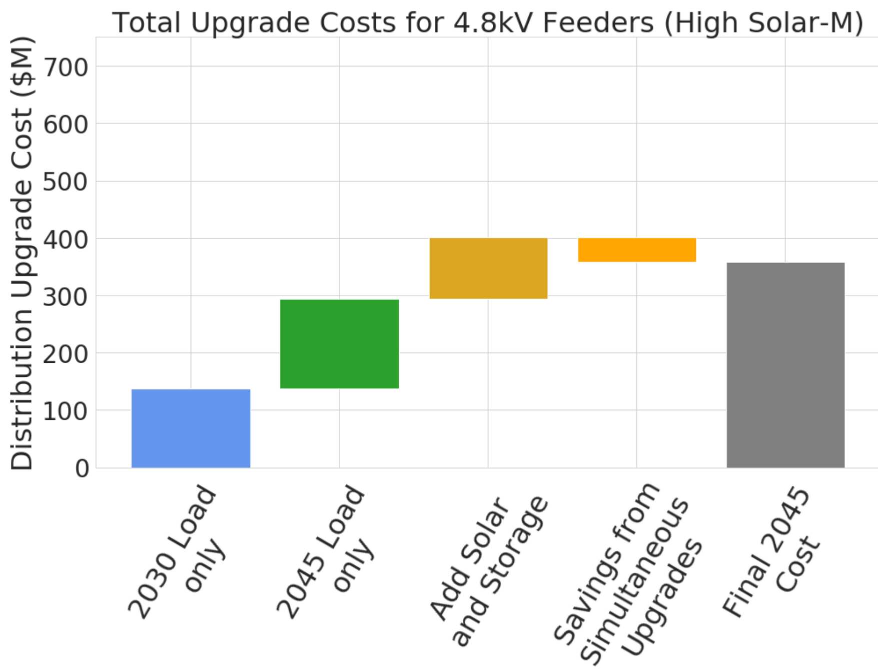

Figure 25. Sequential upgrade costs compared to simultaneous upgrade costs for 4.8kV system for Early & No Biofuels – Moderate (= Limited New Transmission – Moderate), assuming existing deferred maintenance already addressed

Comparing SB100 – Stress (Figure 23) and SB100 – Moderate (Figure 24) shows that the potential for simultaneous upgrade savings is larger when the load is high. For SB100 – Stress the savings exceed the addition distribution upgrade costs when sequentially adding rooftop solar and customer storage. In contrast, the lower load growth in SB100 – Moderate shows a lower savings that is smaller than the sequential upgrade costs for adding solar and storage.

Comparing Early & No Biofuels – Moderate (Figure 25) to SB100 – Moderate (Figure 24) shows how the simultaneous upgrade savings amount is not as strongly affected with increases in rooftop solar and customer storage adoption. While increased solar and storage do increase the simultaneous upgrade savings, the difference is modest. Similar results are seen for the corresponding higher load scenarios.

As summarized in Table 2, upgrading the system considering load and solar/storage simultaneously reduces total system upgrade costs by $37 million–$91 million or 12%–15%, depending on scenario, compared to sequentially.

Table 2. Savings Due to Simultaneous Upgrades for Loads, Rooftop-Adopted Solar, and Customer-Adopted Storage In 2045

Scenario	Savings	
SB100, Transmission Focus – Moderate	$37 million	12%
Early & No Biofuels, Limited New Transmission – Moderate	$43 million	12%
SB100, Transmission Focus – High	$66 million	13%
Early & No Biofuels, Limited New Transmission – High	$78 million	15%
SB100 – Stress	$91 million	15%

We also analyzed the relative impact of the sequential versus simultaneous addition of rooftop solar and customer-adopted storage on violations. Specifically, the addition of rooftop solar and customer-adopted storage can address undervoltage violations that arise in feeders due to load growth. On the other hand, in other areas, the additional power injection from high levels of solar and storage can also introduce overvoltage violations. Figure 26 (SB100 – Moderate) and Figure 27 (SB100 – Stress) show the relative breakdown by violation type for feeders that experienced an increase or decrease in violations with the addition of customer-adopted solar and storage compared to the load-only case. With the addition of rooftop solar and customer-adopted storage, the number of feeders with overvoltage and transformer violations increase whereas those with undervoltage and line violations decrease.

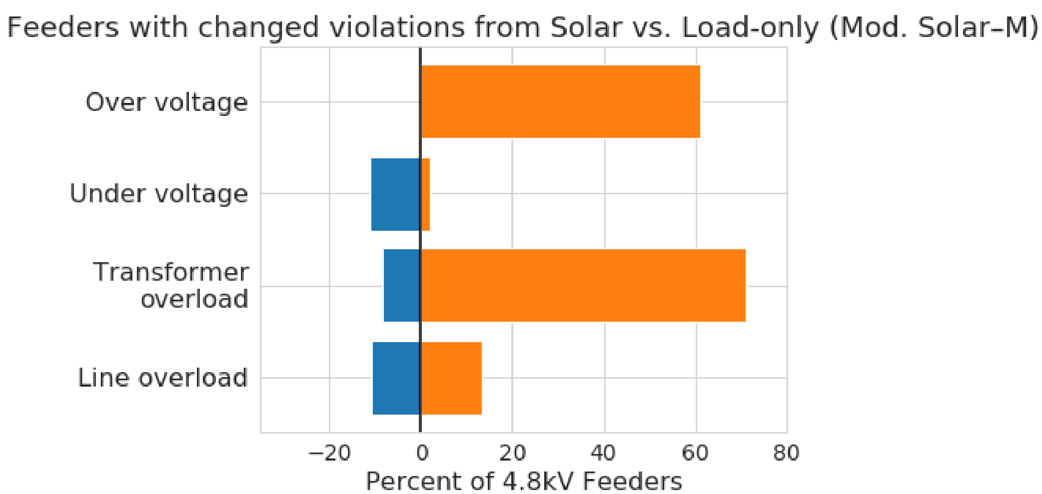

Figure 26. Change in violations on 4.8kV feeders for SB100 – Moderate (= Transmission Focus – Moderate) in 2045

The x-axis shows the percent of feeders experiencing a decrease versus an increase in violations with addition of these DERs compared to the load-only case.

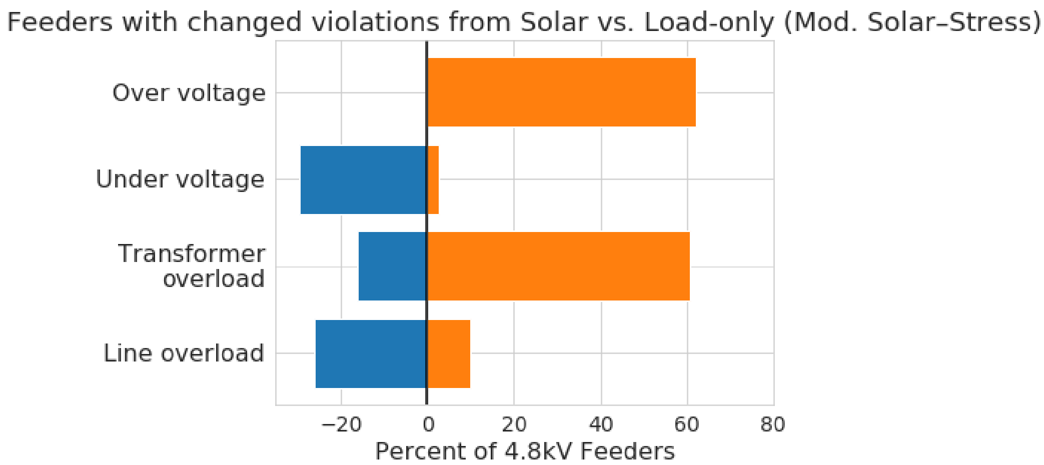

Figure 27. Change in violations on 4.8kV feeders for SB100 – Stress in 2045

The x-axis shows the percent of feeders experiencing a decrease versus an increase in violations with addition of these DERs compared to the load-only case.

4.3 Looking Deeper: What Is The Effect Of Local Solar And Storage on Net Load?

The addition of local solar and storage can provide additional sources of generation that can help to reduce the total demand of portions of the distribution system on external sources. This reduces the total power demand on substation transformers, lines, and other equipment and therefore can help to offset equipment upgrades that might otherwise be needed. However, the extent of these savings depends on the correlation of generation from DERs with demand in space and time.

The resulting difference of demand minus solar and storage production is the "net load." The net load may be negative if the total solar and storage production exceeds demand, causing power to flow in reverse of traditional power systems with the distribution system feeding power into the next higher voltage portion of the grid. When storage is discharging its production joins that from solar in reducing the net load, but when storage is charging it increases net load.

The following figures show how as the installed quantity of DERs grows over time, its impact on net load also grows for every combination of RS and timepoint. In the 2020 baseline (Figure 28) all of the net load is below the maximum RS capacity of 600 MW.[26] In 2030 (Figure 29), the raw load generally increases, shifting the histogram and the collection of sample lines below the axis to the right, although the total RS loads all stay below 600 MW. DER production decreases the net load proving some additional headroom for growth. Visually this is shown as the histogram and (shorter) sample lines shifting to the left. In a few scenarios, there are also a few timepoints

[26] The actual capacity limit for each RS substation varies with the number and size of its transformers. Most RS transformers are rated at 150 MVA, and RS substations are designed with some redundancy with ratings from about 300 MVA to 800 MVA, with 600 MVA as the most common size. For simplicity we describe these results based on 600 MVA capacities and also refer to the real power units of MW rather than apparent power in MVA.

where some RS stations experience reverse power flow where the RS station feeds excess generation up to the transmission system.

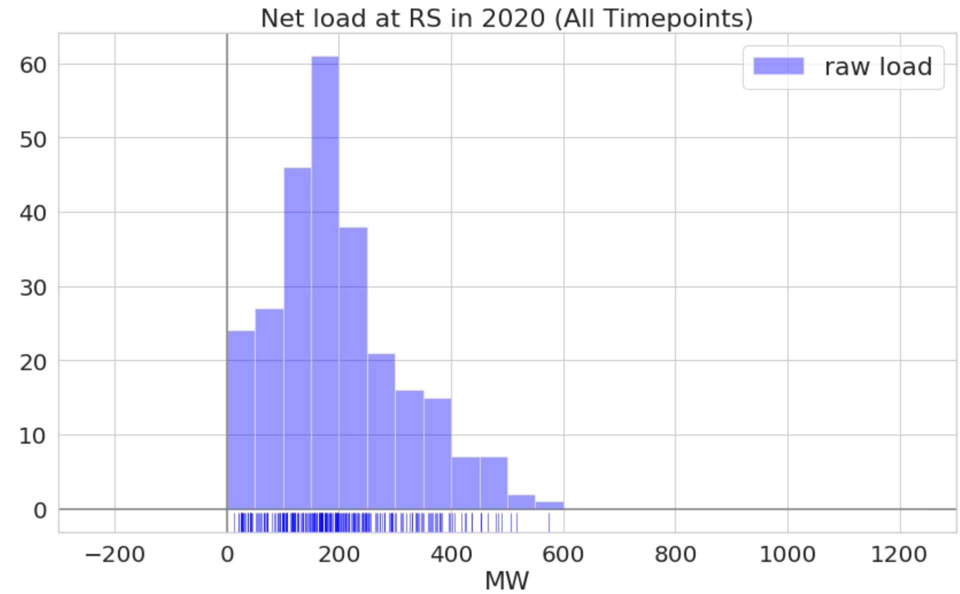

Figure 28. Histogram of baseline net load in 2020

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

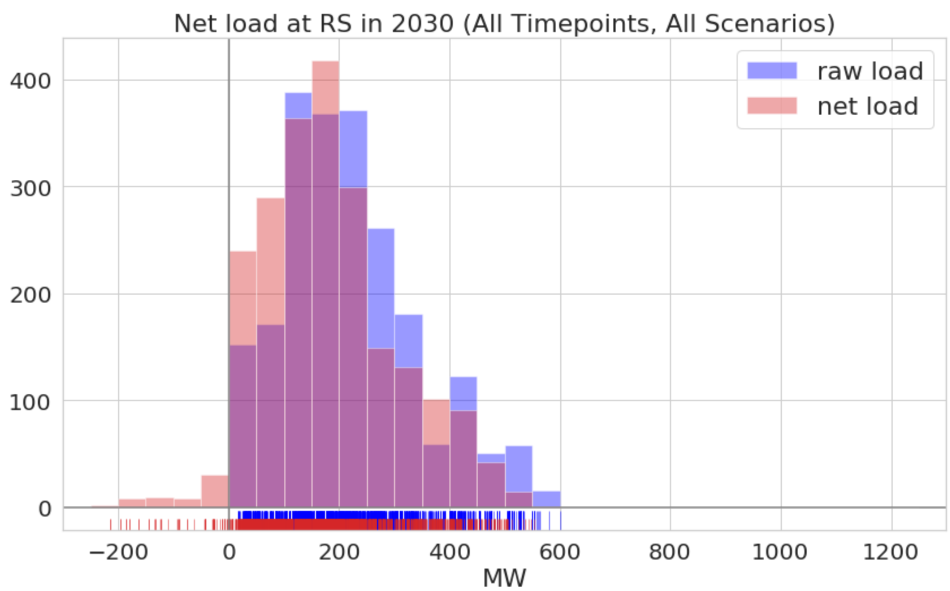

Figure 29. Histogram of net load in 2030

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point for one scenario.

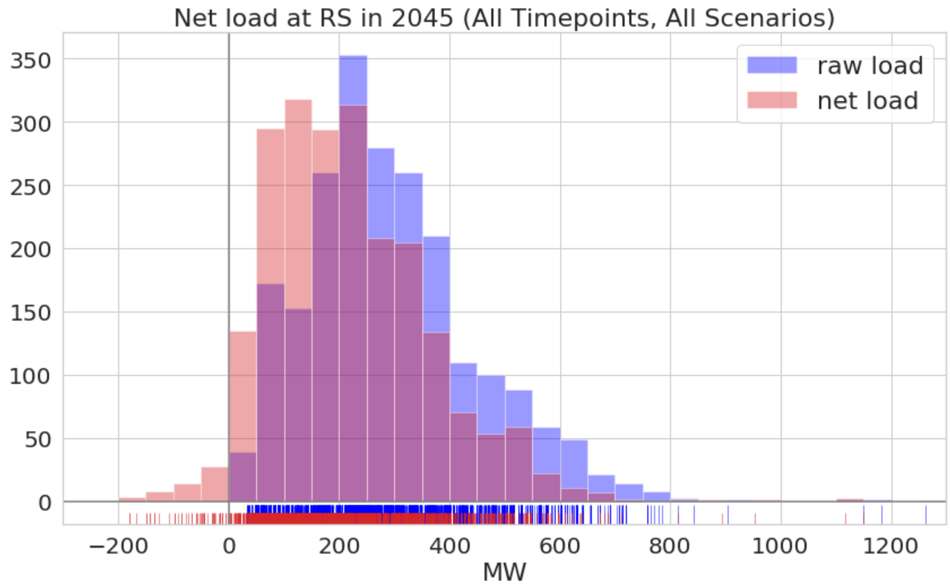

Figure 30. Histogram of net load in 2045

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point for one scenario.

In 2045 (Figure 30), accelerated load growth due to electrification results in much higher raw loads across all scenarios. The addition of DERs again reduces these net loads and results in reverse power flow in all scenarios of up to 215 MW. The figure also shows a strong reduction in the maximum net load, which helps avoid the need to upgrade some RS stations. The largest loads observed in the raw data of >1,260 MW is reduced to a maximum net load of 1,150 MW, and the number of very large loads >600 MW is greatly reduced.

However, the extent of these reductions, and corresponding avoidance of upgrade costs, strongly depends on the relative timing of load and DERs, and in particularly storage dispatch. For example, the top four levels for both raw and net loads, all occur in Region B during the SB100 – Stress scenario. However, their relative ranking changes depending on the amount of solar production. The highest raw load level of 1,261 MW (4:30 p.m. on August 10) is reduced by 144 MW of solar production to 1,117 MW, such that it falls to the 3rd largest net load. The maximum net load of 1,150 MW (7:00 p.m. on August 11) occurs late enough that there is no solar production to offset it. Moreover, storage is idle during all of the top raw RS load conditions for multiple regions. This is because in LA100, storage dispatch is driven by systemwide needs. In practice, shifting some of this dispatch to help offset distribution needs would result in further reductions in maximum net load, resulting in corresponding upgrade cost savings. Additional net load results by RS are included in Appendix G.

4.4 To What Extent Are Distribution Upgrades Needed?

As described below, the core distribution analysis found a need for distribution upgrades on feeders and circuits throughout the LADWP in-basin system; however, typically only a few pieces of equipment require upgrades in each case. An explanatory example of this situation is shown visually in Figure 31.

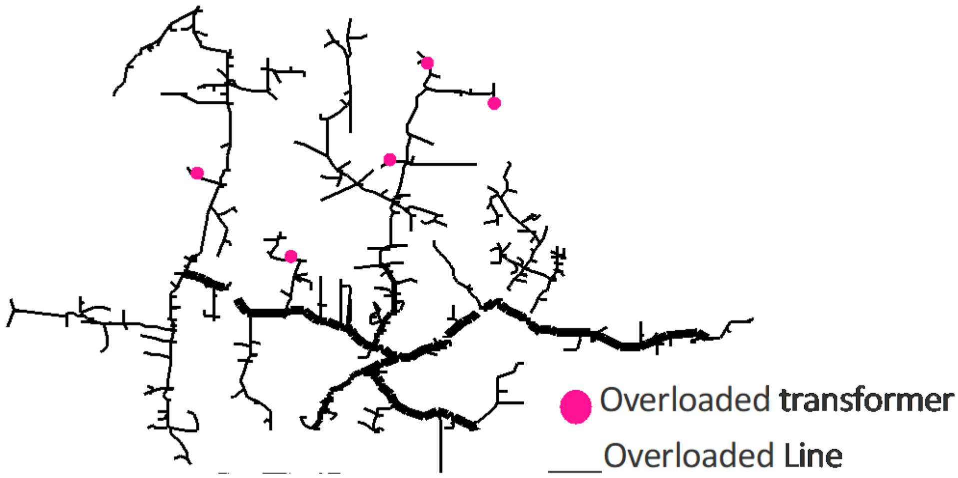

Figure 31. Representative feeder showing the general extent and scale while illustrating how even multiple overloaded pieces of equipment can be a small fraction of those on a feeder

4.4.1 Local Distribution (4.8kV) Needs

On average, 77% of the 4.8kV feeders require some form of thermal upgrades between tomorrow and 2030, and an average of 84% require upgrades between 2030 and 2045. Figure 32 shows a histogram of the corresponding number of devices needing upgrades and illustrates how in this scenario, about 80% of feeders have transformer overloads, while fewer than 15% of feeders have line overloads. Figure 32 also shows that the number of transformers per feeder that need upgrades is generally less than 15, with most less than five, while typically less than three line segments require upgrades. Figure 33 shows how after upgrades are applied, the overloads are nearly 100% corrected.

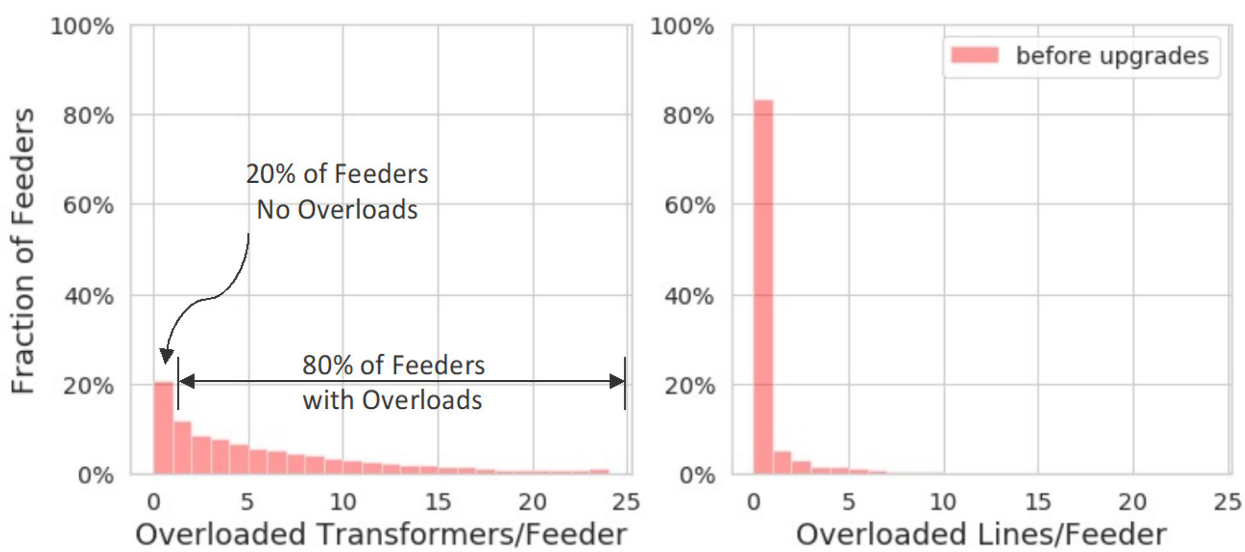

Figure 32. Pre-upgrade histograms of line and transformer overload counts for 4.8kV system across all scenarios and years

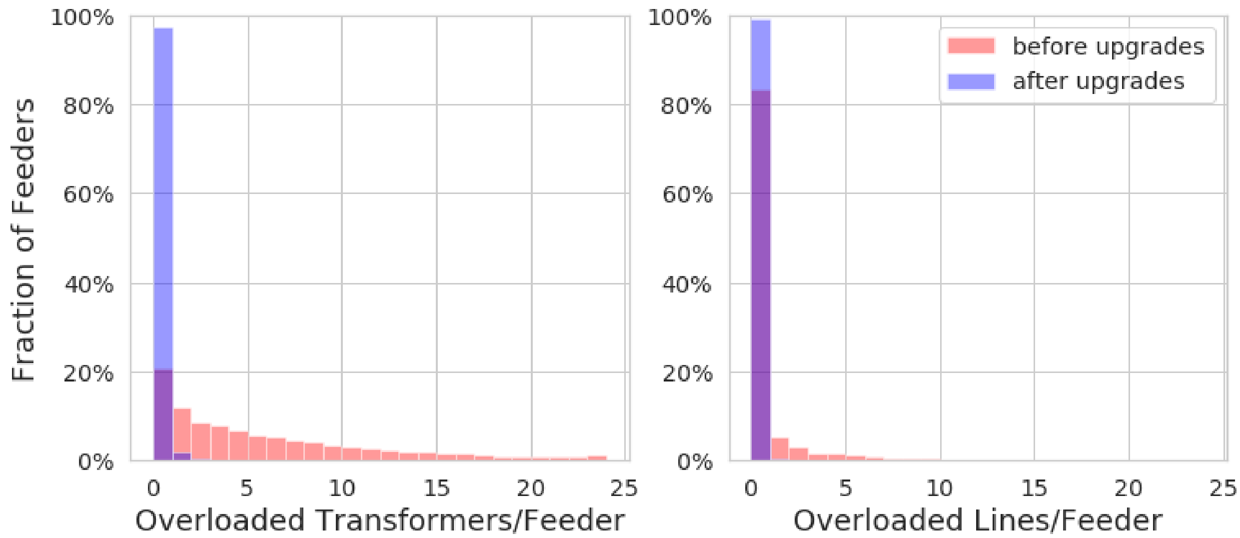

Figure 33. Histograms comparing line and transformer overload counts before and after upgrades for the 4.8kV system across all scenarios and years

In addition to looking at the counts of violations, we can explore the corresponding extent of overloads found on the system. Figure 34 shows that before upgrades, the maximum transformer loading is often at or above 200%, with some approaching 400%, while the maximum pre-upgrade line loadings are generally less than 200%. It is important to note that these figures show the highest-loaded transformer on each feeder, and not all transformer loadings. Because, as discussed above, only a few devices are overloaded per feeder, this implies that the majority of transformers and lines are not overloaded.

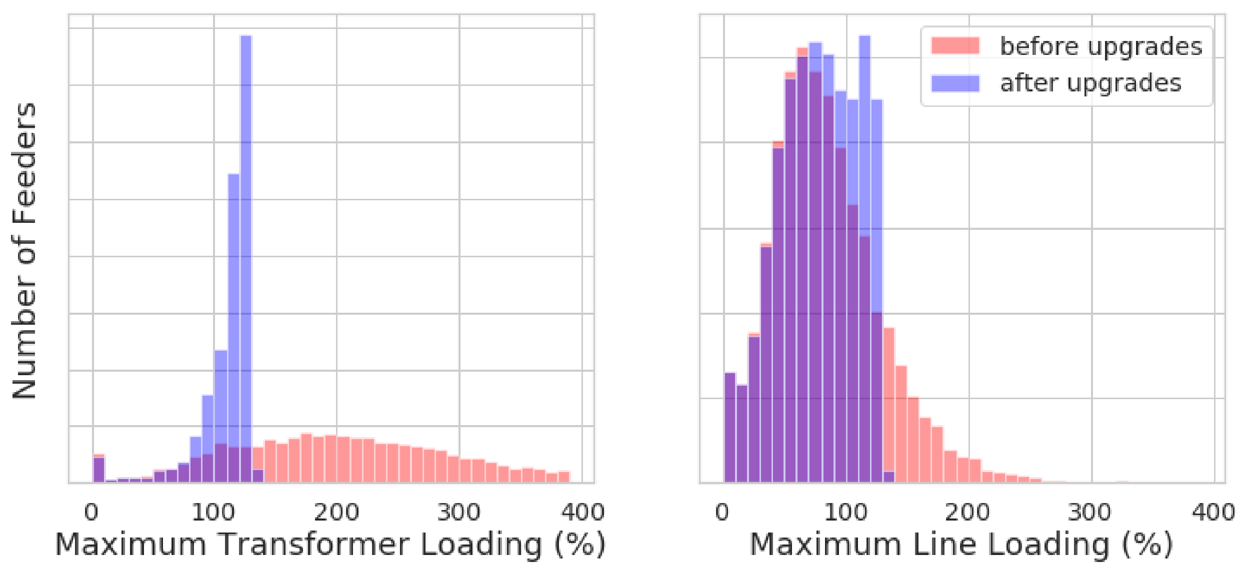

Figure 34. Histograms comparing the highest line and transformer overloading levels by 4.8kV feeder before and after upgrades for the 4.8kV system across all scenarios and years

Similar results are seen for the voltage violations, which are shown before and after upgrades as counts and extents in Figure 35 and Figure 36, respectively. Note that the changes described above to manage overloads also help alleviate voltage challenges, which results in the starting point before upgrades having only about 10.7% and 12.5% of feeders requiring upgrades for tomorrow through 2030 and 2031 through 2045, respectively.

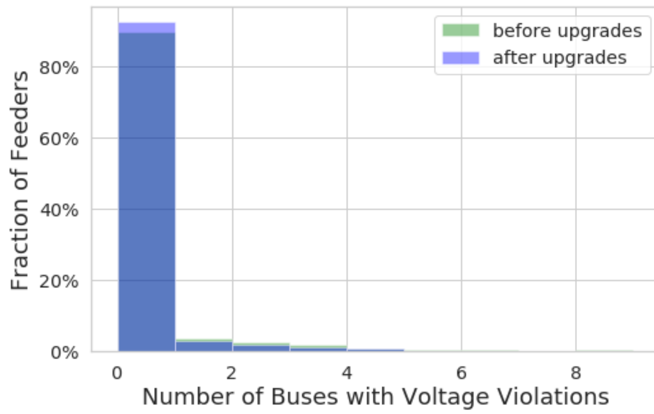

Figure 35. Histogram of the number of voltage violations before and after upgrades for the 4.8kV system across all scenarios and years

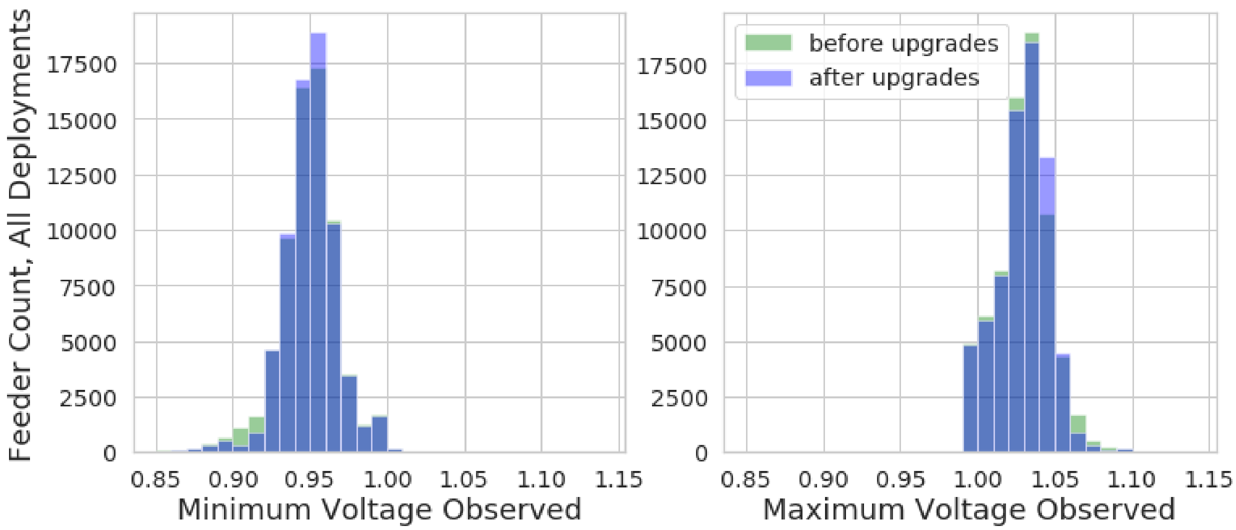

Figure 36. Histograms comparing the minimum and maximum voltages observed by feeder before and after upgrades for the 4.8kV system across all scenarios and years

4.4.2 Subtransmission (34.5kV) Needs

As seen in Figure 37, the 34.5kV system shows that all regions have at least one line or transformer overload across all scenarios and years. Before upgrades, there is a wide range of numbers of transformer upgrades required. All of these overloads are readily corrected by upgrades. For lines, a little more than 40% of circuits require at least limited line upgrades. Figure 38 shows how the upgrades are also very effective at managing the overloads, bringing the maximum overloading seen in each region to be well within the 125% loading limit for both transformers and lines.

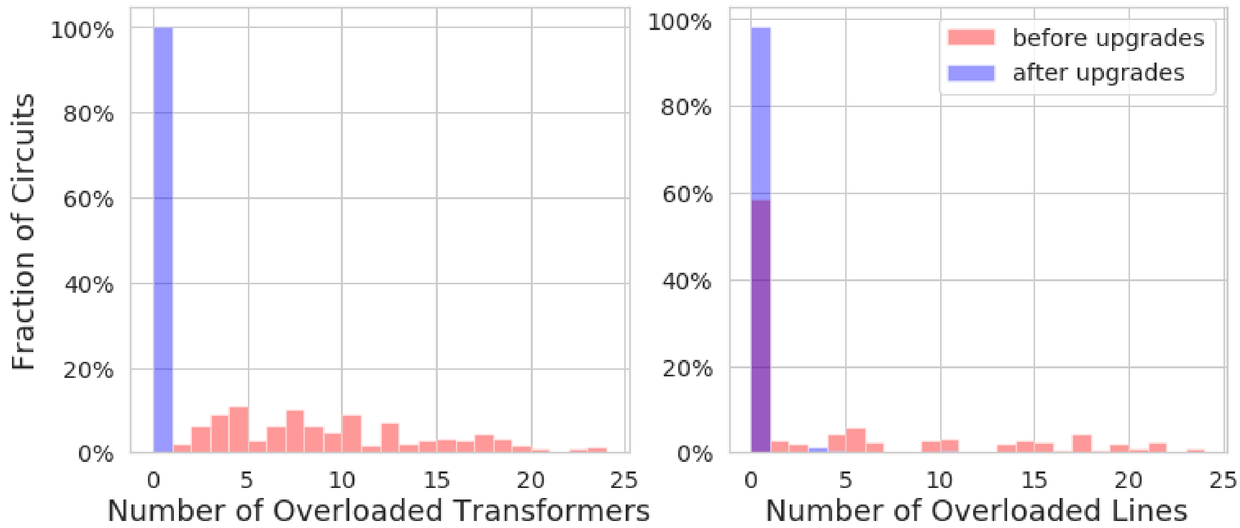

Figure 37. Histograms comparing line and transformer overload counts before and after upgrades for the 34.5kV system across all scenarios and years

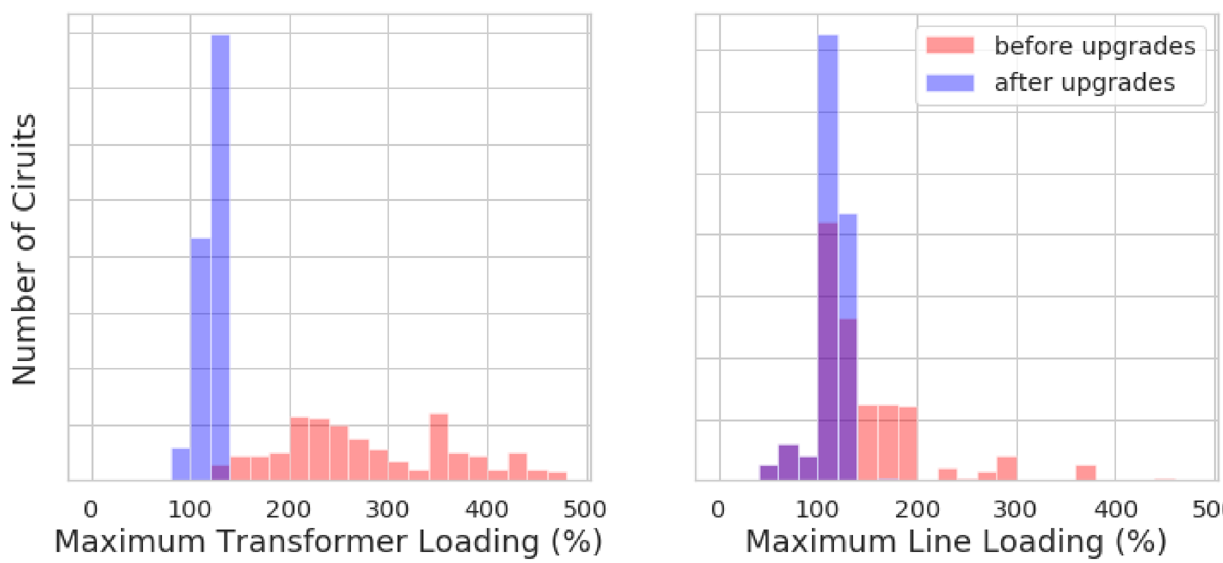

Figure 38. Histograms comparing the highest line and transformer overloading levels by 34.5kV circuit before and after upgrades across all scenarios and years

Figure 39 shows how voltage violations are relatively rare on the 34.5kV system and are generally corrected with upgrades. Figure 40 looks at the corresponding minimum and maximum observed voltages. Although the upgrades are highly effective, a few outlier low-voltage nodes linger after upgrades. These isolated problems may require load/node-specific corrections such as customer co-located capacitors or more advanced grid-edge devices to help mitigate.

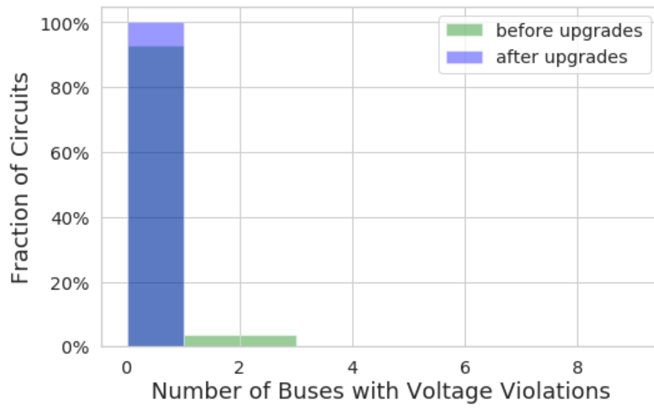

Figure 39. Histogram of the number of voltage violations before and after upgrades for the 34.5kV system across all scenarios and years

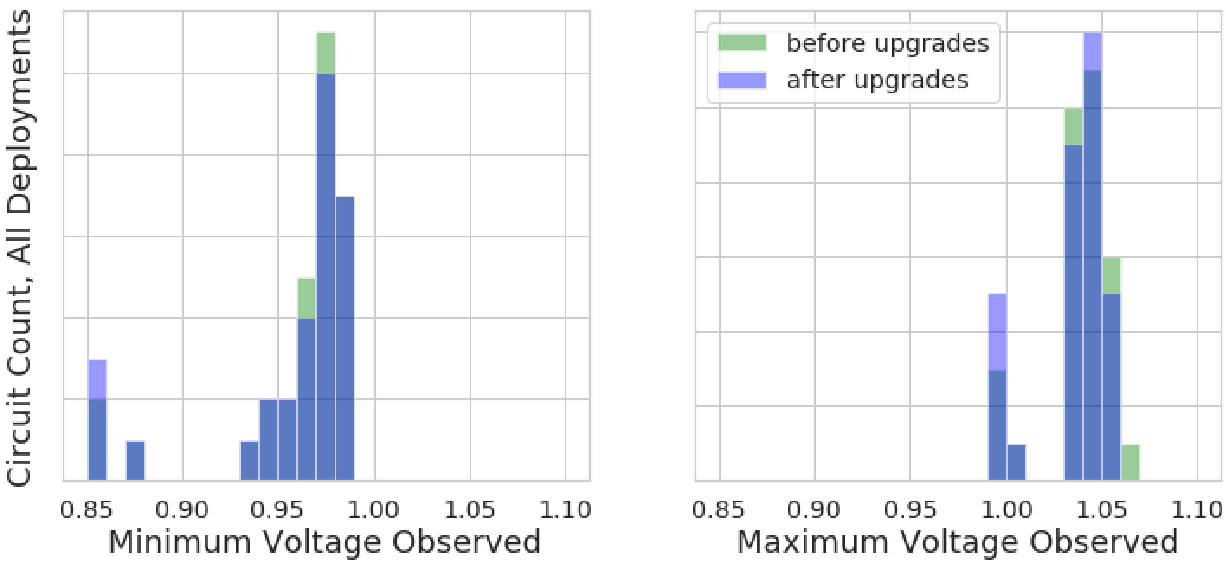

Figure 40. Histograms comparing the minimum and maximum voltages observed by feeder before and after upgrades for the 34.5kV system across all scenarios and years

4.5 Looking Deeper: The Effect of Uncertainty in the Spatial Distribution of Customer-Adopted PV and Battery Storage

It is impossible to predict exactly where DERs will be installed in the next 10–25 years. This is especially true of customer-adopted resources. However, precise location information is required to understand and assess DER distribution impacts (e.g., which specific households adopt rooftop PV). NREL's customer adoption model was adapted to provide this level of spatial resolution for LA100, as described in Chapter 4. In this framework, each "agent" (potential adopter of PV or energy storage) has a probability of adoption that is sampled. In this section, we explore how distribution upgrade cost results could vary under uncertainty regarding exactly which customers adopt PV and storage. We do so by performing calculations on five different spatial deployments of PV and storage corresponding to five samples of adoption probability curves for individual agents, simply re-calculating upgrade costs using the methodologies described above for those five different samples.

As seen in Figure 41, we found that the range of costs was generally consistent within each load scenario, with a small reduction in cost variations with higher levels of customer-adopted PV and storage (Early & No Biofuels and Limited New Transmission). The resulting deviation in cost ranges from $22 million–$62 million depending on scenario, which represents only 4%–12% of the corresponding total costs. This indicates that even with differences in the upgrade costs for various spatial patterns of rooftop solar and customer storage adoption, total systemwide costs are very similar.

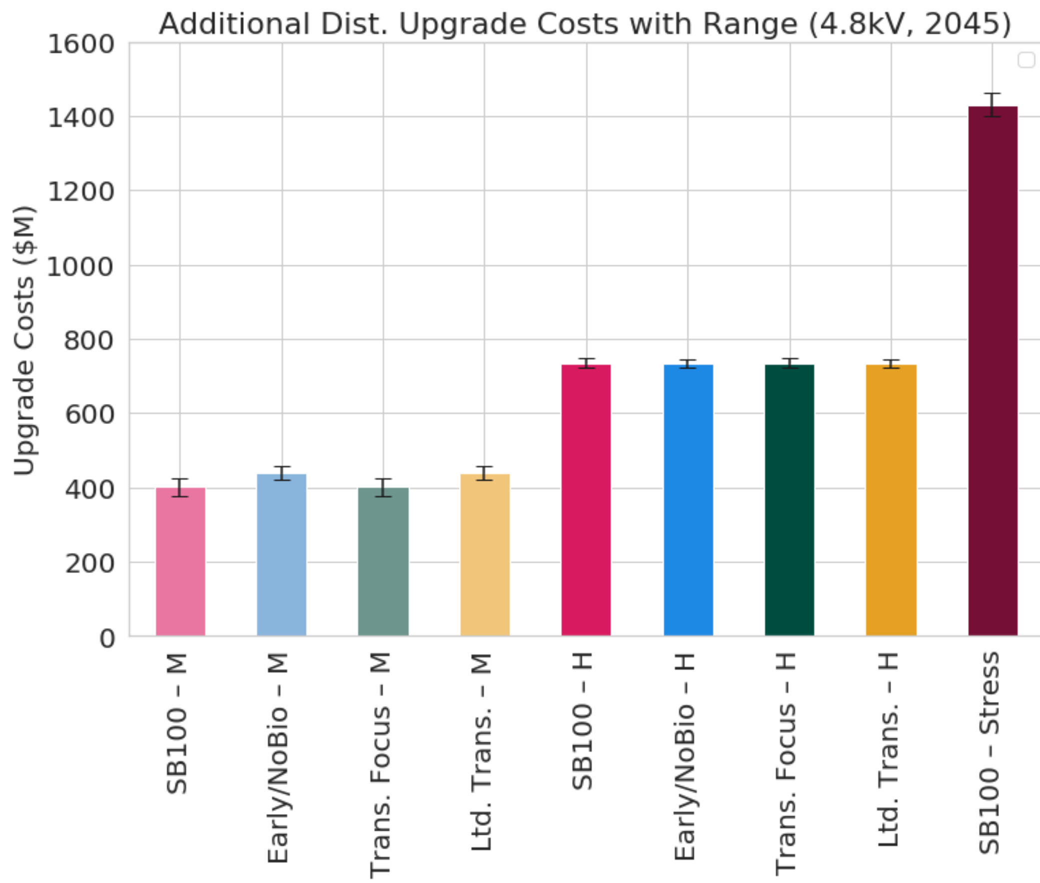

Figure 41. Effects of uncertainty in individual customer adoption of PV and battery storage on distribution upgrade costs incurred by 2045

The error bars represent the spread in costs calculated for five different spatial patterns of customer adoption. Results assume existing deferred maintenance already addressed.

5 Caveats

While this portion of the LA100 study is one of the most extensive and integrated distribution-level analyses ever conducted for studying pathways to 100% renewables, there are still a number of caveats to consider—some of which suggest opportunities to further refine both technical and economic assessments in future studies. Many of these caveats are embedded in the assumptions listed in Section 2 and Appendix A. Here, we discuss a few key points.

Perhaps most important is that the quality of any study's results is limited by the quality of the data. For LA100, we endeavored to obtain and verify the best data available, but these data are still not perfect. Some specific challenges for distribution include:

- **Inaccuracies in the Electrical Model Itself:** The PGES database used to build up these models is known not to exactly match the system on the ground. In fact, in parallel with the LA100 study, LADWP was working on a separate project to clean up these data and modernize its GIS data system. Still, particularly for the 25-year horizon of this study, we believe the data are sufficiently accurate relative to other uncertainties—and considerably more representative than most studies of this type, which often only explore a small number of representative feeders.
- **Challenges and Unknowns with Disaggregated Loads and High Spatial Resolutions of Solar and Storage Deployment:** Like other aspects of LA100, the distribution analysis relies on the highly detailed load projections described in Chapter 3 and the estimates of customer DER adoption described in Chapter 4. However, the distribution system work requires assigning these estimates to individual customer locations, which introduces considerably more uncertainty than aggregated results at the system level. It is highly unlikely our estimates will precisely match load 25 years from now for a given home or office compared to its neighbors next door or across town. It is also computationally intractable to match the tens of thousands of building agents to millions of customers while matching billing data, SCADA data, and systemwide totals. Even with our best efforts, considerable uncertainty remains at the highest spatial resolutions. In particular, demographic effects including income level, building age, and other factors were not directly included in the spatial disaggregation. Still, our estimates should reflect the overall direction of trends and systemwide impacts and opportunities.

Another consideration is that the distribution analysis only estimates infrastructure upgrades needed for the 100% renewable pathways for the years 2030 and 2045,[27] due in part to intensive computational and data needs. In actuality, infrastructure upgrades are continuously needed as loads change and DERs come online. This will undoubtedly change LADWP's actual upgrade deployment, and the changes in timing may result in different overall results. However, one clear outcome of this work (notably Section 4.2) is that simultaneously considering load growth and distributed solar and storage upfront when upgrading the distribution system can save costs compared to sequentially upgrading for one followed by the other.

These results also only consider infrastructure upgrades needed to address system violations introduced due to load growth, electrification, and solar and storage deployments. They do not include other routine maintenance or capital costs like component replacement due to aging.

[27] As described in Sections 2.1, 2.4, 2.5, and Appendix D, we did also conduct upgrade analysis for "today's" 2020 system to separate the costs and impacts from deferred maintenance and other needs from those driven by the 100% renewable energy pathways.

They also do not include potential additional costs due to extreme weather, cyber, or other disasters. In some cases, these routine upgrades could also introduce opportunities for preemptive upgrades that could save LADWP and its customers money overall. The results also do not include some considerations beyond techno-economic drivers. For example, with any substation upgrades—such as transformer size increase, the addition of a new transformer/bank, or other reconfiguration—there may also be a need to expand the footprint of the substation, which can be difficult in dense portions of LA. In this case, our study does include equipment costs, labor, and some additional costs for reconfiguration and engineering work; however, we do not include land acquisition, community resistance, or other practical factors that could greatly complicate such a project in reality.

We also do not include a number of technical analyses such as protection,[28] voltage flicker, coordinated controls, and system reconfiguration. It is expected that these will be secondary considerations to the main thrusts of this analysis. However, some of them—notably considerations around reverse power flow—may require updated practices and perceptions in planning and operations that might otherwise present challenges in the transition to 100% renewable energy.

In short, long-term studies like this one can never perfectly predict the future of load changes, customer adoption, community support/resistance, equipment costs, disruptive technologies, regulations, and other factors. Still, we expect the results presented here accurately capture the trade-offs among various options and scenarios.

[28] Note: the additional cost adders for substation reconfiguration described in Section 2.4.5 at least partially estimate some protection overhauls needed in more extreme cases.

6 What Don't We Know About Distribution?

In the course of the LA100 distribution analyses, we identified a number of unknowns that were out of scope for this study but could represent fruitful areas for further research.

6.1 Might It Be Better to Upgrade the 4.8kV System to 12–15kV?

Throughout the country, older 4kV-class systems, like the LADWP 4.8kV system, have gradually transitioned to 15kV-class distribution systems (e.g., 12.47kV and 13.2kV). This transition enables serving much higher loads and hence providing capacity for higher quantities of DERs on a given feeder, while also generally reducing losses due to lower currents for the same power levels. Perhaps the basin-wide 34.5kV system has enabled LADWP to maintain its widespread use of 4.8kV because mid- to large-sized customers or installations that outgrow the 4.8kV system can switch to 34.5kV connections. However, the combination of upgrades to manage deferred maintenance and the additional upgrades expected for 100% renewables may make such a transition, or partial transition, more practical. It could be a transformative way to manage distribution upgrades for 100% pathways. Additional study is required to determine whether this approach would be better than the in-place upgrades considered in LA100.

6.2 To What Extent Might Coordinated Control Help?

In this study, we modeled the system as it is today, with most distribution controls handled locally such as with time-based capacitor switching or line-drop compensation-based regulator controls. In many cases our upgrade analysis indicated opportunities to update the settings or add new local controls (e.g., voltage-based capacitor control); however, we did not include the potential for systemwide coordinated controls such as advanced distribution management systems (ADMS) and/or distributed energy resource management systems (DERMS). Such systems have become increasingly widely used ("Voices of Experience | Advanced Distribution Management Systems" 2015) and in addition to the potential to improve existing operations can enable enhanced operations with large amounts of DER while potentially eliminating the need for some upgrades. This includes both complementing advanced inverter controls and opportunities to fine-tune voltage profiles to enable energy reductions and cost savings through dynamic conservation voltage reduction (Palmintier et al. 2016). Similarly, emerging efforts have shown that there can be value in using selective curtailment of DERs during a limited number of hours as an alternative to traditional utility equipment upgrades when integrating large amounts of solar (K. A. Horowitz et al. 2019). We do not know to what extent these and similar coordinated control approaches could help with the transition to 100%, but they could be a key enabler, especially in supporting dynamic control settings during system reconfiguration or other off-nominal operating conditions.

6.3 What Is the Value of Optimizing Distributed Resources for the Grid?

In the LA100 study, the location of DERs and their simulated operations were all determined without considering implications for the distribution system. It is likely that adjusting the locations and scale of DERs could reduce upgrade needs or offer deferment benefits. For instance, siting storage downstream of a potential congested line could reduce or eliminate the need for upgrading that portion of the line. For operations, we considered DERs to be operated uniformly (within a region) and optimally in support of systemwide needs, such as charging and discharging storage to help balance the ups and downs of wind, solar, and load. However, such operations could create added stress on the distribution system that requires additional upgrades or changes. It is also likely that adjusting operations approaches to account for distribution needs could further reduce the need for upgrades to the system. Additional study would be needed to assess the value of such grid-supporting planning and operations with DER.

6.4 To What Extent Could Resiliency and Other Value Streams Change DER Deployment and Distribution Needs?

The LA100 study largely considered economic and routine operations for the electric power system, including capturing reliability, contingency analysis, and other key systemwide drivers (see Chapter 6). However, like most power systems studies, this analysis does not directly consider the impacts of grid resiliency challenges during extreme events such as wildfires, earthquakes, cyberattacks, or other disasters. Such disasters may interfere with the ability to transport power over long distances to serve load, and hence place a high value on energy production from DERs, microgrids, and other distribution-connected assets. Yet assessing the economic value to adapting the system to be more resilient to such challenges is both difficult and subjective.

There has also been increasing interest and support for DER participation in wholesale electric energy and service markets either directly or through aggregators. This could open up additional value streams to DERs that might increase the economically optimal level of deployment. Additional value could come from non-market grid services such as voltage control that might readily be provided by DERs. Even harder to quantify are customer preference values, such as support or resistance to locating solar, or level of enthusiasm for having locally visible projects to support carbon reduction goals. Additional study would be required to understand to what extent such incorporating such value streams might increase (or decrease) the optimal level and location for DER deployment and the complementary need for distribution system adaptation or enhancement.

7 References

Horowitz, Kelsey. 2019. "2019 Distribution System Upgrade Unit Cost Database." National Renewable Energy Laboratory. https://doi.org/10.7799/1491263.

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Appendix A. Data Sources for Distribution Analysis

Data requirements for modeling the distribution network include technical characteristics and locations of lines, substations, capacitors, and transformers. All data were obtained from LADWP. Additional data elements are listed below.

Table 3 summarizes the circuit level load data. These data sets capture changes in demand that may occur at the circuit level. These are calibrated against data from LADWP's supervisory control and data acquisition (SCADA) system.

Table 3. Load Data

Name	Units	Resolution	Information	Source
Load profiles	kW	Circuit	15-minute time-series real power load profiles	LA100 Customer Electricity Demand modeling (Chapter 3)
Load profiles (reactive power)	kVar	Circuit	15-minute time-series reactive power load profiles	Derived using information on loads by end use from LA100 Customer Electricity Demand modeling (Chapter 3) combined with information on typical ZIP parameters for each end use for residential loads[a],[b],[c] and with typical constant power factors for commercial and industrial loads
Agents	N/A	Agent	Locations and characteristics of load-generating properties (or "agents") used in the LA100 model. See Appendices L-N.	LA100 Customer Electricity Demand modeling (Chapter 3)

[a] A. Bokhari et al., "Experimental Determination of the ZIP Coefficients for Modern Residential, Commercial, and Industrial Loads," *IEEE Transactions on Power Delivery* 29 (3): 1372–1381 (June 2014).

[b] Ning Lu, Yulong Xie, Zhenyu Huang, F. Puyleart and S. Yang, "Load Component Database of Household Appliances and Small Office Equipment," 2008 IEEE Power and Energy Society General Meeting: Conversion and Delivery of Electrical Energy in the 21st Century, Pittsburgh, PA, 2008, pp. 1–5.

[c] A. Arif, Z. Wang, J. Wang, B. Mather, H. Bashualdo and D. Zhao, "Load Modeling: A Review," *IEEE Transactions on Smart Grid* (2013).

Table 4 lists the renewable data used in the distribution system models.

Table 4. Renewable Data

Name	Resolution	Information	Source
PV output data	For PV system	Output of systems in a given location	Customer adoption modeling (see Chapter 4) for initial power output of behind-the-meter resources and PLEXOS for front-of-the-meter resources. Real and reactive power output may be adjusted from these values based on the Volt-VAR/Volt-Watt inverter functionalities.
PV and other distributed energy resources	Circuit and substation	Location and capacity of distributed energy resources	Existing installations from LADWP. New rooftop solar and customer-owned storage from customer adoption modeling (see Chapter 4) based on five samples of agent-level adoption probability (each called a “deployment”) Larger ground mounted solar and storage from RPM model results assigned in rank order to suitable locations from geospatial analysis of probable sites.

Table 5 lists the distribution network data used to model the LADWP distribution grid.

Table 5. Distribution Network Data

Name	Resolution	Information	Source
GIS Distribution Grid Data	Various native resolutions (point locations, lines, etc.)	Full GIS database of LADWP's distribution network	FRAMME and PGES
One-line diagrams for substations, RS, DS, CS, IS	All RS and DS, most CS, IS	Number and rating of transformers (for all station types) For DS and RS: arrangement of circuits per bank, lines per bank, switching configuration, and location to regulating equipment. This information used to develop representative types of DS and RS designs that are included in the electrical models.	LADWP one-line diagrams
RS, DS, and 34.5kV operational configuration and substation capacitors	All RS, DS, and 34.5 circuits	Information on standard operating configuration of transformer banks, buses, and circuits (i.e., topology effect of switches being open or close)	LADWP 34.5kV Powerworld model
Customer to Transformer Connectivity	Premise	We used these data to tag customer premise IDs from the Customer Billing data to transformers (or Station IDs) allowing us to ultimately tag agents to transformers using our derived premise-to-agents lookup tables.	LADWP's Customer Address to Transformer System (CAtTs)
DS-RS and IS-RS Connectivity	DS or IS	DS-to-RS and IS-to-RS connectivity lookup tables	LADWP sources; Partially from PGES GIS Data, 34.5kV Powerworld and LADWP SMEs
Circuit to DS-Bank Connectivity	Circuit	Circuit to DS bank connectivity lookup tables	LADWP sources; PGES GIS Data

Table 6 lists the assumptions made to fill in missing data during the creation of electrical models for LADWP's distribution system.

Table 6. Missing Data Assumptions for Creating Distribution System Electric Models

	Data Source	Additional Information
Capacitor Set Points	Based on interviews with LADWP distribution SMEs about typical set points for capacitors (estimated 70%-80% of capacitors), we assume that all capacitor controls are time-based, coming on at approximately 9 a.m. and turning off at approximately 5 p.m. We will include some randomization in the settings (e.g., varying on and off times within a 30 min. – 1 hour window around 9 a.m. and 5 p.m., respectively) based on LADWP practice to avoid all capacitors switching on simultaneously.	The automated upgrade algorithms may adjust the capacitor control settings to accommodate LA100 pathways.
Voltage at the Substation	Based on interviews with LADWP, we select the voltage at the substation such that the voltage at the "feeder center" is 1.0 p.u. The feeder center refers to the point on the feeder just before the closest load transformer is connected. This voltages management is performed using line drop compensation.	—
Line Types and Parameters	Data for wire and cable specifications are constructed using the Nexans online catalog for each wire type,[29] supplemented with data from CYME's library of line codes where needed. Wire and cable data types were assigned to lines using the names provided in the LADWP database.	Some line type data are included in the PGES database, but unique identifiers for each line type are often missing.[30]
Phase Information	Limited phase information was available in the LADWP PGES database, so delta-configured three phase lines were used throughout the model. Phase imbalances were caused by the assignment of transformer connections for single-phase customers to these lines. Phases of the loads were estimated by attempting to balance the length of all single-phase lines as closely as possible.	—
Nominal Voltage on the Low Side of Service Transformers	Assumed to be 240/120V split phase for all single-phase customers. Larger three-phase customers (nominally ≥100 kW) that are connected to the 4.8kV system (typically via a customer station (CS)) are assumed 480/277V. 34.5kV-connected customers (typically via an industrial station (IS)) are assumed three-phase 480/277V.	—

[29] "Utility Cable," Nexans, https://www.nexans.us/eservice/US-en_US/navigate_198257/Utility_Cable.html.
[30] The values of CU_ID are assigned using the map_txt1 and map_txt2 columns. A mapping between the map_txt1/map_txt2 columns to the dwp_cuc1/dwp_cuc2 columns is created from entries containing non-empty information from both columns.

	Data Source	Additional Information
Feeder Heads, Feeder, and Substation Mapping	Feeder heads were selected from the tables OH_FDR and UG_FDR if node1_id was equal to zero. For all elements in the connectivity table, information about the feeder and substation is provided with the attributes circuit1 and circuit2. We use circuit1 to assign feeders and substations to all elements (lines, capacitors, transformers etc.). For example, if circuit1 is “63-08” for a transformer we assume that the transformer is on feeder 08 of substation 63.	—
Distribution Station (DS), 34.5kV Line, and Receiving Station (RS) Connectivity	Based on DS and RS one-line diagrams	—
Secondary Circuits	All loads are assumed to be directly connected to the low side of their corresponding service transformer.	—

Table 7 lists the SCADA data used for distribution modeling and load calibration.

Table 7. Distribution SCADA Data

Name	Units	Resolution	Information	Source
RS SCADA	MW, MVAR	RS, 15-minute	RS SCADA data at 15-minutes (average) for real (P) and reactive power (Q) demand + voltage (V) for multiple full years: 2012, 2015, 2016, 2017	LADWP
DS Bank SCADA	MW, MVAR, kV	DS Bank, 15-minute	DS Bank SCADA data at 15-minutes (average) for MW, MVAR and kV (A,B,C-phase) for multiple full years: 2015, 2016, 2017, 2018	LADWP
DS SCADA	MW	DS, 15-minute	DS SCADA data at 15-minutes (average) for MW for multiple full years: 2015, 2016, 2017, 2018	LADWP
Circuit SCADA	kW, kV	Circuit, 15-minute	All available circuit SCADA data at 15-minutes (average) for kW and kV (A and B-phase only) for multiple full years: 2015, 2016, 2017, 2018. Available circuits with SCADA are roughly half of the LADWP circuits.	LADWP

Table 8 lists the cost and financial data used to determine the cost of circuit upgrades.

Table 8. Cost and Financial Data

Name	Value	Information	Source
Capital costs for distribution upgrades	varies	Capital cost for distribution system upgrades	Historical cost data for upgrades from LADWP, supplemented with data from CA IOUs in NREL's Distribution Grid Integration Unit Cost Database where LADWP data unavailable. All data were reviewed by LADWP SMEs.
Distribution device lifetimes	Varies	Used to estimate changes in O&M (due to changes in number of device operations and thus life) for circuits where time-series analysis is performed.	NREL internal databases from prior work with other utilities. NREL's Distribution Grid Integration Unit Cost Database.

Table 9. Other Distribution Data Used in This Analysis

Name	Information	Source
Distribution upgrade selection tool/analysis	Various	Multiple in-person and telephone interviews with LADWP SMEs. Secondary design guide, overhead power and distribution construction standards
Data on known problem circuits	Information from LADWP on circuits that have known voltage problems or experience overloading. This is compared against results from NREL's distribution power flow analysis in order to validate results.	Data from ECC Trouble Board

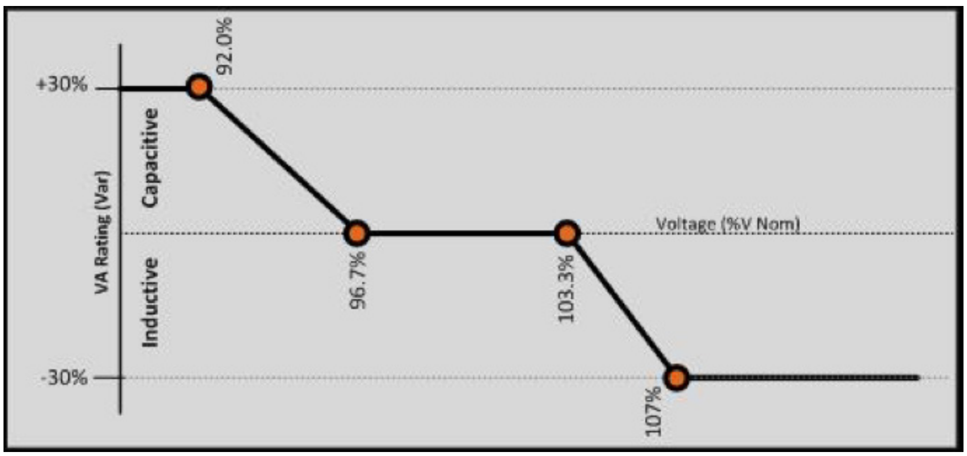

Figure 42. Volt-var curve used for advanced PV inverters in this analysis
Figure courtesy of LADWP.

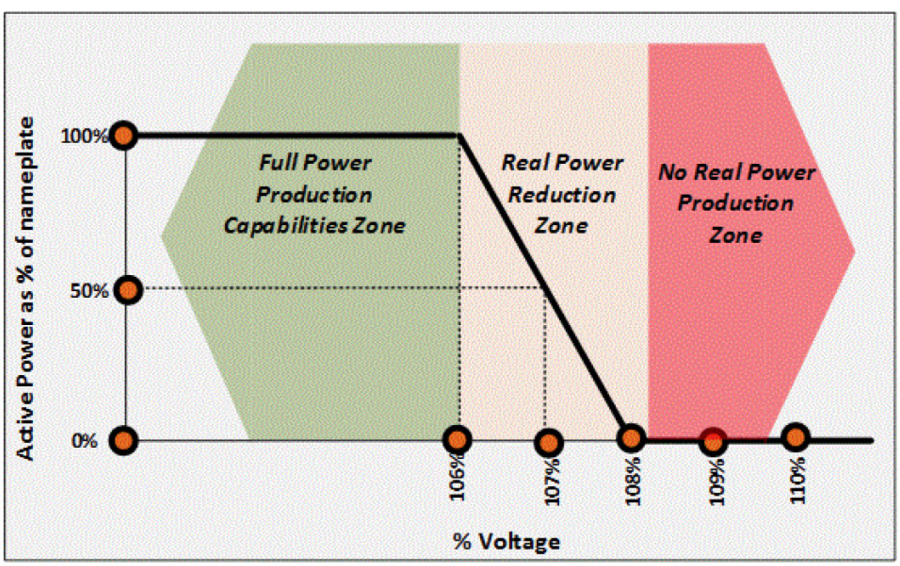

Figure 43. Volt-watt curve used for advanced PV inverters in this analysis
Figure courtesy of LADWP

Table 10. Assumptions for Distribution Upgrade Analysis

- Overload violation flagged at >100% of rated. 125% overload requires upgrades. New equipment sized to be at a maximum of 75% of loading.
- When overloaded, transformers and line segments are replaced with the next largest size in the catalog of sizes used in LADWP. If no sufficiently large equipment is available, duplicate equipment is placed in parallel.
- Voltage violations flagged when outside of ANSI Range B. Upgrades designed to keep voltages within ANSI Range A.
- Regulators only placed on overhead line segments.

Table 11. Time Period Selection for Distribution Analysis

- Multiple time points based on: Maximum PV/load ratio for LADWP's whole territory, minimum PV/load ratio for LADWP's whole territory, peak EV charging load for LADWP's whole territory, additional days of the year recommended by LADWP: weekend in August, holiday.

Table 12. Distribution Circuit/Circuit Selection Criteria

- All 34.5kV RS stations and circuits are included
- We start with all 4.8kV DS substations and circuits, but may not include all in the final analysis for the following reasons:
- Data challenges with the base network
- Significant errors with load or solar allocation (rare)
- Power flow convergence challenges during impact analysis and/or upgrade analysis
- Minimum of 80% of circuits included in final analysis.

Any circuits that we were unable to analyze successfully (i.e., those which were not in the 80%+ included in the final analysis) are replaced with lumped loads at the corresponding substation connection point.

Appendix B. Map of RS Substation Regions

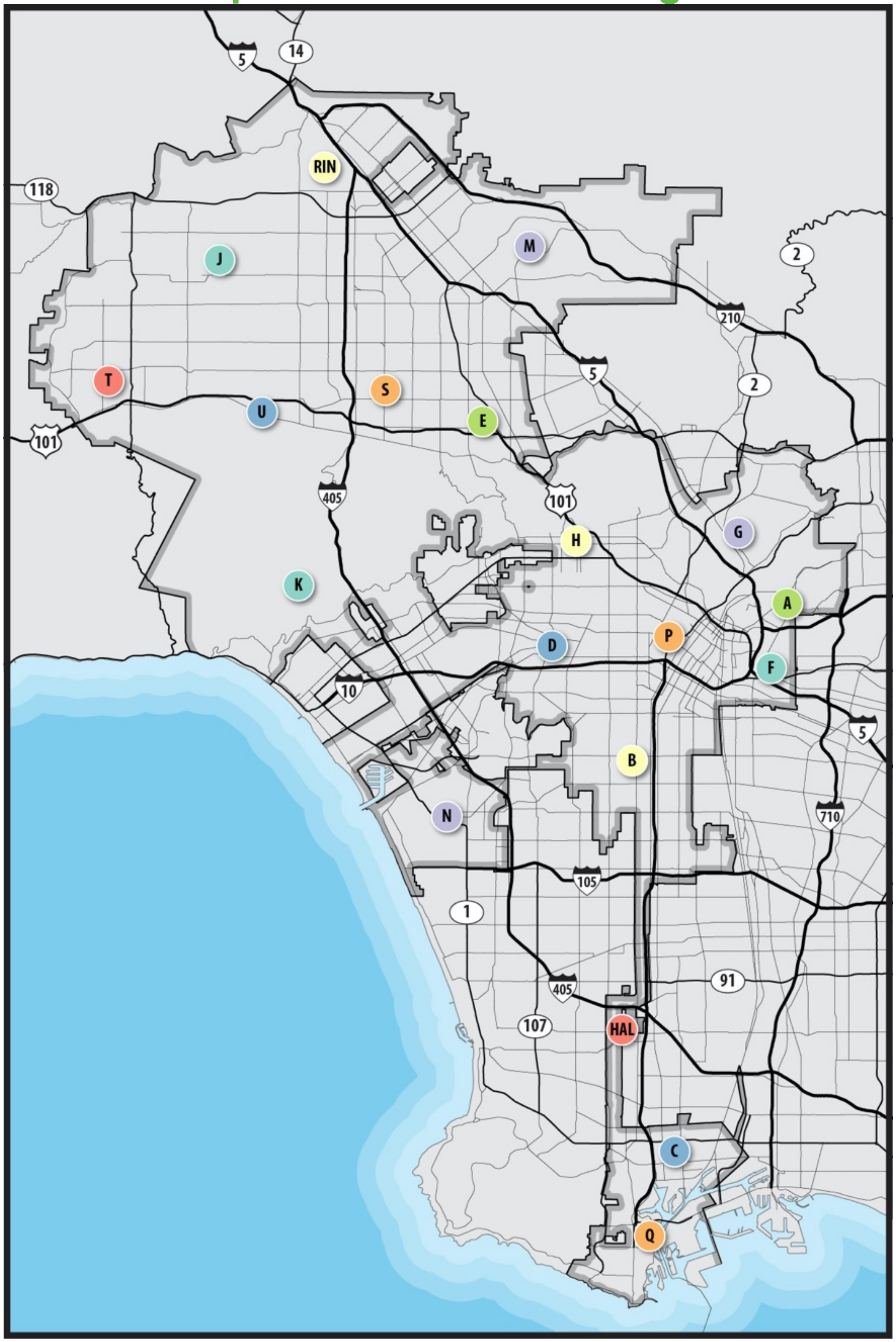

Figure 44. Map showing approximate location of RS regions within the LADWP in-basin service territory

Appendix C. Result Tables

This appendix contains the raw cost and upgrade tables from the core upgrade analysis. Note that values may not sum to the totals seen systemwide because these results have not been scaled to cover missing feeders.

Table 13. Cumulative (2021–2040) Raw Distribution Upgrade Costs by Scenario and RS region ($Thousands)

Region	Voltage class	SB100 - M	Early/NoBio - M	Trans. Focus - M	Ltd. Trans. - M	SB100 - H	Early/ NoBio - H	Trans. Focus - H	Ltd. Trans. - H	SB100 - Stress
A	34_5kV	$ 8,402	$ 8,230	$ 8,402	$ 8,302	$ 8,157	$ 8,019	$ 8,157	$ 8,238	$ 11,148
A	4_8kV	$ 7,266	$ 7,862	$ 7,266	$ 7,862	$ 21,517	$ 22,425	$ 21,517	$ 22,425	$ 29,873
B	34_5kV	$ 3,588	$ 1,141	$ 3,340	$ 1,602	$ 9,884	$ 8,137	$ 9,884	$ 9,171	$ 18,465
B	4_8kV	$ 70,353	$ 76,564	$ 70,353	$ 76,564	$ 173,034	$ 167,055	$ 173,034	$ 167,055	$ 244,411
C	34_5kV	$ 313	$ 139	$ 313	$ 139	$ 238	$ 1,951	$ 238	$ 1,951	$ 386
C	4_8kV	$ 4,491	$ 6,748	$ 4,491	$ 6,748	$ 6,672	$ 6,744	$ 6,672	$ 6,744	$ 15,208
D	34_5kV	$ 2,383	$ 1,950	$ 2,383	$ 1,819	$ 4,844	$ 4,363	$ 9,705	$ 9,192	$ 7,427
D	4_8kV	$ 33,202	$ 36,908	$ 33,202	$ 36,908	$ 55,140	$ 55,822	$ 55,140	$ 55,822	$ 87,808
E	34_5kV	$ 337	$ 323	$ 337	$ 323	$ 649	$ 635	$ 649	$ 635	$ 607
E	4_8kV	$ 19,846	$ 22,554	$ 19,846	$ 22,554	$ 27,881	$ 26,238	$ 27,881	$ 26,238	$ 89,590
F	34_5kV	$ 197	$ 0	$ 197	$ 2,808	$ 3,229	$ 1,533	$ 3,229	$ 3,894	$ 2,396
F	4_8kV	$ 5,853	$ 5,529	$ 5,853	$ 5,529	$ 9,134	$ 8,582	$ 9,134	$ 8,582	$ 15,682
G	34_5kV	$ 2,253	$ 2,253	$ 2,253	$ 2,253	$ 2,405	$ 2,486	$ 2,405	$ 2,486	$ 4,806
G	4_8kV	$ 35,925	$ 43,527	$ 35,925	$ 43,527	$ 63,318	$ 63,894	$ 63,318	$ 63,894	$ 117,987
H	34_5kV	$ 1,736	$ 1,736	$ 1,736	$ 1,544	$ 9,497	$ 8,869	$ 9,497	$ 8,578	$ 5,357
H	4_8kV	$ 33,391	$ 36,027	$ 33,391	$ 36,027	$ 39,338	$ 43,755	$ 39,338	$ 43,755	$ 61,647
HAL	34_5kV	$ 2,166	$ 2,250	$ 2,166	$ 2,250	$ 2,039	$ 2,051	$ 2,039	$ 2,051	$ 2,175
HAL	4_8kV	$ 1,474	$ 1,424	$ 1,474	$ 1,424	$ 7,475	$ 7,126	$ 7,475	$ 7,126	$ 10,244
J	34_5kV	$ 3,577	$ 3,657	$ 3,577	$ 3,657	$ 13,003	$ 8,030	$ 13,003	$ 8,030	$ 10,260
J	4_8kV	$ 29,583	$ 28,147	$ 29,583	$ 28,147	$ 36,426	$ 35,406	$ 36,426	$ 35,406	$ 109,303
K	34_5kV	$ 2,898	$ 2,153	$ 2,898	$ 2,153	$ 6,599	$ 7,191	$ 6,599	$ 6,672	$ 5,287

Region	Voltage class	SB100 - M	Early/NoBio - M	Trans. Focus - M	Ltd. Trans. - M	SB100 - H	Early/ NoBio - H	Trans. Focus - H	Ltd. Trans. - H	SB100 - Stress
K	4_8kV	$ 42,797	$ 47,237	$ 42,797	$ 47,237	$ 67,020	$ 64,353	$ 67,020	$ 64,353	$ 90,885
M	34_5kV	$ 69	$ 460	$ 69	$ 759	$ 416	$ 416	$ 416	$ 416	$ 210
M	4_8kV	$ 15,230	$ 16,011	$ 15,230	$ 16,011	$ 32,949	$ 37,639	$ 32,949	$ 37,639	$ 97,360
N	34_5kV	$ 4,141	$ 3,491	$ 3,893	$ 3,503	$ 5,602	$ 4,024	$ 5,602	$ 4,908	$ 4,500
N	4_8kV	$ 3,101	$ 5,845	$ 3,101	$ 5,845	$ 15,604	$ 18,690	$ 15,604	$ 18,690	$ 25,092
P	34_5kV	$ 10,762	$ 5,865	$ 10,762	$ 9,753	$ 10,747	$ 10,546	$ 10,747	$ 10,969	$ 23,810
P	4_8kV	$ 4,690	$ 4,773	$ 4,690	$ 4,773	$ 7,046	$ 3,961	$ 7,046	$ 3,961	$ 8,420
Q	34_5kV	$ 8,854	$ 8,854	$ 8,854	$ 8,854	$ 2,252	$ 3,248	$ 2,252	$ 2,597	$ 10,183
Q	4_8kV	$ 5,836	$ 7,489	$ 5,836	$ 7,489	$ 10,592	$ 11,832	$ 10,592	$ 11,832	$ 16,877
RIN	34_5kV	$ 5,544	$ 5,466	$ 6,198	$ 5,466	$ 7,439	$ 7,309	$ 7,439	$ 7,309	$ 3,148
RIN	4_8kV	$ 15,630	$ 13,688	$ 15,630	$ 13,688	$ 33,675	$ 25,536	$ 33,675	$ 25,536	$ 74,638
S	34_5kV	$ 1,297	$ 1,785	$ 1,297	$ 1,785	$ 463	$ 3,370	$ 463	$ 3,370	$ 3,431
S	4_8kV	$ 23,169	$ 25,374	$ 23,169	$ 25,374	$ 33,110	$ 32,779	$ 33,110	$ 32,779	$ 76,802
T	34_5kV	$ 2,018	$ 2,003	$ 2,018	$ 2,003	$ 6,935	$ 6,901	$ 6,935	$ 6,901	$ 1,582
T	4_8kV	$ 7,853	$ 9,611	$ 7,853	$ 9,611	$ 10,622	$ 12,026	$ 10,622	$ 12,026	$ 40,905
U	34_5kV	$ 7,342	$ 7,342	$ 7,342	$ 7,342	$ 7,127	$ 7,517	$ 7,127	$ 7,517	$ 7,124
U	4_8kV	$ 14,031	$ 15,502	$ 14,031	$ 15,502	$ 19,424	$ 20,039	$ 19,424	$ 20,039	$ 67,968

Table 14. Average Across Scenarios of Cumulative (2021–2040) Distribution Upgrade Count by Type for Each RS Region

Region	Voltage class	Trans-former	Lines	Substation LTC setting change	New line regulator	Line regulator control setting change	New cap. control	Cap. setting change	New feeder	RS rework	Total
A	34_5kV	39.8	105.9	-	-	-	-	-	-	1.0	145.7
A	4_8kV	501.8	82.9	16.6	25.4	4.4	7.7	12.1	3.2	-	654.1
B	34_5kV	6.2	11.2	-	-	-	-	-	-	0.6	17.4
B	4_8kV	2968.5	716.7	22.6	29.0	4.8	16.5	22.2	36.3	-	3816.7
C	34_5kV	4.6	-	1.2	-	1.2	-	1.2	-	-	8.2
C	4_8kV	326.4	21.4	1.1	1.5	-	1.1	1.1	1.4	-	353.9
D	34_5kV	7.3	2.9	-	-	-	-	-	-	0.3	10.2
D	4_8kV	1465.2	179.1	34.9	35.5	15.2	13.7	25.7	11.4	-	1780.8
E	34_5kV	13.3	0.9	-	-	-	-	-	-	-	14.2
E	4_8kV	1492.1	85.7	16.8	23.6	5.4	10.7	15.5	5.5	-	1655.4
F	34_5kV	3.3	2.2	-	-	-	-	-	-	-	5.6
F	4_8kV	282.8	47.8	21.4	18.8	19.0	4.2	11.5	1.1	-	406.5
G	34_5kV	19.2	25.9	-	-	-	-	-	-	0.1	45.1
G	4_8kV	1559.2	143.8	29.3	40.8	10.4	18.1	27.0	14.8	-	1843.4
H	34_5kV	12.3	18.7	-	-	-	-	-	-	0.4	31.0
H	4_8kV	1095.1	238.6	38.1	23.6	17.9	11.4	23.4	9.6	-	1457.8
HAL	34_5kV	13.1	0.7	-	-	-	-	-	-	-	13.8
HAL	4_8kV	148.7	24.5	1.0	1.1	0.4	0.7	0.9	1.2	-	178.5
J	34_5kV	28.3	21.4	1.3	-	4.0	0.7	1.1	-	0.6	56.9
J	4_8kV	1842.3	132.8	16.6	27.0	2.0	14.8	15.6	7.6	-	2058.7
K	34_5kV	17.0	4.7	-	-	-	-	-	-	0.1	21.7
K	4_8kV	1178.4	163.6	25.6	31.3	19.5	10.0	19.0	16.0	-	1463.5

Region	Voltage class	Trans-former	Lines	Substation LTC setting change	New line regulator	Line regulator control setting change	New cap. control	Cap. setting change	New feeder	RS rework	Total
M	34_5kV	8.2	-	-	-	-	-	-	-	-	8.2
M	4_8kV	1422.6	71.9	12.1	18.9	2.4	10.8	12.7	6.7	-	1558.1
N	34_5kV	-	-	-	-	-	-	-	-	-	-
N	4_8kV	393.8	24.5	4.4	2.1	0.3	2.1	3.8	3.1	-	434.2
P	34_5kV	48.6	41.1	-	-	-	-	-	-	1.6	89.7
P	4_8kV	127.7	31.8	36.0	26.5	14.4	3.7	8.5	0.4	-	249.0
Q	34_5kV	16.4	43.6	1.6	-	3.1	0.6	1.0	-	0.6	66.2
Q	4_8kV	381.1	23.9	7.6	12.5	1.4	5.6	6.0	1.8	-	439.8
RIN	34_5kV	12.3	32.7	-	-	-	-	-	-	0.9	45.0
RIN	4_8kV	1065.7	40.4	11.9	15.6	1.6	7.6	9.9	6.1	-	1158.7
S	34_5kV	13.6	1.1	-	-	-	0.2	0.2	-	-	15.1
S	4_8kV	1376.9	111.9	19.5	22.5	3.8	11.6	16.6	6.8	-	1569.6
T	34_5kV	17.6	33.9	-	-	-	-	-	-	0.4	51.4
T	4_8kV	970.9	18.3	11.8	13.4	5.9	10.1	12.3	1.2	-	1043.9
U	34_5kV	15.7	23.8	-	-	-	-	-	-	-	39.4
U	4_8kV	1144.6	59.3	9.5	11.5	6.7	5.1	6.9	4.0	-	1247.6

Appendix D. Estimated Upgrades and Costs for Today's Distribution System

As described in Section 2.1, the LA100 analysis first upgrades "today's" system to correct known existing challenges and lingering modeling errors, before identifying the impacts and upgrades needed with load and DER change for the various LA100 scenarios. This step also allows us to account for any data errors or other errors in the base model. The corresponding upgrades and costs are not included in the total costs for LA100. In this appendix, we provide a few results from our approximation of upgrading the current system to manage existing overloads and voltage challenges. As with the LA100 analyses, these estimated costs are only for upgrades due to these technical challenges and do not include routine maintenance, operations, or the replacement of equipment that has reached the end of its service life.

Moreover, these estimates also do not include extensive data clean up that occurred before running the automated upgrade analysis. As a result, these estimates likely represent only a small fraction of the total cost required to upgrade the current system to account for deferred maintenance; however, the spatial patterns for these upgrades may be informative. Figure 45 shows the spatial distribution of these estimated upgrade investments and Table 15 provides a cost summary broken down by RS region and upgrade type.

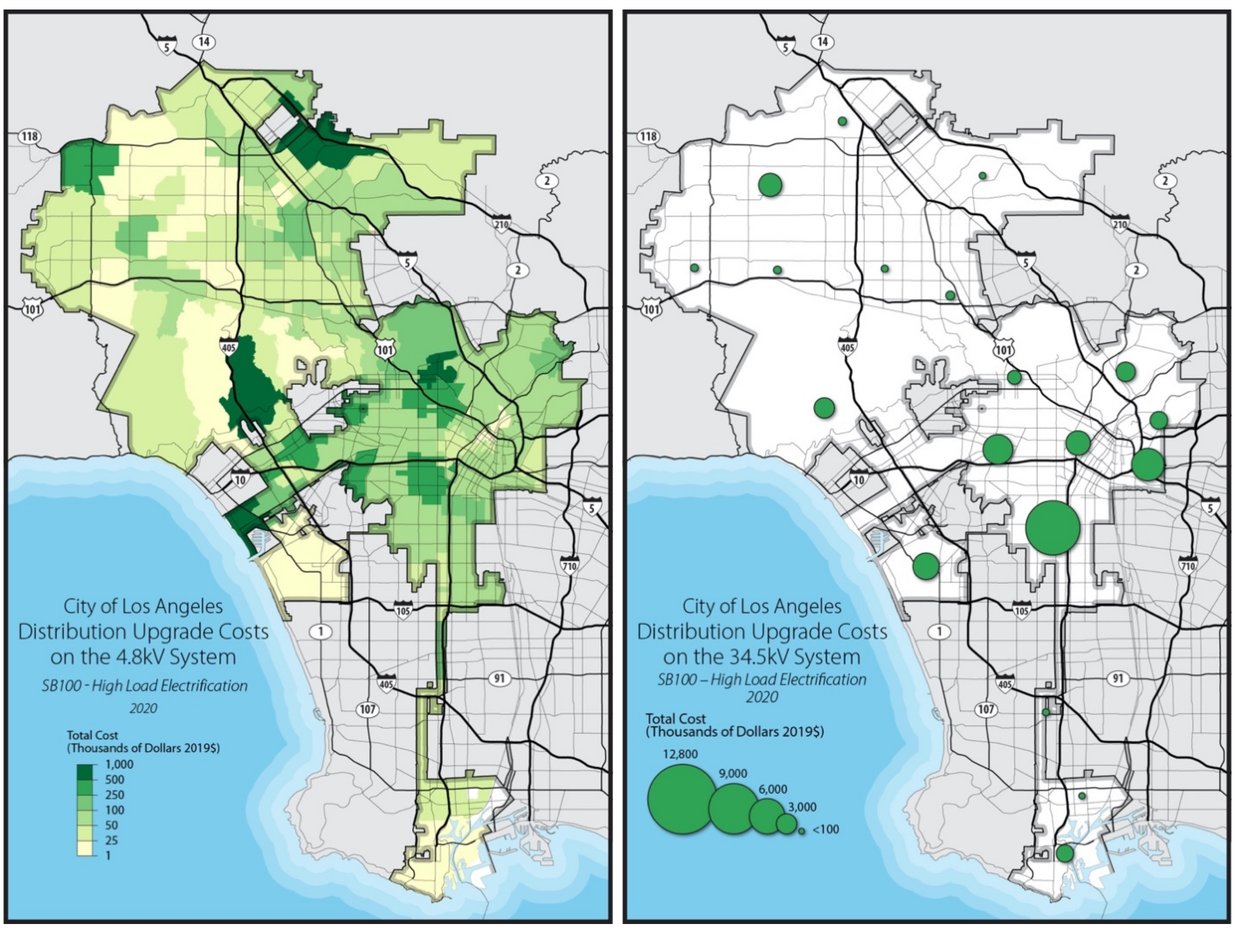

Figure 45. Regional map of 2020 upgrade costs for the 4.8kV (left) and the 34.5kV (right) system

Appendix E. Simulation Time Points for Distribution Analysis

A total of 13 timepoints were run for distribution analyses. In addition to the 10 in the table, we also ran August 11, 3 p.m.; August 11, 7 p.m.; and April 27, 2 p.m. for all regions, scenarios, and years. These provided additional support for light load/high solar and peak load conditions.

Table 15. Specific Timepoints Used for Distribution Analysis as a Function of Year, Load Scenario, and Region (RS)

Year	Load Scenario	RS	System Peak	System Min	RS Peak	RS Min	RS Max Solar-to-Load	System Max Solar-to-Load	RS Max EV Load	Christmas Afternoon	Fall Weekday Afternoon	Winter Weekday Afternoon
2020	moderate	A	Wed Aug 08 12:30	Fri Apr 20 02:00	Wed Aug 08 12:45	Sun Mar 04 06:15	Tue Mar 13 12:00	Sun Mar 11 12:00	Thu Jun 21 19:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	B	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Aug 10 12:45	Sun Mar 04 06:15	Mon May 28 12:00	Sun Mar 11 12:00	Wed Feb 15 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	C	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Oct 26 12:15	Sun Apr 08 05:30	Sat Mar 31 11:00	Sun Mar 11 12:00	Mon Apr 16 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	D	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Aug 10 14:45	Sun Mar 04 06:15	Wed Jun 27 12:00	Sun Mar 11 12:00	Tue Feb 21 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	E	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Aug 10 15:00	Sat Mar 10 05:00	Fri Jun 08 11:00	Sun Mar 11 12:00	Mon Mar 05 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	F	Wed Aug 08 12:30	Fri Apr 20 02:00	Wed Aug 08 12:45	Sun Mar 04 06:15	Wed May 09 11:00	Sun Mar 11 12:00	Wed Feb 15 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	G	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Aug 10 15:00	Sat Mar 10 05:00	Mon Mar 26 12:00	Sun Mar 11 12:00	Sun May 06 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	H	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Aug 10 15:00	Sat Mar 10 05:00	Mon May 28 12:00	Sun Mar 11 12:00	Sun Oct 21 19:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	HAL	Wed Aug 08 12:30	Fri Apr 20 02:00	Wed Aug 08 12:00	Sat Aug 04 17:30	Sat Apr 14 12:00	Sun Mar 11 12:00	Mon Oct 29 19:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	J	Wed Aug 08 12:30	Fri Apr 20 02:00	Wed Aug 08 13:45	Sun Jan 29 04:15	Thu Jul 26 11:00	Sun Mar 11 12:00	Sun Feb 12 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

Year	Load Scenario	RS	System Peak	System Min	RS Peak	RS Min	RS Max Solar-to-Load	System Max Solar-to-Load	RS Max EV Load	Christmas Afternoon	Fall Weekday Afternoon	Winter Weekday Afternoon
2020	moderate	K	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Oct 26 15:00	Sun Jan 01 16:30	Tue Apr 03 11:00	Sun Mar 11 12:00	Thu Feb 23 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	M	Wed Aug 08 12:30	Fri Apr 20 02:00	Thu Aug 09 13:45	Sun Apr 22 05:15	Thu Apr 05 11:00	Sun Mar 11 12:00	Sun May 06 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	N	Wed Aug 08 12:30	Fri Apr 20 02:00	Wed Aug 29 20:00	Sun Apr 01 15:45	Fri Mar 02 12:00	Sun Mar 11 12:00	Wed Mar 28 18:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	P	Wed Aug 08 12:30	Fri Apr 20 02:00	Wed Aug 08 12:30	Sun Mar 04 06:15	Thu May 17 12:00	Sun Mar 11 12:00	Tue Jan 03 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	Q	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Oct 26 11:45	Sun Apr 08 05:30	Mon Jun 04 10:00	Sun Mar 11 12:00	Thu Apr 12 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	RIN	Wed Aug 08 12:30	Fri Apr 20 02:00	Mon Aug 06 15:00	Sat Mar 10 03:30	Mon Jun 04 11:00	Sun Mar 11 12:00	Sun Aug 26 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	S	Wed Aug 08 12:30	Fri Apr 20 02:00	Thu Aug 09 14:00	Sun Mar 04 05:00	Sat Jul 07 11:00	Sun Mar 11 12:00	Sun Jun 03 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	T	Wed Aug 08 12:30	Fri Apr 20 02:00	Fri Aug 10 15:00	Sat Mar 10 03:30	Tue May 22 12:00	Sun Mar 11 12:00	Sun Sep 30 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2020	moderate	U	Wed Aug 08 12:30	Fri Apr 20 02:00	Mon Aug 06 15:15	Sat Mar 10 03:00	Thu Jun 28 12:00	Sun Mar 11 12:00	Sun Apr 15 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	A	Mon Aug 06 14:45	Fri Apr 20 02:00	Wed Aug 08 12:45	Sun Jan 15 15:00	Mon Apr 09 11:00	Sun Apr 01 12:00	Mon Jan 02 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	B	Mon Aug 06 14:45	Fri Apr 20 02:00	Fri Aug 10 12:45	Sun Mar 04 06:15	Wed Jun 20 12:00	Sun Apr 01 12:00	Sun Sep 16 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	C	Mon Aug 06 14:45	Fri Apr 20 02:00	Fri Oct 26 11:45	Sun May 27 05:00	Mon May 14 12:00	Sun Apr 01 12:00	Sun Apr 29 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

Year	Load Scenario	RS	System Peak	System Min	RS Peak	RS Min	RS Max Solar-to-Load	System Max Solar-to-Load	RS Max EV Load	Christmas Afternoon	Fall Weekday Afternoon	Winter Weekday Afternoon
2030	moderate	D	Mon Aug 06 14:45	Fri Apr 20 02:00	Fri Aug 10 15:00	Mon Jan 02 05:00	Fri Jun 22 12:00	Sun Apr 01 12:00	Sun Mar 25 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	E	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 14:45	Sat Mar 10 05:00	Mon Jun 04 12:00	Sun Apr 01 12:00	Thu Jan 19 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	F	Mon Aug 06 14:45	Fri Apr 20 02:00	Wed Aug 08 12:15	Sun Apr 01 16:30	Mon Jul 16 11:00	Sun Apr 01 12:00	Tue Nov 27 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	G	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 05:00	Mon Jul 16 13:00	Sun Apr 01 12:00	Wed Apr 04 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	H	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 15:00	Mon Jan 02 05:00	Tue Mar 06 12:00	Sun Apr 01 12:00	Sun Dec 23 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	HAL	Mon Aug 06 14:45	Fri Apr 20 02:00	Wed Aug 08 12:15	Sat Aug 04 17:15	Thu Aug 30 11:00	Sun Apr 01 12:00	Sat Dec 01 12:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	J	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 14:45	Sun Mar 04 05:00	Wed Jul 25 13:00	Sun Apr 01 12:00	Sun Jan 08 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	K	Mon Aug 06 14:45	Fri Apr 20 02:00	Sat Aug 11 20:00	Mon Jan 02 05:00	Thu Jul 05 11:00	Sun Apr 01 12:00	Sun May 20 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	M	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 14:45	Sat Mar 10 05:00	Mon Mar 26 11:00	Sun Apr 01 12:00	Sun Apr 01 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	N	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 13 20:00	Sun Apr 01 15:45	Sun Jun 24 12:00	Sun Apr 01 12:00	Tue May 01 19:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	P	Mon Aug 06 14:45	Fri Apr 20 02:00	Wed Aug 08 12:00	Sun Jan 01 00:15	Fri Apr 20 12:00	Sun Apr 01 12:00	Sun Nov 11 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	Q	Mon Aug 06 14:45	Fri Apr 20 02:00	Fri Oct 26 11:45	Sun Jul 08 05:15	Sun Jul 15 12:00	Sun Apr 01 12:00	Tue Sep 11 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

Year	Load Scenario	RS	System Peak	System Min	RS Peak	RS Min	RS Max Solar-to-Load	System Max Solar-to-Load	RS Max EV Load	Christmas Afternoon	Fall Weekday Afternoon	Winter Weekday Afternoon
2030	moderate	RIN	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 05:00	Sat Jun 02 12:00	Sun Apr 01 12:00	Sun Jul 22 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	S	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 05:00	Sun Jul 29 11:00	Sun Apr 01 12:00	Sun Jun 10 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	T	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 15:00	Sat Mar 10 04:00	Mon Apr 09 12:00	Sun Apr 01 12:00	Sun Jun 10 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	moderate	U	Mon Aug 06 14:45	Fri Apr 20 02:00	Mon Aug 06 15:15	Sat Mar 10 03:00	Mon Jun 04 11:00	Sun Apr 01 12:00	Sun Feb 26 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	A	Fri Aug 10 15:00	Fri Apr 20 02:00	Wed Aug 08 12:30	Sat Mar 10 05:00	Wed Apr 04 12:00	Sun Apr 01 12:00	Thu Mar 22 18:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	B	Fri Aug 10 15:00	Fri Apr 20 02:00	Fri Aug 10 12:45	Mon Jan 02 05:00	Mon Jul 16 12:00	Sun Apr 01 12:00	Sun Jun 17 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	C	Fri Aug 10 15:00	Fri Apr 20 02:00	Fri Oct 26 12:00	Sun May 27 05:00	Sat Jun 30 10:00	Sun Apr 01 12:00	Sun Jan 01 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	D	Fri Aug 10 15:00	Fri Apr 20 02:00	Fri Aug 10 15:00	Mon Jan 02 05:00	Thu Jul 05 11:00	Sun Apr 01 12:00	Tue Apr 10 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	E	Fri Aug 10 15:00	Fri Apr 20 02:00	Mon Aug 06 15:00	Sat Mar 10 05:00	Fri Jun 29 11:00	Sun Apr 01 12:00	Sun May 06 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	F	Fri Aug 10 15:00	Fri Apr 20 02:00	Wed Aug 08 12:30	Sun Apr 01 16:30	Fri Apr 06 12:00	Sun Apr 01 12:00	Mon Oct 22 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	G	Fri Aug 10 15:00	Fri Apr 20 02:00	Fri Aug 10 15:15	Sun Mar 04 05:00	Sat Mar 31 12:00	Sun Apr 01 12:00	Sun Jun 03 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	H	Fri Aug 10 15:00	Fri Apr 20 02:00	Fri Aug 10 15:00	Mon Jan 02 05:00	Mon Mar 26 12:00	Sun Apr 01 12:00	Tue May 29 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

Year	Load Scenario	RS	System Peak	System Min	RS Peak	RS Min	RS Max Solar-to-Load	System Max Solar-to-Load	RS Max EV Load	Christmas Afternoon	Fall Weekday Afternoon	Winter Weekday Afternoon
2030	high	HAL	Fri Aug 10 15:00	Fri Apr 20 02:00	Wed Aug 08 12:00	Sat Aug 04 17:30	Thu Apr 05 12:00	Sun Apr 01 12:00	Sat Sep 01 12:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	J	Fri Aug 10 15:00	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 04:30	Sun Jun 17 12:00	Sun Apr 01 12:00	Mon Mar 12 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	K	Fri Aug 10 15:00	Fri Apr 20 02:00	Fri Oct 26 15:00	Mon Jan 02 05:00	Sat Apr 07 12:00	Sun Apr 01 12:00	Sun Aug 12 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	M	Fri Aug 10 15:00	Fri Apr 20 02:00	Mon Aug 06 15:15	Sat Mar 10 05:00	Mon May 21 12:00	Sun Apr 01 12:00	Mon Oct 15 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	N	Fri Aug 10 15:00	Fri Apr 20 02:00	Mon Aug 13 20:00	Sun Apr 01 15:45	Thu Apr 26 11:00	Sun Apr 01 12:00	Tue Jan 31 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	P	Fri Aug 10 15:00	Fri Apr 20 02:00	Wed Aug 08 12:00	Sun Jan 01 00:15	Sun Apr 08 11:00	Sun Apr 01 12:00	Sat Jun 09 12:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	Q	Fri Aug 10 15:00	Fri Apr 20 02:00	Fri Oct 26 11:45	Sun Jul 08 05:15	Sat Jun 16 11:00	Sun Apr 01 12:00	Sat Apr 14 12:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	RIN	Fri Aug 10 15:00	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 04:30	Tue Mar 06 12:00	Sun Apr 01 12:00	Sun Oct 28 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	S	Fri Aug 10 15:00	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 05:00	Sat Mar 31 11:00	Sun Apr 01 12:00	Thu Oct 11 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	T	Fri Aug 10 15:00	Fri Apr 20 02:00	Mon Aug 06 15:15	Sat Mar 10 04:15	Fri Jun 01 12:00	Sun Apr 01 12:00	Tue Jan 24 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	high	U	Fri Aug 10 15:00	Fri Apr 20 02:00	Mon Aug 06 15:15	Sat Mar 10 03:00	Sat Mar 31 11:00	Sun Apr 01 12:00	Sun Mar 04 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	A	Mon Aug 06 15:15	Fri Apr 20 02:00	Wed Aug 08 12:30	Sat Mar 10 05:15	Tue Jun 26 11:00	Sun Apr 01 12:00	Sun Nov 11 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

Year	Load Scenario	RS	System Peak	System Min	RS Peak	RS Min	RS Max Solar-to-Load	System Max Solar-to-Load	RS Max EV Load	Christmas Afternoon	Fall Weekday Afternoon	Winter Weekday Afternoon
2030	stress	B	Mon Aug 06 15:15	Fri Apr 20 02:00	Fri Aug 10 15:15	Sun Mar 04 05:00	Mon Jun 04 10:00	Sun Apr 01 12:00	Sun Sep 02 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	C	Mon Aug 06 15:15	Fri Apr 20 02:00	Fri Oct 26 12:30	Sun May 27 05:00	Sun Jun 17 11:00	Sun Apr 01 12:00	Sun Jun 03 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	D	Mon Aug 06 15:15	Fri Apr 20 02:00	Fri Aug 10 15:00	Mon Jan 02 05:00	Mon Jun 04 12:00	Sun Apr 01 12:00	Sun Jan 29 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	E	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 05:00	Thu Jul 05 12:00	Sun Apr 01 12:00	Sun Nov 18 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	F	Mon Aug 06 15:15	Fri Apr 20 02:00	Wed Aug 08 12:30	Sun Mar 04 06:45	Tue Jun 26 11:00	Sun Apr 01 12:00	Wed May 30 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	G	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 15:30	Sun Mar 04 05:00	Sun Apr 08 11:00	Sun Apr 01 12:00	Sun May 06 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	H	Mon Aug 06 15:15	Fri Apr 20 02:00	Fri Aug 10 15:00	Mon Jan 02 05:00	Tue Mar 06 11:00	Sun Apr 01 12:00	Sun Sep 16 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	HAL	Mon Aug 06 15:15	Fri Apr 20 02:00	Wed Aug 08 13:15	Sun Feb 26 06:30	Thu May 31 11:00	Sun Apr 01 12:00	Thu Jul 05 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	J	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 05:00	Mon Jul 16 12:00	Sun Apr 01 12:00	Sun Oct 21 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	K	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 20:00	Mon Jan 02 05:00	Thu May 17 12:00	Sun Apr 01 12:00	Sun Jan 15 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	M	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 15:15	Sat Mar 10 05:00	Mon Jun 04 11:00	Sun Apr 01 12:00	Thu Dec 06 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	N	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 13 20:00	Sun Apr 01 13:15	Tue Jun 19 11:00	Sun Apr 01 12:00	Tue Mar 20 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

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2030	stress	P	Mon Aug 06 15:15	Fri Apr 20 02:00	Wed Aug 08 12:00	Sun Jan 01 00:15	Sat Mar 31 11:00	Sun Apr 01 12:00	Mon Apr 23 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	Q	Mon Aug 06 15:15	Fri Apr 20 02:00	Fri Oct 26 11:45	Sun Jul 08 05:15	Sun Jul 15 13:00	Sun Apr 01 12:00	Sun Jul 01 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	RIN	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 15:30	Sun Mar 04 05:00	Mon Jun 04 12:00	Sun Apr 01 12:00	Sun Apr 08 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	S	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 05:00	Tue Jun 05 12:00	Sun Apr 01 12:00	Wed Aug 08 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	T	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 15:15	Sun Mar 04 05:00	Fri Mar 23 12:00	Sun Apr 01 12:00	Wed Dec 26 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2030	stress	U	Mon Aug 06 15:15	Fri Apr 20 02:00	Mon Aug 06 15:15	Sat Mar 10 05:00	Mon Jun 04 11:00	Sun Apr 01 12:00	Sun May 13 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	A	Fri Aug 10 15:15	Fri Apr 20 02:00	Wed Aug 08 12:15	Sat Mar 10 05:00	Mon Jun 25 11:00	Sun Mar 11 12:00	Sun Jul 29 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	B	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 12:45	Sun Mar 04 05:00	Mon Apr 09 11:00	Sun Mar 11 12:00	Sun Apr 29 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	C	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Oct 26 12:15	Sun May 27 05:00	Tue May 22 11:00	Sun Mar 11 12:00	Sun Nov 25 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	D	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 15:00	Mon Jan 02 05:00	Mon Apr 09 11:00	Sun Mar 11 12:00	Sun Jan 08 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	E	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 15:15	Sat Mar 10 05:00	Thu May 10 12:00	Sun Mar 11 12:00	Sun Jul 15 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	F	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 12:45	Sun Jan 08 14:45	Mon Aug 13 12:00	Sun Mar 11 12:00	Sun Nov 04 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

Year	Load Scenario	RS	System Peak	System Min	RS Peak	RS Min	RS Max Solar-to-Load	System Max Solar-to-Load	RS Max EV Load	Christmas Afternoon	Fall Weekday Afternoon	Winter Weekday Afternoon
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2045	moderate	H	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 15:00	Sat Mar 10 05:00	Thu Jun 07 12:00	Sun Mar 11 12:00	Sun May 27 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	HAL	Fri Aug 10 15:15	Fri Apr 20 02:00	Wed Aug 08 12:15	Sat Mar 03 17:30	Mon Mar 19 11:00	Sun Mar 11 12:00	Fri Nov 16 16:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	J	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 15:15	Sun Jan 08 04:30	Mon May 28 11:00	Sun Mar 11 12:00	Sun Sep 23 18:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	K	Fri Aug 10 15:15	Fri Apr 20 02:00	Sat Aug 11 20:00	Mon Jan 02 05:00	Mon Apr 09 11:00	Sun Mar 11 12:00	Sun Jan 15 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	M	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 16:15	Sat Mar 10 05:00	Mon Jul 30 12:00	Sun Mar 11 12:00	Sun Dec 23 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	N	Fri Aug 10 15:15	Fri Apr 20 02:00	Wed Sep 12 20:00	Sun Jan 08 14:15	Thu Jul 05 11:00	Sun Mar 11 12:00	Sun Mar 11 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	P	Fri Aug 10 15:15	Fri Apr 20 02:00	Wed Aug 08 12:00	Sun Jan 15 15:15	Sat Mar 31 13:00	Sun Mar 11 12:00	Wed Feb 22 19:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	Q	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Oct 26 11:45	Sun Aug 05 05:30	Fri Jul 27 11:00	Sun Mar 11 12:00	Tue Jun 19 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	RIN	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 16:15	Sun Jan 08 04:30	Sun May 13 11:00	Sun Mar 11 12:00	Sun Sep 23 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	S	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 15:15	Sun Mar 04 05:00	Fri Jul 06 11:00	Sun Mar 11 12:00	Sun Dec 16 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	moderate	T	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 15:15	Sun Jan 08 04:15	Sat May 26 11:00	Sun Mar 11 12:00	Sun Feb 12 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

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2045	moderate	U	Fri Aug 10 15:15	Fri Apr 20 02:00	Fri Aug 10 16:15	Sat Mar 10 03:15	Sat Mar 31 11:00	Sun Mar 11 12:00	Tue Jan 24 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	A	Fri Aug 10 12:45	Fri Apr 20 02:00	Wed Aug 08 12:15	Sat Mar 10 05:00	Mon Jul 30 12:00	Sun May 13 12:00	Sun Apr 29 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	B	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 12:45	Sat Mar 10 05:00	Fri Jun 29 11:00	Sun May 13 12:00	Sun Apr 22 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	C	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Oct 26 12:15	Sun Jan 08 04:30	Sun Jul 15 12:00	Sun May 13 12:00	Sun Feb 26 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	D	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 15:15	Sat Mar 10 05:00	Sun May 06 12:00	Sun May 13 12:00	Sun Dec 16 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	E	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 16:15	Sat Mar 10 05:00	Wed Jun 27 12:00	Sun May 13 12:00	Sun Dec 09 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	F	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 12:45	Sun Jan 08 14:30	Mon May 07 11:00	Sun May 13 12:00	Wed Sep 26 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	G	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 16:15	Sat Mar 10 05:00	Tue Jun 19 12:00	Sun May 13 12:00	Thu Oct 04 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	H	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 15:00	Sat Mar 10 05:00	Sun Jun 10 12:00	Sun May 13 12:00	Thu Nov 01 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	HAL	Fri Aug 10 12:45	Fri Apr 20 02:00	Wed Aug 08 12:15	Sun Aug 05 05:15	Tue May 15 11:00	Sun May 13 12:00	Sat Apr 07 11:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	J	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 12:45	Sun Jan 08 04:30	Mon Jun 25 11:00	Sun May 13 12:00	Sun Jul 22 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	K	Fri Aug 10 12:45	Fri Apr 20 02:00	Sat Aug 11 20:00	Mon Mar 05 05:00	Wed May 16 12:00	Sun May 13 12:00	Sun May 20 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

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2045	high	N	Fri Aug 10 12:45	Fri Apr 20 02:00	Wed Sep 12 19:15	Sun Mar 11 03:00	Mon May 14 12:00	Sun May 13 12:00	Wed May 30 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	P	Fri Aug 10 12:45	Fri Apr 20 02:00	Wed Aug 08 12:00	Sat Mar 10 05:00	Sun Jun 24 12:00	Sun May 13 12:00	Sat Dec 08 12:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	Q	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Oct 26 11:45	Sun Aug 05 05:15	Sun May 13 11:00	Sun May 13 12:00	Sat Dec 15 12:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	RIN	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 16:15	Sun Jan 08 04:30	Sun Jul 15 13:00	Sun May 13 12:00	Sun Oct 28 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	S	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 16:15	Sun Jan 29 04:15	Thu Apr 05 11:00	Sun May 13 12:00	Thu Apr 19 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	T	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 15:15	Sun Jan 08 04:15	Fri Jun 22 12:00	Sun May 13 12:00	Sun Sep 02 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	high	U	Fri Aug 10 12:45	Fri Apr 20 02:00	Fri Aug 10 16:45	Sat Mar 10 04:30	Mon Apr 09 12:00	Sun May 13 12:00	Thu Jun 28 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	A	Fri Aug 10 16:30	Fri Apr 20 02:00	Fri Aug 10 12:45	Sat Mar 10 05:00	Sat Jun 02 11:00	Sun Mar 11 12:00	Mon Oct 29 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	B	Fri Aug 10 16:30	Fri Apr 20 02:00	Fri Aug 10 16:30	Mon Mar 05 04:30	Fri Jun 29 12:00	Sun Mar 11 12:00	Sun Jun 10 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
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2045	stress	F	Fri Aug 10 16:30	Fri Apr 20 02:00	Fri Aug 10 12:30	Sun Mar 11 13:45	Fri Jul 27 12:00	Sun Mar 11 12:00	Sun Feb 26 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	G	Fri Aug 10 16:30	Fri Apr 20 02:00	Mon Aug 06 17:45	Sat Mar 10 05:00	Sat Jun 02 12:00	Sun Mar 11 12:00	Sun May 06 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	H	Fri Aug 10 16:30	Fri Apr 20 02:00	Fri Aug 10 15:15	Sat Mar 10 05:00	Mon May 14 10:00	Sun Mar 11 12:00	Sun Feb 19 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	HAL	Fri Aug 10 16:30	Fri Apr 20 02:00	Fri Aug 10 13:30	Sun Aug 05 05:30	Mon Jul 23 11:00	Sun Mar 11 12:00	Thu Mar 22 19:00	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	J	Fri Aug 10 16:30	Fri Apr 20 02:00	Mon Aug 06 17:45	Sun Jan 08 05:00	Fri Jun 22 11:00	Sun Mar 11 12:00	Sun May 06 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	K	Fri Aug 10 16:30	Fri Apr 20 02:00	Thu Oct 25 20:00	Mon Mar 05 05:00	Thu Jul 05 10:00	Sun Mar 11 12:00	Sun Jun 03 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	M	Fri Aug 10 16:30	Fri Apr 20 02:00	Mon Aug 06 17:45	Sat Mar 10 05:00	Fri Jun 08 11:00	Sun Mar 11 12:00	Sun Jun 17 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	N	Fri Aug 10 16:30	Fri Apr 20 02:00	Wed Sep 05 19:15	Sun Jan 08 14:15	Thu Jul 05 12:00	Sun Mar 11 12:00	Tue Nov 20 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	P	Fri Aug 10 16:30	Fri Apr 20 02:00	Wed Aug 08 12:00	Sun Jan 15 14:45	Mon May 28 11:00	Sun Mar 11 12:00	Sun Aug 19 18:15	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	Q	Fri Aug 10 16:30	Fri Apr 20 02:00	Fri Oct 26 11:45	Sun Aug 05 05:15	Mon Jun 11 12:00	Sun Mar 11 12:00	Sun Nov 04 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	RIN	Fri Aug 10 16:30	Fri Apr 20 02:00	Mon Aug 06 17:45	Sat Mar 10 05:00	Thu May 17 11:00	Sun Mar 11 12:00	Sun Oct 07 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

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2045	stress	S	Fri Aug 10 16:30	Fri Apr 20 02:00	Mon Aug 06 17:45	Sun Mar 04 05:00	Sun May 27 11:00	Sun Mar 11 12:00	Sun Mar 04 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	T	Fri Aug 10 16:30	Fri Apr 20 02:00	Mon Aug 06 17:45	Sun Jan 08 04:30	Thu May 17 11:00	Sun Mar 11 12:00	Sun Nov 25 18:45	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00
2045	stress	U	Fri Aug 10 16:30	Fri Apr 20 02:00	Mon Aug 06 17:45	Sat Mar 10 05:00	Sun May 13 11:00	Sun Mar 11 12:00	Sun Jul 01 18:30	Tue Dec 25 15:00	Thu Nov 01 15:00	Wed Jan 18 15:00

Appendix F. Local Solar Scenario Deployment Maps

F.1 Non-Rooftop Local Solar Deployments

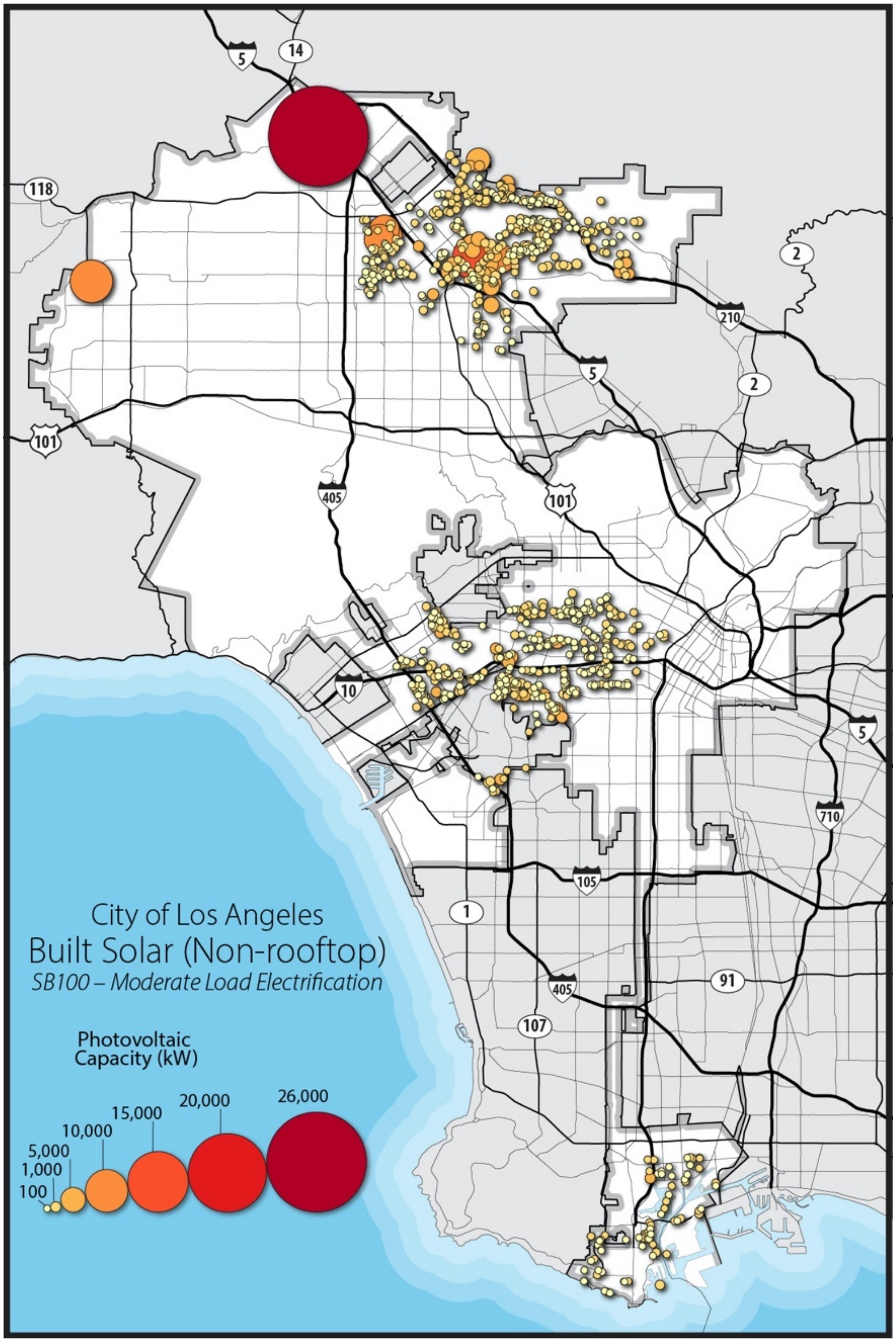

Figure 46. Non-rooftop local solar deployment capacities in 2045 under the SB100 – Moderate scenario

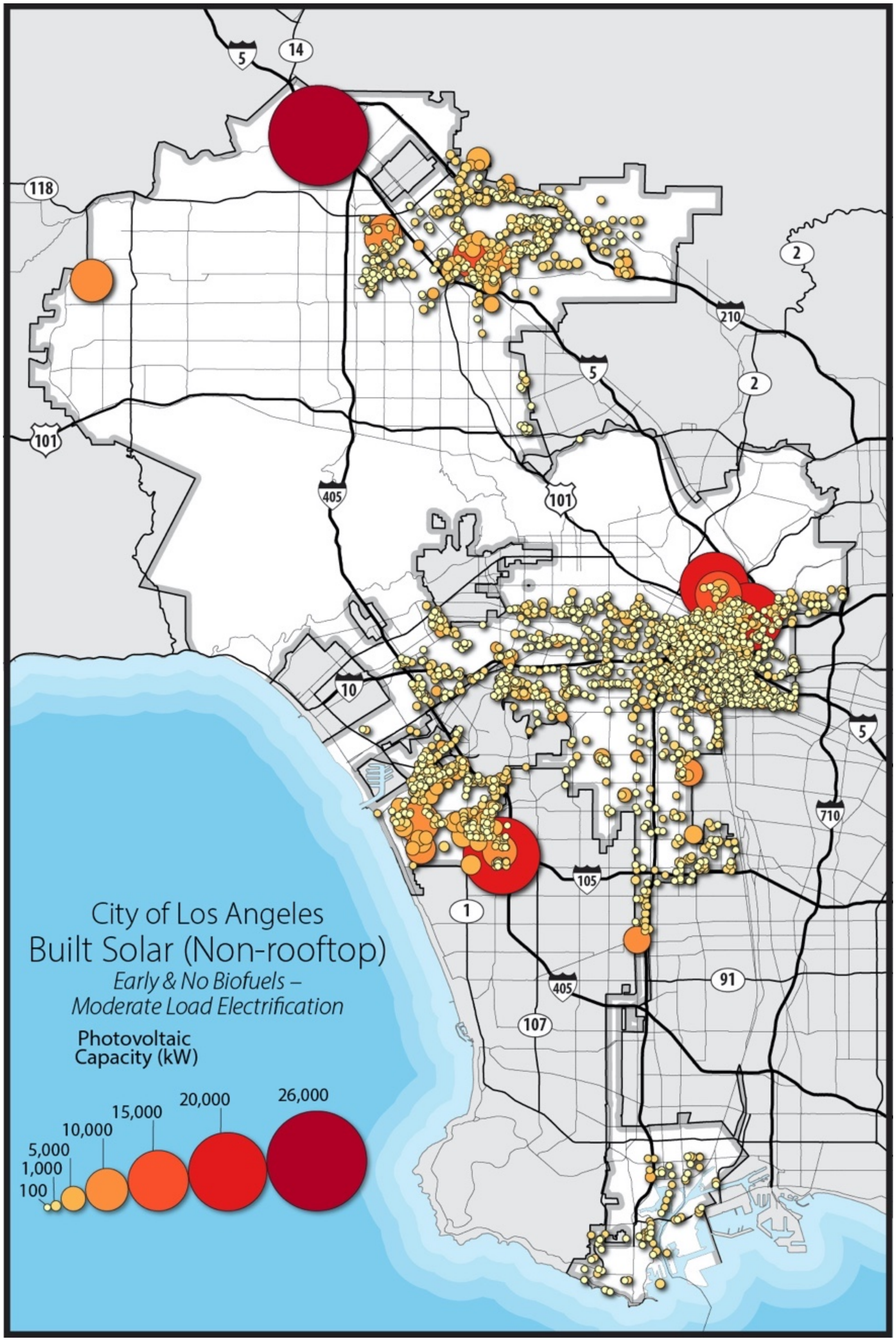

Figure 47. Non-rooftop local solar deployment capacities in 2045 under the Early & No Biofuels – Moderate scenario

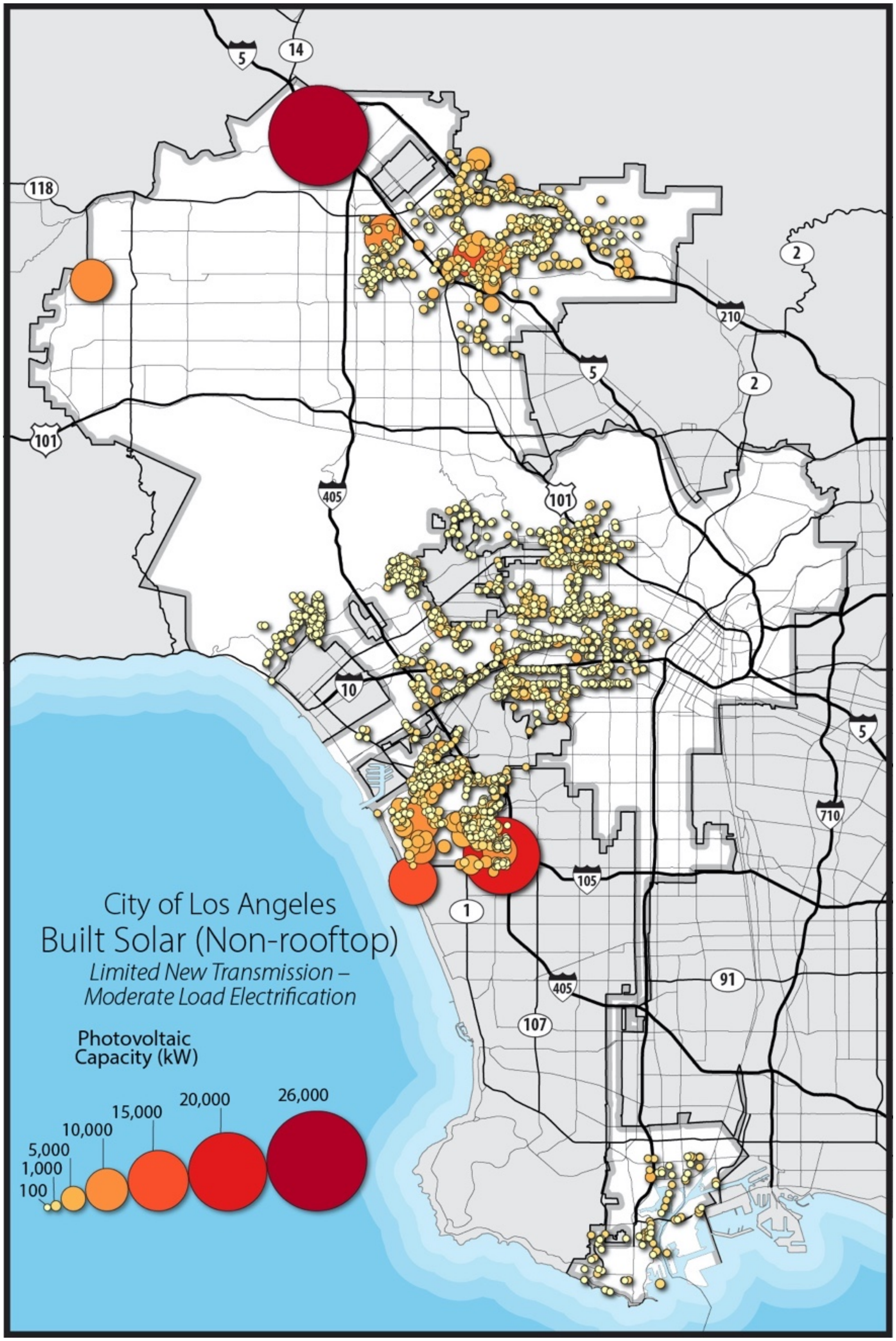

Figure 48. Non-rooftop local solar deployment capacities in 2045 Limited New Transmission – Moderate scenario

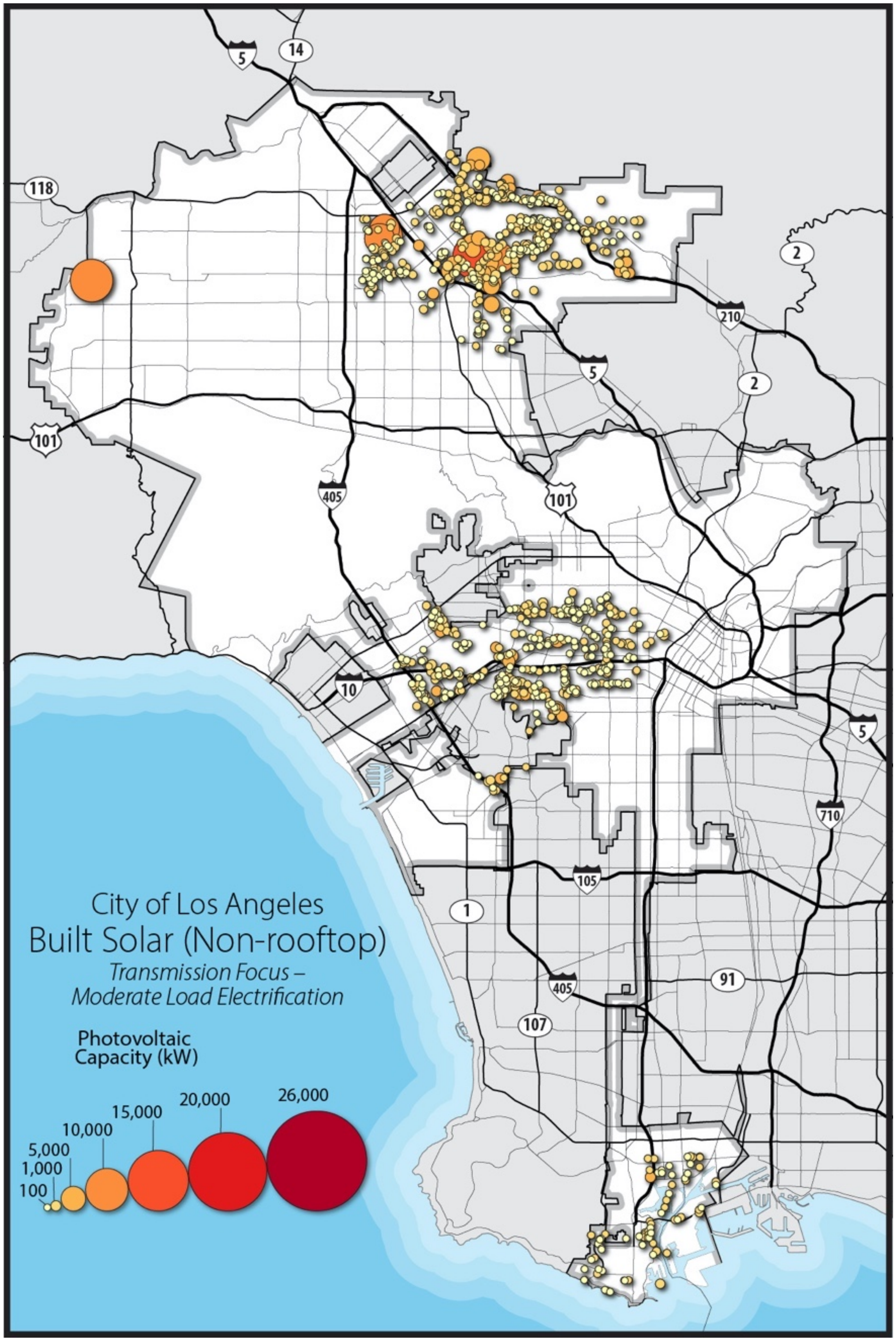

Figure 49. Non-rooftop local solar deployment capacities in 2045 under the Transmission Focus – Moderate scenario

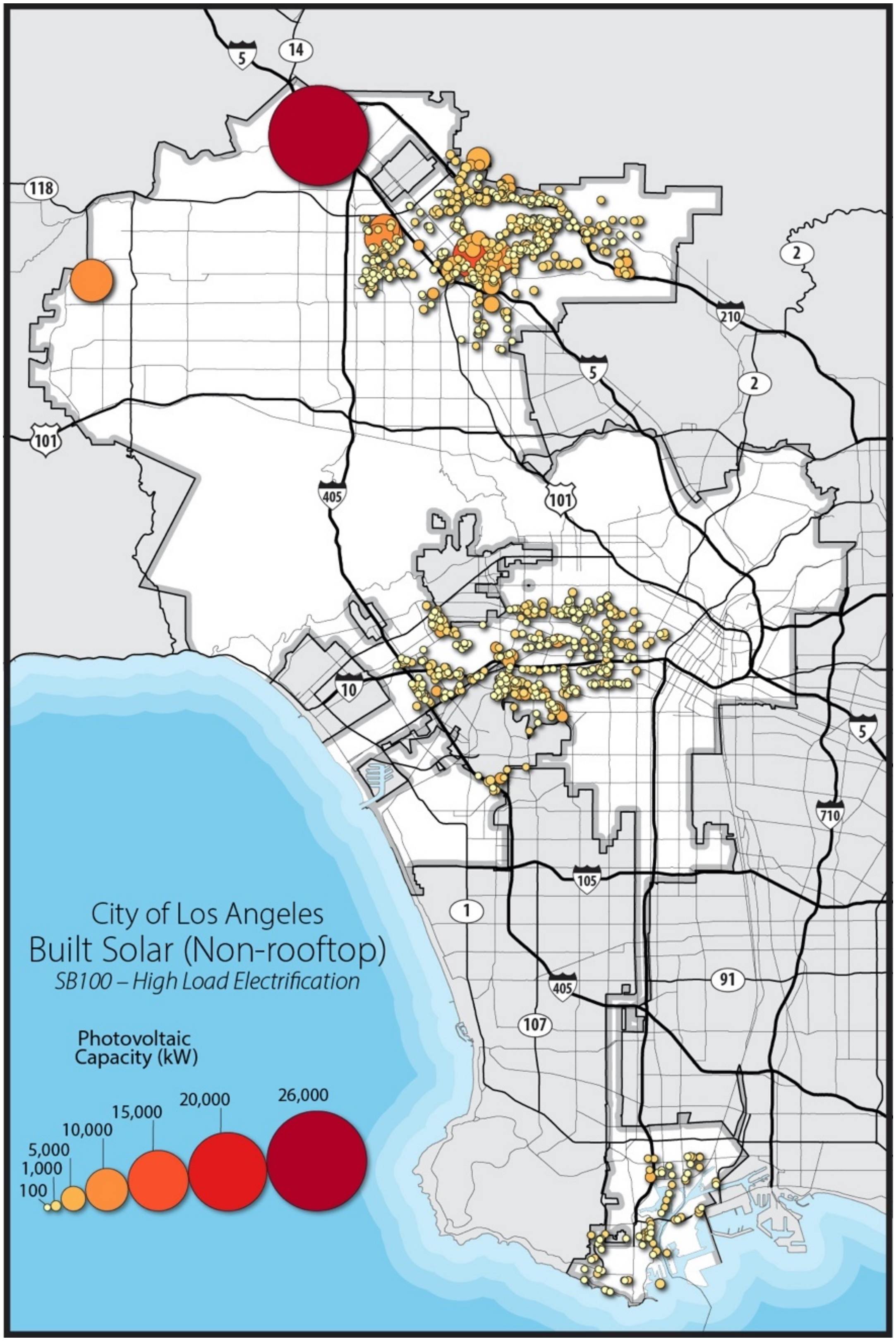

Figure 50. Non-rooftop local solar deployment capacities in 2045 under the SB100 – High scenario

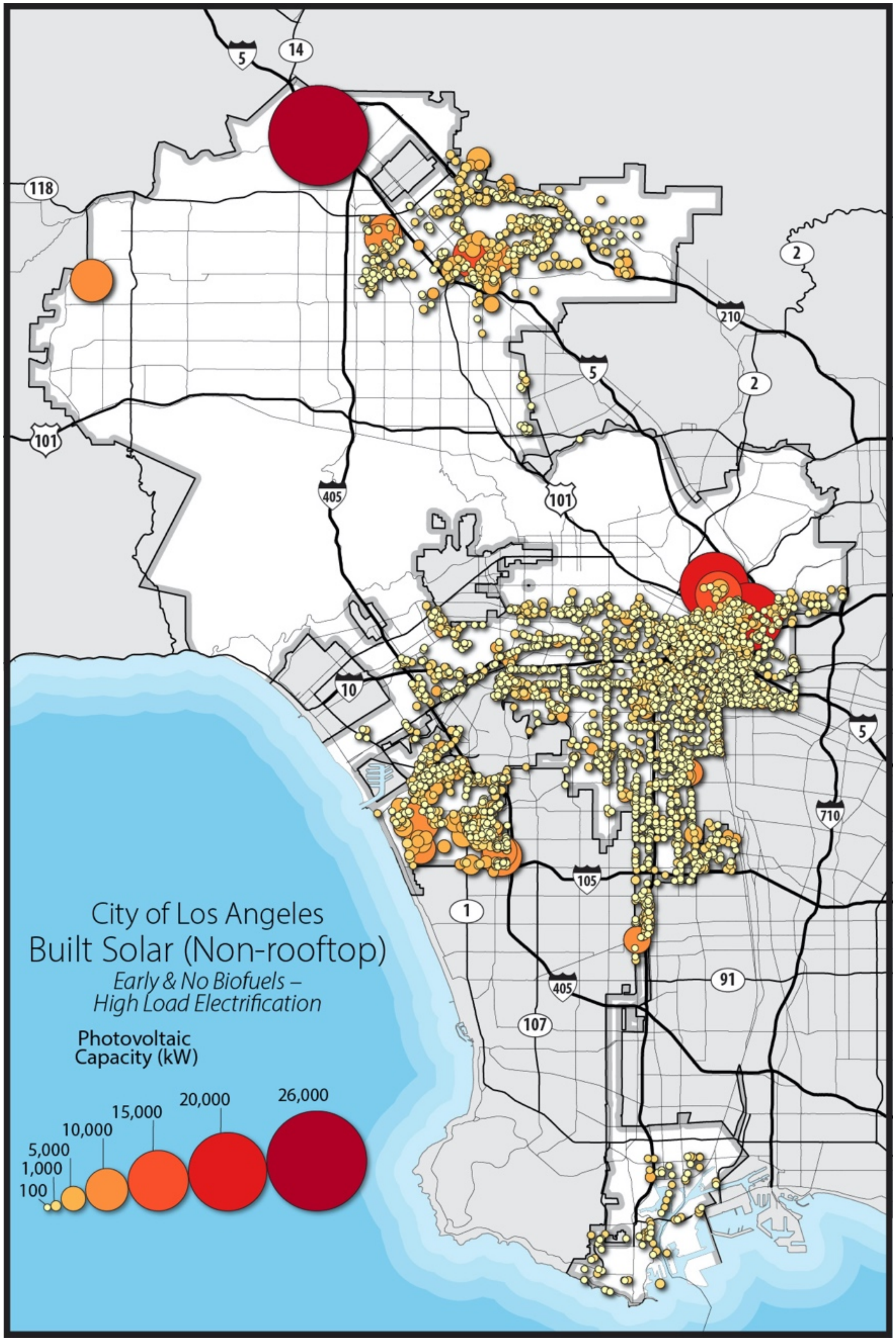

Figure 51. Non-rooftop local solar deployment capacities in 2045 under the Early & No Biofuels – High scenario

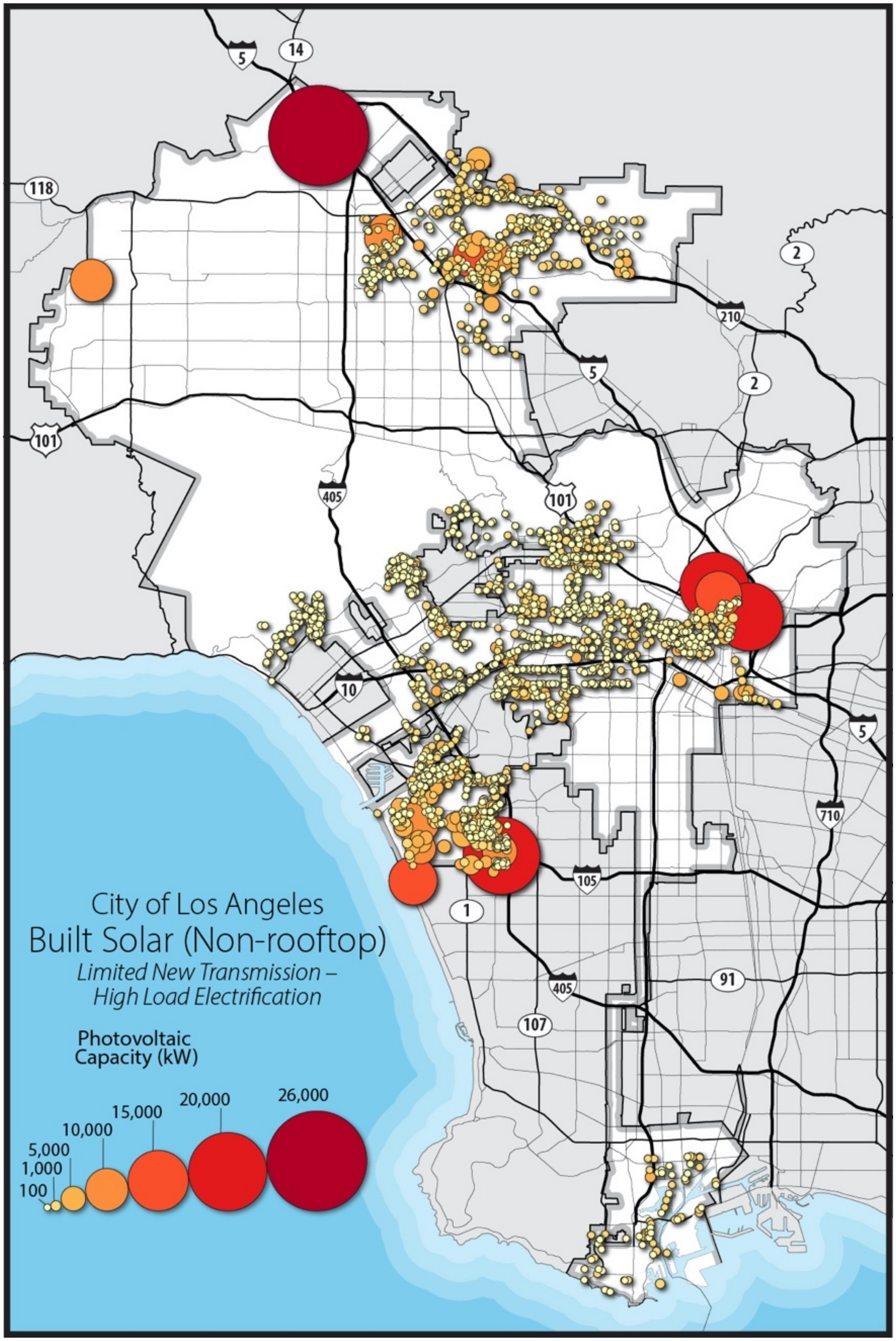

Figure 52. Non-rooftop local solar deployment capacities in 2045 under the Limited New Transmission – High scenario

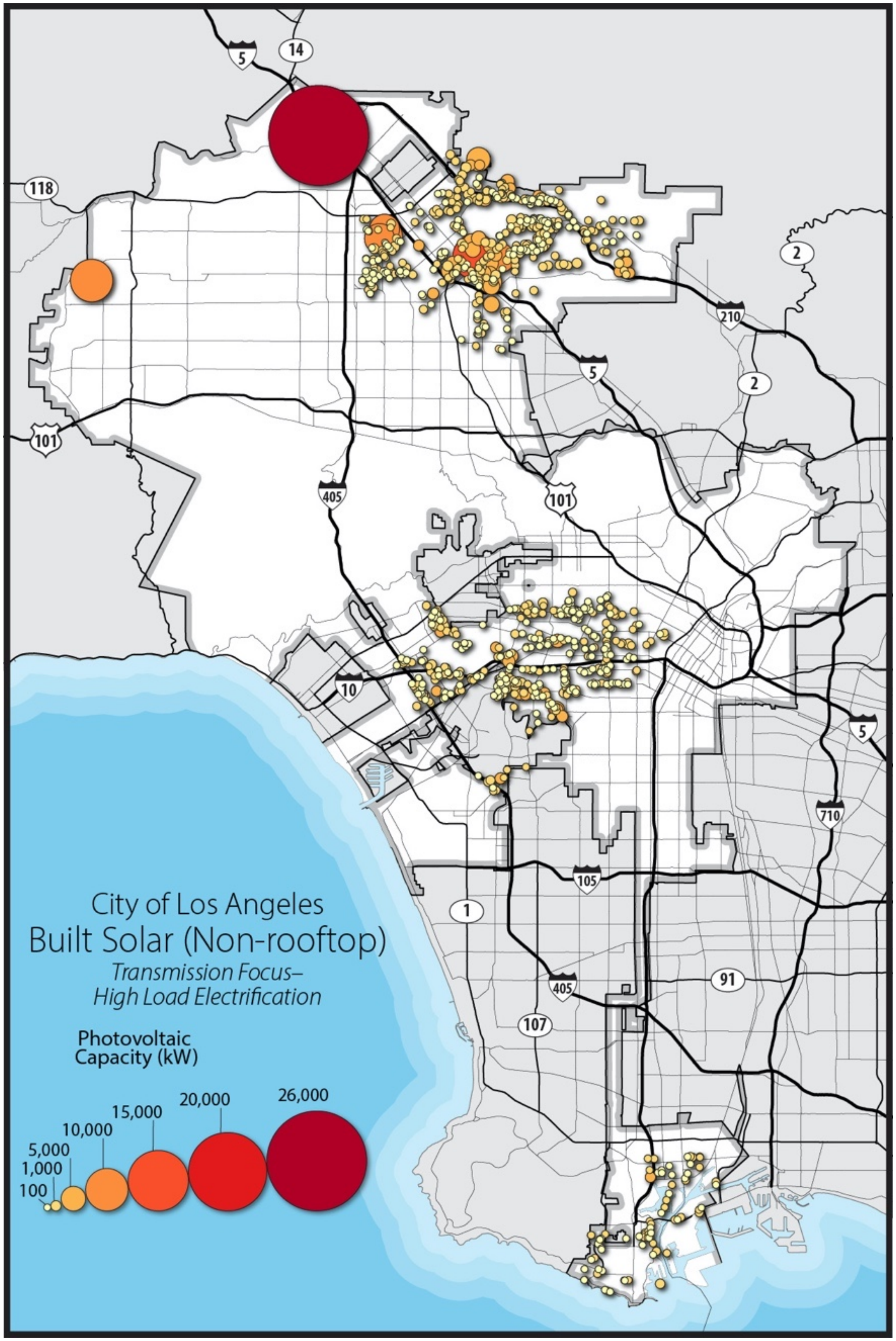

Figure 53. Non-rooftop local solar deployment capacities in 2045 under the Transmission Focus – High scenario

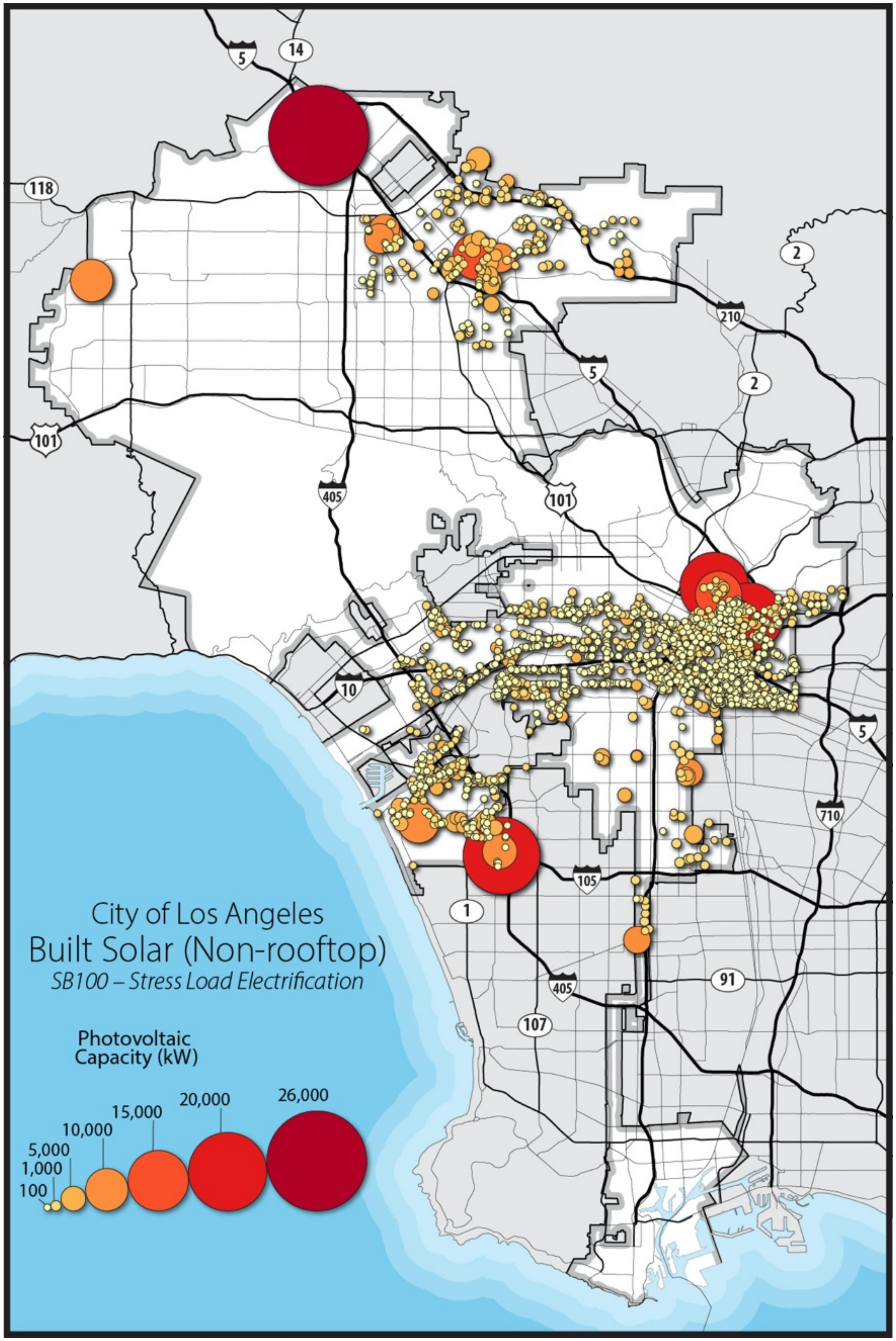

Figure 54. Non-rooftop local solar deployment capacities in 2045 under the SB100 – Stress scenario

F.2 Rooftop Local Solar Deployments

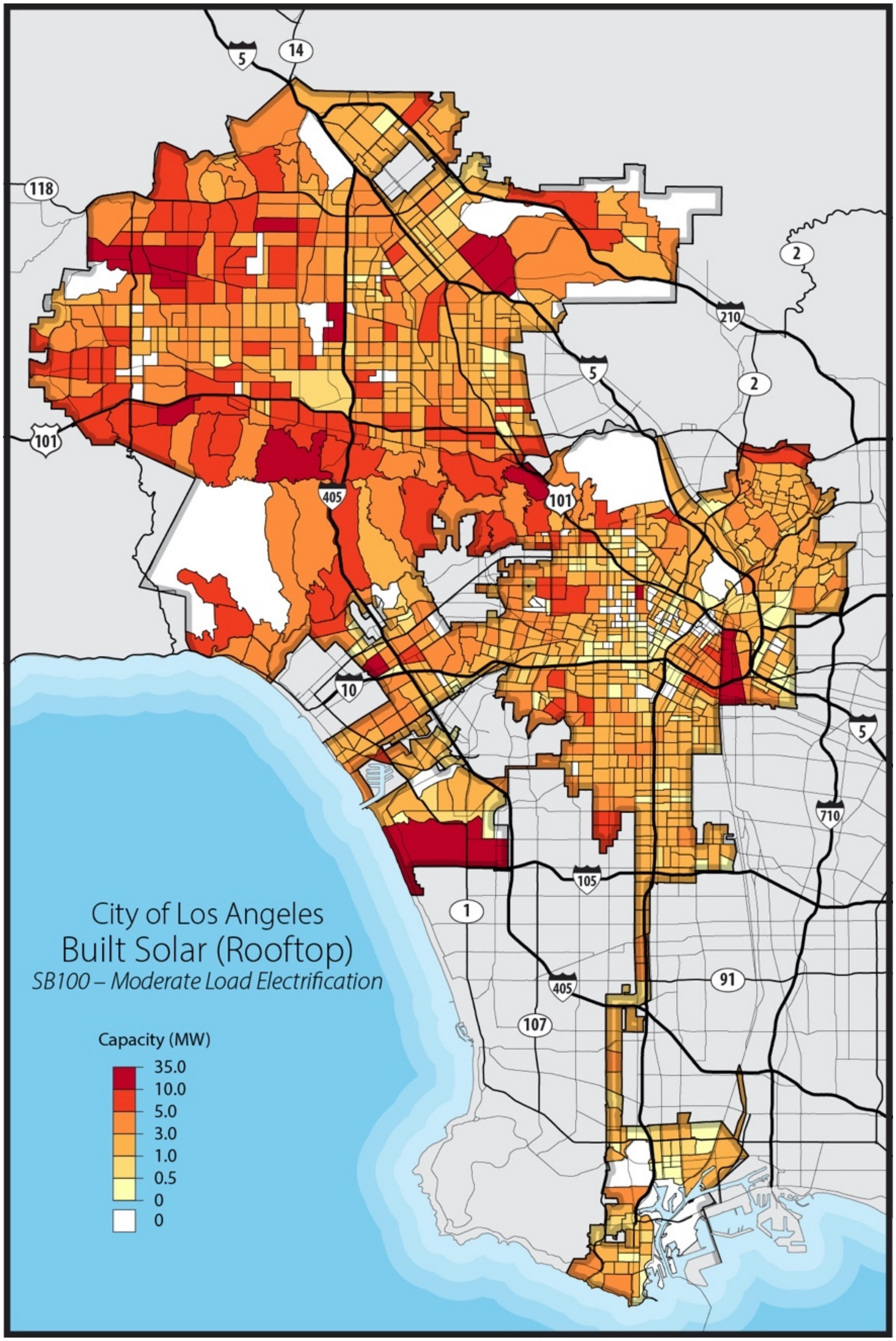

Figure 55. Rooftop local solar deployment capacities in 2045 under the SB100 – Moderate scenario

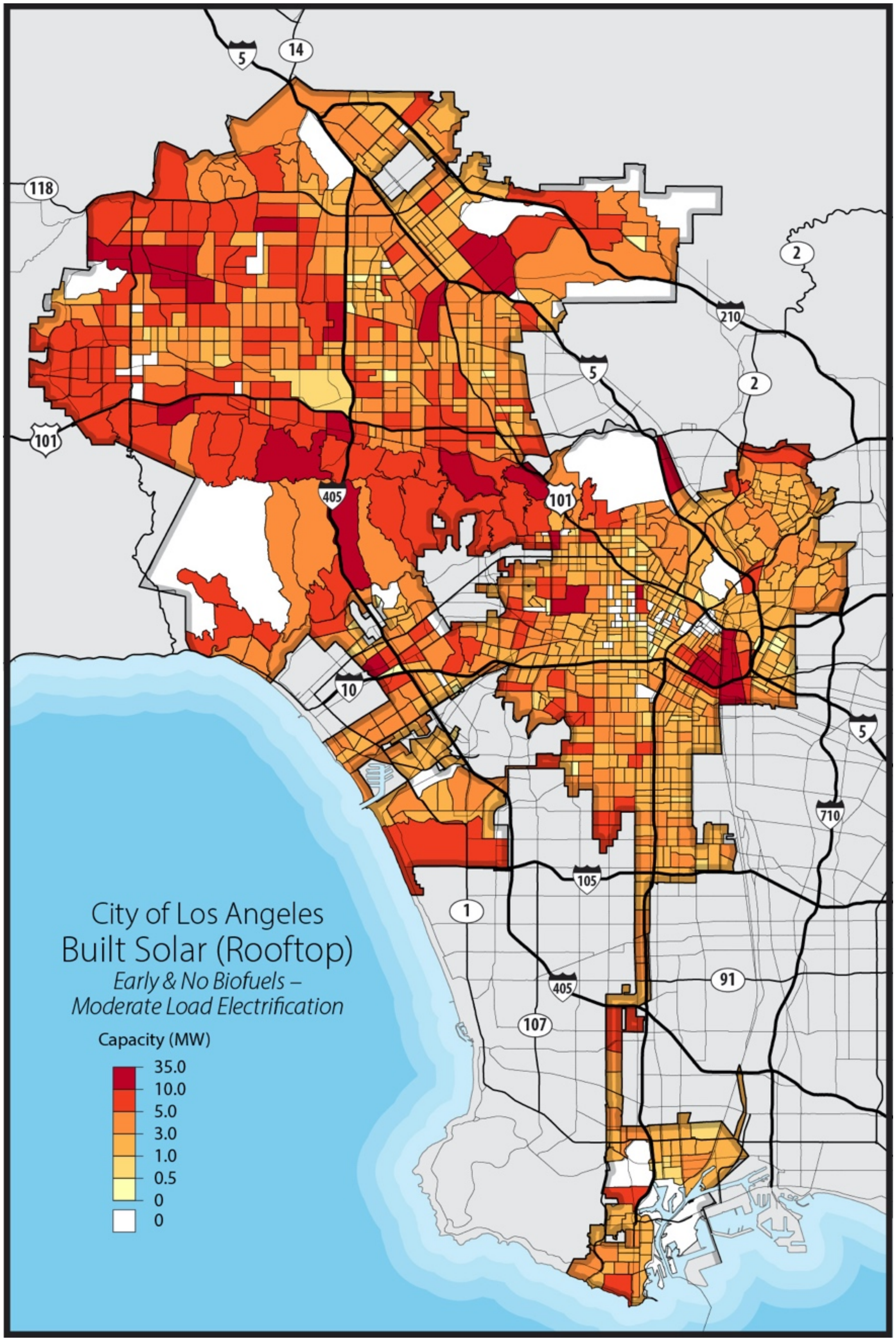

Figure 56. Rooftop local solar deployment capacities in 2045 under the Early & No Biofuels – Moderate scenario

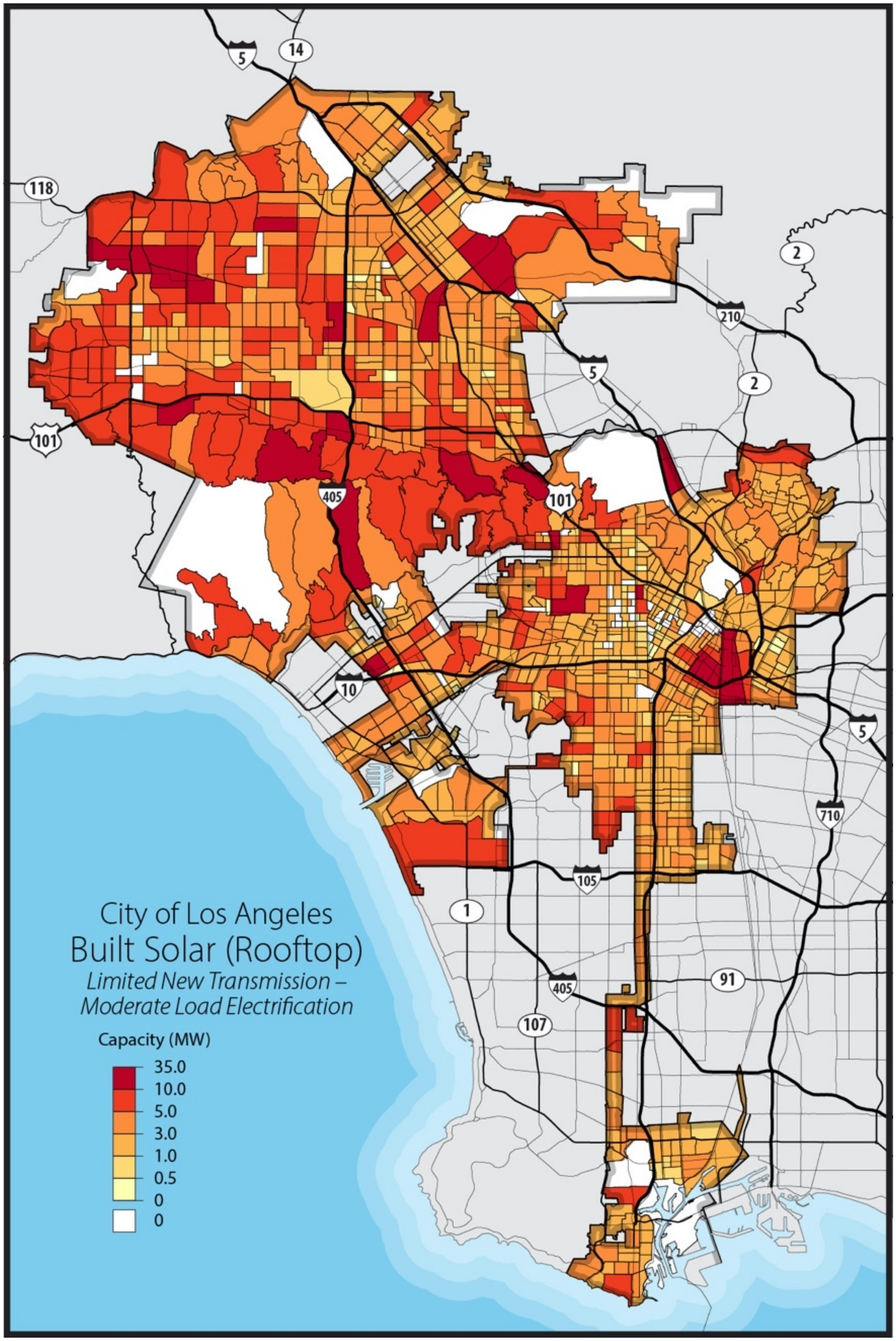

Figure 57. Rooftop local solar deployment capacities in 2045 under the Limited New Transmission – Moderate scenario

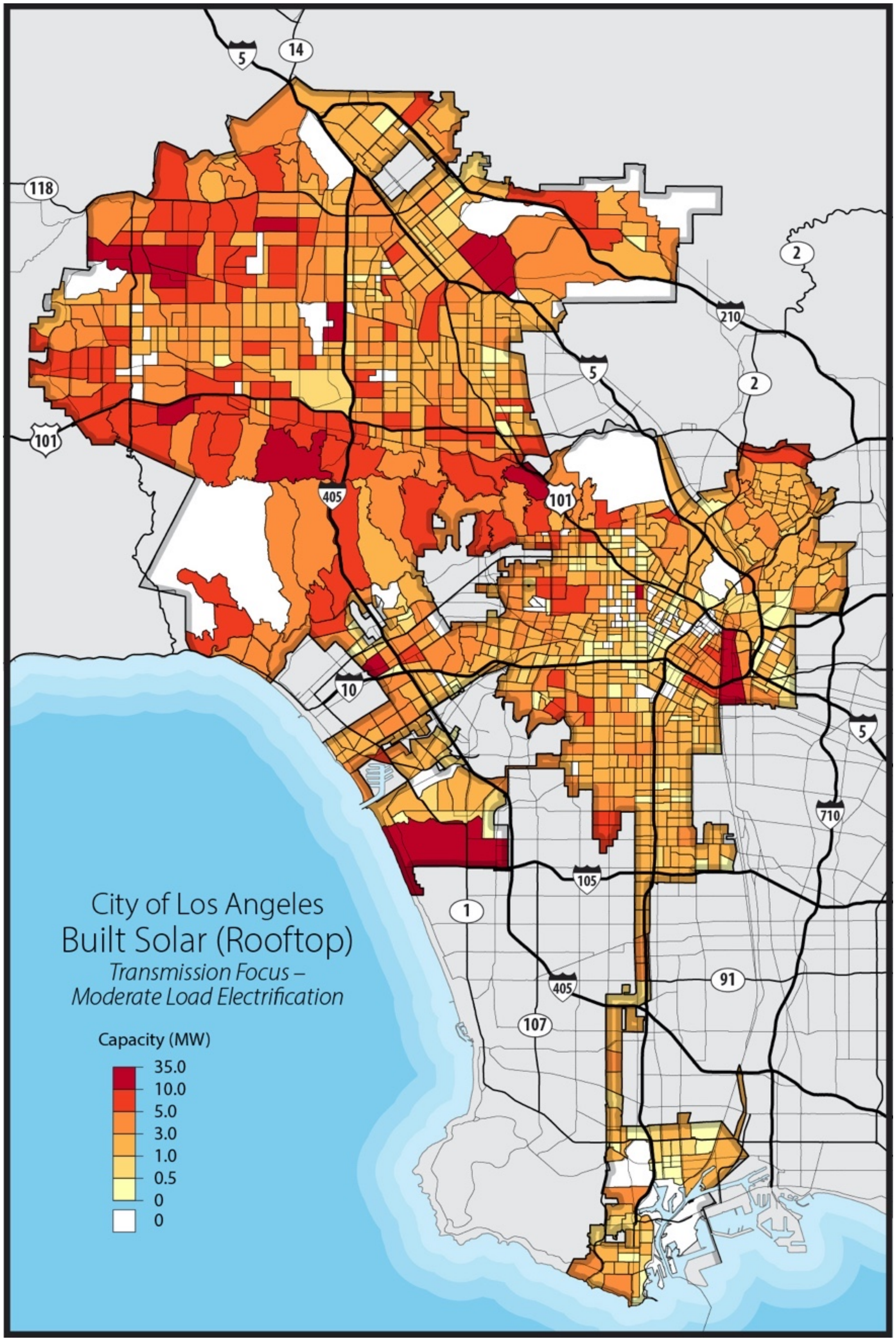

Figure 58. Rooftop local solar deployment capacities in 2045 under the Transmission Focus – Moderate scenario

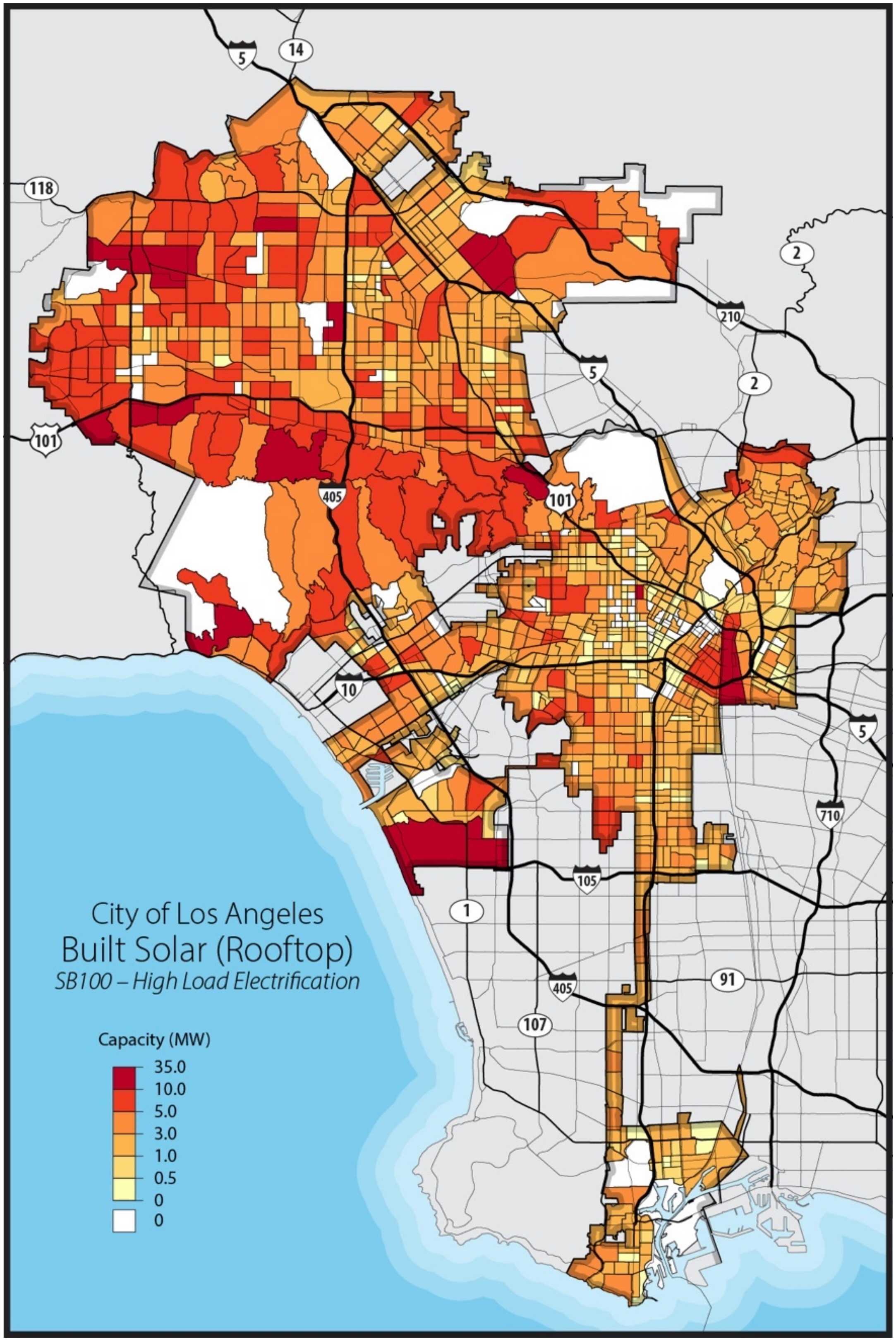

Figure 59. Rooftop local solar deployment capacities in 2045 under the SB100 – High scenario

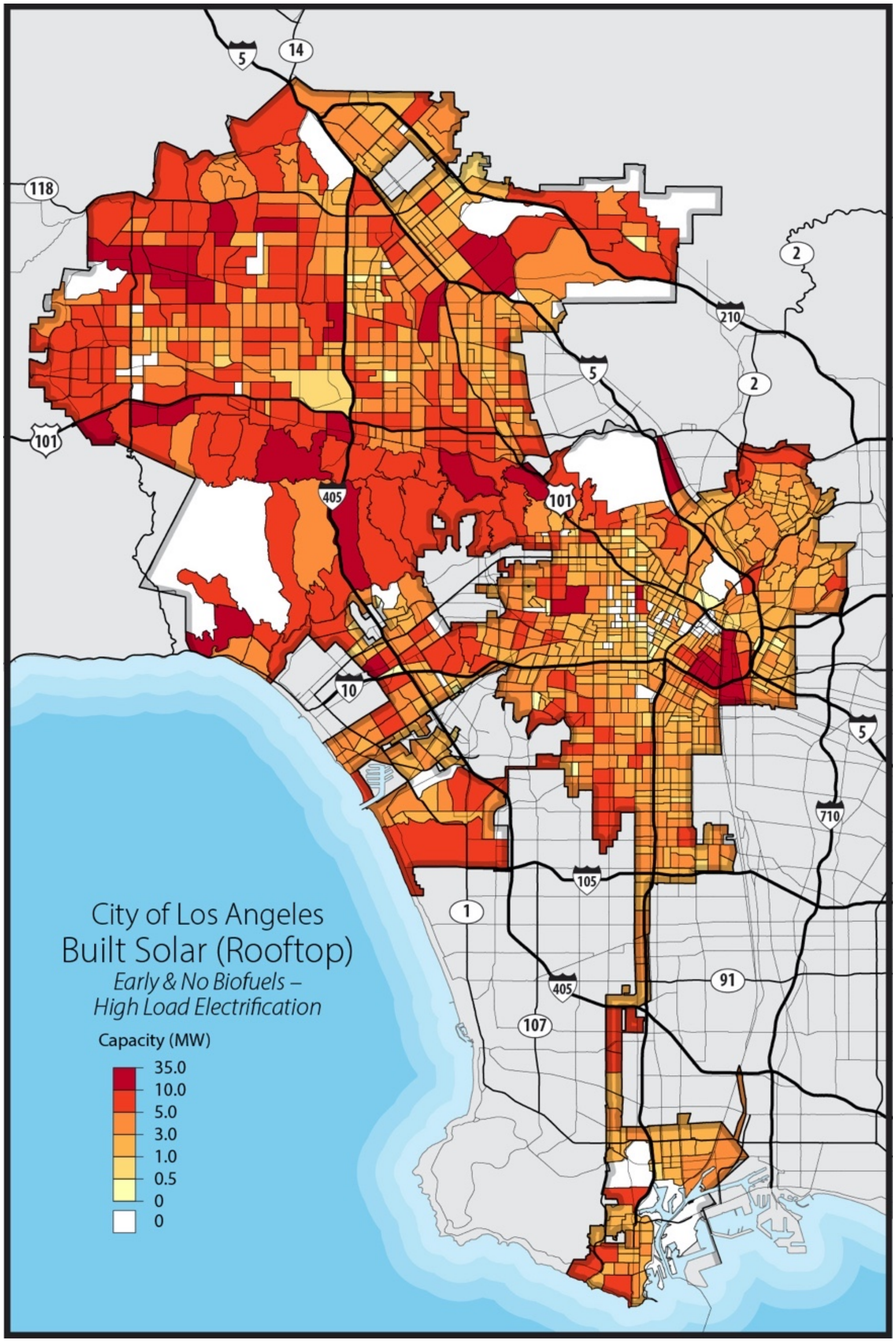

Figure 60. Rooftop local solar deployment capacities in 2045 under the Early & No Biofuels – High scenario

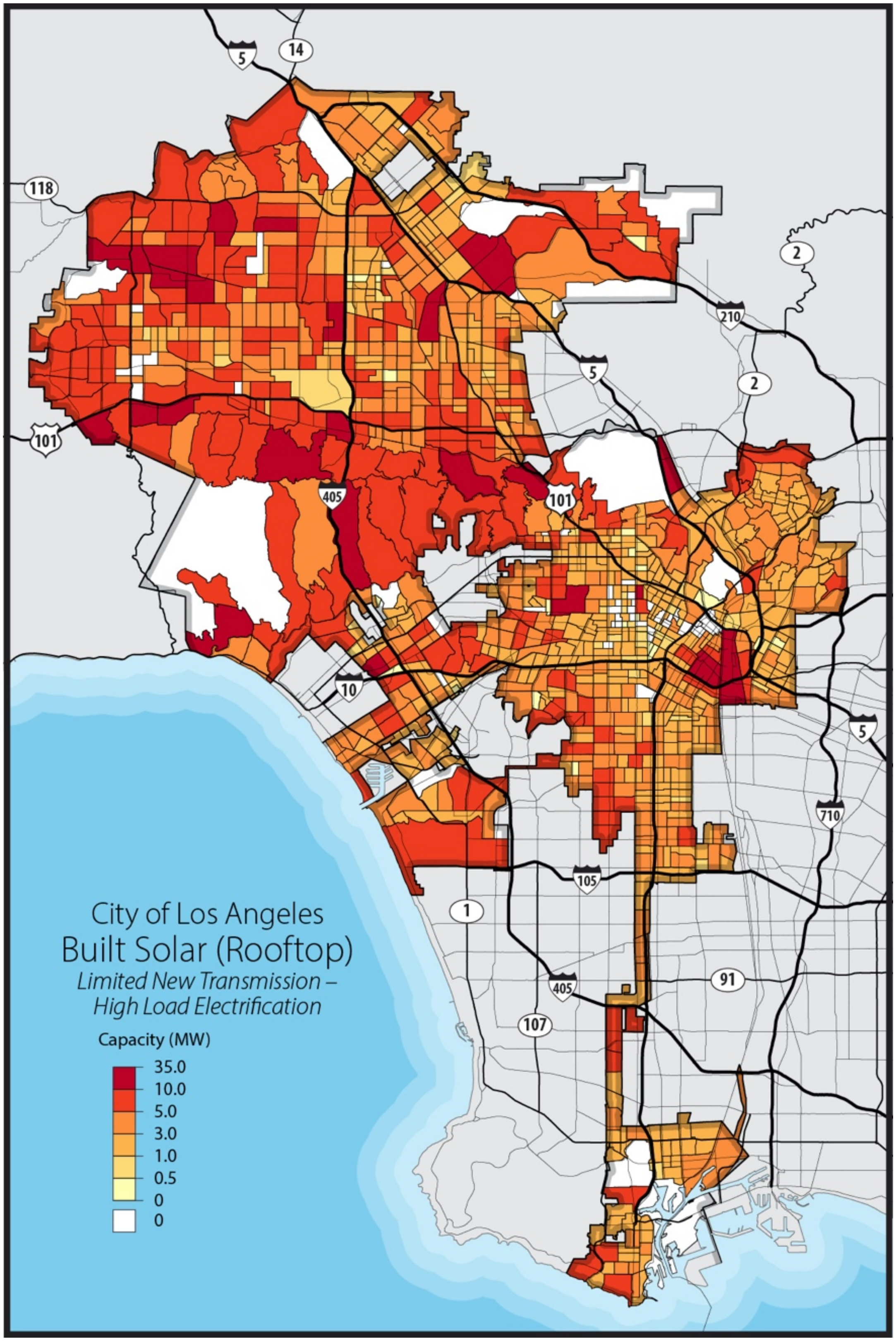

Figure 61. Rooftop local solar deployment capacities in 2045 under the Limited New Transmission – High scenario

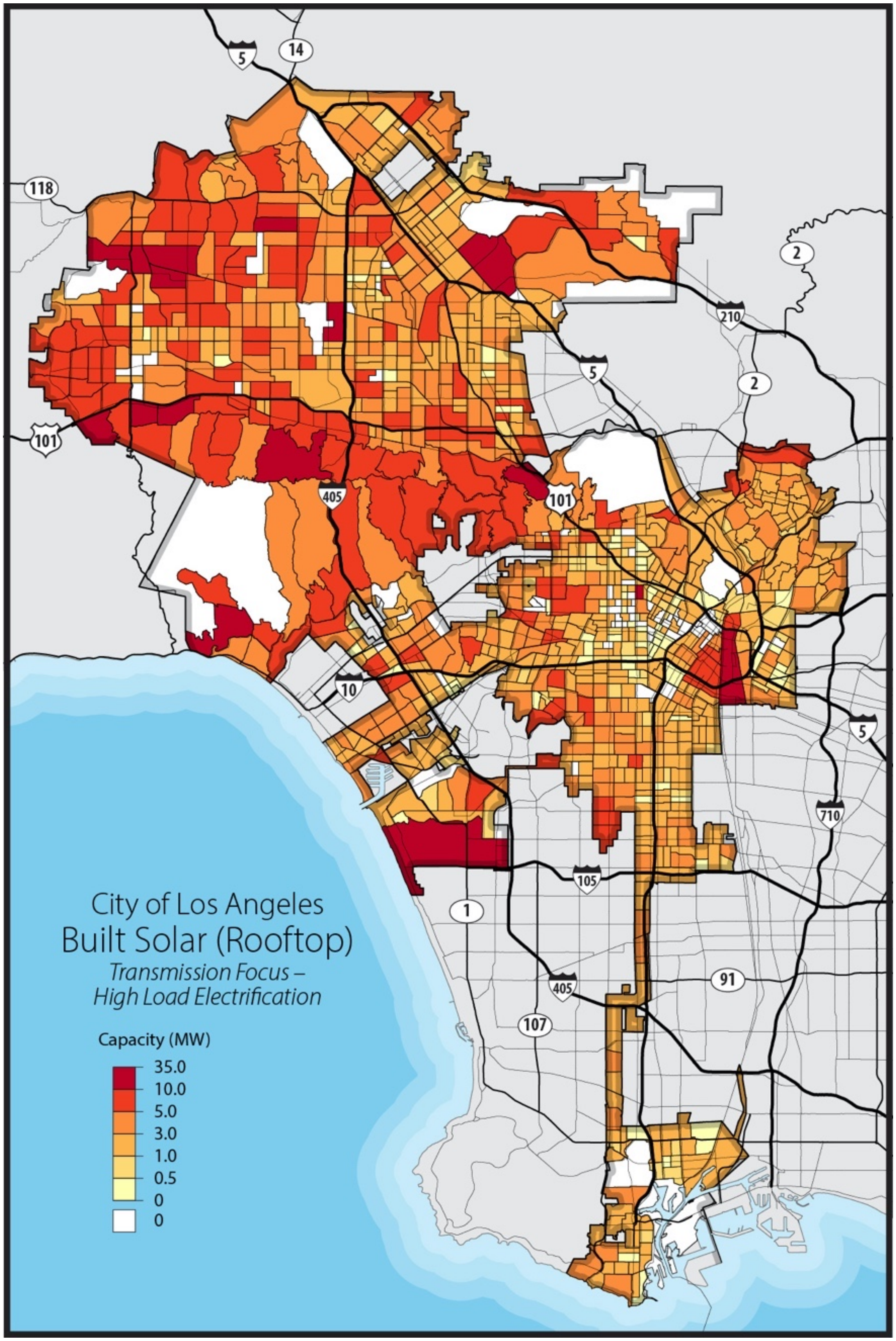

Figure 62. Rooftop local solar deployment capacities in 2045 under the Transmission Focus – High scenario

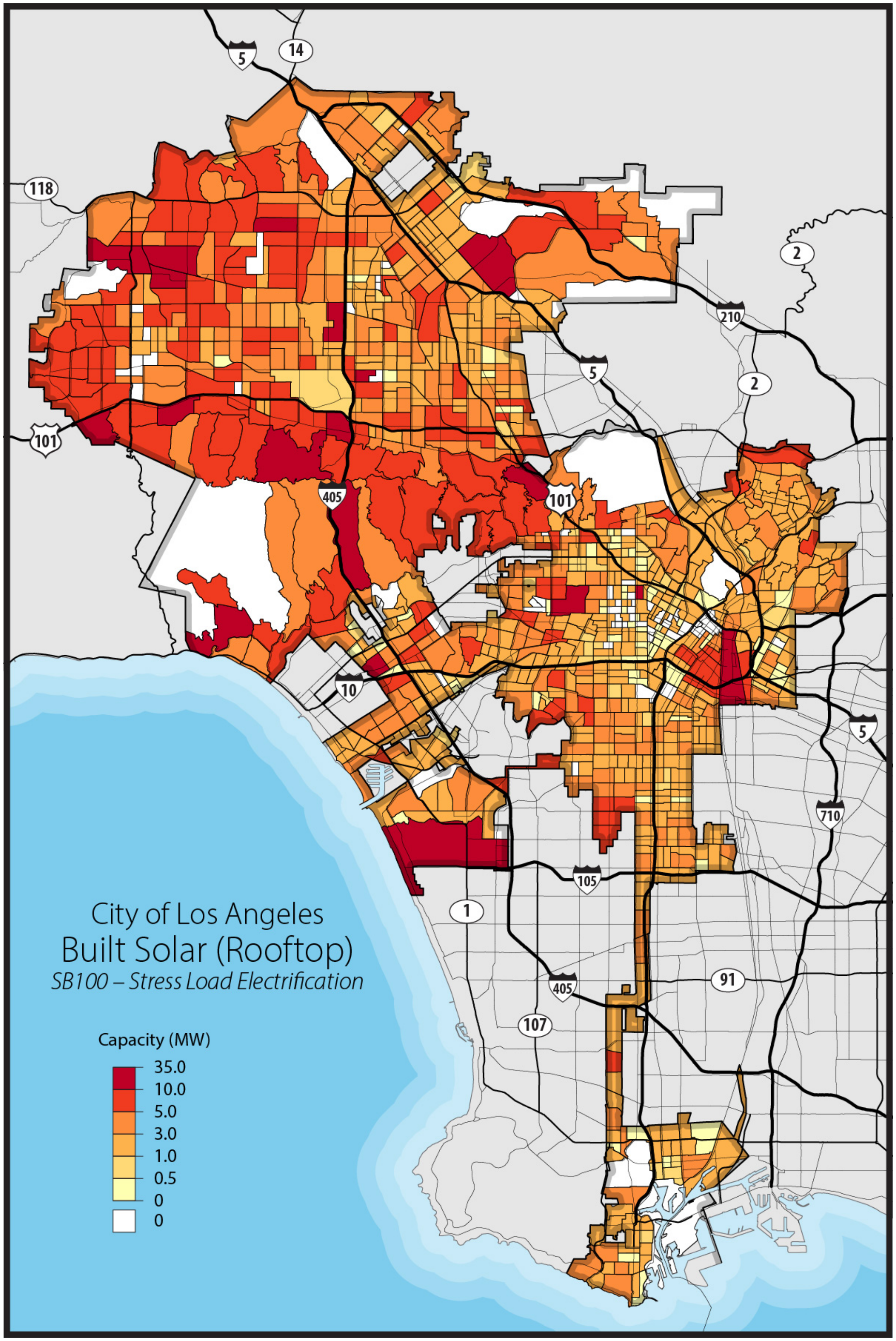

Figure 63. Rooftop local solar deployment capacities in 2045 under the SB100 – Stress scenario

Appendix G. Additional Net Load Results

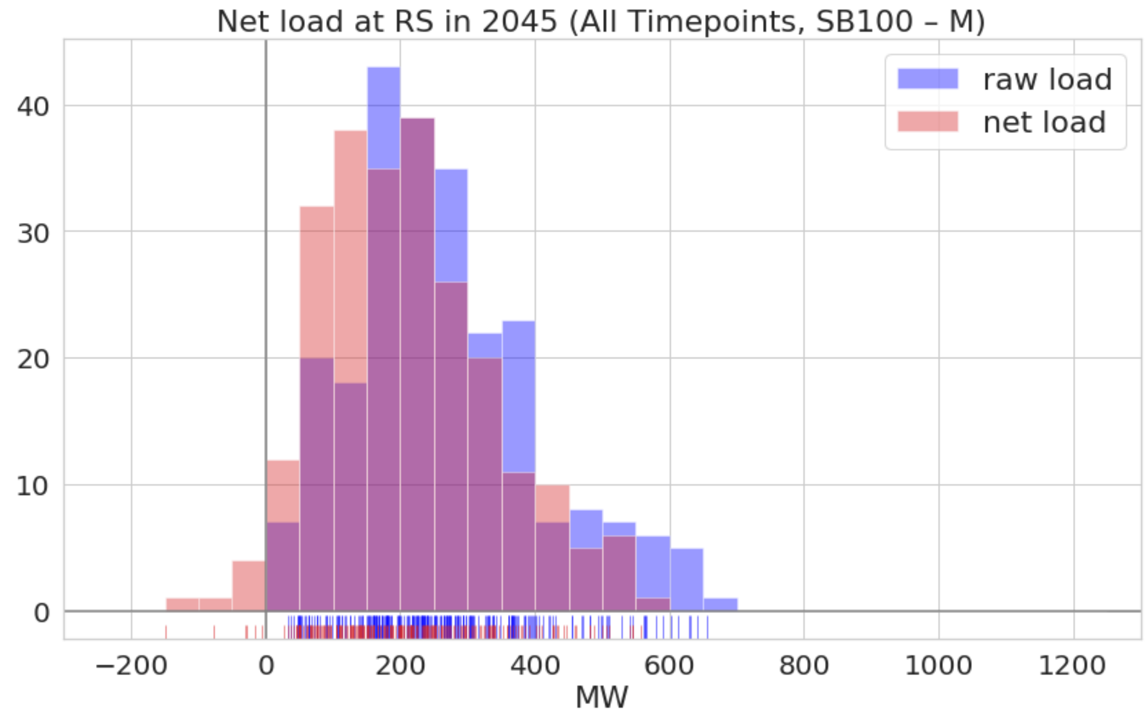

Figure 64. Histogram of net load in 2045 for the SB100 – Moderate load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

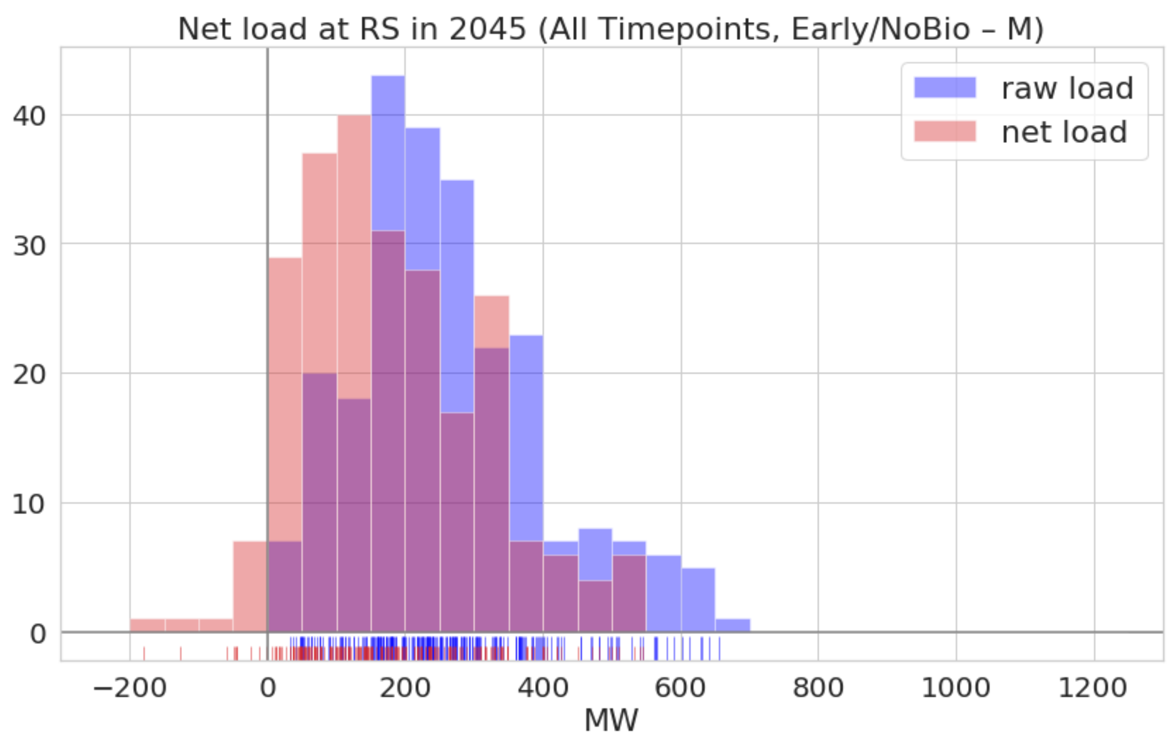

Figure 65. Histogram of net load in 2045 for the Early & No Biofuels – Moderate load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

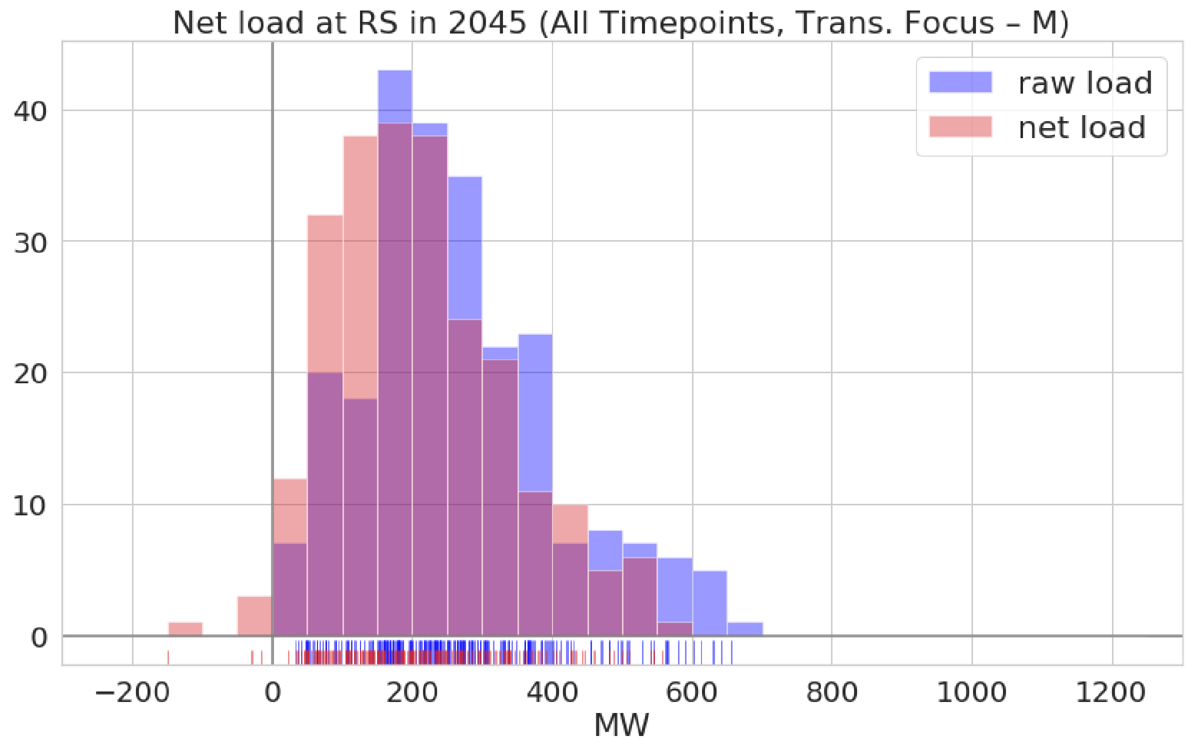

Figure 66. Histogram of net load in 2045 for the Transmission Focus – Moderate load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

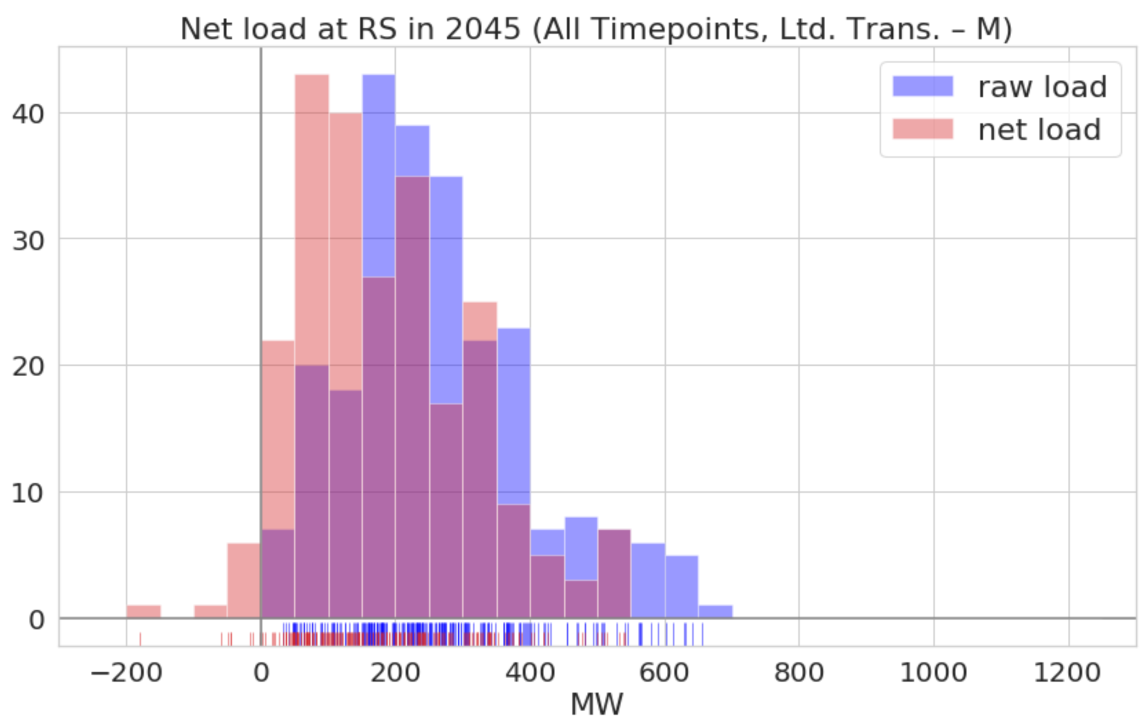

Figure 67. Histogram of net load in 2045 for the Limited New Transmission – Moderate load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

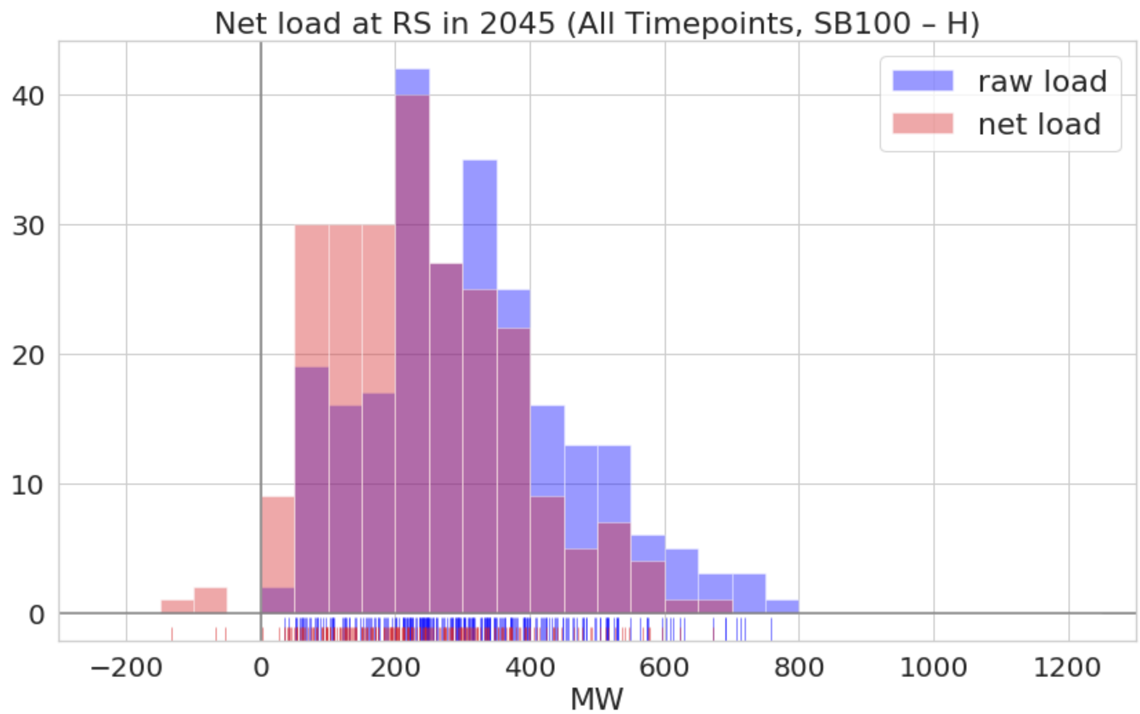

Figure 68. Histogram of net load in 2045 for the SB100 – High load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

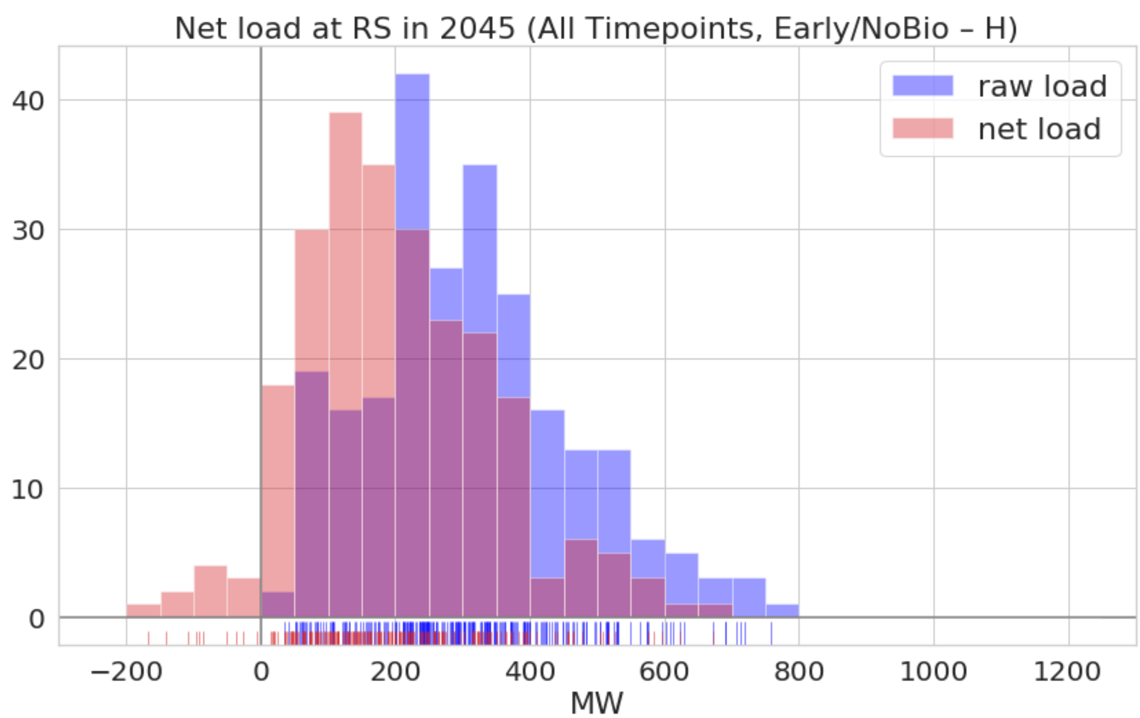

Figure 69. Histogram of net load in 2045 for the Early & No Biofuels – High load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

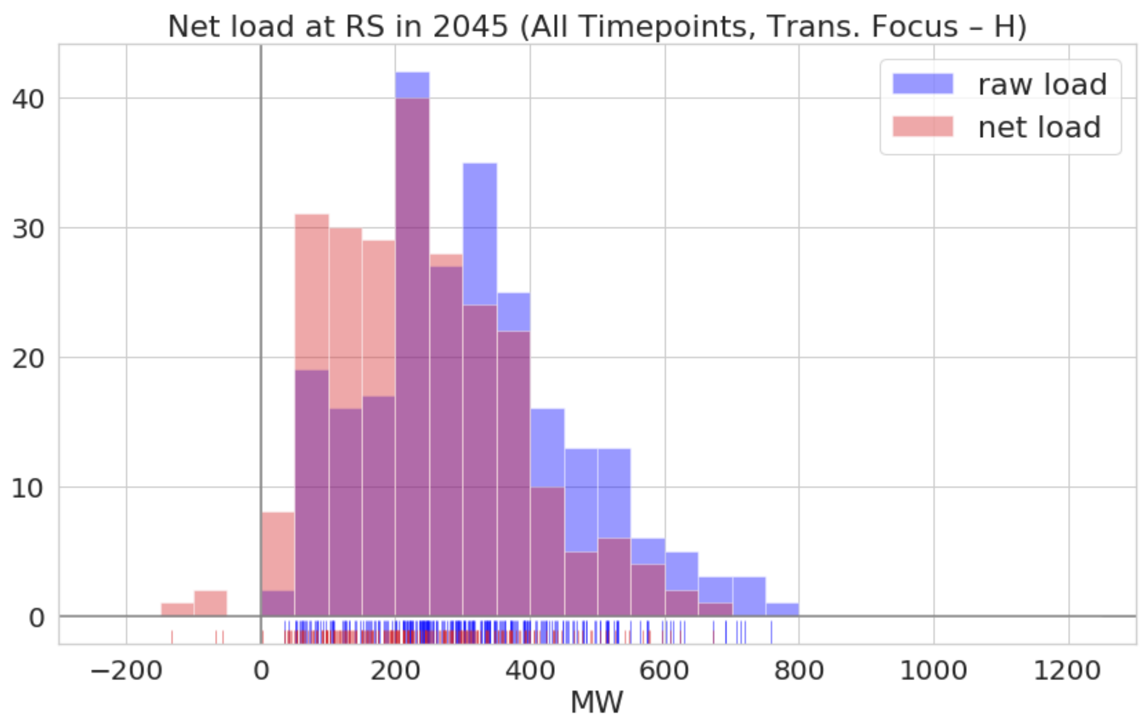

Figure 70. Histogram of net load in 2045 for the Transmission Focus – High load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

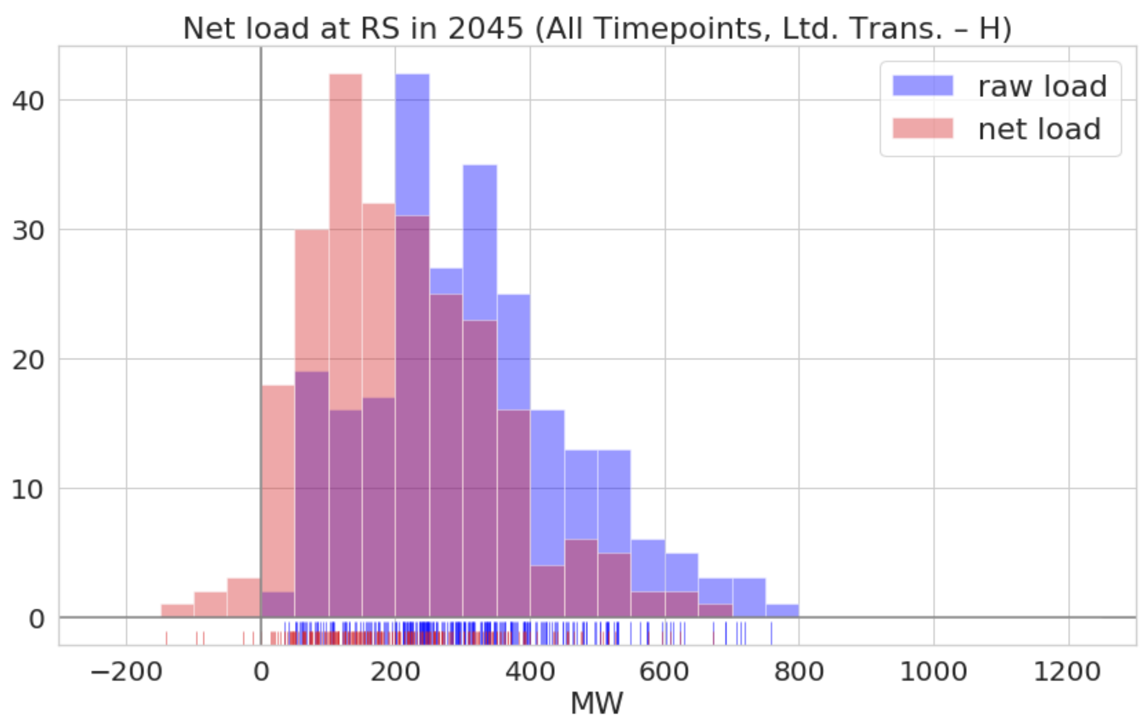

Figure 71. Histogram of net load in 2045 for the Limited Transmission – High load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

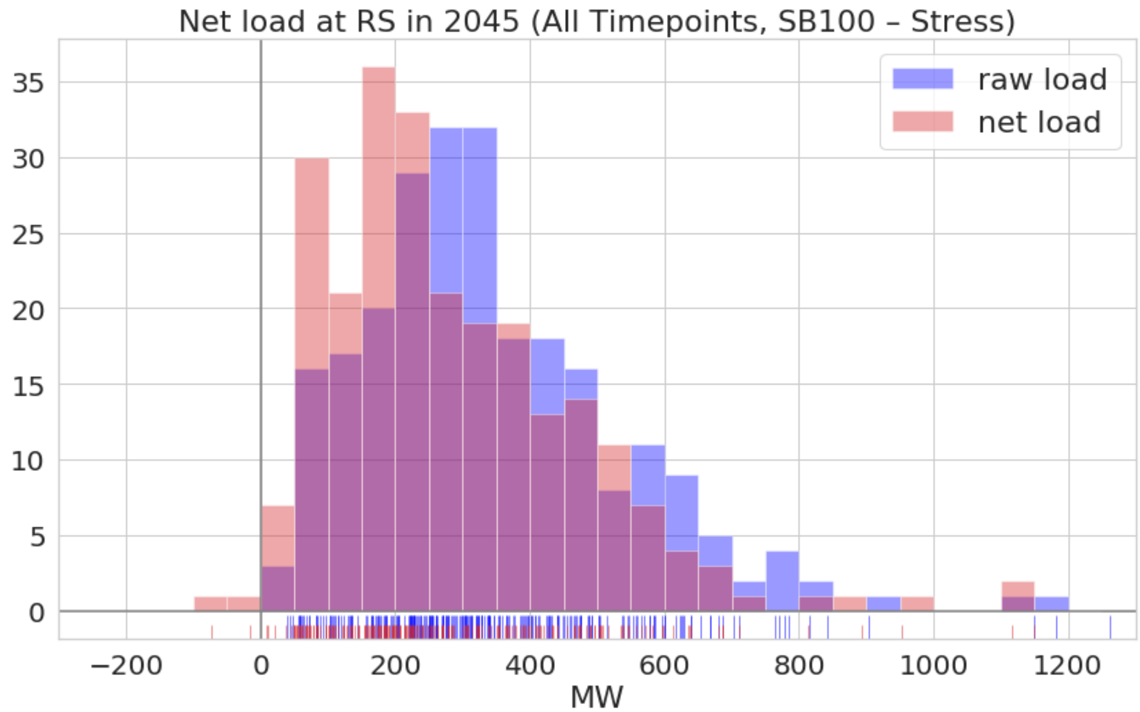

Figure 72. Histogram of net load in SB100 – Stress load scenario

The small lines at the bottom illustrate each sample net load for one RS at a single modeled time point.

Appendix H. Summary of Distribution Cost Assumptions

This appendix summarizes the specific cost assumptions used in the distribution upgrade analysis. The unit costs are derived from an LADWP-specific unit cost database developed by NREL for this project using sample cost data for different upgrades from LADWP. The data in this database was reviewed by LADWP's subject-matter experts prior to use. When LADWP-specific data was not available, we used additional cost data from NREL's publicly available Unit Cost Database (K. Horowitz 2019).

Table 16. Summary of Line Cost Assumptions

Description	Type[a]	Voltage (kV)	Cost per ft	Source
Reconductor	ug	4.8	$104.0	LADWP sample jobs
Reconductor	oh	4.8	$101.7	LADWP sample jobs
New Line	oh	4.8	$83.9	LADWP sample jobs
New Line	ug	4.8	$70.9	LADWP sample jobs

[a] Ug=underground, oh = overhead

Table 17. Summary of Transformer Cost Assumptions

Rating (kVA)	Voltage Class	Install Cost (each)	Removal Cost (each)	Source
1	4.8kV	$4,487	$4,119	interpolated from LADWP sample labor costs
5	4.8kV	$4,542	$3,988	interpolated from LADWP sample labor costs
10	4.8kV	$4,611	$4,335	interpolated from LADWP sample labor costs
25	4.8kV	$4,818	$3,710	interpolated from LADWP sample labor costs
50	4.8kV	$5,162	$2,994	interpolated from LADWP sample labor costs
75	4.8kV	$5,507	$3,194	interpolated from LADWP sample labor costs
100	4.8kV	$5,851	$3,218	interpolated from LADWP sample labor costs
150	4.8kV	$6,540	$3,401	interpolated from LADWP sample labor costs
167	4.8kV	$6,775	$3,984	interpolated from LADWP sample labor costs
200	4.8kV	$7,229	$4,750	interpolated from LADWP sample labor costs
250	4.8kV	$7,918	$3,294	interpolated from LADWP sample labor costs
300	4.8kV	$8,607	$3,882	interpolated from LADWP sample labor costs
333	4.8kV	$9,062	$4,087	interpolated from LADWP sample labor costs
500	4.8kV	$11,363	$3,682	interpolated from LADWP sample labor costs
112	4.8kV	$6,017	$3,309	interpolated from LADWP sample labor costs
225	4.8kV	$7,574	$3,151	interpolated from LADWP sample labor costs
750	4.8kV	$14,808	$3,465	interpolated from LADWP sample labor costs
300	34.5kV	$8,607	$3,882	interpolated from LADWP sample labor costs

Rating (kVA)	Voltage Class	Install Cost (each)	Removal Cost (each)	Source
500	34.5kV	$11,363	$3,682	interpolated from LADWP sample labor costs
750	34.5kV	$14,808	$3,465	interpolated from LADWP sample labor costs
1,000	34.5kV	$18,253	$3,833	interpolated from LADWP sample labor costs
1,500	34.5kV	$25,143	$3,872	interpolated from LADWP sample labor costs
2,000	34.5kV	$32,033	$1,602	interpolated from LADWP sample labor costs
2,500	34.5kV	$38,923	$2,063	interpolated from LADWP sample labor costs
3,750	34.5kV	$56,148	$21,561	interpolated from LADWP sample labor costs
5,000	34.5kV	$73,373	$15,408	interpolated from LADWP sample labor costs

Table 18. Summary of Control Change Cost Assumptions

Control Settings Change Type	Total Cost (per upgrade)	Source
LTC setpoint change	$10,625	existing DISCO cost database
LTC control replacement	$28,333	existing DISCO cost database
Voltage regulator or capacitor setting change	$3,038	existing DISCO cost database
Replace voltage regulator controller	$15,194	existing DISCO cost database
Replace capacitor controller	$5,603	LADWP sample jobs

Table 19. Summary of Regulator Cost Assumptions

Voltage Regulator Type	Voltage Class (kV)	Total Cost (each)	Source
New voltage regulator	4.8	$93,178	DISCO cost database (for 15kV equipment)
New voltage regulator	34.5	$452,250	DISCO cost database
Relocate voltage regulator		$46,500	DISCO cost database
Remove voltage regulator		$15,510	DISCO cost database

Table 20. Summary of Capacitor Cost Assumptions

Capacitor Upgrade	Total Cost (each)	Source
New Capacitor	$30,290	Averaged of sample capacitor jobs from LADWP
Relocate Capacitor	$14,036	Ratio of new capacitor cost to relocate and remove from the DISCO cost database and multiplied by LADWP new capacitor cost
Remove Capacitor	$4,682	Ratio of new capacitor cost to relocate and remove from the DISCO cost database and multiplied by LADWP new capacitor cost

The Los Angeles 100% Renewable Energy Study

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